MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

FOR THE YEARS ENDED DECEMBER 31, 2019 and 2018

ORYX PETROLEUM

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

*The following Management's Discussion and Analysis ("**MD&A**") should be read in conjunction with the consolidated financial statements of Oryx Petroleum Corporation Limited ("**OPCL**" or, the "**Company**") and its subsidiaries for the years ended December 31, 2019 and 2018 (the "**Financial Statements**"), which have been prepared in accordance with International Financial Reporting Standards ("**IFRS**") as issued by the International Accounting Standards Board ("**IASB**").*

The date of this MD&A is March 11, 2020.

Unless otherwise noted, all amounts are in thousands of U.S. dollars.

Selected terms and abbreviations used in this MD&A are listed and described in the "Glossary and Abbreviations" section.

This MD&A contains non-IFRS measures. Please refer to the "Non-IFRS Measures" section for further information.

Readers should refer to the "Forward-Looking Information" advisory on page 27. Additional information relating to OPCL, including OPCL's Annual Information Form dated March 23, 2019, is on SEDAR at www.sedar.com. The Company will file an Annual Information Form for the year ended December 31, 2019 on or before March 30, 2020.

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Company Overview

The Company is a public company incorporated in Canada under the Canada Business Corporations Act and is the holding company for the Oryx Petroleum group of companies (together, the "**Group**" or "**Oryx Petroleum**").

Oryx Petroleum is an upstream oil and gas entity with operating activities focused on the Middle East and West Africa. The Group holds interests in the following License Areas:

License Area	Location	Participating Interest	Working Interest	Role
Hawler	Iraq – Kurdistan Region	65%	65%	Operator
AGC Central	Senegal and Guinea Bissau	85%	80%(1)	Operator

Notes:

(1) Assuming the AGC exercises back-in rights.

Operational Highlights

2019

- Average gross (100%) oil production of 11,700 bbl/d (working interest 7,600 bbl/d) for the year ended December 31, 2019 vs 6,500 bbl/d (working interest 4,200 bbl/d) for the year ended December 31, 2018
  - 80% increase in gross (100%) oil production in 2019 versus 2018; 12% increase in gross (100%) oil production in Q4 2019 versus Q3 2019
  - Successful completion of four producing wells during the year
  - First successful completion of a well targeting the Cretaceous reservoir at the Demir Dagh field utilising a horizontal well design
- Gross (working interest) proved plus probable oil reserves of 103 million barrels as at December 31, 2019
- Environmental and Geohazard Assessments related to planned drilling in the AGC Central License Area initiated and largely completed.

2020

- Average gross (100%) oil production of 14,500 bbl/d (working interest 9,400 bbl/d) and 14,400 bbl/d (working interest 9,400 bbl/d) in January and February 2020, respectively.
- The drilling of a horizontal sidetrack of the previously drilled Banan-1 well in the portion of the Banan field east of the Great Zab river was completed in early 2020
  - Data obtained during drilling indicate that the Tertiary reservoir in the eastern portion of the Banan field contains oil of similar density to oil produced from the Tertiary reservoir in the portion of the Banan field west of the Great Zab river. Attempts to complete the well as a producer in the Cretaceous reservoir were unsuccessful
  - Further drilling targeting both the Tertiary and Cretaceous reservoirs is planned in 2020
- Operations in recent weeks were successful in shutting off water production from the Banan-5 well which is producing oil from the Cretaceous reservoir in the portion of the Banan field west of the Great Zab river
- The planned drilling of an exploration well in 2020 in the AGC Central License Area has been deferred. In 2019 the Corporation requested that the First Renewal Period of its Production Sharing Contract (due to end on October 1, 2020) be suspended until Senegal and Guinea Bissau have agreed on a long-term extension or renewal of the AGC accord. The Corporation has not yet received a formal response to its request.

Financial Highlights and Outlook

Liquidity outlook

The Group expects cash on hand as of December 31, 2019 and cash receipts from net revenues and export sales will allow it to fund its forecasted capital expenditures and operating and administrative costs into early 2021. Additional capital is expected to be required to be able to both meet any contingent consideration obligations that become payable and to fund drilling in the AGC Central License Area now planned in 2021.

Financial performance

The following table contains financial performance highlights for the three and twelve months ended December 31, 2019 and December 31, 2018.

	Three months ended		Year ended	
($ thousands unless otherwise stated)	December 31, 2019	December 31, 2018	December 31, 2019	December 31, 2018
Revenue	40,879	36,456	150,496	97,642
Cash generated by / (used in) operating activities	(1,558)	7,354	28,141	8,101
Operating Funds Flow(1)	(3,918)	9,079	26,895	23,207
Operating Funds Flow(1) per basic and diluted share ($/share)	(0.01)	0.02	0.05	0.05
(Loss) / Profit for the period	(81,334)	56,765	(59,199)	43,753
(Loss) / Earnings per basic and diluted share ($/share)	(0.15)	0.11	(0.11)	0.09
Average sales price ($/bbl)	47.32	52.37	48.72	57.00
Field production costs(2) ($/bbl)	7.44	8.43	7.96	9.54
Operating expense ($/bbl)	9.73	11.03	10.41	12.48
Field Netback(1) ($/bbl)	16.05	17.15	15.95	18.30
Oryx Petroleum Netback(1) ($/bbl)	19.00	20.36	18.90	21.68
Capital additions	13,390	9,027	38,240	36,418

Notes:

(1) Operating Funds Flow, Field Netback, and Oryx Petroleum Netback are non-IFRS measures. See the "Non-IFRS Measures" section of this MD&A.

(2) Field production costs represent Oryx Petroleum's Working Interest share of gross production costs and exclude partner share of production costs which are being carried by Oryx Petroleum. See the "Operating expense" section of this MD&A.

Revenue and cash receipts

Revenue of $40.9 million was recorded for the three months ended December 31, 2019. Included in revenue is $36.8 million ($47.32/bbl) realised on the sale of 777,800 bbl (WI) of crude oil and $4.1 million related to the recovery of costs carried on behalf of partners. Revenue for the fourth quarter of 2019 increased by $4.0 million compared to the same period in 2018. The increase is attributable to a 24% increase in sales volumes partly offset by a 10% decrease in realised sales price.

Revenue of $150.5 million was recorded for the year ended December 31, 2019. Included in revenue is $135.5 million ($48.72/bbl) realised on the sale of 2,780,800 bbl (WI) of crude oil and $15.0 million related to the recovery of costs carried on behalf of partners. Revenue for the year ended December 31, 2019 increased by $52.9 million compared to the same period in 2018. The increase is attributable to an 80% increase in sales volumes partially offset by a 15% decrease in realised sales price.

All sales during the year ended December 31, 2019 were made via the Kurdistan Oil Export Pipeline.

The Group has received payment in full for all crude oil delivered and sold through the Kurdistan Oil Export Pipeline up to and including September 30, 2019. At the date of this MD&A, the Group's share of amounts receivable from the KRG for crude oil delivered to the pipeline from October 2019 through February 2020 totals $44.2 million.

Field production costs and netbacks

Field production costs during the fourth quarter of 2019 amounted to $5.8 million ($7.44/bbl) in comparison to $5.3 million ($8.43/bbl) during the fourth quarter of 2018, representing a 12% decrease on a per barrel basis. The per barrel decrease was primarily due to increases in sales volumes.

Field Netback of $16.05/bbl for the three months ended December 31, 2019 has decreased from $17.15/bbl for the fourth quarter of 2018. Field Netback per barrel decreased by 6% in comparison to the fourth quarter of 2018. The primary drivers for reduced Field Netbacks from the fourth quarter of 2018 has been lower average sales prices partly offset by the decrease in per barrel field production costs.

Field production costs for the twelve months ended December 31, 2019 amounted to $22.1 million ($7.96/bbl) in comparison to $14.7 million ($9.54/bbl) for the twelve months ended December 31, 2018, representing a 17% decrease on a per barrel basis. The per barrel decrease was primarily due to increases in sales volumes.

Field Netback of $15.95/bbl for the twelve months ended December 31, 2019 has decreased from $18.30/bbl for the twelve months ended December 31, 2018, representing a 13% decrease on a per barrel basis. The primary drivers for reduced Field Netbacks from the twelve months ended December 31, 2018 has been lower average sales prices partly offset by the decrease in per barrel field production costs.

Operating Funds Flow

Operating Funds Flow for the fourth quarter of 2019 was negative $3.9 million compared to $9.1 million for the three months ended December 31, 2018.

For the year ended December 31, 2019, Operating Funds Flow was $26.9 million compared to $23.2 million during the same period in 2018.

Operating Funds Flow for the three and twelve months ended December 31, 2019 is impacted by the negative and non-recurring $15.7 million provision for the Haute Mer B arbitration award recorded during the fourth quarter of 2019 (see Operating Results section of this MD&A). The negative impact is offset by increased cash generated from the Group's ongoing operation. This increase is primarily due to higher Oryx Petroleum Netbacks which have contributed cash in excess of cash general and administrative expenditures.

Cash used in operating activities during the quarter ended December 31, 2019 amounted to $1.6 million reflecting Operating Funds Flow of negative $3.9 million offset by a $2.4 million decrease in non-cash working capital which was primarily related to an increase in trade and other payables, partially offset by an increase in oil sales receivables.

Cash generated by operating activities during the year ended December 31, 2019 amounted to $28.1 million reflecting Operating Funds Flow of $26.9 million and a $1.2 million decrease in non-cash working capital which was primarily related to an increase in trade and other payables, partially offset by an increase in oil sales receivables.

Profit / Loss

Loss for the three months ended December 31, 2019 was $81.3 million compared to a $56.8 million profit during the fourth quarter of 2018. The variance in profit/loss for three months ended December 31, 2019 in comparison to the same period in 2018 is primarily attributable to i) a $54.4 million impairment expense recorded in the three months ended December 31, 2019 compared to a $54.1 million impairment reversal during the same period in 2018, both on the Hawler License Area, and ii) an impairment of Assets held for disposal and provision for a tribunal award in relation to the Haute Mer B exploration License Area during the three months ended December 31, 2019 of $13.3 million and $15.7 million, respectively.

Loss for the year ended December 31, 2019 was $59.2 million compared to a $43.8 million profit in 2018. The variance in profit/loss for the year ended December 31, 2019 in comparison to the same period in 2018 is primarily attributable to i) a $54.4 million impairment expense recorded in the year ended December 31, 2019 compared to a $54.1 million impairment reversal during the same period in 2018, both on the Hawler License Area, ii) an impairment of Assets held for disposal and provision for a tribunal award in relation to the Haute Mer B exploration License Area during the year ended December 31, 2019 of $13.3 million and $15.7 million, respectively, iii) a $9.7 million increase in operating expense that is primarily attributable to expanded operations at the Banan field, and iv) an $8.0 million increase in the depletion charge during 2019 resulting from higher production during 2019. These negative variances were partially offset by i) an increase in net revenue of $29.6 million during 2019 in comparison with 2018, and ii) $15.2 million in income related to the change in fair value of contingent consideration during the year ended December 31, 2019 versus a $2.7 million charge during the year ended December 31, 2018.

Capital additions

During the fourth quarter of 2019, the Group recorded net capital additions of $13.4 million. The Group invested $12.7 million primarily on drilling activities in the Banan and Demir Dagh fields in the Hawler License Area, and $0.7 million to prepare for drilling activities in the AGC Central License Area.

During the year ended December 31, 2019, the Group recorded net capital additions of $38.2 million. The Group invested $36.4 million primarily on drilling activities in the Banan and Demir Dagh fields in the Hawler License Area, and $1.8 million to prepare for drilling activities and to conduct an environmental and social impact assessment in the AGC Central License Area.

Financial position

The following table contains highlights of the Group's financial position as at the dates indicated below.

($ thousands)	December 31, 2019	December 31, 2018
Total cash and cash equivalents	8,912	14,410
Working Capital [(1)]	(73,543)	(8,627)
Total assets	768,254	812,976
Borrowings [(1)]	79,883	76,624
Total long-term liabilities [(1)]	80,985	133,526

(1) Borrowings are classified as a current liability as at December 31, 2019 whilst at December 31, 2018 they were classified as a non-current liability. Subsequent to December 31, 2019, the Borrowings' maturity date was extended to July 1, 2021. See Liquidity and Capital Resources section of the MD&A for details.

The cash and cash equivalents balance of $14.4 million as at December 31, 2018 decreased to $8.9 million at December 31, 2019. This decrease is due to $35.1 million in cash used in investing activities, partially offset by $28.1 million in cash generated by operating activities and $1.4 million received from financing activities.

Working capital decreased to negative $73.5 million at December 31, 2019 from negative $8.6 million at December 31, 2018, chiefly due to $79.9 million of borrowings becoming a current payable until the loan agreement was renegotiated after December 31, 2019. Changes in working capital also included cash and cash equivalents decreased by $5.5 million, a $13.3 million reduction due to impairment of assets held for disposal, a $21.6 million decrease in trade and other payables primarily comprised of a $33.5 million reclassification of contingent consideration payable partially offset by a $15.7 million increase due to the provision for the HMB arbitration award and an $11.4 million increase in the trade and other receivables balance.

The total assets balance decreased to $768.3 million at December 31, 2019 from $813.0 million at December 31, 2018. This change is primarily due to i) $21.9 million in depletion, ii) $54.4 million of impairment recorded during the period, and iii) a $5.5 million decrease in cash, partially offset by a $38.2 million increase in property, plant and equipment resulting from capital additions.

The increase in total long-term liabilities is due to i) the reclassification of contingent consideration from partly current as at December 31, 2018 to wholly non-current as at December 31, 2019, ii) a $3.9 million increase in decommissioning obligations, and iii) interest and accretion expense recorded on the Loan Facility during 2019.

The undiscounted balance owed under the Loan Facility (discussed in the Liquidity and Capital Resources section of this MD&A) as at December 31, 2019 was $80.1 million, including $4.0 million in accrued interest.

The undiscounted balance of principal and accrued interest potentially owed under the contingent consideration obligation to the vendor of the Hawler License Area as at December 31, 2019 was $75.7 million.

2020 capital expenditure forecast

Oryx Petroleum re-forecasted capital expenditures for 2020 are $59 million, reduced from the previously announced budget of $106 million. The reduction reflects the deferment of planned drilling in the AGC License Area, and the deferment of two wells and certain facilities expenditures in the Hawler License Area. The Group now does not plan to drill a sidetrack of the Zey Gawra-2 well and will only drill one rather than two wells targeting the Demir Dagh Cretaceous reservoir and will not build a permanent processing facility at the Banan field. The following table summarises the Group's 2020 forecasted capital expenditure program against budget:

Location	License/Field/Activity	2020 Budget	2020 Forecast
		$ millions	$ millions
Kurdistan Region	Hawler		
	Zey Gawra-Drilling	5	4
	Demir Dagh-Drilling	14	8
	Ain Al Safra-Drilling	2	2
	Banan-Drilling	14	14
	Facilities	26	19
	Other(1)	3	3
	Total Hawler	**63**	**50**
West Africa	AGC Central—Drilling & Prep	40	6
	AGC Central--Other	3	3
	Capex Total(2)	**106**	**59**

Note:

(1) Other is comprised primarily of license maintenance costs

(2) Totals may not add-up due to rounding.

Kurdistan Region of Iraq -- Hawler License Area

Demir Dagh drilling -- consists of a new horizontal well targeting the Cretaceous reservoir expected to be drilled in the second half of 2020.

Zey Gawra drilling -- consists of a new well targeting the Tertiary reservoir. This new well has replaced the planned sidetrack of the previously drilled Zab-1 well. The drilling of the well is planned in the first half of 2020. The sidetrack of the previously drilled Zey Gawra-2 well targeting the Cretaceous reservoir has been deferred.

Banan drilling -- consists of two wells in the eastern portion of the Banan field: the workover of the Banan-1 well targeting the Cretaceous reservoir and one new well targeting the Tertiary reservoir; and one well in the western portion of the Banan field targeting the Cretaceous reservoir. The workover of the Banan-1 well was completed in early 2020 and the other two wells are planned for the second half of 2020.

Ain Al Safra drilling -- consists of the completion of the Ain Al Safra-2 well targeting the Triassic reservoir. The Ain Al Safra-2 well was suspended in 2014 prior to testing due to security developments. The completion of the Ain Al Safra-2 well is expected to be completed in the second half of the year.

Facilities -- Demir Dagh facilities expenditures comprised of infrastructure works including the construction of additional storage tanks, replacement of generators and construction of a solar power station. Zey Gawra facilities expenditures comprised of studies and minor infrastructure works including flowlines for new wells. Banan facilities expenditures comprised of studies and infrastructure needed to accommodate drilling plans and additional production as well as a pipeline between the Banan field and the Hawler processing facilities located at the Demir Dagh field. The construction of the pipeline is expected in the second half of 2020 and is expected to be in service in early 2021. The planned construction of processing facilities at the Banan field has been deferred. The construction of the pipeline is contingent on production performance from the Banan wells. Ain Al Safra facilities expenditures comprised of infrastructure works including flowlines, camp set up, and a tie-in line to the Kurdistan Oil Export Pipeline.

AGC Central License Area

Consists of studies, preparation costs for drilling, and license maintenance costs. The drilling of one exploration well has been deferred.

Business Environment

Following various destabilising geopolitical events impacting the Kurdistan Region of Iraq over several years, relative political stability has supported conditions where the Group has been able to continue its activities in the Kurdistan Region of Iraq. However, the eventual impact of the underlying and unresolved political disputes on the Group's operations may be significant and remains uncertain. Political and other risk factors which are disclosed in OPCL's Annual Information Form could have an adverse effect on Oryx Petroleum's performance.

The Group's future revenues and cash flows from operating activities are dependent on the Group's ability to produce, deliver, and receive payment for sales of crude oil. Production rates are subject to fluctuation over time and are difficult to predict.

Uncertainty related to global, social, political, and economic conditions and the resulting changes in global oil supply chains and infrastructure investment contribute to volatility in the price of crude oil. Most recently, the global response to the spread of COVID-19 has decreased global economic activity and, correspondingly, the demand for and price of crude oil. The related uncertainty regarding returns on investments in upstream oil and gas exploration and development has impacted the availability and cost of capital resources. Furthermore, future oil prices, which directly impact the Group's expected cash inflows, are difficult to forecast reliably. The Group's ability to fund its ongoing operations and its forecasted capital investments is consequently subject to significant uncertainty. See the "Liquidity and Capital Resources" section of this MD&A for further discussion.

On March 14, 2016, the Group initiated crude oil deliveries to international markets through the Kurdistan Oil Export Pipeline. Although management does not expect restrictions on its ability to access pipeline capacity, Oryx Petroleum is not aware of official allocations of export pipeline capacity and is uncertain of the extent to which its future production will continue to be sold through this export pipeline. Arrangements currently in place to sell oil produced from the Hawler License Area may not continue to be in effect. Furthermore, there remains an ongoing risk that any renewed worsening of the regional security situation could have a material adverse effect on the operating and financial performance of the Group.

The market on which oil produced from the Hawler License Area is sold affects the price realised and, consequently, Oryx Petroleum's cash flows. Complexities in local, regional, and international market access dynamics may impact the Group's realised oil sales prices and its future ability to sell its produced oil.

The timing and execution of the Group's capital expenditure program may also be affected by the availability of services from third party oil field contractors and the Group's ability to obtain, sustain or renew necessary government licenses and permits on a timely basis to conduct exploration and development activities.

In respect of the Group's exploration activities in the area administered jointly by the AGC, the governments of Senegal and Guinee-Bissau are currently in the process of renegotiating the terms of the agreement to manage and administer petroleum and fishing activities in the maritime zone between Senegal and Guinea Bissau. The Group's future activities and investments in the AGC Central License Area are subject to satisfactory resolution of these negotiations.

With the exception of the items discussed above, together with risks disclosed in the OPCL's Annual Information Form dated March 23, 2019, management has not identified trends or events that are expected to have a material adverse effect on the financial performance of Oryx Petroleum.

Operations Review

Kurdistan Region of Iraq

The following table summarises production and sales data for the three months ended December 31, 2019, September 30, 2019, and December 31, 2018 and for the year ended December 31, 2019 and December 31, 2018:

	Three months ended			Year ended	
	December 31, 2019	September 30, 2019	December 31, 2018	December 31, 2019	December 31, 2018
Gross (100%) Production (bbl)	1,201,000	1,072,500	965,900	4,278,100	2,372,200
Gross (100%) Production per day (bbl/d)	13,100	11,700	10,500	11,700	6,500
WI Production (bbl)	780,700	697,200	627,900	2,780,800	1,541,900
WI Production per day (bbl/d)	8,500	7,600	6,800	7,600	4,200
WI sales (bbl)	777,800	698,600	626,700	2,781,000	1,542,300
WI sales per day (bbl/d)	8,500	7,600	6,800	7,600	4,200

Production and sales

Gross (100%) oil production for the three months ended December 31, 2019 was 1,201,000 bbl representing an average rate of 13,100 bbl/d. The Group's Working Interest share of oil production during this period was 780,700 bbl representing an average rate of 8,500 bbl/d.

The increase in production and sales volumes during the fourth quarter of 2019 is attributable to increased production from Banan field wells completed and brought on to production during the second, third, and fourth quarters of 2019.

Gross (100%) oil production for the year ended December 31, 2019 was 4,278,100 bbl representing an average rate of 11,700 bbl/d. The Group's Working Interest share of oil production during this period was 2,780,800 bbl representing an average rate of 7,600 bbl/d.

The Group recognised revenue on the sale of 777,800 bbl (Working Interest) and 2,781,000 bbl (Working Interest) of crude oil during the three and twelve months ended December 31, 2019, respectively.

Crude oil sale prices

Commencing in March 2016, the Group began selling crude oil to the KRG's Ministry of Natural Resources via deliveries at the Hawler License Area into the Kurdistan Oil Export Pipeline. The realised sales prices on export sales through this pipeline made after February 1, 2018 are referenced to monthly average Brent crude oil prices, discounted by approximately $8/bbl for pipeline system tariffs and fees, and adjusted for differences in API gravity and sulphur from standard Brent specifications. For sales made prior to February 1, 2018, the realised sales prices on export sales through this pipeline were referenced to monthly average Brent crude oil prices, discounted by $12/bbl for crude oil quality and transport, and adjusted for actual API gravity and sulphur content outside of agreed quality specification ranges.

The following table indicates average Brent crude oil prices and the Group's realised crude oil sales prices for each quarter ended on the dates indicated below:

	2019				2018			
	Dec 31	Sept 30	June 30	Mar 31	Dec 31	Sept 30	Jun 30	Mar 31
Brent average price ($/bbl)	63.08	62.00	68.86	62.93	68.81	75.16	74.39	66.82
Realised sales price ($/bbl)	47.32	46.05	53.47	48.35	52.37	61.33	61.51	56.31

Netbacks

The following table summarises the Field Netback and Oryx Petroleum Netback for the three months ended December 31, 2019 and 2018:

	Three months ended December 31, 2019		Three months ended December 31, 2018	
	($ thousands)	($/bbl)	($ thousands)	($/bbl)
Oil sales	36,802	47.32	32,821	52.37
Royalties	(17,989)	(23.13)	(16,042)	(25.60)
Field production costs(1)	(5,784)	(7.44)	(5,284)	(8.43)
Current taxes	(543)	(0.70)	(744)	(1.19)
Field Netback(2)	**12,486**	**16.05**	**10,751**	**17.15**
Recovery of Carried Costs	4,077	5.24	3,635	5.80
Partner share of production costs	(1,779)	(2.29)	(1,626)	(2.59)
Oryx Petroleum Netback(2)	**14,784**	**19.00**	**12,760**	**20.36**

Notes:

(1) Field production costs represent the Oryx Petroleum's Working Interest share of gross production costs and exclude partner share of production costs which are being carried by Oryx Petroleum.

(2) Field Netback and Oryx Petroleum Netback are non-IFRS measures. See the "Non-IFRS Measures" section of this MD&A.

Field Netback for the three months ended December 31, 2019 of $12.5 million incorporates field production costs of $5.8 million. On a per barrel basis, Field Netback has decreased to $16.05/bbl for the three months ended December 31, 2019 from $17.15/bbl for the three months ended December 31, 2018. This variance is attributable to a decrease in the realised sales prices, partially offset by a lower per barrel royalties and to a decrease in per barrel field production costs.

The following table summarises the Field Netback and Oryx Petroleum Netback for the year ended December 31, 2019 and 2018:

	Year ended December 31, 2019		Year ended December 31, 2018	
	($ thousands)	($/bbl)	($ thousands)	($/bbl)
Oil sales	135,488	48.72	87,905	57.00
Royalties	(66,226)	(23.81)	(42,967)	(27.87)
Field production costs(1)	(22,134)	(7.96)	(14,714)	(9.54)
Current taxes	(2,782)	(1.00)	(1,994)	(1.29)
Field Netback(2)	**44,346**	**15.95**	**28,230**	**18.30**
Recovery of Carried Costs	15,008	5.40	9,737	6.32
Partner share of production costs	(6,810)	(2.45)	(4,527)	(2.94)
Oryx Petroleum Netback(2)	**52,544**	**18.90**	**33,440**	**21.68**

Notes:

(1) Field production costs represent the Oryx Petroleum's Working Interest share of gross production costs and exclude partner share of production costs which are being carried by Oryx Petroleum.

(2) Field Netback and Oryx Petroleum Netback are non-IFRS measures. See the "Non-IFRS Measures" section of this MD&A.

Field Netback for the year ended December 31, 2019 of $44.3 million incorporates field production costs of $22.1 million. On a per barrel basis, Field Netback has reduced to $15.95/bbl for the year ended December 31, 2019 from $18.30/bbl for the year ended December 31, 2018. This variance is attributable to a decrease in the realised sales prices and to a decrease in per barrel field production costs and per barrel royalties.

Hawler license operation, appraisal and early production

Key activity during 2019 Is summarised below.

Zey Gawra field

Crude oil from the Zey Gawra field is being processed through temporary facilities at the Zey Gawra field and is being delivered by truck to the Group's offloading and storage facilities located at the Demir Dagh field, for injection into the Kurdistan Oil Export Pipeline.

Banan field

During 2018, the Group installed temporary facilities required to produce and process oil from appraisal wells at its Banan field. Temporary loading facilities were also constructed allowing crude oil produced from the Banan field to be delivered by truck to tanker terminal facilities located at the Demir Dagh field, for injection into the Kurdistan Oil Export Pipeline.

The Banan-6 well targeting the Cretaceous reservoir was spudded in March 2019, drilled to a measured depth of 1,840 metres and completed as a producing well in late May 2019.

The Banan-7 well targeting the Cretaceous reservoir was spudded in August 2019, was drilled to a measured depth of 1,468 metres and was completed and placed on production in late September 2019.

The Banan-5 well was spudded in September 2019. The well was designed to obtain information to enhance understanding of both the Banan Tertiary and Cretaceous reservoirs and was drilled to a measured depth of 1,669 metres. The well was completed in the Cretaceous reservoir and placed on production in October 2019.

Demir Dagh

A pump was successfully installed in the Demir Dagh-8 well targeting the Cretaceous reservoir and the well was placed on production in late October 2019.

Efforts to facilitate oil production from the horizontal sidetrack of the Demir Dagh-5 well targeting the Cretaceous reservoir as a producing well, including acid stimulation operations, have not yet been successful. Further efforts to stimulate or recomplete this well may be planned after further assessment of the behaviour of the Demir Dagh Cretaceous reservoir.

A horizontal sidetrack of the previously drilled Demir Dagh-3 well targeting the Cretaceous reservoir was completed as a producing well.

During 2019, activity at the Demir Dagh field has continued to include production, offloading, storage, and processing activities. All Hawler License Area crude oil continues to be delivered for sale into the Kurdistan Oil Export Pipeline injection point which is located at the Demir Dagh field.

Ain Al Safra

The previously planned completion of the Ain Al Safra-2 well has been deferred into 2020.

West Africa

AGC Central License Area

The Group has licensed approximately 2,000 km^2 of 3D seismic data over the AGC Central License Area. The data has been processed and interpretation is positive. Final prospect ranking has been completed and an environmental impact assessment was largely completed in 2019 with preparation for drilling in 2021 to follow.

Other than the above, activities in West Africa during the year ended December 31, 2019 were limited to license maintenance and data analysis.

Haute Mer B License Area

On April 23, 2018, a subsidiary of Oryx Petroleum (the "**Seller**") entered into an agreement providing for the sale of a 30% participating interest in the Haute Mer B exploration license offshore Congo (Brazzaville) ("**HMB License**") to the HMB License's operator (the "**Buyer**") (the "**Sale Agreement**"). The Sales Agreement provided for the Seller's interest in the HMB License to be transferred for cash consideration of $13.3 million.

Contrary to the Seller's position that all conditions to closing were either satisfied or waived notwithstanding, the Buyer declined to close the transaction and purported to terminate the Sale Agreement. The matter was referred to arbitration. On January 31, 2020, the arbitration tribunal released its decision rejecting the Seller's position that all conditions to closing had been either satisfied or waived and that the Buyer was required to close the transaction and acquire the Seller's interest. The tribunal also awarded $15.7 million to the Buyer, including $15.1 million in respect of the Seller's share of HMB License expenditures incurred and carried by the Buyer following the date of the Sale Agreement.

The Group has consequently adjusted the carrying value of the asset held for disposal to Nil as at December 31, 2019 (December 31, 2018 - $13.3 million) and has recorded a provision for the costs awarded to the Seller. Given that the Seller has no assets to satisfy the arbitration award, the Group does not expect outflows of cash or other assets pursuant to the Sale Agreement or the related arbitration.

During the second quarter of 2019, the Buyer and other members of the HMB License contractor group relinquished their rights to explore and produce crude oil from the License Area.

Capital Additions

The following table summarises the capital additions incurred by activity during the three and twelve months ended December 31, 2019 and December 31, 2018:

	Three months ended		Year ended	
($ thousands)	December 31, 2019	December 31, 2018	December 31, 2019	December 31, 2018
Middle East				
Drilling	9,394	5,260	28,375	25,455
Facilities	975	479[(2)]	3,224	707
Studies, license, and support	2,319	1,952	4,816	2,314
Sub-Total Middle East	**12,688[(1)]**	**7,691**	**36,415[(1)]**	**28,476**
West Africa				
Exploration drilling	107	139	538	295
Facilities	(1)	52	2	181
Seismic	-	440	79	5,861
Studies, license, and support	596	701	1,187	1,362
Sub-Total West Africa	**702**	**1,332**	**1,806**	**7,699**
Corporate	**-**	**4**	**19**	**243**
Total capital additions	**13,390**	**9,027**	**38,240**	**36,418**

Notes:

(1) Included in capital additions for the Middle East for the three and twelve months ended December 31, 2019 are non-cash additions of $3.5 million primarily related to the changes in discount and inflation rates used to calculate the decommissioning obligation.

(2) Facilities capital additions for the twelve months ended December 31, 2018 include a $0.7 million credit relating to the disposal of equipment

Middle East

During the three months ended December 31, 2019, the Group invested $12.7 million in the Hawler License Area. The Group invested $9.4 million related to drilling the Banan-5 and Banan-7 wells, Demir Dagh-3 and Demir Dagh-5 sidetracks, and Banan-1 workover. Expenditure of $1.0 million on facilities and $2.3 million on license costs, studies and support were also incurred in the period.

The Group recorded capital additions of $36.4 million during the year ended December 31, 2019. These additions are primarily comprised of $28.4 million to drill and complete the Banan-5, Banan-6 and Banan-7 wells, Demir Dagh-3 and Demir Dagh-5 sidetracks and Banan-1 workover. Facilities expenditure of $3.2 million and license, studies and support costs of $4.8 million were also incurred during the period.

West Africa

Capital additions of $1.8 million for the year ended December 31, 2019 were primarily comprised of costs related to preparation for drilling, the conduct of an environmental and social impact assessment, a geohazard assessment, and directly attributable technical support costs in the AGC Central License Area.

Cost Pools

Cost Pools for each License Area, which are available for recovery through future oil sales from such License Area, as at December 31, 2019, are detailed in the table below:

License Area	Location	Gross Cost Pool	Group Participating Interest Cost Pool	Costs carried by Oryx Petroleum	Costs recovered through cost oil	Group share of recoverable costs available[1][2]
		($ million)	($ million)	($ million)	($ million)	($ million)
Hawler	Iraq – Kurdistan Region	917.1	578.1	201.8[3]	149.2	630.7
AGC Central	Senegal and Guinea Bissau	53.7	45.6	8.0	-	53.6
		970.8	**623.7**	**209.8**	**149.2**	**684.3**

Notes:

(1) Cost Pool balances are subject to audit by relevant government entities.

(2) Oryx Petroleum share of costs available for future recovery through the sale of cost oil.

(3) Carried costs include $149.2 million in expenditures related to a commitment to carry $300 million on behalf of a partner for the Hawler License Area development.

Property, plant and equipment and intangible assets

The capital additions described in the sections above, net of depletion, depreciation and amortisation ("**DD&A**") and net impairment reversals, have resulted in the following movements in intangible asset and PP&E balances during the three months ended March 31, 2019, June 30, 2019, September 30, 2019 and December 31, 2019:

($ thousands)	Exploration and Evaluation Assets	Other Intangible Assets	Total Intangible Assets
As at January 1, 2019	**99,852**	**23**	**99,875**
Capital additions	433	15	448
DD&A	-	(3)	(3)
As at March 31, 2019	**100,285**	**35**	**100,320**
Capital additions	361	(1)	360
DD&A	-	(3)	(3)
As at June 30, 2019	**100,646**	**31**	**100,677**
Capital additions	431	1	432
DD&A	-	(4)	(4)
As at September 30, 2019	**101,077**	**28**	**101,105**
Capital additions	706	(1)	705
DD&A	-	(3)	(3)
As at December 31, 2019	**101,783**	**24**	**101,807**

($ thousands)	Oil & Gas assets	Furniture and fixtures	Total PP&E
As at January 1, 2019	**651,376**	**203**	**651,579**
Capital additions	1,863	2	1,865
DD&A	(4,711)	(19)	(4,730)
As at March 31, 2019	**648,528**	**186**	**648,714**
Capital additions	10,278	1	10,279
DD&A	(4,974)	(18)	(4,992)
As at June 30, 2019	**653,832**	**169**	**654,001**
Capital additions	11,464	2	11,466
DD&A	(5,118)	(19)	(5,137)
As at September 30, 2019	**660,178**	**152**	**660,330**
Capital additions	12,685	-	12,685
Impairment	(54,390)	-	(54,390)
DD&A	(7,054)	(19)	(7,073)
As at December 31, 2019	**611,419**	**133**	**611,552**

Financial Results

Revenue

The following table summarises Oryx Petroleum's revenue for the three and twelve months ended December 31, 2019 and 2018. All oil sold during each of the below periods was produced at the Hawler License Area.

	Three months ended December 31		Year ended December 31	
($ thousands)	2019	2018	2019	2018
Oil Sales	36,802	32,821	135,488	87,905
Recovery of Carried Costs	4,077	3,635	15,008	9,737
Revenue	**40,879**	**36,456**	**150,496**	**97,642**

The Group recognised revenue on the sale of 777,800 bbl (Working Interest) of oil during the three months ended December 31, 2019, compared to revenue on the sale of 626,700 bbl (Working Interest) of oil during the same period in the previous year. Revenue of $40.9 million during the fourth quarter of 2019 increased by $4.4 million compared to the three months ended December 31, 2018. The increase in oil sales is attributable to a 24% increase in sales volumes partly offset by a 10% decrease in realised sales price.

The Group recognised revenue on the sale of 2,781,000 bbl (Working Interest) of oil during the year ended December 31, 2019, compared to revenue on the sale of 1,542,300 bbl (Working Interest) of oil during the previous year. Revenue of $150.5 million during the year ended December 31, 2019 increased by $52.9 million compared to the year ended December 31, 2018. The increase is attributable to an 80% increase in sales volumes partially offset by a 15% decrease in realised sales price.

Sales volumes are determined by the timing of deliveries to customers and are not directly correlated with production volumes. As at December 31, 2019, the Group's Working Interest share of oil inventory amounted to 11,333 bbl.

The Group has received payment in full for all crude oil delivered and sold through the Kurdistan Oil Export Pipeline up to and including September 30, 2019. At the date of this MD&A, the Group's share of amounts receivable from the KRG for crude oil delivered to the pipeline from October 2019 through February 2020 totals $44.2 million.

Royalties

The following table summarises royalty expense during the three and twelve months ended December 31, 2019 and December 31, 2018:

	Three months ended December 31		Year ended December 31	
($ thousands)	2019	2018	2019	2018
Royalties	**17,989**	**16,042**	**66,226**	**42,967**

All remittances to governments that are directly attributable to the sale of oil during the reporting period, including the government share of Profit Oil but excluding income taxes, are reported as royalties. Royalties increased by $1.9 million during the three months ended December 31, 2019, and by $23.3 million during the year ended December 31, 2019, compared to the same periods in the previous year. The variances in royalties from period to period are attributable to the same factors as those applicable to revenues from oil sales as discussed above.

Operating expense

	Three months ended December 31		Year ended December 31	
($ thousands)	2019	2018	2019	2018
Field production costs(1)	5,784	5,284	22,134	14,714
Partner's share of production costs carried by Oryx Petroleum	1,779	1,626	6,810	4,527
Operating expense	**7,563**	**6,910**	**28,944**	**19,241**
Sales(2) (bbl)	777,800	626,700	2,781,000	1,542,300
Field production costs(1) ($/bbl)	**7.44**	**8.43**	**7.96**	**9.54**
Operating expense ($/bbl)	**9.72**	**11.03**	**10.41**	**12.48**

Notes:

(1) Field production costs represent the Oryx Petroleum's Working Interest share of gross production costs and exclude partner share of production costs which are being carried by Oryx Petroleum.

(2) Oryx Petroleum's Working Interest share.

Operating expense of $7.6 million in the three months ended December 31, 2019 increased by $0.7 million compared to the same period in the previous year. The increase in operating expenses is primarily attributable to increased facilities and trucking costs related to the operation of a greater number of wells and associated infrastructure at the Banan field during 2019 in comparison with 2018. Operating costs per barrel decreased during the three months ended December 31, 2019 compared to the three months ended December 31, 2018 due to a 24% increase in sales volumes.

Operating expense for the year ended December 31, 2019 increased by $9.7 million compared to the year ended December 31, 2018. The increase in operating expenses is primarily attributable to increased facilities and trucking costs related to the operation of a greater number of wells and associated infrastructure at the Banan field during 2019 in comparison with 2018. Operating costs per barrel decreased to $10.41/bbl during the year ended December 31, 2019 compared to $12.48/bbl during the year ended December 31, 2018. This decrease was due to an 80% increase in sales volumes, partially offset by a 50% increase in operating expenses.

The following table indicates the impact of the variances in operating expense between the third and fourth quarters of 2019:

($ thousands)	($000)	($/bbl)
Operating expense – three months ended September 30, 2019	**7,172**	**10.26**
Contribution of the following to variance:		
Personnel and camp costs	(57)	(0.07)
Well maintenance	43	0.06
Facilities lease and maintenance, diesel and operation	408	0.52
Security	(3)	-
Increase in production	-	(1.05)
Operating expense – three months ended December 31, 2019	**7,563**	**9.72**

General and administration

	Three months ended December 31		Year ended December 31	
($ thousands)	2019	2018	2019	2018
Total General and Administration	**3,742**	**4,439**	**12,007**	**11,923**

General and administration expenses of $3.7 million and $12.0 million, incurred during the three and twelve months ended December 31, 2019, respectively, is broadly consistent with $4.4 million and $11.9 million in the comparable periods during 2018.

Impairment of oil and gas assets

	Three months ended December 31		Year ended December 31	
($ thousands)	2019	2018	2019	2018
Impairment (reversal) / expense of property, plant and equipment	54,390	(54,109)	54,390	(54,109)
Total impairment (reversal)	**54,390**	**(54,109)**	**54,390**	**(54,109)**

During the fourth quarter of 2019, the Group recorded an impairment of $54.4 million related to the Hawler License Area. The carrying value of this asset at December 31, 2019 is $611.4 million.

During the fourth quarter of 2018, the Group recorded an impairment reversal of $54.1 million related to the Hawler License Area.

Refer to the "New Accounting Pronouncements, Policies and Critical Estimates" section of this MD&A for further information.

Depletion, depreciation and amortisation

The following table summarises the component parts of depletion, depreciation and amortisation for the three and twelve months ended December 31, 2019 and 2018:

	Three months ended December 31		Year ended December 31	
($ thousands)	2019	2018	2019	2018
Intangible assets: Amortisation	4	2	13	28
PP&E assets: Depreciation	19	18	75	18
Depletion	7,017	4,723	21,844	13,890
Total DD&A	**7,040**	**4,743**	**21,932**	**13,936**

Depletion is calculated on a unit of production basis, which is the ratio of oil production volume during the period to the estimated quantities of proved plus probable oil reserves at the beginning of the period.

The increased depletion charge for the twelve months ended December 31, 2019 is due to increased production compared to the same periods in 2018. The per barrel charge for depletion has increased primarily due to reductions in proved plus probable oil reserve estimates at a rate greater than the decrease in depletable base.

The depletion charge for the three months ended December 31, 2019 increased to $7.0 million from $4.7 million during the same period in 2018. This increase is due to higher production during the fourth quarter of 2019 and a higher per barrel depletion charge, primarily due to reductions in proved plus probable oil reserve estimates at a rate greater than the decrease in depletable base.

Other expense / (income)

The following table summarises the components of other expense / income for the three and twelve months ended December 31, 2019 compared to the same periods in 2018:

	Three months ended December 31		Year ended December 31	
($ thousands)	2019	2018	2019	2018
Increase of provision against trade and other receivables	1,465	346	1,432	1,766
Provision for arbitration award	15,731	-	15,731	-
Increase / (Reduction) in materials inventory provision	(330)	1,500	(2,183)	671
Other	(8)	(15)	38	(83)
Other expense / (income)	**16,858**	**1,831**	**15,018**	**2,520**

Other expense for the three months ended December 31, 2019 relates primarily to a $1.5 million increase in the provision against trade and other receivables, combined with a $15.7 million provision for an arbitration award relating to the Haute Mer B License Area.

Other expense for the year ended December 31, 2019 relates primarily to a $1.4 million increase in the provision against trade and other receivables, a $15.7 million provision discussed above, combined with a $2.2 million decrease in the inventory impairment provision.

Other expense for the year ended December 31, 2018 relates primarily to a $1.8 million impairment provision on trade and other receivables combined with a $0.7 million increase in the inventory impairment provision.

Finance expense

	Three months ended December 31		Year ended December 31	
($ thousands)	2019	2018	2019	2018
Interest expense on Loan Facility	2,012	2,012	7,983	7,983
Accretion of deferred financing costs on Loan Facility	90	88	351	770
Change in fair value of contingent consideration	-	(4,036)	-	2,704
Interest on contingent consideration	418	839	263	3,502
Accretion of decommissioning liability	117	116	465	421
Issue of warrants	-	-	478	-
Other	(3)	-	64	142
Finance expense / (income)	**2,634**	**(981)**	**9,604**	**15,238**

Finance expense for the three and twelve months ended December 31, 2019 and December 31, 2018 primarily relates to accrued interest associated with the Loan Facility and on contingent consideration.

The change in fair value of contingent consideration and the interest on contingent consideration is discussed in the "Liquidity and Capital Resources" section of this MD&A.

Income tax expense

The following table summarises the component parts of income tax expense for the three and twelve months ended December 31, 2019 and December 31, 2018.

	Three months ended December 31		Year ended December 31	
($ thousands)	2019	2018	2019	2018
Current income tax expense	949	831	3,357	2,202
Deferred tax (benefit) / expense	4	9	15	18
Total income tax expense	**953**	**840**	**3,372**	**2,220**

The current income tax expense, which varies proportionately with oil sales revenues. includes amounts deemed to be collected by the KRG through its allocation of Profit Oil under the Hawler PSC.

Liquidity and Capital Resources

During 2019, the Group met its day to day working capital requirements and funded its capital and operating expenditures through funding received from the proceeds of share issuances and its share of oil sales revenues from the Hawler License Area.

Loan Facility

On March 11, 2015, the Group entered into a committed and unsecured term loan facility agreement (the "Loan Facility") with a subsidiary of its indirect controlling shareholder The Addax and Oryx Group PLC (the "Lender"). The $100 million Loan Facility has been fully drawn and had an initial maturity of March 10, 2018 (the "Maturity Date").

On April 28, 2017, the Loan Facility was amended to extend the Maturity Date from March 10, 2018 to July 1, 2019 and to amend interest payment terms (the "Loan Amendment"). Under the terms of the Loan Amendment, interest at an annual compound rate of 10.5%, and principal amounts owing to the Lender up to and including May 11, 2017 (the "Loan Amount") are payable at the Maturity Date or earlier, at the option of the borrower. Interest accrued on the Loan Amount after May 11, 2017 was determined on each of November 11, 2017, May 11, 2018, November 11, 2018, (each, an "Interest Calculation Dates") and has been settled by way of issuance of Common Shares. The numbers of Common Shares were determined using the issue price per share equal to the volume weighted average trading price for the five trading days immediately preceding the Interest Calculation Dates.

On December 31, 2018, the Group agreed with the Lender to amend the Loan Facility to further extend the Maturity Date from July 1, 2019 to July 1, 2020 and to amend interest provisions (the "2nd Loan Amendment"). The Company issued warrants to acquire 6,132,804 Common Shares to an affiliate of the Lender in consideration of the 2nd Loan Amendment. The Loan Amount and interest rate remains unchanged from the terms agreed under the Loan Amendment. Interest accrued on the Loan Amount for the period beginning on November 12, 2018 and ending on July 1, 2019 was settled by way of issuance of Common Shares as contemplated in the Loan Amendment. If cash payments to the Lender are then permitted under the terms of other corporate agreements, interest on the Loan Amount accruing after July 1, 2019 is payable in cash on January 1, 2020 and July 1, 2020. The 2nd Loan Amendment was approved by the Toronto Stock Exchange on March 11, 2019.

On August 19, 2019, the Group extinguished $5.1 million of accrued interest under the Loan Facility, for the period beginning on November 12, 2018 and ending on July 1, 2019 in consideration for 23,901,430 Common Shares.

On March 11, 2020, the Group agreed with the Lender to further amend the Loan Facility to extend the Maturity Date from July 1, 2020 to July 1, 2021 (the "3rd Loan Amendment"). The Company has agreed to issue warrants to acquire 33,149,000 Common Shares to an affiliate of the Lender in consideration of the 3rd Loan Amendment. The interest rate remains unchanged from the terms agreed under the 2nd Loan Amendment. The Toronto Stock Exchange ("TSX") has reviewed the applicable transaction materials and management expects that the TSX will approve the 3rd Loan Amendment in due course.

As at December 31, 2019, the carrying value of the balance owed under the Loan Facility was $79.9 million, including $4.0 million in accrued interest. The total undiscounted principal plus accrued interest owed at December 31, 2019 was $80.1 million.

Interim credit facilities

On November 13, 2018, the Group entered into a committed and unsecured term loan agreement ("2019 Interim Credit Facility") jointly with an affiliate of AOG and Zeg Oil and Gas Limited. The amount of the 2019 Interim Credit Facility was subsequently reduced to $7.25 million and the availability period to draw funds under the facility was extended to September 23, 2019. On September 30, 2019, the 2019 Interim Credit Facility expired in accordance with its terms. No amounts were borrowed by the Group under the facility. The Group incurred a commitment fee equivalent to 1% of the undrawn amount under the 2019 Interim Credit Facility.

On March 11, 2020 the Group entered into a $5 million committed and unsecured short-term credit facility agreement ("2020 Interim Credit Facility") with an affiliate of AOG. Amounts drawn under the 2020 Interim Credit Facility ("Principal"), if any, will bear interest at an annual rate of 10.5% calculated daily and compounding at the end of each calendar month ("Interest"). Principal and Interest are payable in cash no later than September 30, 2020 (the "2020 Interim Credit Facility Maturity Date"). A commitment fee equivalent to 1% per annum of the undrawn amount is payable under the 2020 Interim Credit Facility. The Toronto Stock Exchange has reviewed the applicable transaction materials and management expects that the TSX will approve the 2020 Interim Credit Facility in due course.

Common Share issuance to Zeg Oil and Gas Limited

On September 16, 2019, the Company issued 6,711,444 Common Shares to Zeg Oil and Gas Limited for cash consideration of $1.4 million.

Contingent consideration

During 2011, the Group acquired OP Hawler Kurdistan Limited under the terms of a sale and purchase agreement (the "Purchase Agreement").

The Purchase Agreement establishes that additional consideration in the remaining amount of $66 million plus interest at LIBOR plus 0.25% per annum becomes payable if the potential of a Hawler License Area discovery beyond the initially declared Demir Dagh commercial discovery, is declared to be commercial. While the Purchase Agreement has been amended by subsequent agreement ("Amending Agreements"), these agreements each had expiry provisions which have been triggered. Consequently, the terms of the original Purchase Agreement prevail.

For the specific purpose of estimating the fair value of the contingent consideration obligation in accordance with IFRS, management has applied the expected present value technique. Management has accordingly set out possible future cash outflow scenarios and has aggregated the probability-weighted present value of each cash outflow forecast scenario, discounted at a rate of 10% per annum. The liability is presented at management's estimate of fair value, which as at December 31, 2019 amounted to $56.0 million (December 31, 2018 - $71.0 million).

Management has based cash outflow forecast scenarios on possible future circumstances that may cause the contingent consideration to become payable, or not, in its entirety at various future dates or on a scheduled basis. The scenarios range from Nil cash outflow in the event that the conditions causing the contingent consideration to become payable do not materialize, to maximum undiscounted principal and interest in the amount of $95.7 million scheduled over time through 2023. The balance of unpaid principal and accrued interest potentially owed under the contingent consideration obligation to the vendor of the Hawler License Area as at December 31, 2019 was $75.7 million.

During the twelve months ended December 31, 2019, contingent interest accrued at a revised rate of 2.71% per annum (year ended December 31, 2018 – 2.74%). Interest had previously been accrued at a rate of 5% per annum in accordance with Amending Agreements which are no longer in effect.

Management expects that, should cash outflows related to the contingent consideration liability arise, it is more likely than not that these cash outflows would occur after June 30, 2021. Consequently, the liability has been classified as a non-current liability.

The fair value of the liability was established using a combination of observable inputs other than quoted prices and unobservable inputs derived from management's internal analysis and judgement (IFRS 13 Level 2 and 3 hierarchy category).

Liquidity outlook

The Group expects cash on hand as of December 31, 2019 and cash receipts from net revenues and export sales will allow it to fund its forecasted capital expenditures and operating and administrative costs into early 2021. Additional capital is expected to be required to be able to both meet any contingent consideration obligations that become payable and to fund drilling in the AGC Central license area now planned in 2021.

See the "New Accounting Pronouncements, Policies, and Critical Estimates – Going Concern" section of this MD&A for discussion regarding uncertainties and risks associated with the Group's ability to continue as a going concern.

The following table summarises the components of Oryx Petroleum's consolidated cash flows for the periods indicated:

	Three months ended December 31		Year ended December 31	
($ thousands)	2019	2018	2019	2018
Operating Funds Flow[(1)]	(3,918)	9,079	26,895	23,207
Change in non-cash working capital	2,360	(1,725)	1,246	(15,106)
Net cash generated by / (used in) operating activities	**(1,558)**	**7,354**	**28,141**	**8,101**
Additions to E&E and PP&E	(13,086)	(8,882)	(33,955)	(34,232)
Additions to Assets held for disposal	-	-	-	(5,266)
Change in non-cash working capital	3,115	(2,387)	(1,070)	6,689
Net cash used in investing activities	**(9,971)**	**(11,269)**	**(35,065)**	**(32,809)**
Net cash generated by financing activities	**-**	**1,277**	**1,426**	**546**
Total change in cash	**(11,529)**	**(2,638)**	**(5,498)**	**(24,162)**
Cash and cash equivalents at beginning of the period	20,441	17,048	**14,410**	**38,572**
Cash and cash equivalents at end of the period	**8,912**	**14,410**	**8,912**	**14,410**

Note:

(1) Operating Funds Flow is a non-IFRS measure. See the "Non-IFRS Measures" section of this MD&A.

During the three months ended December 31, 2019, the Group invested $13.1 million in exploration, appraisal, and development activities in the Hawler and AGC Central License Areas. The Group invested $12.4 million primarily on drilling activities in the Banan and Demir Dagh fields in the Hawler License Area, and $0.7 million to prepare for drilling activities in the AGC Central License Area. Operating activities for the three months ended December 31, 2019 used $1.6 million in cash, reflecting Operating Funds Flow of negative $3.9 million, partially offset by a $2.4 million decrease in non-cash working capital which was primarily related to an increase in trade and other payables partially offset by an increase in trade and other receivables.

The Group invested $34.0 million during the year ended December 31, 2019 in exploration, appraisal, and development in the Hawler and AGC Central License Areas. During this period, the Group invested $24.8 million primarily on drilling activities in the Banan and Demir Dagh fields in the Hawler License Area, $3.2 million on facilities, and $4.1 million on studies and directly attributable support costs. The Group also invested $1.8 million on an environmental and social impact assessment and to prepare for drilling activities in the AGC Central License Area. Operating activities for the period generated $28.1 million in cash reflecting Operating Funds Flow of $26.9 million and a decrease in non-cash working capital of $1.2 million comprising an increase in trade and other payables partially offset by an increase in trade and other receivables. Financing activities for the period generated $1.4 million being cash received from a private placement of Common Shares.

Risks and uncertainties

The Group's ability to realise cash inflows from crude oil sales is subject to significant uncertainty related to the future performance and productivity of individual wells and production facilities, future crude oil prices, and customer credit risk. In particular credit risk is impacted by the uncertainty associated with political tensions between the governments of Iraq and the Kurdistan Region of Iraq as discussed in the "Business Environment" section of this MD&A. The Group's ability to secure external financing, if, and when required, is also subject to significant uncertainty and is dependent on the Group's performance and on market conditions. Furthermore, the execution of capital investment plans requires significant capital expenditures. Long lead times between initiation of commitments to capital projects and completion thereof are common in the industry. During these lead times, Oryx Petroleum expects to incur significant costs at a level which may be difficult to predict. The Group expects to finance its activities through the first quarter of 2021 through current cash reserves and positive Operating Funds Flow. Additional capital is likely required to i) fund contingent consideration obligations should they become payable, and ii) fund drilling in the AGC Central License Area planned in 2021. Prevailing market conditions, together with Oryx Petroleum's business performance, will impact the Group's ability to realise required Operating Funds Flows and to arrange further financing as needed. While the Group retains the flexibility to defer certain budgeted expenditures and to adjust the timing of its expenditures on the development of the Hawler License Area, slowing the rate of development expenditures related to the Hawler License Area would be likely to impede the Group's ability to achieve expected production and sales levels. Refer to the "Critical estimates" section of this MD&A for additional discussion regarding management's going concern assumption which contemplates that the Group will realise its assets and settle its liabilities and commitments in the normal course of business for the foreseeable future.

Economic Sensitivities

The following table shows the estimated effect that changes to crude oil prices, Gross (100%) oil sale volumes, operating costs and interest rates would have had on the Group's profit for the year ended December 31, 2019, had these changes occurred on January 1, 2019. These calculations are based on business conditions, production and sales volumes existing during the year ended December 31, 2019. The 1,000 bbl/d increase assumes the increase is to Gross (100%) sale volumes and the Group's entitlement is calculated according to the provisions of the Hawler PSC and Joint Operating Agreement.

	Change	Profit impact ($000s)	Profit impact ($ per basic share)
Change in average realised price	$10.00/bbl	18,975	0.04
Change in crude oil sales volumes	1,000 bbl/d	7,887	0.02
Change in operating expenses	$1.00/bbl	2,781	0.01
Change in interest rate	1%	560	-

The future cash flows relating to the contingent consideration balance (refer to the "Liquidity and Capital Resources" section of this MD&A) have been estimated based on the terms outlined in the agreement with the counterparty and discounted using an observed market rate for similar obligations. As at December 31, 2019, management has assumed interest at LIBOR plus 0.25% per annum and a 10% discount rate. The following table shows the estimated effect that a 5% change in the interest and discount rates would have had on the Group's profit for the year ended December 31, 2019.

	Change	Profit impact ($000s)	Profit impact ($ per basic share)
Change in interest rate	5%	2,801	0.01
Change in discount rate	5%	4,967	0.01

The impact of the above changes may be compounded or offset by changes to other business conditions. In addition, the tables do not reflect any inter-relationships between the above factors. Changes in foreign exchange rates have not been considered in this analysis as they do not have a significant impact on the Group's operations.

Non-IFRS Measures

Field Netback

Field Netback is a non-IFRS measure that represents the Group's Working Interest share of oil sales net of the Group's Working Interest share of Royalties, the Group's Working Interest share of operating expense and the Group's Working Interest share of taxes.

Management believes that Field Netback is a useful supplemental measure to analyse operating performance and provides an indication of the results generated by the Group's principal business activities prior to the consideration of PSC and Joint Operating Agreement financing characteristics, and other income and expenses. Field Netback does not have a standard meaning under IFRS and may not be comparable to similar measures used by other companies. See the "Operations Review" section of this MD&A for a reconciliation of Field Netback.

Oryx Petroleum Netback

Oryx Petroleum Netback is a non-IFRS measure that represents Field Netback adjusted to reflect the impact of Carried Costs incurred and recovered through the sale of Cost Oil during the reporting period. Management believes that Oryx Petroleum Netback is a useful supplemental measure to analyse the net cash impact of the Group's principal business activities prior to the consideration of other income and expenses. Oryx Petroleum Netback does not have a standard meaning under IFRS and may not be comparable to similar measures used by other companies. See the "Operations Review" section of this MD&A for a reconciliation of Oryx Petroleum Netback.

Operating Funds Flow

Operating Funds Flow is a non-IFRS measure that represents cash generated from operating activities before changes in non-cash working capital. The term Operating Funds Flow should not be considered an alternative to or more meaningful than "net cash used in operating activities" as determined in accordance with IFRS.

Management considers Operating Funds Flow to be a key measure as it demonstrates the Group's ability to generate the cash necessary to fund future growth through capital investment. Operating Funds Flow does not have any standardised meaning prescribed by IFRS and therefore may not be comparable to similar measures used by other companies. In previous disclosure, Operating Funds Flow was referred to as Operating Cash Flow.

The following table reconciles Operating Funds Flow to the IFRS measure of 'Net cash generated by / (used in) operating activities':

	Three months ended December 31		Year ended December 31	
($ thousands)	2019	2018	2019	2018
Net cash generated by / (used in) operating activities	(1,558)	7,354	28,141	8,101
Changes in non-cash working capital	(2,360)	1,725	(1,246)	15,106
Operating Funds Flow	**(3,918)**	**9,079**	**26,895**	**23,207**

Outstanding Share Data

At the date of this M&DA, a total of 552,481,662 Common Shares are issued and outstanding. Upon vesting, OPCL LTIP share awards granted to the date of this MD&A will result in the issuance of up to an additional 28,862,478 Common Shares in 2020 and 2021.

2019 share capital transactions

On August 19, 2019, the Company extinguished $5.1 million of accrued interest under the Loan Facility in consideration for 23,901,430 Common Shares.

On September 3, 2019, the Company issued 6,837,566 Common Shares to employees under the Company's LTIP.

On September 16, 2019, the Company issued 6,711,444 Common Shares to Zeg Oil and Gas Limited for cash consideration of $1.4 million.

2018 share capital transactions

In January 2018, the directors of OPCL were awarded 360,372 Common Shares ($0.1 million) for services provided in the third and fourth quarters of 2017.

On July 3, 2018, OPCL issued 22,188,975 Common Shares to a subsidiary of AOG in satisfaction of $4.0 million of interest accrued under the Loan Facility between November 11, 2017 and May 10, 2018.

On September 4, 2018, OPCL issued 4,054,887 Common Shares to employees under the LTIP.

On November 12, 2018, OPCL issued 23,051,817 Common Shares to a subsidiary of AOG in satisfaction of $4.0 million of interest accrued under the Loan Facility.

On December 27, 2018, the Company issued 7,312,764 Common Shares to Zeg Oil and Gas Limited for cash consideration of $1.3 million.

Warrants

On November 13, 2018, the Company agreed with the Lender to amend the Loan Facility to further extend the Maturity Date from July 1, 2019 to July 1, 2020 and to amend interest payment terms. The Company issued warrants to acquire a total of 6,132,804 Common Shares to an affiliate of the Lender in connection with this agreement. 3,637,262 warrants were issued on February 26, 2019 and an additional 2,495,542 warrants were issued on April 2, 2019. The warrants have an exercise price of $0.2094 per Common Share and expire on November 13, 2021.

On March 11, 2020, the Company agreed with the Lender to further amend the Loan Facility to extend the Maturity Date from July 1, 2020 to July 1, 2021. The Company has agreed to issue warrants to acquire 33,149,000 Common Shares to an affiliate of the Lender in consideration of the 3rd Loan Amendment. The interest rate remains unchanged from the terms agreed under the 2nd Loan Amendment.

At the date of this MD&A, other than the warrants and unvested LTIP shares described above, there are no securities convertible into or exercisable or exchangeable for voting shares.

The Company has not paid or declared any dividends during the twelve months ended December 31, 2019.

There were no repurchases of OPCL's equity securities by the Company during the twelve months ended December 31, 2019.

Commitments and Contractual Obligations

The table below sets forth information relating to Oryx Petroleum's commitments and contractual obligations as at December 31, 2019.

($ thousands)	Within One Year	From 1 to 5 Years	More than 5 Years	Total
Operating leases(1)	298	5	-	**303**
Other obligations(2)	17,419	23,428	14,503	**55,350**
Total	**17,717**	**23,433**	**14,503**	**55,653**

(1) Operating leases primarily relate to office rent.

(2) Consists principally of obligations related to PSC commitments and capital expenditure commitments. The main purpose of these commitments is to develop the Group's oil and gas assets.

Summary of Quarterly Results

The following table sets forth a summary of Oryx Petroleum's results for the indicated quarterly periods.

($ thousands, unless otherwise stated)	2018				2019			
	Mar 31	Jun 30	Sept 30	Dec 31	Mar 31	Jun 30	Sept 30	Dec 31
Revenue, net of royalties	7,800	10,024	16,437	20,414	19,043	22,327	20,010	22,890
Operating expense	(3,128)	(3,632)	(5,571)	(6,910)	(7,270)	(6,938)	(7,173)	(7,563)
Depletion	(2,224)	(2,622)	(4,315)	(4,723)	(4,708)	(4,990)	(5,129)	(7,017)
G&A	(2,712)	(2,358)	(2,414)	(4,439)	(2,103)	(3,361)	(2,801)	(3,742)
Profit / (Loss)	(4,275)	(3,522)	(5,216)	56,765	1,544	2,313	18,278	(81,334)
Earnings / (Loss) per basic and diluted share ($/share)	(0.01)	(0.01)	(0.01)	0.11	0.00	0.00	0.03	(0.15)
Operating Funds Flow(2)	1,428	4,298	8,400	9,079	9,180	11,852	9,781	(3,918)
Gross Production (bbl)	341,700	402,600	661,900	965,900	975,000	1,029,500	1,072,500	1,201,000
WI Production (bbl)	222,100	261,700	430,200	627,900	633,800	669,200	697,200	780,700
Gross Sales (bbl)	342,600	403,000	662,900	964,100	974,300	1,032,800	1,074,800	1,196,600
WI Sales (bbl)	222,700	262,000	430,900	626,700	633,300	671,300	698,600	777,800
Field production costs(1)	(2,392)	(2,777)	(4,260)	(5,284)	(5,560)	(5,306)	(5,484)	(5,784)
Field Netback(2)	3,735	5,096	8,649	10,751	9,397	12,231	10,233	12,486
Oryx Petroleum Netback(2)	4,388	6,026	10,266	12,760	11,078	14,575	12,108	14,784
Brent price ($/bbl)	66.82	74.39	75.16	68.81	62.93	68.86	62.00	63.08
Sales price ($/bbl)	56.31	61.51	61.33	52.37	48.35	53.47	46.05	47.32
Royalties ($/bbl)	(27.53)	(30.06)	(29.98)	(25.60)	(23.63)	(26.14)	(22.51)	(23.13)
Field production costs(1) ($/bbl)	(10.74)	(10.60)	(9.89)	(8.43)	(8.78)	(7.90)	(7.85)	(7.44)
Current taxes ($/bbl)	(1.28)	(1.40)	(1.39)	(1.19)	(1.10)	(1.21)	(1.04)	(0.70)
Field Netback(2) ($/bbl)	16.76	19.45	20.07	17.15	14.84	18.22	14.65	16.05
Oryx Petroleum Netback(2) ($/bbl)	19.70	23.00	23.83	20.36	17.49	21.71	17.33	19.00
Capital additions	6,164	8,774	12,454	9,027	2,313	10,639	11,899	13,390

Notes:

(1) Field production costs represent the Oryx Petroleum's Working Interest share of gross production costs and exclude partner share of production costs which are being carried by Oryx Petroleum. See the "Operating expense" section of this MD&A.

(2) Operating Funds Flow, Field Netback and Oryx Petroleum Netback are non-IFRS measures. See the "Non-IFRS Measures" section of this MD&A.

Variations in revenue are attributable to changes in realised sales prices which have been broadly referenced to Brent crude oil prices and sales volumes which have fluctuated due to the variations in production from the Hawler License Area. There were no significant interruptions in production during the three or twelve months ended December 31, 2019, other than a four-day suspension of exports arising from temporary shut-downs of the Kurdistan Oil Export Pipeline for scheduled maintenance during February 2019 and a further seven-day shut down in September/October 2019. Production and sales volumes began to increase starting in the second quarter of 2018 as a result of incremental production from the Hawler License Area's Zey Gawra and Banan fields, respectively.

Variations in Field Netback and Oryx Petroleum Netback reflect changes in revenue discussed above and the impact of changes in field production costs. Field production costs increased during 2018 and into 2019 as wells from the Zey Gawra and Banan fields have been brought onto production. Capital additions are otherwise primarily associated with appraisal activity in the Hawler License Area for all quarterly periods presented. Capital additions during the three months ended December 31, 2019 include $0.7 million related to the AGC Central License Area.

Selected Annual Information

The following table sets forth a summary of Oryx Petroleum's results for the years indicated, in each case prepared in accordance with IFRS as issued by the IASB.

	Year ended December 31		
($ thousands except per share amounts)	2019	2018	2017
Revenue	150,496	97,642	37,368
Profit / (Loss) attributable to owners	(59,199)	43,753	(39,033)
Earnings / (Loss) per share (basic and diluted)	(0.11)	0.09	(0.11)
Total assets	768,254	812,976	744,798
Non-current financial liabilities(1)	80,985	133,526	144,689

Notes:

(1) Includes non-current trade and other payables, decommissioning obligation and finance lease obligation.

There have been no changes due to changes in accounting policies, significant acquisitions or dispositions.

Financial and Other Instruments and Off-Balance Sheet Arrangements

Oryx Petroleum operates internationally and has foreign exchange risk arising from various currency exposures, notably the Swiss Franc. In January 2019, the Group entered into eight foreign exchange contracts to purchase CHF 0.3 million and to sell US Dollars at various rates for each of the eight months from February to September 2019 in order to hedge its exposure to foreign exchange risk. In November 2020, the Group entered into six foreign exchange contracts to purchase CHF 0.4 million and to sell US Dollars at various rates at any time during the six months from January to June 2020 in order to hedge its exposure to foreign exchange risk.

Oryx Petroleum was not party to any off-balance sheet arrangements during the twelve months ended December 31, 2019 that have, or are reasonably likely to have, a current or future effect on the financial performance or financial condition of Oryx Petroleum. Further, on the date of this MD&A, Oryx Petroleum is not party to any such off-balance sheet arrangements.

Refer to the Financial Statements for further information on significant assumptions made in determining the fair value and classification of financial instruments recognised during the period.

Transactions with Related Parties

On March 11, 2015, the Group entered into a committed and unsecured term loan facility agreement with a subsidiary of its indirect controlling shareholder AOG. On July 3, 2018, OPCL issued 22,188,975 Common Shares to a subsidiary of AOG in satisfaction of $4.0 million of interest accrued under the Loan Facility between November 11, 2017 and May 10, 2018. On November 12, 2018, OPCL issued 23,051,817 Common Shares to a subsidiary of AOG in satisfaction of $4.0 million of interest accrued under the Loan Facility. On August 19, 2019, the Company extinguished $5.1 million of accrued interest under the Loan Facility, in consideration for 23,901,430 Common Shares. Each of the Loan Amendment, 2nd Loan Amendment and 3rd Loan Amendment discussed in the "Liquidity and Capital Resources" section of this MD&A was a transaction involving related parties. On March 11, 2020, the Group agreed with the Lender to amend the Loan Facility to further extend the Maturity Date to July 1, 2021. Management believes the terms and conditions negotiated to be materially comparable to terms applicable to similar market transactions.

On December 27, 2018, the Company issued 7,312,764 Common Shares to Zeg Oil and Gas Limited for consideration of $1.3 million. On September 16, 2019, the Company issued 6,711,444 Common Shares to Zeg Oil and Gas Limited for cash consideration of $1.4 million.

On November 13, 2018, the Group entered into an Interim Credit Facility jointly with an affiliate of AOG and Zeg Oil and Gas Limited. The Interim Credit Facility provided the Group with access to $7.25 million, which had to be drawn no later than September 23, 2019. Refer to the "Liquidity and Capital Resources" section of this MD&A.

On March 11, 2020, the Group entered into a $5 million committed and unsecured short-term credit facility with an affiliate of AOG. Management believes the terms and conditions of the above facilities to be materially comparable to terms applicable to similar market transactions. Refer to the "Liquidity and Capital Resources" section of this MD&A.

On October 19, 2016, the Group entered into an office lease agreement with a subsidiary of its indirect controlling shareholder. Rental expense of $45 thousand and $193 thousand relating to this agreement was recorded for the three and twelve months ended December 31, 2019, respectively.

For the three and twelve months ended December 31, 2019, the Group incurred costs of $0.2 million and $1.5 million, respectively, for goods and services provided by related parties, all of which are subsidiaries of AOG (2018: $0.4 million and $1.7 million). Costs related to trademark license fees, parent company guarantees, and management services have been incurred under agreements between the Group and AOG. Additional information relating to such agreements is available in OPCL's Annual Information Form dated March 23, 2019 available on SEDAR at www.sedar.com. Management exercised judgment, which was based on its industry specific knowledge and experience, to determine that i) the transactions described above did not contain any unusual commercial terms, and ii) the fees charged under the agreements were reasonable and not materially inconsistent with fees which would normally be associated with broadly comparable agreements.

In January 2020, the directors of OPCL were awarded $0.2 million in cash as remuneration for services provided in the third and fourth quarters of 2019. In July 2019, directors of OPCL were paid $0.2 million in cash as remuneration for services provided in the first and second quarters of 2019. In July 2018, directors of OPCL were awarded $0.3 million in cash as remuneration for services provided in the first and second quarters of 2018. In January 2018, directors of OPCL were awarded 360,372 Common Shares ($0.1 million) and $0.2 million in cash as remuneration for services provided in the third and fourth quarters of 2017.

New Accounting Pronouncements, Policies, and Critical Estimates

New Pronouncements

Oryx Petroleum has adopted the new and revised standards and interpretations issued by the IASB and the International Financial Reporting Interpretations Committee that are relevant to its operations and effective for accounting periods beginning on or after January 1, 2019 as described in Note 2 of the Financial Statements. The adoption of these standards and interpretations has not had a material effect on OPCL.

Effective January 1, 2019, the Group adopted the following IFRS as issued or amended by the IASB:

Amendments to Standards	**Effective for annual periods beginning on or after**
IFRS 16 – Leases	January 1, 2019
Annual improvements – 2015 – 2017 Cycle	January 1, 2019
Amendments to IAS 19: Plan amendment, curtailment or settlement	January 1, 2019
IFRIC 23 – Uncertainty over income tax treatments	January 1, 2019

The above amended standards have not had a material impact on the Group's Financial Statements.

Critical estimates

In the process of applying the Group's accounting policies management makes estimates, judgments and assumptions concerning the future. These accounting estimates, judgments and assumptions may differ from actual results. The estimates and underlying assumptions are reviewed on an ongoing basis. Such estimates, judgments and assumptions have a significant risk of causing a material adjustment to the carrying amounts of assets and liabilities

Going Concern

Financial statement disclosure

The Financial Statements have been prepared on a going concern basis which contemplates the realisation of assets and the satisfaction of liabilities and commitments in the normal course of business for the foreseeable future. During the year ended December 31, 2019, the Group met its day to day working capital requirements and funded its capital and operating expenditures through funding received from the proceeds of share issuances and its share of oil sales revenues from the Hawler License Area.

The Group's ability to continue as a going concern in accordance with management's estimates and forecasts is primarily dependent on the Group's ability to produce, sell and receive payment for crude oil from the Hawler License Area in accordance with its current 2020 work program and forecast adjusted to exclude discretionary investments.

The Directors expect that cash resources will be sufficient to fund the Group's capital and operating expenditures and to meet forecast obligations as they fall due in the 15 months following December 31, 2019.

In preparing forecasts supporting the going concern assumption, management has applied the following significant judgments and assumptions:

i) Hawler License Area oil sales are based on Brent crude oil prices averaging $52.61 per barrel during the 15-month period ending March 31, 2021.

ii) Oil sales proceeds will be received in accordance with the Group's current forecast.

iii) The timing and extent of forecast capital and operating expenditures is based on the Group's current forecast work program and expenditures adjusted to exclude selected discretionary investments. The Group retains a high degree of control and flexibility over both the extent and timing of expenditure under its capital investment program.

iv) Cash outflows arising from contingent consideration will not materialize prior to mid-2021.

v) There will be no outflows of cash or other assets in satisfaction of the claim outlined in note 12 of the financial statements.

Management continually monitors the Group's financing requirements and has plans to secure external funding, if required. Specifically, management is engaged with principal shareholders to consider the financing arrangements required to provide for the financing of the Group's cash outflows as they materialise. Management expects that sufficient time is available to clarify precise requirements for modification to existing financing arrangements or to secure additional financing, if any, and to subsequently conclude the arrangements required.

Should the Group be unable to meet its obligations as they fall due and to fund its anticipated capital investments and operating expenditures, the preparation of the Financial Statements on a going concern basis may not be appropriate. The Financial Statements do not reflect adjustments that would be necessary if the going concern assumption were not appropriate. Such adjustments may be material.

The directors have considered the judgments, estimates, and related uncertainties discussed above and have concluded that there is a reasonable expectation that the Group will have adequate resources to continue operations for the foreseeable future and, therefore, continue to adopt the going concern basis in preparing the Financial Statements. However, the directors have determined that, in aggregate, the uncertainties related to the judgments and estimates outlined in i) to v) above are material to the conclusion that the Group will be able to continue operations on a going concern basis.

Carrying value of intangible exploration and evaluation assets

The carrying amounts for E&E assets represent costs incurred on exploration projects. For the purpose of impairment assessments and testing, E&E assets are aggregated in cash-generating units ("CGU"). Determination of what constitutes a CGU is subject to management judgments and the circumstances. The carrying amounts remain capitalised, provided there are no indications of impairment, until the process to determine whether commercial reserves are established is complete. At that stage the relevant costs are either transferred to PP&E or written-off to the statement of profit and loss as an impairment of oil and gas assets.

Management has exercised significant judgment in determining that the Hawler – Ain al Safra sub-contract area and the AGC Central License Area constitute individual CGUs and that there are no substantive indicators suggesting that the carrying amounts of exploration and evaluation assets exceed their recoverable amounts. Most significantly, assessments regarding the presence of impairment indicators include complex judgments and estimates relating to i) management's current and future capital allocation priorities, and ii) the Group's ability to finance its commitments within the time limitations imposed by the agreements governing the Group's activities in each of the related License Areas / CGUs.

Carrying value of Oil and Gas assets

The carrying amounts for Oil & Gas assets are subject to impairment assessment and testing in accordance with IAS 36.

For the purpose of impairment assessments and testing, Oil & Gas assets are aggregated in CGUs. Determination of what constitutes a CGU is subject to management judgments and the circumstances. For the purposes of impairment assessments and testing of Oil & Gas assets, management has determined that the Oil & Gas assets in the Hawler License Area, excluding the Ain al Safra sub-contract area constitute the group's single CGU which contains property, plant and equipment.

In conducting impairment assessments and tests, management considers internal and external sources of information regarding the manner in which assets are expected to be used, and indications of economic performance of the assets. Estimates include but are not limited to the determination of expected future cash flows from the asset being tested and the discount rate used to determine the value of the cash flows at the measurement date. Reductions in oil price forecasts, increases in estimated future costs of production, increases in estimated future capital costs, reductions in the amount of recoverable reserves and resources and/or adverse economic conditions can result in estimated carrying amounts exceeding the recoverable amounts of the Group's Oil & Gas assets. An impairment loss is recognized if and when the carrying amount exceeds the recoverable amount. An impairment reversal is recognized if and when there has been a change in the estimates used to determine the asset's recoverable amount since the last impairment loss was recognized.

Following the presence of indicators that the Hawler License Area CGU's recoverable amount may differ from its carrying amount, management conducted an impairment test as at December 31, 2019.

In performing the impairment test as at December 31, 2019, management used significant assumptions and estimates derived from and consistent with those incorporated in the proved plus probable reserves development case contained in the independent evaluator's report referenced in the Group's Material Change Report dated February 19, 2020, adjusted to reflect management's current assumptions related to future crude oil sale prices.

Expected cash inflows from oil sales are based on quoted Brent Crude forward contract prices for 2020, 2021, and 2022. Management's Brent Crude assumptions beyond 2022 are benchmarked against the forward contract prices and pricing forecasts prepared by external firms. Expected cash inflows assume that all sales of crude oil from the Hawler License Area are completed through the Kurdistan Oil Export Pipeline. In accordance with management's best estimate of the terms most likely to govern future sales of Hawler License Area crude oil, realized prices are referenced to management's estimated future Brent Crude prices discounted by approximately $8/bbl for pipeline system tariffs and fees, and adjusted for differences in forecast API gravity and sulphur from standard Brent specifications.

Based on the above, expected cash inflows from oil sales are determined using the following estimated average nominal sales prices:

Year ending December 31,	External Forecast ($/bbl)	Brent Crude Price ($/bbl)	Assumed realised Price ($/bbl)
2020	66.33	63.38	46.70
2021	67.94	59.37	43.14
2022	70.06	57.32	41.54
2023	71.66	67.17	51.37
2024	73.27	68.41	52.17
2025	74.57	74.57	58.12
2026	76.22	76.22	59.38
2027	77.83	77.83	60.59
Thereafter	2% escalation	2% escalation	2% escalation

Expected cash outflows are based on the capital, operating, and abandonment expenditure profiles incorporated in the independent evaluator's report referenced in the Group's Material Change Report dated February 19, 2020.

Management has applied the fair value less costs of disposal methodology to establish the net present value of expected after-tax cash flows associated with proved plus probable reserves as at December 31, 2019 using a 15% nominal after-tax discount rate. The 15% discount rate is based on management's estimate of the cost of capital invested in upstream oil & gas assets in the Kurdistan Region of Iraq.

In measuring the recoverable amount of the Hawler License Area CGU as defined in IFRS 13, management has relied on i) observable inputs other than quoted prices for identical assets, and ii) inputs that are not publicly observable and are the result of management's estimates and judgments arising from analysis of internally generated data.

Application of the fair value less costs of disposal methodology using the assumptions described above indicates an estimated recoverable amount of the Hawler License Area CGU as at December 31, 2019 to be $591.9 million. Consequently, the Group has recorded a $54.4 million impairment as at December 31, 2019. The impairment represents the difference between the estimated recoverable amount of the Hawler License Area CGU and its carrying amount prior to the impairment reversal which includes the carrying values of decommissioning obligation for which settlement is included in the discounted expected after-tax cash-flows.

The net present value of expected after-tax cash-flows associated with the proved plus probable oil reserves development case described above has been subjected to sensitivities arising from changes in crude oil price forecasts and discount rates. The following table indicates the estimated recoverable amounts as at December 31, 2019 that result from applying various crude oil price forecasts and discount rates:

	Discount rate		
Estimated recoverable amount ($ millions)	12.5%	15%	17.5%
Management Forecast prices less $5/bbl	601.3	533.8	476.6
Management Forecast prices, shown above	660.4	591.9	533.6
Management Forecast prices plus $5/bbl	718.3	648.3	588.6

The net present value of expected cash-flows associated with the proved plus probable oil reserves development case is also highly sensitive to the Group's independently evaluated estimation of proved plus probable oil reserves and to the production profile associated with the exploitation of these reserves. The estimated recoverable and carrying values of the Group's Hawler License Area CGU are subject to significant adjustment should there be significant changes to estimates of proved plus probable oil reserves and their production profile.

Contingent Consideration

Refer to the "Liquidity and Capital Resources" section of this MD&A.

Financial Controls

Disclosure Controls and Procedures

Disclosure Controls and Procedures ("**DC&P**") have been designed under the supervision of the Chief Executive Officer ("**CEO**") and the Head of Corporate Finance and Planning (acting as CFO), with the participation of other management, to provide reasonable assurance that information required to be disclosed is recorded, processed, summarised and reported within the time periods specified in applicable securities legislation, and include controls and procedures designed to ensure that information required to be disclosed is accumulated and communicated to management, including the CEO and Head of Corporate Finance and Planning (acting as CFO), as appropriate to allow timely decisions regarding required disclosure.

An evaluation of the design and operational effectiveness of Oryx Petroleum's DC&P in place during 2019 was carried out under the supervision of, and with the participation of, management, including its certifying officers. Based on the evaluation, the certifying officers concluded that the design and operation of the DC&P were effective as at December 31, 2019.

Internal Controls over Financial Reporting

Internal Controls over Financial Reporting ("**ICFR**") have been designed under the supervision of the CEO and the Head of Corporate Finance and Planning (acting as CFO), with the participation of other management, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of Financial Statements in accordance with IFRS. ICFR can only provide reasonable assurance and may not prevent or detect misstatements. Projections of an evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate due to changes in conditions, or that the degree of compliance with the policies and procedures may deteriorate.

An evaluation of the design and operational effectiveness of Oryx Petroleum's ICFR in place during 2019 was carried out under the supervision of, and with the participation of management, including its certifying officers. Based on the evaluation, the certifying officers concluded that the design and operation of the ICFR were effective as at December 31, 2019. There were no changes in Oryx Petroleum's ICFR during the year ended December 31, 2019 that have materially affected, or are reasonably likely to materially affect, Oryx Petroleum's ICFR.

Forward-Looking Information

Certain statements in this MD&A constitute "forward-looking information" within the meaning of applicable Canadian securities legislation, including statements related to the nature, timing and effect of Oryx Petroleum's forecast capital expenditure for 2020, budgeted capital expenditures for 2020, financing and capital activities, the additional liquidity required to fund future expenditures, expectations that cash on hand as of December 31, 2019 and cash receipts from net revenues and export sales will allow the Group to fund its forecasted capital expenditures and operating and administrative costs through early 2021, preparation for drilling in the AGC Central License Area, business and acquisition strategy and goals, opportunities, drilling and well workover plans, development plans and schedules and chance of success, results of exploration activities, declarations of commercial discovery, contingent liabilities and government approvals, the ability to consistently access the export pipeline or other exterior facilities to sell oil production, sales channels for future sales, future drilling of new wells and the reservoirs to be targeted, costs and drilling times for new wells, ultimate recoverability of current and long-term assets, estimates of oil reserves and resources, future royalties and tax levels, access to and sources of future financing and liquidity, future debt levels, availability of committed credit facilities, possible commerciality of our projects, expected operating capacity, expected operating costs, estimates on a per share basis, future foreign currency exchange rates, the issuance of shares as a result of the vesting of LTIP awards and exercise of outstanding warrants, the issuance of warrants to AOG pursuant to the 3rd Loan Amendment, estimates for the fair value of the contingent consideration arising from the acquisition of OP Hawler Kurdistan Limited in 2011, the expected timing for settlement of liabilities including the Loan Facility and the contingent consideration arising from the acquisition of OP Hawler Kurdistan Limited in 2011, expected execution of an agreement to amend the terms of such contingent consideration with a payment to follow, changes in any of the foregoing, and statements that contain words such as "may", "will", "would", "could", "should", "anticipate", "believe", "intend", "expect", "plan", "estimate", "budget", "outlook", "propose", "potentially", "project", "forecast" or the negative of such expressions and statements relating to matters that are not historical fact. Although Oryx Petroleum believes these statements to be reasonable, the assumptions upon which they are based may prove to be incorrect. In making certain statements in this MD&A, Oryx Petroleum has made assumptions with respect to the following: the general continuance of the current or, where applicable, assumed industry conditions, the continuation of assumed tax, royalties and regulatory regimes, forecasts of capital expenditures and the sources of financing thereof, timing and results of exploration activities, access to local and international markets for future crude oil production and future crude oil prices, Oryx Petroleum's ability to obtain and retain qualified staff, contractors and personnel and equipment in a timely and cost-efficient manner, the political situation and stability in jurisdictions in which Oryx Petroleum has licenses, the ability to renew its licenses on attractive terms, Oryx Petroleum's future production levels, the applicability of technologies for the recovery and production of Oryx Petroleum's oil reserves and resources, the amount, nature, timing and effects of capital expenditures, geological and engineering estimates in respect of Oryx Petroleum's reserves and resources, the geography of the areas in which Oryx Petroleum is conducting exploration and development activities, operating and other costs, the extent of Oryx Petroleum's liabilities, and business strategies and plans of management and Oryx Petroleum's business partners. For more information about these assumptions and risks facing the Group, refer to the Group's Annual Information Form dated March 23, 2019, available at www.sedar.com and the Group's website at www.oryxpetroleum.com.

Any forward-looking information concerning prospective exploration, results of operations, financial position, production, expectations of capital expenditures, cash flows and future cash flows or other information described above that is based upon assumptions about future results, economic conditions and courses of action are presented for the purpose of providing readers with a more complete perspective on Oryx Petroleum's present and planned future operations and such information may not be appropriate for other purposes and actual results may differ materially from those anticipated in such forward-looking information. In addition, included herein is information that may be considered financial outlook and/or future-oriented financial information. Its purpose is to indicate the potential results of Oryx Petroleum's intentions and may not be appropriate for other purposes.

Readers are strongly cautioned that the above list of factors affecting forward-looking information is not exhaustive. Although OPCL believes that the expectations conveyed by the forward-looking information are reasonable based on information available to it on the date such forward-looking information was made, no assurances can be given as to future results, levels of activity and achievements. Readers should not place undue importance or reliance on the forward-looking information and should not rely on the forward-looking information as of any date other than the date hereof. Further, statements including forward-looking information are made as at the date they are given and, except as required by applicable law, Oryx Petroleum does not intend, and does not assume any obligation, to update any forward-looking information, whether as a result of new information or otherwise. If OPCL does update one or more statements containing forward-looking information, it is not obligated to, and no inference should be drawn that it will make additional updates with respect thereto or with respect to other forward-looking information. The forward-looking information contained in this MD&A is expressly qualified by this cautionary statement.

Reserves and Resources Advisory

Oryx Petroleum's reserves and resource estimates have been prepared and evaluated in accordance with National Instrument 51-101 - *Standards of Disclosure for Oil and Gas Activities* and the Canadian Oil and Gas Evaluation Handbook.

Proved oil reserves are those reserves which are most certain to be recovered. There is at least a 90% probability that the quantities actually recovered will equal or exceed the estimated proved oil reserves. Probable oil reserves are those additional reserves that are less certain to be recovered than proved oil reserves. There is at least a 50% probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable oil reserves.

Contingent oil resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political, and regulatory matters, or a lack of markets. Contingent oil resources entail additional commercial risk than reserves. There is no certainty that it will be commercially viable to produce any portion of the contingent oil resources. Moreover, the volumes of contingent oil resources reported herein are sensitive to economic assumptions, including capital and operating costs and commodity pricing.

Prospective oil resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective oil resources have both a chance of discovery and a chance of development. Prospective oil resources entail more commercial and exploration risks than those relating to oil reserves and contingent resources. There is no certainty that any portion of the prospective resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources.

Glossary and Abbreviations

The following abbreviations and definitions are used in this MD&A:

AGC
Agence de Gestion et de Cooporation, an inter-governmental agency established in 1993 to manage and administer petroleum and fishing activities in the maritime zone between Senegal and Guinea Bissau

AOG
The Addax and Oryx Group PLC

bbl
Barrel(s) of oil

bbl/d
Barrel(s) of oil per day

Carried Cost
Costs related to the Group's funding another party's share of costs, by agreement, in excess of the Group's Participating Interest. Carried Costs are typically recovered through Cost Oil

Common Shares
Common shares of the Company

Company
Oryx Petroleum Corporation Limited

Contractor
An oil company operating in a country under a PSC on behalf of the host government, for which it receives either a share of production or a fee

Cost Oil
The portion of oil sold used to reimburse the Contractor for exploration, development, and operating costs

Cost Pool
Costs incurred to explore and/or develop a License Area to be recovered as Cost Oil through future oil sales

Farm-in
To acquire an interest in a license from another party

G&A
General and administration

Gross
In respect of reserves, resources, future net revenue, production, sales, area, capital expenditures or operating expenses, the total reserves, resources, future net revenue, production, sales, area, capital expenditures or operating expenses, as applicable, attributable to either (i) 100% of the License Area or field; or (ii) the Group's working interest in the License Area or field, as indicated, prior to the deductions specified in the applicable PSC, REC or fiscal regime for each License Area.

IAS
International Accounting Standards

IFRS
International Financial Reporting Standards

KRG
Kurdistan Regional Government of Iraq

License Area
Area of specified size, which is licensed to a company by a government for the production of oil and gas

Loan Facility
A committed and unsecured term loan facility agreement that the Group entered into with a subsidiary of its indirect controlling shareholder AOG. Refer to Liquidity and Capital Resources section

Operator
A company that organises the exploration and productions programs in a License Area on behalf of all the interest holdings in the license

Participating Interest
The Group's current interest in an applicable License Area

PP&E
Property, plant and equipment

Profit Oil
Production remaining after contractual Royalties and Cost Oil, which is split between the government and the Contractors according to the prevailing contract terms in the PSC

Production Sharing Agreement (PSA) / Production Sharing Contract (PSC)
A contractual agreement between a Contractor and a host government, whereby the Contractor bears certain defined exploration costs, risks, and development and production costs in return for a stipulated share of the production resulting from this effort

Reserves
Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on

- analysis of drilling, geological, geophysical and engineering data;
- the use of established technology;
- specified economic conditions, which are generally accepted as being reasonable

Royalty
All remittances to governments who are party to the applicable PSCs/PSAs that are directly attributable to the sale of oil and natural gas products during the reporting period including the government share of Profit Oil described above, except for income taxes

Working Interest or WI
The Group's interest in an applicable License Area, assuming the exercise of back-in rights or options