SDX Energy Inc.
2018 Annual Report

Delivering superior results across our North African portfolio

Our Highlights
2018 Annual Report

Paul Welch, President & CEO of SDX Energy commented:

"During 2018, we achieved strong operational success across our portfolio, significantly grew our annual cash flows, achieved our Egyptian production targets and began to grow our Moroccan business meaningfully. Thus making 2018 another successful year for the Company.

In Egypt, we completed our drilling program at South Disouq, with an 80% success rate, and stand poised to achieve first gas from the concession in mid-2019. At Meseda and North West Gemsa we achieved seven discoveries from seven wells drilled and undertook successful ESP replacement/workover programs in both concessions. We also reduced our trade and other receivables by 36%/US$13.4 million, during the course of the year, allowing us to significantly increase our investment program without requiring any external funding. This increase has continued post-period end, with a further US$7.65 million of trade receivables in Egypt being offset against costs from State contractors used on the South Disouq development project.

In Morocco, we completed our highly successful drilling campaign in-country, amassing seven discoveries from nine wells. We also acquired and processed a 240km^2 3D seismic program at our Gharb Centre licence, which has yielded further drilling targets for our 12-well drilling campaign, expected to begin in Q3 2019. We also signed gas sales agreements with several new customers, all of which are expected to be highly beneficial to the value of our business in the future.

Our focus remains on realizing value for shareholders through low-cost, high-margin production across our current portfolio. We are looking forward to another exciting year in 2019 and will keep all our shareholders updated throughout the period."

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Highlights

Corporate & Financial

13.1 mmboe

Working interest share of audited 2P reserves

US$53.7m

37% increase in net revenue in the year ended December 31, 2018 compared to the year ended December 31, 2017

US$41.7m

44% increase in netback in the year ended December 31, 2018 compared to the year ended December 31, 2017

Highlights

As at December 31, 2018, the Company's working interest share of audited 2P reserves was 13.1 mmboe(1). The Company's 2P reserves estimate has been audited in accordance with the COGE Handbook by ERC Equipoise Limited, an independent qualified reserves evaluator and auditor.

SDX's key financial metrics for the three and twelve months ended December 31, 2018 and 2017 are:

	Three months ended December 31		Twelve months ended December 31	
US$ millions except per unit amounts	**2018**	2017	**2018**	2017
Net revenues	**13.8**	11.0	**53.7**	39.2
Netback(2)	**10.4**	8.5	**41.7**	28.9
Net realized average oil price/service fees - US$/barrel	**59.07**	54.39	**62.43**	46.70
Net realized average Morocco gas price - US$/mcf	**9.78**	9.72	**10.33**	9.51
Netback - US$/boe	**28.94**	28.26	**32.01**	24.47
EBITDAX(2)(3)	**7.1**	8.0	**34.3**	21.4
Exploration & evaluation expense ("E&E")	**(0.2)**	-	**(5.7)**	(0.2)
Depletion, depreciation and amortization ("DD&A")	**(6.3)**	(4.8)	**(17.3)**	(17.8)
Impairment expense	**(3.5)**	-	**(3.5)**	-
(Loss)/gain on acquisition	**-**	(4.7)	**(0.2)**	29.6
Total comprehensive (loss)/income	**(4.0)**	(3.4)	**0.1**	28.3
Net cash generated from operating activities	**8.9**	15.1	**36.2**	21.6
Cash and cash equivalents	**17.4**	25.8	**17.4**	25.8

(1) Using a conversion ratio of 5.8 Mcf:1 boe.

(2) Refer to the "Non-IFRS Measures" section of this release below and the Company's MD&A for the three and twelve months ended December 31, 2018 and 2017 for details of netback and EBITDAX.

(3) EBITDAX for Q4 2018 and 2017 and twelve months to December 31, 2018 and 2017 includes US$1.4 million and US$0.9 million, and US$5.0 million and US$3.6 million respectively of non-cash revenue relating to the grossing up of Egyptian corporate tax on the North West Gemsa PSC, which is paid by the Egyptian State on behalf of the Company.

- The above financial metrics for the three and twelve months ended December 31, 2018 reflect the impact of the acquisition of the Egyptian and Moroccan businesses of Circle Oil plc (the "Circle Acquisition") from January 27, 2017 for consideration of US$28.1 million.

- The main components of SDX's comprehensive income of US$0.1 million for the twelve months ended December 31, 2018 are:
  - US$41.7 million netback;
  - US$5.7 million of E&E, of which US$5.1 million related to two sub-commercial wells in Morocco and one sub-commercial well in Egypt;
  - US$17.3 million of DD&A;
  - US$3.5 million impairment on North West Gemsa as a result of the recent reduction in Brent crude oil price forecasts reducing the asset's economic life;
  - US$4.8 million of G&A; and
  - US$2.5 million of transaction costs covering M&A activities and the proposed re-domicile of the Company from Canada to the UK.

Corporate & Financial (continued)

13.1 mmboe

Working interest share of audited 2P reserves

US$53.7m

37% increase in net revenue in the year ended December 31, 2018 compared to the year ended December 31, 2017

US$41.7m

44% increase in netback in the year ended December 31, 2018 compared to the year ended December 31, 2017

Highlights (continued)

- Netback for the twelve months ended December 31, 2018 was US$41.7 million, up from US$28.9 million for the twelve months to December 31, 2017. This increase has been driven by 2018 production increasing to 3,574 boe/d from 3,237 boe/d in 2017, and 2018 realized average prices increasing to US$62.43/bbl and US$10.33/mcf respectively for natural gas liquids and Moroccan natural gas, compared to US$46.70/bbl and US$9.51/mcf in 2017.

- The cash position of US$17.4 million as at December 31, 2018 is US$8.4 million lower than the US$25.8 million as at December 31, 2017. This cash movement reflects strong 2018 operating cashflows of US$36.2 million (2017: US$21.6 million) as a result of improving netbacks and a US$13.4 million reduction in predominantly Egyptian receivables, which enabled the Company to fund the US$44.0 million capital investment program discussed below. In addition, the Company's three year, US$10.0 million credit facility established in July 2018 with the European Bank for Reconstruction and Development ("EBRD"), remains undrawn.

- US$44.0 million of capital expenditure has been invested into the business during the twelve months ended December 31, 2018. This comprised of:
  - US$20.3 million in Morocco, comprising US$13.9 million for the now completed nine-well drilling program and customer connection projects, and US$6.4 million relating to the 240km^2 3D seismic program in Gharb Centre;
  - US$10.6 million for the South Disouq drilling program, including US$8.5 million for the drilling of the Ibn Yunus-1X, SD-4X and SD-3X discovery wells and the sub-commercial Kelvin-1X well, and US$2.1 million for the equipment mobilization and start of data collection for the 170km^2 3D seismic program;
  - US$7.9 million in North West Gemsa for the AASE-25, AASE-27 and Al-Ola-4 development wells and the ongoing well workover program;
  - US$1.9 million in Meseda for the Rabul-5, Rabul-4, MSD-16 and MSD-15 development wells and the ongoing electrical submersible pump ("ESP") replacement program;
  - US$2.6 million in South Ramadan for the SRM-3 well drilled in the year, the results of which are currently being assessed; and
  - US$0.7 million relating to new office equipment in Cairo and additional technical software.

- Trade and other receivables have reduced to US$24.3 million as at December 31, 2018, (2017: US$37.7 million), a 36% reduction. A further US$7.65 million reduction has been achieved post-year end as a result of an agreed offset of trade receivables due from the State against costs due to State contractors used on the South Disouq development project.

Operational Highlights

2,194boe/d

North West Gemsa

734boe/d

Meseda

646boe/d

Morocco

The Company's entitlement share of production from its operations for the year ended December 31, 2018 was 3,574 boe/d (gross - 9,100 boe/d) split as follows:

- North West Gemsa 2,194 boe/d (gross - 4,388 boe/d)
- Meseda 734 bbl/d (gross - 3,851 bbl/d)
- Morocco 646 boe/d (gross - 861 boe/d)

As a result of the ongoing workover program in Meseda and the new customer connections in Morocco, post-period end production has increased in both of these concessions. Production in North West Gemsa is currently below budget due to three wells being offline for pump replacements and other workovers. It is expected that these wells will come back on stream during Q2 and Q3 adding 500-750 boe/d to gross production. As at March 21, 2019, actual entitlement production for Egypt and Morocco amounted to 3,408 boe/d (gross - 9,064 boe/d) split as follows:

- North West Gemsa 1,797 boe/d (gross - 3,598 boe/d)
- Meseda 848 bbl/d (gross - 4,449 bbl/d)
- Morocco 763 boe/d (gross - 1,017 boe/d)

Egypt

- In North West Gemsa (SDX 50% working interest and non-operator), a three-well infill drilling program was undertaken together with a seven-well workover program. The three new infill wells, AASE-25, AASE-27 and Al Ola-4, were all successfully drilled and completed as new producers. AASE-25 was targeting an un-swept area of the field in the Rahmi sand and encountered 32 feet of net light crude oil-bearing pay in this section. The well was subsequently completed as a producer in the Rahmi and is currently producing approximately 810 boe/d of light crude oil. AASE-27 was also targeting an un-swept area of the field in the Rahmi and encountered 13.5 feet of net light crude oil-bearing pay. The well was completed as a producer in the Rahmi and is currently producing approximately 260 boe/d of light crude oil. Al Ola-4 was drilled as a replacement well in the Rahmi after the original well failed because of a mechanical problem. Al Ola-4 encountered 14 feet of net light crude oil-bearing in the Rahmi section and, on test, flowed 1,011 boe/d. It is currently producing approximately 894 boe/d of light crude oil. The results of these wells and the ongoing workover program resulted in an average field production rate for the year of approximately 4,388 (SDX net: 2,194 boe/d), which was in line with the Company's 2018 guidance.

- In Meseda (SDX 50% working interest and joint operator), an ESP replacement program was undertaken during the year and four development wells were successfully drilled and completed: Rabul-5, Rabul-4, MSD-16 and MSD-15. Rabul-5 encountered 151 feet of net heavy crude oil pay, with an average porosity of 18% across the Yusr and Bakr formations and Rabul-4 encountered 43 feet of net heavy crude oil pay, also across the Yusr and Bakr formations, with an average porosity of 16%. Both wells were completed and placed on production with Rabul-5 currently producing approximately 500 bbl/d of heavy crude oil and Rabul-4 producing approximately 250 bbl/d of heavy crude oil. MSD-16 was drilled as a crestal infill producer in a newly available area of the field 100 meters from the concession boundary after an agreement was reached with the offset operator to reduce the boundary stand-off limits. The well encountered 176 feet of net heavy crude oil pay in the ASL reservoir section with an average porosity of 22%. The well was completed as a producer in the ASL using an ESP pump to provide artificial lift and is currently producing approximately 1,100 bbl/d of heavy crude oil. A second lease line development well, MSD-15, was successfully completed after encountering 226 feet of net heavy crude oil pay in the ASL section and is currently producing approximately 300 bbl/d using an ESP to provide artificial lift. The Rabul-2R well was completed during Q4 2018, accessing additional volumes in the original Rabul-2 area, with incremental production of approximately 150 bbl/d of heavy crude oil from this well. The results of these wells and the ongoing workover program resulted in an average field production rate for the year of 3,851 bbl/d of heavy crude oil (SDX net: 734 bbl/d) which was in line with the Company's 2018 guidance.

Operational Highlights (continued)

87%

Success rate for wells drilled in recent Moroccan and Egyptian campaigns

Gas discoveries at Ibn Yunus, SD-4X and SD-3X wells in South Disouq

Success at Rabul-5, Rabul-4, MSD-16 and MSD-15 wells in Meseda concession

Egypt (continued)

- In South Disouq (SDX 55% working interest and operator), the Company completed four wells during the year, three of which were conventional natural gas discoveries in the Abu Madi and Kafr el Sheik horizons. Details and test results from the wells are shown below:

Date	Name	Result	Net Pay	Porosity	Rate
April 12, 2018	Ibn Yunus-1X	Conventional natural gas discovery	101ft	28.5%	39.3 MMscf/d
May 22, 2018	Kelvin -1X	Uncommercial discovery	n/a - low gas saturation	21.0%	Not tested
June 18, 2018	SD-4X	Conventional natural gas discovery	89ft	24.0%	30.4 MMscf/d
July 23, 2018	SD-3X	Conventional natural gas discovery	33ft	21.7%	16.1 MMscf/d

- During H1 2019, SDX will complete construction of the central processing facility, the 10km export pipeline, and the tie-ins for the above three discoveries and the initial SD-1X discovery well, which was drilled in 2017. First gas is targeted for mid-2019, at a gross plateau production rate of between 50 and 60 MMscf/d, with the conventional natural gas being sold to the Egyptian National Gas Holding Company ("EGAS") at a price of US$2.85/Mcf.

- Prospect inventory for future drilling is expected to increase with the interpretation of the recently acquired 170km^2 of 3D seismic in the southern section of the concession. The Company is planning to drill two further exploration wells in 2019, with multiple additional conventional gas prospects and a conventional oil prospect already identified for drilling in future periods.

- At South Ramadan (SDX 12.75% working interest and non-operator), the SRM-3 appraisal well was spud on June 14, 2018 and reached a target depth of 15,635 feet. The operator reported encountering 75 feet of net conventional oil pay in the Matulla section (primary target), 20 feet of net conventional oil pay in the Brown Limestone formation, and a further 15 feet of net conventional oil pay in the Sudr section. The Company continues to review technical data from the well result and will provide further updates to the market in due course.

Operational Highlights (continued)

Morocco and South Disouq 3D seismic acquisitions programs complete and interpretation underway

US$10 million credit facility signed with European Bank for Reconstruction and Development to fund drilling and customer connections in Morocco

Morocco

- The Company's Moroccan acreage (SDX 75% working interest and operator) consists of five concessions, all of which are located in the Gharb Basin in northern Morocco: Sebou, Lalla Mimouna Nord, Gharb Centre, Lalla Mimouna Sud, and Moulay Bouchta Ouest.
- During 2018, the Company completed a nine-well drilling program, starting in September 2017, which covered six appraisal/development wells in Sebou, one appraisal/development well in Gharb Centre, and two exploration wells in Lalla Mimouna Nord.
- Out of the nine wells drilled, seven were successful, including the LNB-1 and LMS-1 exploration wells in Lalla Mimouna Nord, which resulted in a two-year extension being granted to the concession, extending its validity from July 2018 to July 2020 with no additional work commitments.
- In Q3 2018, the Company successfully completed the acquisition and processing of a 240km^2 3D seismic acquisition program in Gharb Centre and began an initial interpretation in advance of a proposed 12-well drilling campaign to take place between Q3 2019 and Q2 2020.
- During the year, the Company began selling natural gas to the following new customers: Peugeot, Extralait, and GPC Kenitra. In addition, post-period end, natural gas sales to another new customer, Setexam, began and natural gas sales agreements were signed with Citic Dicastal and Omnium Plastic.
- Post-period end, on February 7, 2019, the Company announced the acquisition of the Lalla Mimouna Sud and Moulay Bouchta Ouest concessions from the Government of Morocco.
- The Moulay Bouchta Ouest exploration concession has been awarded to SDX for a period of eight years with a commitment to reprocess 150km of 2D seismic data, acquire 100km^2 of new 3D seismic, and drill one exploration well within the first 3.5 year period.
- The Lalla Mimouna Sud exploration concession has been re-awarded to SDX for a period of eight years with a commitment to acquire 50km^2 of 3D seismic and drill one exploration well within the first three-year period. The 3D seismic commitment was met as part of the recent Gharb Centre 240km^2 3D seismic acquisition program described above.

Outlook

3,400 - 3,600boe/d

North West Gemsa FY 2019 gross production target

4,000 - 4,200bbl/d

Meseda FY 2019 gross production target

9-11MMscf/d

Morocco gross production target by the end of FY 2019

South Disouq CPF and pipeline construction during H1 2019. First gas targeted mid-2019 at 50-60MMscf/d.

Egypt

North West Gemsa (50% working interest)

- Targeting gross average 2019 production of 3,400-3,600 boe/d.
- As the field is now fully developed, gross capex in 2019 is expected to be approximately US$4 million (US$2 million net to SDX) consisting of up to 10 well workovers and infrastructure maintenance, but no additional new wells.

Meseda (50% working interest)

- Targeting gross average 2019 production of 4,000-4,200 bbl/d.
- The operator plans to drill two wells in H1 2019, one in Rabul, which will continue to develop the discovery area, and one development location in the Meseda field. In addition, two water injection wells are currently planned, one in Rabul and one in Meseda.
- The operator also plans to replace up to five ESPs in the wider Meseda area and upgrade water handling capabilities at the field facilities.
- Gross capex in 2019 is expected to be approximately US$8 million (US$4 million net to SDX of which US$1.6 million relates to the two planned wells and the two water injection wells and US$2.4 million relates to ESP replacements and the facilities upgrade).

South Disouq (55% working interest)

- During H1 2019, SDX will complete construction of the central processing facility, the 10km export pipeline and the tie-ins for the four existing production wells.
- First gas is targeted for mid-2019, at a gross plateau production rate of between 50 and 60 MMscf/d, with the conventional natural gas being sold to the State ("EGAS") at a price of US$2.85/Mcf.
- Prospect inventory for future drilling is expected to increase with the interpretation of the recently acquired 170km^2 of 3D seismic in the southern section of the concession.
- The Company is planning to drill two further exploration wells in 2019, with multiple additional conventional gas prospects and a conventional oil prospect identified for future drilling from the existing seismic.
- Gross capex in 2019 is expected to be approximately US$40.0 million (US$22.0 million net to SDX, of which approximately US$18.5 million relates to the South Disouq development activities and US$3.5 million relates to the two planned exploration wells). Post-period end, the Company has offset US$7.65 million of its accounts receivable due from EGPC against costs incurred with Egyptian State contractors on the South Disouq development.

South Ramadan (12.75% working interest)

- The Company continues to review technical data from the recently announced SRM-3 well result and will provide further updates to the market in due course.

Outlook
(continued)

12 wells

Planned to be drilled as part of 2019/20 campaign in Morocco

Re-domicile of Company from Canada to the UK expected to complete in Q2 2019.

Morocco

Morocco (75% working Interest)

- SDX is targeting gross production of 9-11 MMscf/d of conventional natural gas sales by the end of 2019.

- The Company's 240km^2 3D seismic acquisition program in Gharb Centre has now been processed and an initial interpretation is completed. The data quality is excellent and, as a result, multiple leads and prospects have been identified. An inversion of the dataset will now take place after which a ranking and selection exercise will be undertaken to determine prospects for the proposed 12-well drilling campaign to take place between Q3 2019 and Q2 2020.

- Planning for the drilling campaign has now begun, with three wells expected to be drilled during 2019.

- During this campaign, the LNB-1 and LMS-1 discoveries in Lalla Mimouna Nord, originally drilled in 2018, will be appraised, and another similar prospect in the area will be drilled. The remainder of the program's targets will come from the recently acquired Gharb Centre 3D seismic.

- The 2019 total gross capex is expected to be approximately US$10.0 million, with SDX's share being approximately US$8.0 million. Out of this US$8.0 million, US$6.0 million relates to the three planned wells and US$2.0 million relates to the Company's share of facilities and field maintenance capex.

Corporate

- Subject to shareholder and court approval, the Company plans to relocate its corporate residence from Canada to the UK, with a group reorganisation, and delist from the TSXV. It is expected that this process will be completed in Q2 2019 and will result in meaningful annual savings in administrative costs, management time, and a more tax efficient corporate structure.

- As part of the Company's strategy, it continues to review and explore opportunities to expand the asset base in the North Africa region, including new licencing rounds and acquisitions.

Key Financial & Operating Highlights

US$'000s except per unit amounts	Prior quarter	Three months ended December 31 2018	Three months ended December 31 2017	Twelve months ended December 31 2018	Twelve months ended December 31 2017
Financial					
Gross revenues	21,444	**18,725**	13,972	**73,055**	52,493
Royalties	(6,037)	**(4,885)**	(2,968)	**(19,376)**	(13,327)
Net revenues	15,407	**13,840**	11,004	**53,679**	39,166
Operating costs	(3,380)	**(3,392)**	(2,526)	**(11,934)**	(10,254)
Netback(1)	12,027	**10,448**	8,478	**41,745**	28,912
EBITDAX(1)	10,955	**7,103**	7,959	**34,306**	21,401
Total comprehensive income/(loss)	3,169	**(4,029)**	(2,621)	**112**	28,307
Net income/(loss) per share - basic	0.015	**(0.020)**	(0.010)	**0.001**	0.156
Cash, end of period	18,713	**17,345**	25,844	**17,345**	25,844
Working capital (excluding cash)	14,477	**12,064**	20,881	**12,064**	20,881
Capital expenditures	11,017	**8,316**	15,302	**44,023**	21,040
Total assets	146,239	**138,107**	141,057	**138,107**	141,057
Shareholders' equity	119,848	**116,039**	114,619	**116,039**	114,619
Common shares outstanding (000's)	204,706	**204,723**	204,493	**204,723**	204,493
Operational					
NW Gemsa oil sales (bbl/d)	1,987	**1,808**	1,710	**1,743**	1,733
Block-H Meseda production service fee (bbl/d)	802	**864**	561	**734**	595
Morocco gas sales (boe/d)	615	**648**	680	**646**	596
Other products sales (boe/d)	485	**604**	310	**451**	313
Total sales volumes (boe/d)	3,889	**3,924**	3,261	**3,574**	3,237
Realized oil price (US$/bbl)	70.76	**62.77**	57.77	**66.42**	50.02
Realized service fee (US$/bbl)	55.50	**51.34**	44.11	**52.96**	37.05
Realized oil sales price and service fees ($/bbl)	66.38	**59.07**	54.39	**62.43**	46.70
Realized Morocco gas price (US$/mcf)	11.05	**9.78**	9.72	**10.33**	9.51
Royalties ($/bbl)	16.88	**13.53**	9.89	**14.86**	11.28
Operating costs ($/bbl)	9.45	**9.40**	8.42	**9.15**	8.68
Netback ($/bbl)(1)	33.62	**28.94**	28.26	**32.01**	24.47

(1) Refer to the "Non-IFRS Measures" section of this release below and the Company's MD&A for the three and twelve months ended December 31, 2018 and 2017 for details of netback and EBITDAX.

South Disouq: Ibn Yunus, SD-4X and SD-3X discoveries in 2018. First gas targeted H1 2019 at 50-60MMscf/d

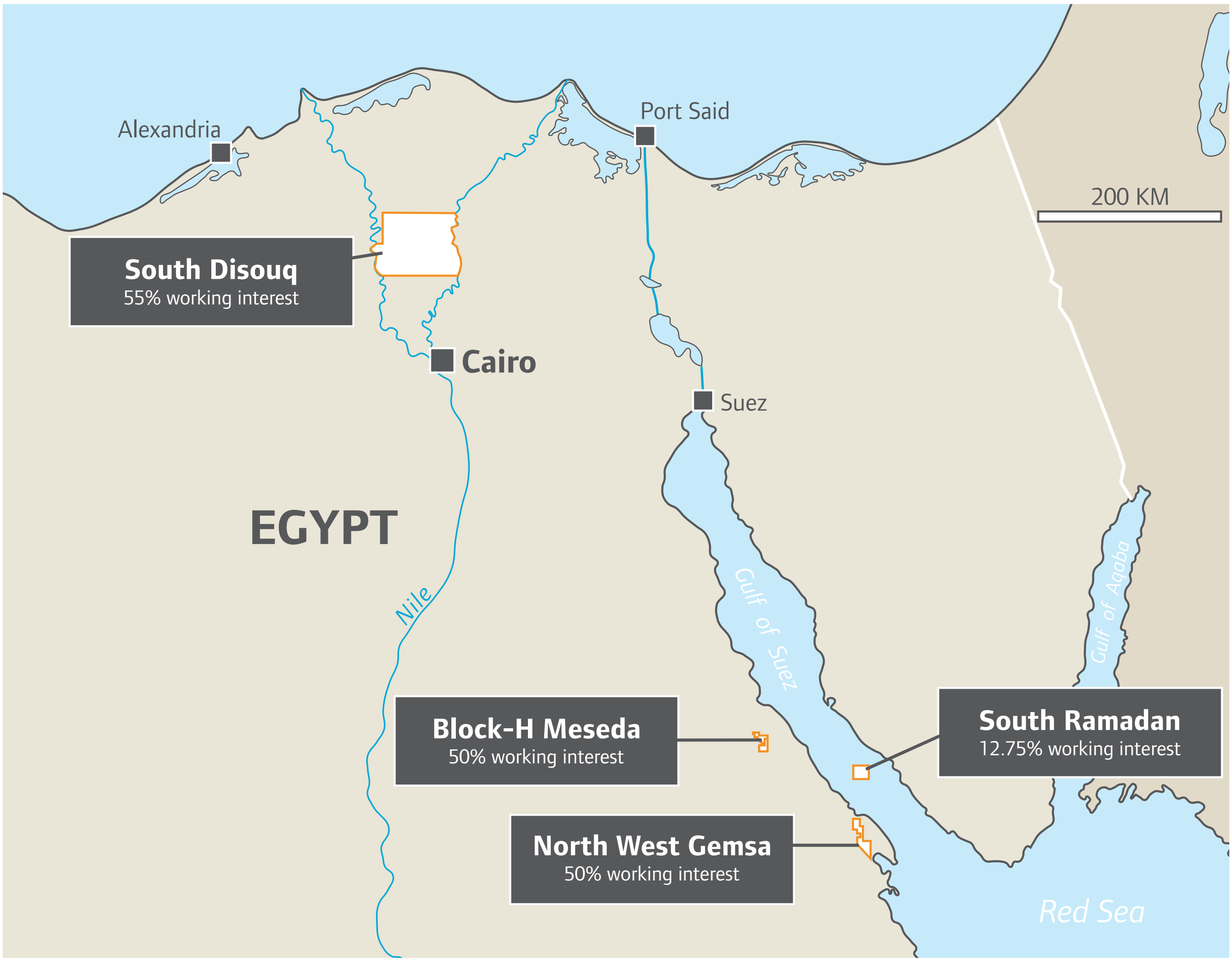
9,100boe/d

Production
Combined Egyptian and Moroccan daily average gross production for the year ended December 31, 2018

24.6MMboe

Reserves
Asset reserves (gross) - North West Gemsa, Meseda, South Disouq and Morocco as at December 31, 2018

Where We Operate
Egypt



959km²

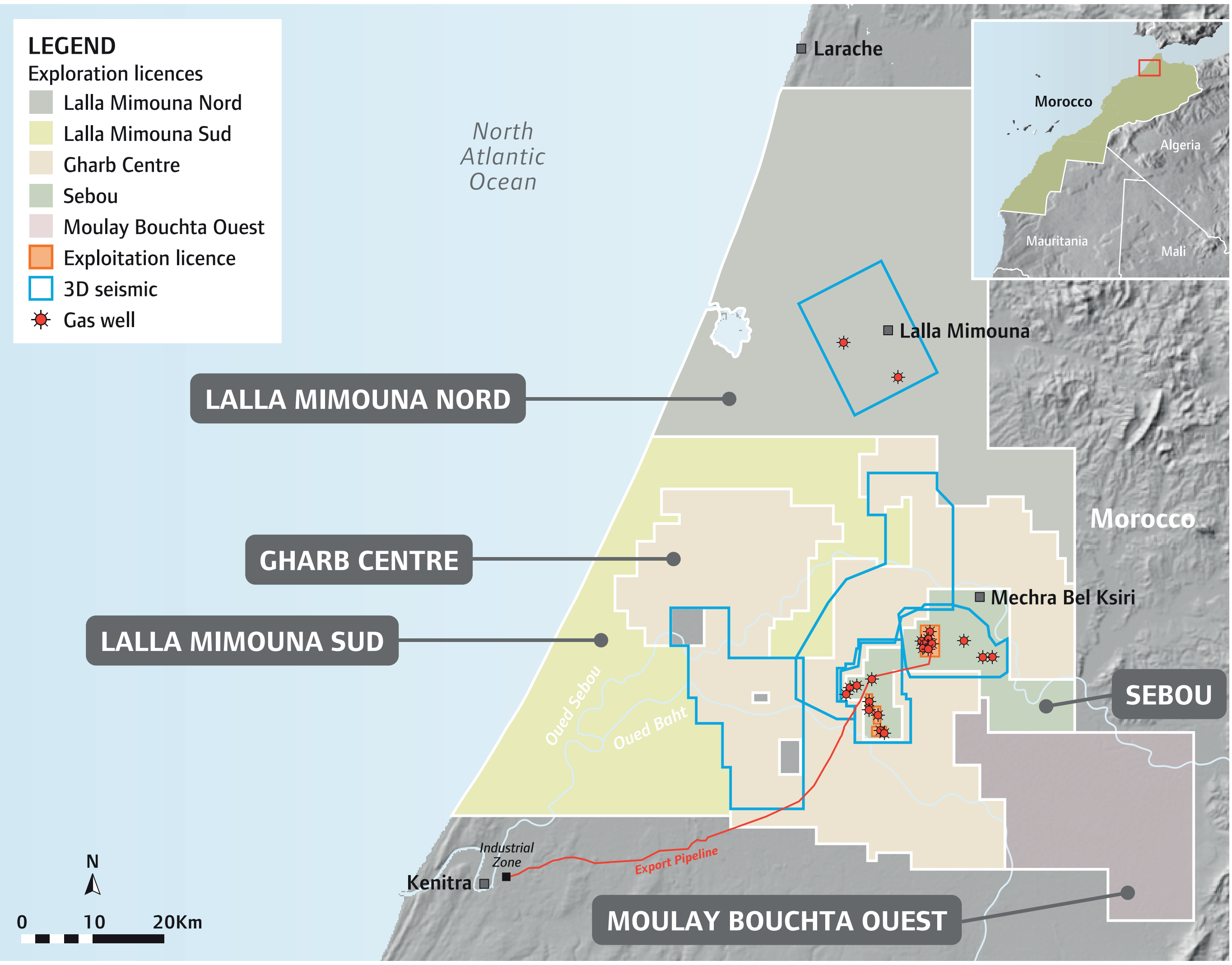
Combined concession area

4

Concessions

SDX Energy is actively involved in exploration and development activities in Egypt's Eastern Desert, Nile Delta, and Gulf of Suez basins.

The Eastern Desert and Gulf of Suez areas account for the bulk of Egypt's historical oil production. These two areas are geologically related and expertise acquired in one translates across to the other. The Nile Delta area offers exciting exploration opportunities in a prolific and proven hydrocarbon system with multiple productive horizons.



4,239km²

Combined concession area

5

Concessions
75% working interest in each, including Lalla Mimouna Sud and Moulay Bouchta Ouest awarded February 7, 2019

The Company's Moroccan acreage consists of three primary concessions, all of which are located in the Gharb Basin in northern Morocco. The initial Moroccan acreage was obtained as part of an acquisition of Circle Oil Plc's assets in late January of 2017.

At the time of the acquisition, the acreage consisted of the Sebou Onshore and Lalla Mimouna permits. In April 2017, the Sebou Onshore permit was renewed for eight years over a larger area and renamed Sebou Central. In June 2017 the Gharb Centre Exploration permit was acquired directly from the State, leading to the current footprint, as described above.

Chairman's Statement

2018 was a landmark year for SDX Energy. Much of this year was spent developing our existing assets to increase production and reserves and to generate value for shareholders.

Along with production growth, and as with other oil and gas companies, we also benefitted from an uptick in realized oil and gas prices during 2018. This growth enabled us to increase our netback year on year, from US$28.9 million in 2017 to US$41.7 million in 2018. This increase is one of the many reasons for the Company's strong financial performance during 2018, the most successful financial year for SDX on record. In addition, we finished 2018 with a cash position of US$17.4 million, leaving the Company well financed for its upcoming work programs.

I am particularly pleased to report that during 2018 the Company achieved safe operations across its portfolio. During the period SDX incurred zero Lost Time Incidents ("LTIs"), building on our strong HSE track record from the previous year, when zero LTIs were reported. Ensuring that our employees and the local communities in which we operate remain safe is of utmost importance to the Company.

We were delighted to report significant success with the drill bit during the year, executing highly value accretive drilling campaigns in both Egypt and Morocco. In total, we announced discoveries from 20 of the 23 wells drilled, representing a success rate of 87%. We hope to build on this success in 2019, as we look to drill a number of wells at our Meseda and South Disouq concessions in Egypt, alongside our planned 12-well drilling campaign in Morocco, which will straddle 2019/20. The exploration drilling planned in South Disouq seeks to complement the field development currently underway, where we expect to achieve first gas during H1 2019.

In terms of corporate governance, we were pleased to welcome Tim Linacre to the board during the year. Tim brings a wealth of experience across finance, capital markets, and M&A in the oil and gas sector. We have already benefitted from his valuable input. I would also like to thank David Richards, who retired from the board, for his invaluable support during what was a transformational period for the business with the Madison Petrogas and Circle Oil transactions.

In line with our stated strategy of growing the business via acquisition, we assessed a number of opportunities during the year. While we were disappointed not to complete a transaction in 2018, we continue to review several opportunities that we believe will add value for our shareholders. We will keep our stakeholders up to date on progress with these developments as appropriate.

On behalf of my fellow board members, I would like to thank our shareholders for their continued support. I would also like to thank our employees for their tireless work and commitment to the Company during what was a very busy period. Finally, I would like to thank the Egyptian and Moroccan governments for their partnership and support. We will continue to ensure that both countries benefit from our operational achievements. The coming year has the potential to be a very exciting one, and we have set some lofty goals to achieve. I look forward to sharing our progress with you on these over the coming 12 months.

Michael Doyle
Non-Executive Chairman

Chief Executive's Statement

2018 saw SDX continue to deliver operational success across its asset base in both Morocco and Egypt. The work program throughout the year, and post-period end, saw material developments throughout the portfolio, which have already resulted in increased cash flow. These developments, combined with our disciplined approach to cost control, ensured that our balance sheet remains healthy. We continue to focus on delivering operationally so that we can build the value in SDX for the benefit of all stakeholders, particularly our shareholders.

In 2018 we achieved an average production rate of 3,574 boe/d. In Egypt we completed our drilling program at South Disouq, resulting in an industry-leading 75% success rate. The highly successful campaign at South Disouq was followed in January 2019 by the project receiving approval of its development lease with SDX committing to deliver first gas by the middle of 2019. Additionally, we completed important infill drilling and work-over programs at both Meseda and North West Gemsa, allowing us to maintain production levels at these key assets.

In Morocco, we successfully concluded our initial drilling campaign with seven discoveries from nine wells. Toward the end of the year and into 2019, we undertook a 3D seismic program at the Gharb Centre licence. This program was undertaken to determine additional drilling targets for our 12-well campaign, scheduled to begin later this year. The market for gas in the Kenitra area of Northern Morocco remains strong, with new customers moving into the area as a result of the Peugeot car plant start-up. This demand allowed us to sign further industrial gas sales agreements with a range of important new customers, several of which are expected to grow significantly in the coming years.

SDX delivered a solid financial performance during 2018. Net revenue for the year increased by 37% over the previous year, a result of our ongoing focus on high-margin, low-cost production. As at December 31, our cash position stood at US$17.4 million with no debt. The cash generating nature of our assets has been key in enabling us to fund our development and exploration activities internally across the portfolio. We were also pleased to sign a three-year US$10 million credit facility with the European Bank for Reconstruction and Development (EBRD). This was a firm endorsement of the quality of our business and its processes. Having the EBRD as an ongoing financing partner increases the potential scope of our future development opportunities.

In summary, 2018 was another year of strong operational performance, resulting in a robust set of financial results. We maintained low operating costs and saw greater revenue resulting from an increase in production and realized prices across the portfolio. During the year, the board also made the decision to relocate our corporate residence to the UK and de-list from TSX-V. We feel this change will result in significant savings for SDX in future periods and is consistent with our corporate growth strategy. As part of this strategy, and in addition to our significant organic growth potential, we continue to assess M&A opportunities that could add value to SDX. The right acquisitions would serve to act as a catalyst to SDX's production rate, and in turn, free cash flow generation and ultimately support our ambition to be a North Africa-focused E&P of scale.

Finally, I would like to extend my thanks to our shareholders, our host governments in both Egypt and Morocco, SDX employees and contractors, and the board and senior leadership team for their unswerving support during another exciting period for the Company. We look forward to keeping everyone up to speed on our continuing developments during 2019 and beyond.

Paul Welch
Chief Executive Officer

Strategy overview

SDX Energy's strategy is simple: "Create value through low cost production growth".

Deliver increased production

Increase value through exploration

Growth through low cost asset acquisition

Review of Operations
Egypt/Eastern Desert

The North West Gemsa concession is located in the Eastern Desert of Egypt, 300km southeast of Cairo. The concession is 83km² in area and includes three fields: Geyad, Al Amir SE, and Al Ola (the southern extension of Al Amir SE). All three fields are covered by development leases. PetroAmir, a joint operating company between the partners and Ganoub El Wadi (a subsidiary of the Egyptian General Petroleum Corporation), operates the fields. SDX Energy's interest in the concession is 50%, with Zenhua Oil, the operator, holding the remaining 50%. The Al Amir SE and Geyad fields produce light oil (40-42° API oil; sold at Brent less approximately 10%) from two reservoir intervals, the Miocene-aged Shagar and Rahmi sandstones of the Kareem Formation.

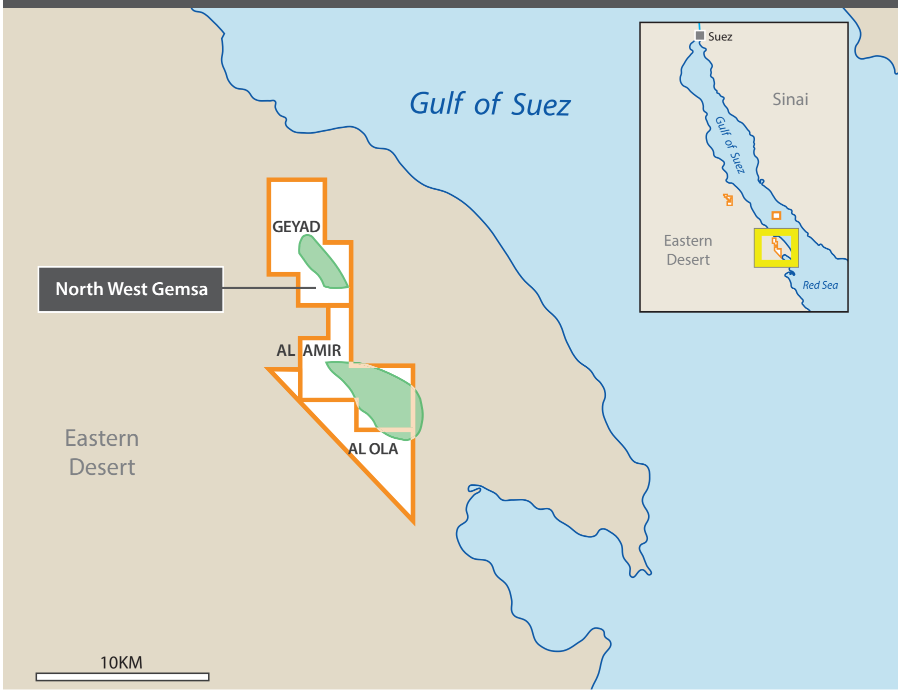
2018 Activity

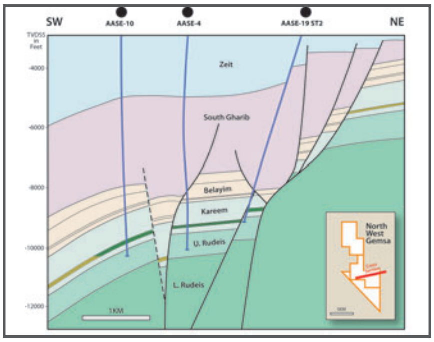
In 2018, a three-well infill drilling program was undertaken in North West Gemsa along with a seven well workover program. The three new infill wells, AASE-25, AASE-27, and Al Ola-4 were all successfully drilled and completed as new producers. The AASE-25 well, drilled during Q1 2018, targeted an un-swept area of the field in the Rahmi sand encountered 32 feet of net light crude oil-bearing pay in this section. The well was subsequently completed as a producer in the Rahmi and is currently producing approximately 810 boe/d of light crude oil. The AASE-27 well, drilled during Q2 2018, also targeted an un-swept area of the field in the Rahmi sand and encountered 13.5 feet of net light crude oil-bearing pay. The well was completed as a producer in the Rahmi and is currently producing approximately 260 boe/d of light crude oil. The Al Ola-4 well, also drilled during Q2 2018, was drilled as a replacement well in the Rahmi after the original well (Al Ola-1) failed due to a mechanical problem. Al Ola-4 encountered 14 feet of net light crude oil-bearing Rahmi section and, on test, flowed 1,011 boe/d. It is currently producing approximately 894 boe/d of light crude oil. The results of these wells and the ongoing workover program resulted in an average field production rate for the year of approximately 4,388 (SDX net: 2,194 boe/d) which was in line with the Company's 2018 guidance.

For 2019 the partners are targeting gross production of 3,400-3,600 boe/d. Now that the field is fully developed, gross capex in 2019 is expected to be approximately US$4.0 million (US$2.0 million net to SDX) consisting of up to 10 workovers and infrastructure maintenance, but no additional wells.

North West Gemsa
concession

Overview
The North West Gemsa concession is located in the Eastern Desert, 300km southeast of Cairo.





83km²

Concession area

For more information please visit our website:
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Review of Operations
Egypt/Eastern Desert

Block-H Meseda is 22km² in area and is currently producing from the Meseda and Rabul fields, both of which are included in the Meseda-H development lease. The concession is covered by a production service agreement, which allows for lower cost operations than the traditional joint venture structure. SDX Energy has a 50% working interest in the operation, with Dublin International Petroleum, the operator, holding the remaining 50% working interest.

The Meseda field produces 18° API oil from the high-quality Miocene-aged Asl sands of the Rudeis Formation. The Rabul field produces 16° API oil from the high-quality Miocene-aged Yusr and Bakr sands, which are also part of the Rudeis Formation.

2018 Activity

During 2018, an ESP replacement program was undertaken and five new wells were successfully drilled and completed: Rabul-5, Rabul-4, Rabul-2R, MSD-16 and MSD-15. The Rabul-5 well, drilled during Q1 2018, encountered 151 feet of net heavy crude oil pay, with an average porosity of 18% across the Yusr and Bakr formations. The Rabul-4 well, drilled during Q2 2018, encountered 43 feet of net heavy crude oil pay also across the Yusr and Bakr, with an average porosity of 16%. Both wells were completed and placed on production, with Rabul-5 currently producing approximately 500 bbl/d of heavy crude oil and Rabul-4 producing approximately 250 bbl/d of heavy crude oil. The Rabul-2R well was completed during Q4 2018, accessing additional volumes in the original Rabul-2 area, with incremental production of approximately 100 bbl/d of heavy crude oil now coming from this well.

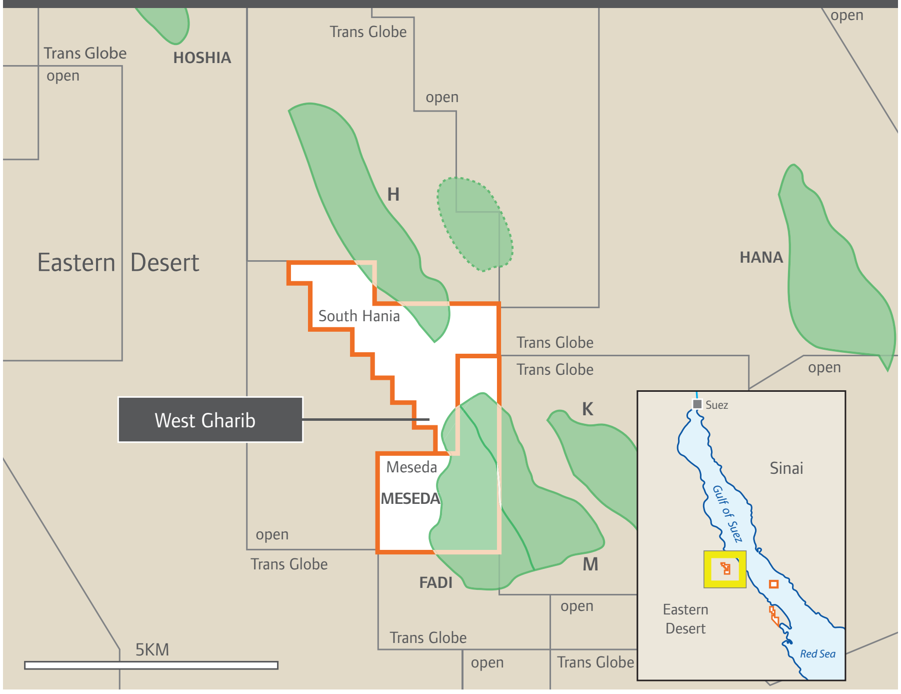
The MSD-16 well was drilled during Q2 2018 as a crestal infill producer in a newly available area of the field 100 meters from the concession boundary after an agreement was reached with the offset operator to reduce the boundary stand-off limits. The well encountered 176 feet of net heavy crude oil pay in the ASL reservoir section, with an average porosity of 22%. The MSD-16 well was completed as a producer in the ASL using an ESP pump to provide artificial lift and is currently producing approximately 1,100 bbl/d of heavy crude oil. A second lease line development well, the MSD-15, was successfully completed in Q3 2018 after encountering 226 feet of net heavy crude oil pay in the ASL section and is currently producing approximately 300 bbl/d using an ESP to provide artificial lift. The results of these wells and the ongoing workover program resulted in an average field production rate for the year of 3,851 of heavy crude oil (SDX net: 734 bbl/d) which was in line in line with the Company's 2018 guidance.

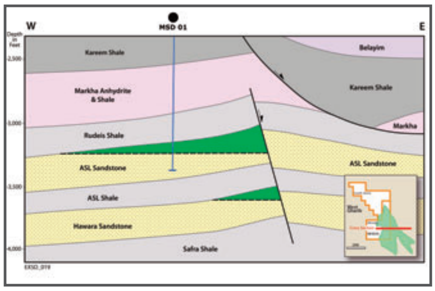
For 2019, the operator plans to drill two wells in H1, one in Rabul, which will continue to develop the discovery area, and one development location in the Meseda field. The partners are targeting gross production of 4,000-4,200 bbl/d. Furthermore, two water injection wells, one each in Rabul and Meseda, are planned and the operator is also aiming to replace up to five electrical submersible pumps ("ESPs") in the wider Meseda area.

Gross capex in 2019 is expected to be approximately US$8.0 million (US$4.0 million net to SDX of which US$1.6 million relates to the two planned wells and the two water injection wells and US$2.4 million relates to ESP replacements and the facilities upgrade).

Block-H Meseda
concession

Overview
Block-H is located in the Eastern Desert, 230km southeast of Cairo.





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22km²

Concession area

Review of Operations
Egypt/Nile Delta

South Disouq is an 828km² concession located 65km north of Cairo in the Nile Delta region. It is on trend with several other prolific gas fields in the Abu Madi Formation. SDX Energy holds a 55% interest and operates the concession. Its partner, IPR, holds the remaining 45% interest. Gas discoveries have been made in the Messinian-aged Abu Madi formation and in the Pliocene-aged Kafr El Sheikh formation.

2018 Activity

The Company completed four wells during the year, three of which were conventional natural gas discoveries in the Abu Madi and Kafr el Sheik horizons. See below for wells drilled in 2018.

To optimize recovery from the SD-3X well, the Abu Madi horizon will be completed and produced initially before the well is re-entered to complete and produce the Kafr el Sheikh horizon.

The Kelvin-1X well was drilled to test an Abu Madi Formation prospect. However sub-commercial quantities of gas were discovered and the well was subsequently plugged and abandoned.

Subsequent to the drilling and testing of the Ibn Yunus-1X well, a development plan was completed and submitted to the authority, EGAS, for approval.

During H1 2019, SDX will complete construction of the Central Processing Facility, the 10km export pipeline and the tie-ins for the above three discoveries and the initial SD-1X discovery well. First gas is targeted for mid-2019, at a gross plateau production rate of between 50-60 MMscf/d with the conventional natural gas being sold to the Government of Egypt (EGAS) at a price of US$2.85/Mcf.

Prospect inventory for future drilling is expected to increase with the interpretation of the recently acquired (Q4 2018-Q1 2019) 170km² of 3D seismic in the southern section of the concession. The Company is planning to drill two further exploration wells in 2019, with multiple additional conventional gas prospects and a conventional oil prospect already identified for drilling in future periods.

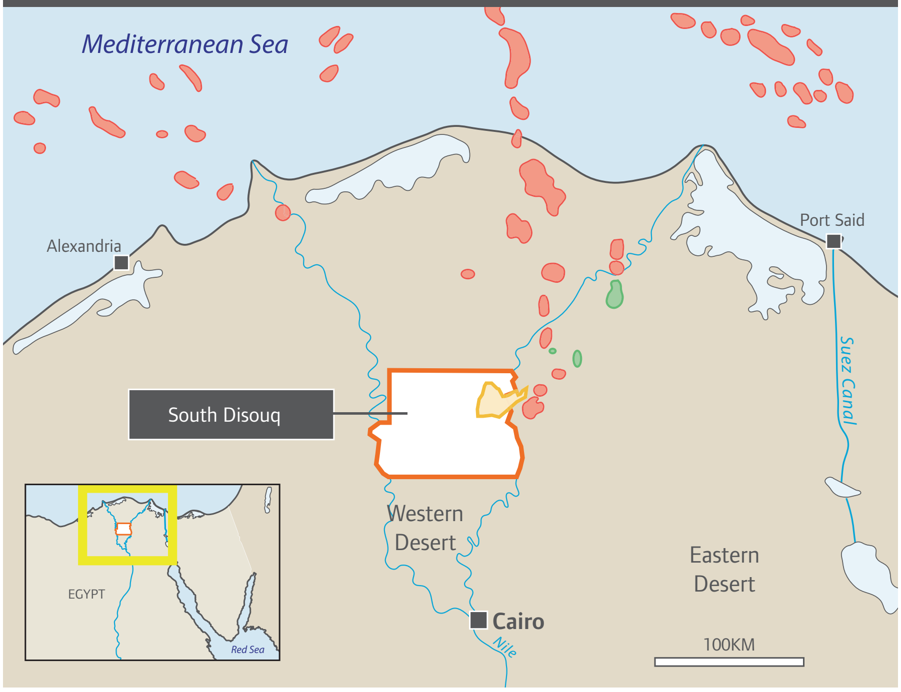
828km²

Concession area

South Disouq
concession

Overview

South Disouq is a 828km² concession located 65km north of Cairo in the Nile Delta region.



Date	Name	Result	Net Pay	Porosity	Rate
April 12, 2018	Ibn Yunus-1X	Conventional natural gas discovery	101ft	28.5%	39.3 MMscf/d
May 22, 2018	Kelvin -1X	Uncommercial discovery	n/a - low gas saturation	21.0%	Not tested
June 18, 2018	SD-4X	Conventional natural gas discovery	89ft	24.0%	30.4 MMscf/d
July 23, 2018	SD-3X	Conventional natural gas discovery	33ft	21.7%	16.1 MMscf/d

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www.sdxenergy.com

The 26km² South Ramadan development concession is located in the offshore Gulf of Suez, between the prolific Ramadan and Morgan fields. SDX Energy holds a 12.75% working interest in the concession, with Pico (operator) holding 37.25% and GPC holding the remaining 50%. The concession is considered prospective for the Lower Cretaceous-aged Nubia sandstone and there has been historical production from the Eocene-aged Thebes and Upper Cretaceous-aged Matulla formations.

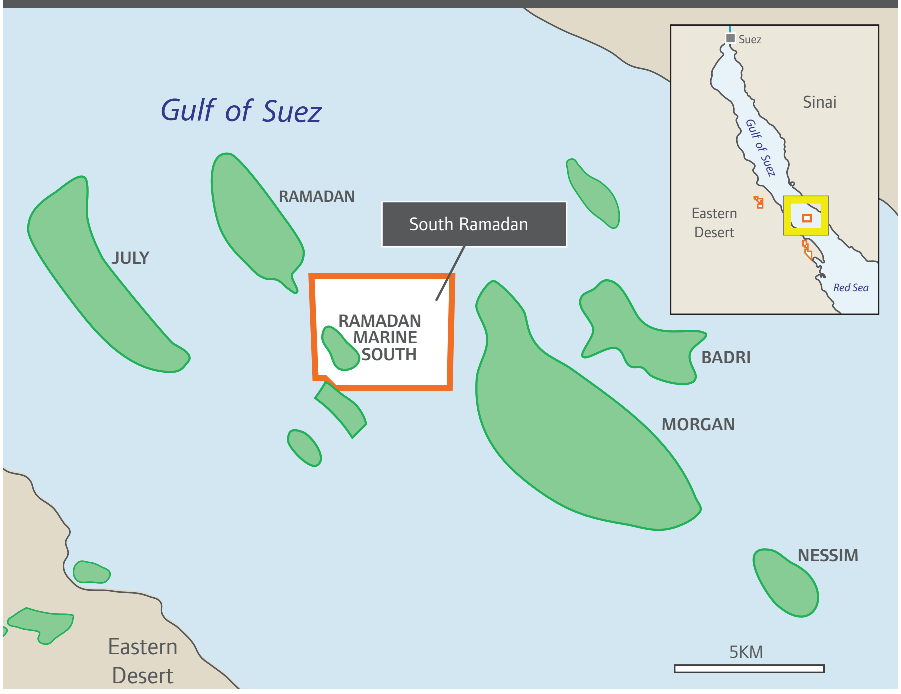
2018 Activity

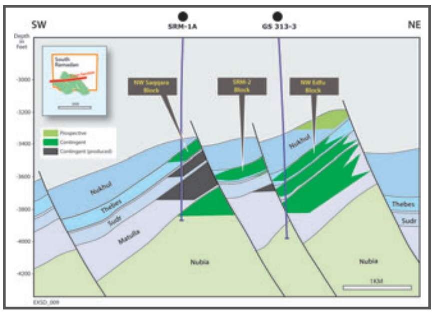
At South Ramadan, the SRM-3 appraisal well was spud on June 14, 2018 and reached a target depth of 15,635 feet on January 13, 2019. The operator reported encountering 75 feet of net conventional oil pay in the Matulla section (primary target), 20 feet of net conventional oil pay in the Brown Limestone formation and a further 15 feet of net conventional oil pay in the Sudr section. The Company continues to review technical data from the well result and will provide further updates to the market in due course.

South Ramadan
concession

Overview

The 26km² South Ramadan development concession is located in the offshore Gulf of Suez, between the prolific Ramadan and Morgan fields.





26km²

Concession area

For more information please visit our website:
www.sdxenergy.com

Review of Operations
Morocco/Gharb Basin

Overview

The Company's Moroccan acreage (SDX 75% working interest and operator) consists of five concessions, all of which are in the Gharb Basin in northern Morocco: Sebou, Gharb Centre, Lalla Mimouna Nord, Lalla Mimouna Sud, and Moulay Bouchta Ouest.

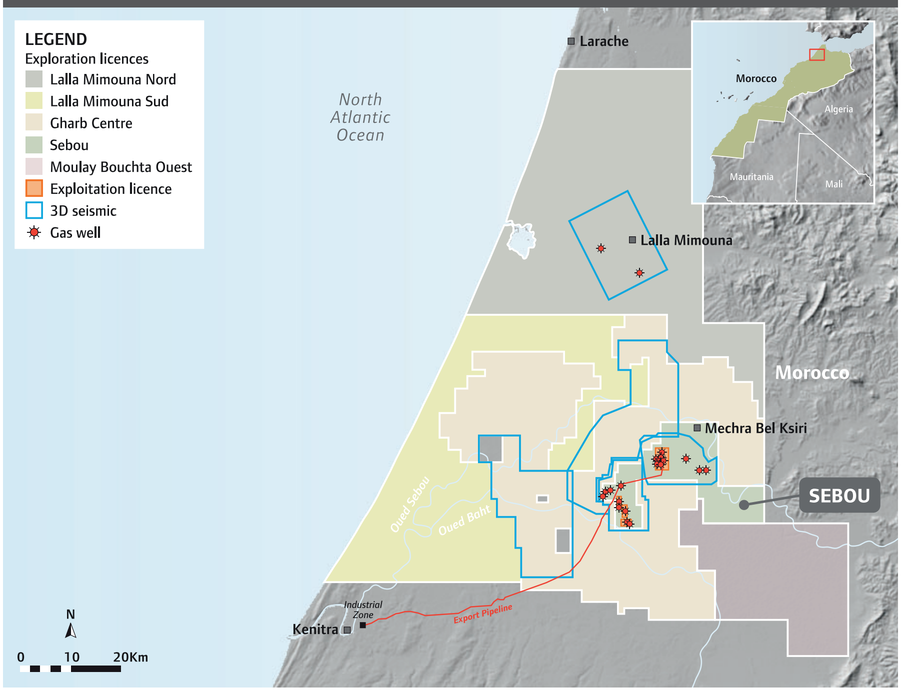
Sebou Central Concession

The Sebou Central concession is a $220km^2$ exploration permit with several exploitation concessions contained within it. The exploitation concessions granted under the Sebou Onshore Petroleum Agreement are:

- Gueddari Sud, expiry January 18, 2020
- Sidi Al Harati SW, expiry September 20, 2023
- Ksiri Central, expiry January 18, 2025
- Sidi Al Harati W, expiry October 17, 2024

The renewal of the Sebou Central exploration area in July 2017 came with a firm commitment to drill three exploration wells within the first four-year period and these were drilled as part of the Company's nine-well drilling program which was completed in Q2 2018.

Sebou Central
concession



220km²

Sebou concession area

For more information please visit our website: www.sdxenergy.com

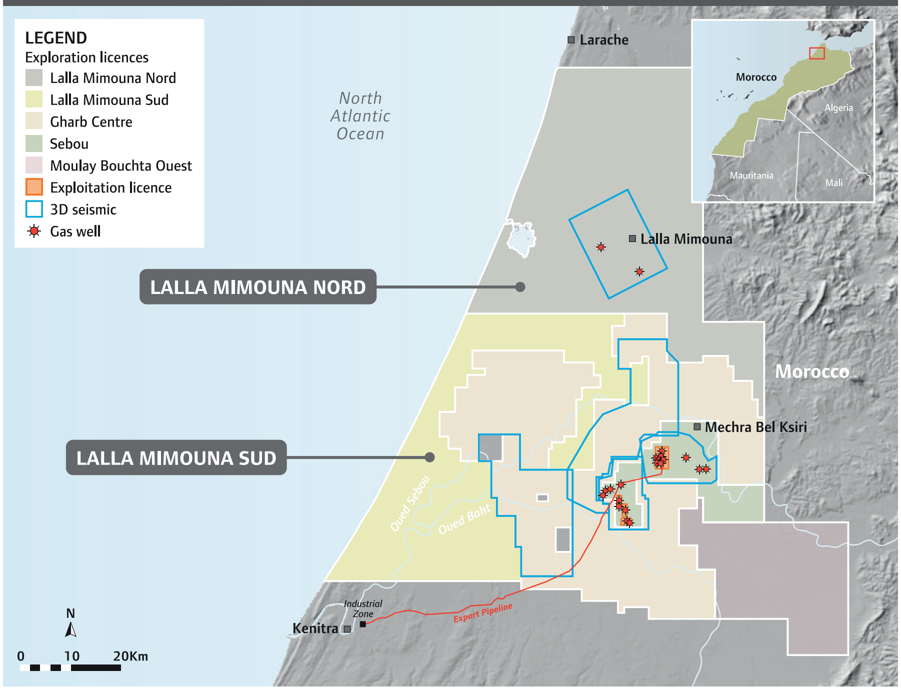
Lalla Mimouna Concession

The Lalla Mimouna area comprises the Lalla Mimouna Nord and Lalla Mimouna Sud permits for a total land area of 2,211km². The area has had a limited amount of exploration activity undertaken on it to date. A previous operator previously acquired approximately 140km² of 3D seismic on the concession and drilled two unsuccessful wells following a small gas discovery at the LAM-1 well. SDX drilled two additional exploration wells in Q1-Q2 2018, which resulted in two gas discoveries. These wells completed the work program requirements of the final extension of the Lalla Mimouna Petroleum Agreement.

Following the two discoveries, the Company applied for and was granted an extension of two years to the Lalla Mimouna Nord permit (1,371km²), in which to evaluate and commercialize the discoveries. This extension did not include any additional work commitments.

The Lalla Mimouna Sud permit lapsed in July 2018 and was re-applied for in a separate request. On February 7, 2019, the Company was re-awarded the Lalla Mimouna Sud permit (857km²) for a period of eight years, with a commitment to drill one exploration well and acquire 50km² of 3D seismic within the first three-year period. The 3D seismic commitment was met as part of the recent Gharb Centre 3D seismic acquisition program described below.

Lalla Mimouna concession



2,228km²

Lalla Mimouna concession area

Review of Operations
Morocco/Gharb Basin (continued)

Gharb Centre Concession
The permit for the Gharb Centre concession was acquired on June 1, 2017 for a period of eight years. Covering an area of over 1,343km^2, it has a work program commitment to acquire 200km^2 of 3D seismic, which was acquired in Q3-Q4 2018, and to drill two exploration wells within the first four-year period, the first of which was drilled in Q1 2018.

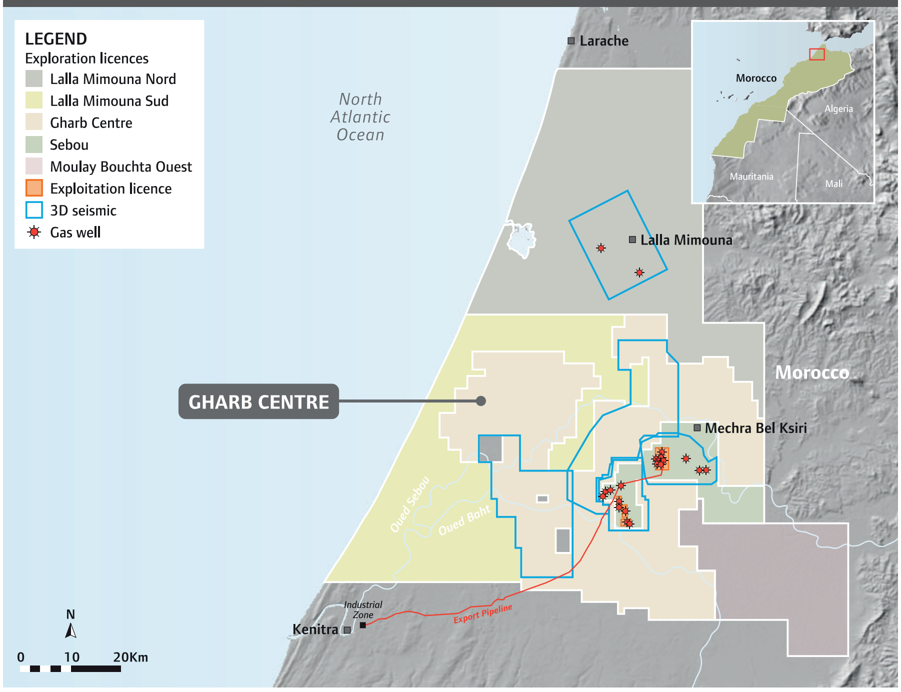
Finally, the Company announced the acquisition of the Moulay Bouchta Ouest concessions from the Government of Morocco on February 7, 2019. This exploration concession has been awarded to SDX for a period of eight years for a commitment to reprocess 150 kilometres of 2D seismic data, acquire 100km^2 of new 3D seismic, and drill one exploration well within the first three-and-a-half-year period.

2018 Activity
During 1H 2018 the Company completed a nine-well drilling program that had begun in September 2017. It covered six appraisal/development wells in Sebou, one appraisal/development well in Gharb Centre, and two exploration wells in Lalla Mimouna Nord. Out of the nine wells drilled, seven were successful, including the LNB-1 and LMS-1 exploration wells in Lalla Mimouna Nord, which resulted in the two-year extension being granted to the concession, extending its validity from July 2018 to July 2020.

In Q3 2018, the Company successfully, safely, and on budget, completed the acquisition and processing of a 240km^2 3D acquisition program in Gharb Centre. The data quality is excellent and, following an initial interpretation, multiple leads and prospects have been identified. An inversion of the dataset will now take place after which a ranking and selection exercise will be undertaken to determine which prospects for the proposed 12-well campaign to take place between Q3 2019 and Q2 2020 will be drilled.

Planning for the drilling campaign has begun with three wells expected to be drilled during 2019. During this campaign, the LNB-1 and LMS-1 discoveries in Lalla Mimouna Nord will be appraised, and another lookalike prospect in the area will be tested. The remainder of the program's targets will come from the recently acquired Gharb Centre 3D seismic.

Gharb Centre
concession



The 2019 total gross capex is expected to be approximately US$10.0 million with SDX's share being approximately US$8.0 million. Out of this US$8.0 million, US$6.0 million relates to the three planned wells and US$2.0 million relates to the Company's share of facilities and field maintenance capex.

Finally, the Company began the sale of gas to several new customers in 2018: Peugeot, Extralait, GPC Kenitra and Setexam, and gas sales agreements were signed with Citic Dicastal and Omnium Plastic.

For 2019, SDX is targeting gross production of 9-11 MMscf/d of conventional natural gas sales by the end of the year.

1,343km^2
Gharb Centre concession area

Reserves Summary

Reserve estimates have been calculated in compliance with the National Instrument 51-101 Standards of Disclosure ("NI 51-101"). Under NI 51-101, proved reserves are defined as reserves that can be estimated with a high degree of certainty to be recoverable with a target of a 90% probability that the actual reserves recovered over time will equal or exceed proved reserve estimates, while probable reserves are defined as having an equal (50%) probability that the actual reserves recovered will equal or exceed the proved and probable reserve estimates. In accordance with NI 51-101, proved undeveloped reserves have been recognized in cases where plans are in place to bring the reserves on production within a short, well defined time frame. Proved undeveloped reserves often involve infill drilling into existing pools. Of the net present value of the Company's reserves, 100% were evaluated by an independent third party engineer, ERC Equipoise, London UK ("ERCE") in their report dated 22 March 2018.

Reconciliation of gross reserves as at December 31, 2018
Forecast prices and costs

	Light and Medium Oil (Mbbl)			Heavy Oil (Mbbl)			Conv. Natural Gas (MMcf)			Natural Gas Liquids (Mbbl)		
	Gross[2] Proved	Gross[2] Probable	Total Gross[2] Proved plus Probable	Gross[2] Proved	Gross[2] Probable	Total Gross[2] Proved plus Probable	Gross[2] Proved	Gross[2] Probable	Total Gross[2] Proved plus Probable	Gross[2] Proved	Gross[2] Probable	Total Gross[2] Proved plus Probable
Opening balance[1] December 31, 2017	1,705	1,468	3,173	3,783	1,431	5,214	18,239	9,980	28,219	107	98	205
Plus:												
Extensions	-	-	-	-	-	-	-	-	-	-	-	-
Improved recovery	-	-	-	-	-	-	-	-	-	-	-	-
Technical revisions	(120)	(1,050)	(1,170)	(73)	412	339	837	(693)	144	(21)	(36)	(57)
Discoveries	-	-	-	-	-	-	11,837	2,187	14,024	97	20	117
Acquisitions	-	-	-	-	-	-	-	-	-	-	-	-
Less:												
Dispositions	-	-	-	-	-	-	-	-	-	-	-	-
Economic factors	-	-	-	-	-	-	-	-	-	-	-	-
Production	659	-	659	997	-	997	2,181	-	2,181	12	-	12
Ending balance December 31, 2017	926	418	1,344	2,713	1,843	4,556	28,732	11,474	40,206	171	82	253

(1) Opening balances are from the ERCE reserve report as of December 31, 2017.

(2) Gross reserves are based on the Company working interest share of the property gross reserves.

The technical revisions in the Light and Medium Oil category reflect the impact of drilling activities carried out by the field operator and SDX on the recoverability potential of North West Gemsa. In the Heavy Oil category, the technical revision reflects development drilling results and the impact of the waterflood program in Meseda. The technical revision in the Conventional Natural Gas category relates to the previously mentioned drilling in North West Gemsa and production data studies in Morocco. The technical revision in Natural Gas Liquids again reflects the impact of the 2018 drilling in North West Gemsa.

Summary of oil and gas reserves at December 31, 2018

	Company's interest in reserves[1][2]							
	Light & Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Conv.Natural gas (MMcf)		Natural Gas Liquids (Mbbl)	
	Gross[3]	Net[4]	Gross[3]	Net[4]	Gross[3]	Net[4]	Gross[3]	Net[4]
Egypt								
Proved developed producing	870	448	2,268	869	1,094	593	16	8
Proved developed non-producing	55	28	431	165	43	24	18	9
Proved undeveloped	-	-	14	4	25,466	14,376	154	90
Total Proved Reserves	**925**	**476**	**2,713**	**1,038**	**26,603**	**14,993**	**188**	**107**
Probable	418	215	1,843	705	9,780	5,510	65	40
Total Proved Plus Probable Reserves	**1,343**	**691**	**4,556**	**1,743**	**36,383**	**20,503**	**253**	**147**
Possible	624	321	1,543	586	11,083	6,239	94	55
Total Proved Plus Probable Plus Possible Reserves	**1,967**	**1,012**	**6,099**	**2,329**	**47,466**	**26,742**	**347**	**202**
Morocco								
Proved developed producing	-	-	-	-	1,662	1,588	-	-
Proved developed non-producing	-	-	-	-	467	441	-	-
Proved undeveloped	-	-	-	-	-	-	-	-
Total Proved Reserves	**-**	**-**	**-**	**-**	**2,129**	**2,029**	**-**	**-**
Probable	-	-	-	-	1,693	1,612	-	-
Total Proved Plus Probable Reserves	**-**	**-**	**-**	**-**	**3,822**	**3,641**	**-**	**-**
Possible	-	-	-	-	2,631	2,503	-	-
Total Proved Plus Probable Plus Possible Reserves	**-**	**-**	**-**	**-**	**6,453**	**6,144**	**-**	**-**
Total								
Proved developed producing	870	448	2,268	869	2,756	2,181	16	8
Proved developed non-producing	55	28	431	165	510	465	18	9
Proved undeveloped	-	-	14	4	25,466	14,376	154	90
Total Proved Reserves	**925**	**476**	**2,713**	**1,038**	**28,732**	**17,022**	**188**	**107**
Probable	418	215	1,843	705	11,473	7,122	65	40
Total Proved Plus Probable Reserves	**1,343**	**691**	**4,556**	**1,743**	**40,205**	**24,144**	**253**	**147**
Possible	624	321	1,543	586	13,714	8,742	94	55
Total Proved Plus Probable Plus Possible Reserves	**1,967**	**1,012**	**6,099**	**2,329**	**53,919**	**32,886**	**347**	**202**

(1) Totals may not add due to rounding.

(2) The definitions of the various categories of reserves and expenditures are those set out in NI 51-101.

(3) "Gross" reserves refer to SDX's working interest share before deducting royalties and are based on their working interest share of the property gross resources.

(4) "Net" reserves refer to the gross reserves less royalties in Morocco and either the service fee or total cost and profit revenues in Egypt. Note, as the Egyptian government pays income taxes on behalf of SDX out of the government's profit revenue share, the net reserves were based on the effective pre-tax profit revenues by adjusting for the tax rate.

Reserves Summary (continued)

Summary of net present values of future net revenues as of December 31, 2018
Forecast prices and costs (in US$ millions)

Reserve category	Net present values of future net revenue[1][2][3][4][5][6][7][8] After income taxes discounted at 0% (US MM$)	5% (US MM$)	10% (US MM$)	15% (US MM$)	20% (US MM$)
Egypt					
Proved Producing Reserves	31	29	27	25	24
Proved Developed Reserves	34	31	28	26	25
Proved Undeveloped Reserves	11	10	9	8	7
Total Proved Reserves	**45**	**41**	**37**	**34**	**32**
Total Proved Plus Probable Reserves	**87**	**76**	**67**	**60**	**55**
Total Proved Plus Probable Plus Possible Reserves	**134**	**115**	**100**	**89**	**80**
Morocco					
Proved Producing Reserves	10	10	10	10	9
Proved Developed Reserves	15	14	14	14	13
Proved Undeveloped Reserves	-	-	-	-	-
Total Proved Reserves	**15**	**14**	**14**	**14**	**13**
Total Proved Plus Probable Reserves	**30**	**29**	**27**	**26**	**25**
Total Proved Plus Probable Plus Possible Reserves	**52**	**48**	**45**	**42**	**40**
Total					
Proved Producing Reserves	41	39	37	35	33
Proved Developed Reserves	49	45	42	40	38
Proved Undeveloped Reserves	11	10	9	8	7
Total proved reserves	**59**	**55**	**51**	**48**	**45**
Total Proved Plus Probable Reserves	**116**	**104**	**95**	**87**	**80**
Total Proved Plus Probable Plus Possible Reserves	**186**	**163**	**145**	**131**	**120**

(1) Based on the Company working interest.
(2) Totals may not add due to rounding
(3) The definitions of the various categories of reserves and expenditures are those set out in NI 51-101. Based on forecast prices and costs at January 1, 2019.
(4) Interest expenses and corporate overhead, etc. were not included.
(5) The net present values may not necessarily represent the fair market value for reserves.
(6) In Egypt the government pay income taxes on behalf of SDX out of the government's profit revenue share and as such the before and after tax are identical.
(7) Unit values are calculated using estimated net present value of future net revenue before income taxes using a discount rate of 10% and the Company net reserves.
(8) Assumes 5.8 Mcf are equivalent to 1 bbl.

Reserve Definitions

- Proved reserves are those that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated Proved reserves.
- Proved Undeveloped reserves have been recognized in cases where plans are in place to bring the reserves on production within a short, well defined time frame. Proved Undeveloped reserves often involve infill drilling into existing pools.
- Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of estimated proved plus probable.
- Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves.

The disclosures required in accordance with National Instrument 51-101 of the Canadian Securities Administrators are available within ERCE's report dated 22 March 2018 filed on the SEDAR website at www.sedar.com.

Board of Directors

Michael Doyle
Non-Executive Chairman
Mr. Doyle is a Certified Corporate Director (ICD.D) and a professional geophysicist with extensive global experience in both the technical aspects of finding and producing hydrocarbons and in corporate finance and capital structures. Mr. Doyle is the principal of CanPetro International Ltd., a private Alberta company. He has served in several corporate governance roles, including as director and Chairman of Equal Energy Ltd., a NYSE and TSX-listed company with operations in Canada and the United States. In addition to his role with SDX, he is currently a director and Chairman of Richmond Road Capital and Colson Capital, two TSX-V listed issuers.

Mr. Doyle was previously a principal and the CEO of Petrel Robertson Ltd., where he was responsible for the overall management of the company and leading teams in the provision of advice and project management to clients throughout the world. Prior to that role, he held a variety of exploration positions at Dome Petroleum and Amoco Canada.

Mr. Doyle holds a BSc (math and physics) from the University of Victoria. He was a founding director and Chairman of predecessor company, Madison PetroGas, which was formed in 2003.

Paul Welch
President, Chief Executive Officer and Director
Mr. Welch is an international energy executive with over 25 years of industry experience gained at Shell Oil Company and several large independents, including Hunt Oil Company and Pioneer Natural Resources. Most recently, he was CEO of the AIM-listed explorer Chariot Oil and Gas.

Mr. Welch graduated from the Colorado School of Mines with both bachelor and master's degrees in petroleum engineering. He also holds an MBA in finance from the Southern Methodist University in Dallas, Texas.

Mr. Welch was appointed CEO of Sea Dragon Energy in April 2013 and became CEO of SDX Energy following the merger with Madison PetroGas in October 2015.

David Mitchell
Non-Executive Director
Mr. Mitchell is a successful oil and gas executive with more than 35 years' experience in international business, including with BP and Nexen. During this time, Mr. Mitchell discovered and built projects with his teams in the Middle East, West Africa, Latin America, and the North Sea. He has lived and worked in a number of countries, including a year in Egypt with BP.

Mr. Mitchell received a BSc (honours geology) from the University of London and an MPhil in mining engineering from the University of Nottingham, UK. He was appointed CEO of Madison PetroGas in 2008, building the company prior to the merger with Sea Dragon Energy in 2015.

Timothy Linacre
Non-Executive Director
Mr. Linacre is a Fellow of the Institute of Chartered Accountants in England and Wales and an experienced City practitioner. After qualifying with Deloitte Haskins and Sells, he spent five years with Hoare Govett before moving to Panmure Gordon in 1992, where he worked for 20 years, including eight years as CEO. Tim is currently senior managing partner at Instinctif Partners, a leading business communications firm.

During his career in the City, Mr. Linacre has advised a range of businesses in a variety of sectors, including oil and gas, from FTSE-100 companies to fast-growing listed and private companies.

Mark Reid
Chief Financial Officer and Director
Mr. Reid has over 20 years' experience in numerous sectors, including financial services, investment banking and oil and gas. He has had significant exposure to M&A transactions and the equity and debt capital markets. Between 2009 and 2015 he was finance director at AIM-listed Aurelian Oil and Gas PLC and Chariot Oil and Gas Limited. He also spent seven years as an emerging markets E&P banker and was head of oil and gas in the London office of BNP Paribas Fortis. Mr. Reid also spent seven years with Ernst & Young Corporate Finance, advising on M&A, IPO, and other fundraising transactions.

Mr. Reid has an MBA (distinction) from Strathclyde University, is a Member of the Institute of Chartered Accountants of Scotland, a Fellow of the Chartered Association of Certified Accountants and a Member of the Chartered Institute for Securities and Investment.

Michael Raynes
Non-Executive Director
Mr. Raynes is the managing partner of Waha Capital International LLP (UK), an energy-focussed investment advisory partnership, and a director of SDX SPV Limited (formerly known as MEA Energy Investment Company Limited). SDX SPV Limited is a significant shareholder in SDX Energy Inc. Mr. Raynes is also the CEO of Waha Capital, an Abu Dhabi-listed investment company that manages assets across several sectors, including energy, aircraft leasing, financial services and fintech, healthcare, infrastructure, industrial real estate, and capital markets. Mr. Raynes brings with him a detailed understanding of investing in the Middle East and North Africa and has established a strong track record of adding value to businesses and generating strong returns for investors.

Prior to his role at Waha Capital, Mr. Raynes was a senior investment banker with Barclays Capital in London.

The remuneration of the directors for the year ended 31 December 2018 was as follows:

	Fees/ basic salary US$	Cash bonus 2018 US$	Pension US$	Benefits in kind US$	Total 2018 US$	Total 2017 US$
Paul Welch(1)	450,000	-(7)	-	89,376	539,376	841,676
Mark Reid(2)	333,700	-(7)	16,685	1,767	352,152	579,384
Michael Doyle(3)	73,414	-	-	-	73,414	59,849
David Mitchell(3)	46,718	-	-	-	46,718	40,655
David Richards(3)(6)	23,359	-	-	-	23,359	42,318
Michael Raynes(4)	46,718	-	-	-	46,718	30,030
Timothy Linacre(5)	23,359	-	-	-	23,359	-

(1) Paul Welch was appointed President and Chief Executive Officer on April 12, 2013.

(2) Mark Reid was appointed Chief Financial Officer on November 13, 2015 and was appointed as a director on September 26, 2016.

(3) Messrs. Doyle, Mitchell and Richards were appointed directors effective October 1, 2015 upon completion of the business combination between the Corporation and Madison Petrogas Ltd.

(4) Mr. Raynes was appointed as a director on September 26, 2016.

(5) Mr. Linacre was appointed as a director on July 1, 2018

(6) Mr. Richards resigned as a director on June 30, 2018.

(7) The cash bonuses for Messrs. Welch and Reid for 2018 have been deferred pending the achievement of certain strategic targets.

Stock-based compensation

In 2018 the Company incurred share-based payment charges of US$996k (2017: US$417k) in respect of the above named directors.

Share options granted for directors who served during the year are as follows:

	Options held at January 1, 2018	Granted during the year	Exercised during the year	Lapsed/cancelled during the year	Options held at December 31, 2018
Executive directors					
Paul Welch	1,570,500	732,337(1)	-	-	2,302,337
Mark Reid	955,555	561,798(1)	-	-	1,517,353
Non-executive directors					
Michael Doyle	320,000	-	-	-	320,000
David Mitchell	320,000	-	-	-	320,000
David Richards	320,000	-	(213,333)(2)	(106,667)(2)	-
Michael Raynes	160,000	-	-	-	160,000
Timothy Linacre	-	-	-	-	-

(1) The share options granted to Messrs. Welch and Reid were under the Corporation's Long Term Incentive Plan ("LTIP").

(2) On 30 August 2018, Mr. Richards exercised 213,333 vested options (granted under the Canadian Stock option plan), in accordance with the 90-day post-leaving exercise period stipulated by the Canadian Stock option plan. The remaining 106,667 unvested options were cancelled.

See note 17 to the Consolidated Financial Statements for the year ended December 31, 2018 for further details.

Corporate Governance Statement

General

The board of directors (the “Board”) of SDX Energy Inc. (the “Corporation”) recognizes that good corporate governance is of fundamental importance to the success of the Corporation. The Corporation’s governance practices are the responsibility of the board.

This Statement of Corporate Governance Practices sets out the board’s assessment of the Corporation’s governance practices in accordance with National Instrument 58-101 - Disclosure of Corporate Governance Practices (“NI 58-101”) and National Policy 58-201 - Corporate Governance Guidelines (“NP 58-201”). The Corporation’s governance practices are generally consistent with the practices and guidelines set out in NI 58-101 and NP 58-201.

Board of Directors

The Corporation’s board of directors consists of six members: Michael Doyle, Paul Welch, David Mitchell, Timothy Linacre, Mark Reid, and Michael Raynes. The board of directors has reviewed the status of each director to determine whether such director is “independent” as defined in NI 58-101. As a result of this review, and after consideration of all business, family, and other relationships among the directors and the Corporation, the board of directors has determined that Messrs. Doyle, Mitchell, Linacre, and Raynes are each independent within the meaning of NI 58-101. Messrs. Welch and Reid are not independent under NI 58-101 as they continue to be officers of the Corporation.

Directorships

Directorships held by directors of the Corporation in other reporting issuers are set forth below:

Director	Directorships held
Michael Doyle	Richmond Road Capital Corp. Colson Capital Corp.

Orientation and continuing education

The board of directors is responsible for the orientation and education of new members of the board of directors and all new directors are provided with copies of the Corporation’s board and committee mandates and policies, the Corporation’s by-laws, documents from recent board meetings and other reference materials relating to the duties and obligations of directors, and the business and operations of the Corporation. New directors are also provided with opportunities for meetings and discussions with senior management and other directors. Prior to joining the board, each new director meets with the chief executive officer of the Corporation. The CEO is responsible for outlining the business and prospects of the Corporation, both positive and negative, with a view to ensuring that all new directors are properly informed before taking up their duties on the board. Each new director is also given the opportunity to meet with the auditors and counsel to the Corporation. As part of the annual board of directors’ assessment process, the board determines whether any additional education and training is required for its members.

Ethical business conduct

As part of their overall responsibility to good stewardship, the directors encourage and promote a culture of ethical business conduct through communication and oversight. In addition, the Corporation has adopted a code of conduct which addresses the Corporation’s continuing commitment to integrity and ethical behaviour. The code of conduct establishes procedures that allow directors, officers, and employees of the Corporation to submit their concerns to the chief executive officer or the chairman of the board regarding questionable ethical, moral, accounting or auditing matters, on a confidential basis and without fear of retaliation. To the Corporation’s knowledge, there have been no departures from this code of conduct that would necessitate the filing of a material change report. A copy of the code of conduct is available to review at the head office of the Corporation during business hours.

Nomination of directors

The board of directors as a whole is responsible for identifying suitable candidates to be recommended for election to the board by the shareholders of the Corporation, with the goal of ensuring that the board consists of an appropriate number of directors who collectively possess the competencies identified as being appropriate to the effectiveness of the board as a whole.

Compensation

The Compensation Committee is responsible for reviewing the Corporation’s overall compensation strategy, and is responsible for reviewing and recommending for approval the salaries and compensation of the Corporation’s executive officers.

The Compensation Committee also reviews the compensation of the outside directors on an annual basis, taking into account such matters as time commitment, responsibility, and compensation provided by comparable organizations.

See page 25 for details of compensation paid to directors during 2018.

Board Committees

The Corporation's board of directors has three committees, the Audit Committee, the Compensation Committee, and the Reserves Committee.

Audit Committee

The Audit Committee consists of Timothy Linacre (chair), Michael Doyle, and Michael Raynes. All members of the Audit Committee have been determined to be independent, and all members are considered to be financially literate, as such terms are defined in National Instrument 52 110 - Audit Committees ("NI 52 110").

The Audit Committee of the Corporation is a committee of the board established for the purpose of overseeing the accounting and financial reporting process of the Corporation. The Audit Committee has set out its responsibilities and composition requirements needed to fulfill its oversight in relation to the Corporation's internal accounting standards and practices, financial information, accounting systems, and procedures. See the Company website, www.sdxenergy.com, for a copy of the Audit Committee terms of reference.

The Corporation has not adopted specific policies and procedures for the engagement of non-audit services, however, the duties of the Audit Committee include the review and pre-approval of all non-audit services to be provided by the external auditor's firm or its affiliates (including estimated fees) and the consideration of the effect of such services on the independence of the external audit.

Compensation Committee

The Compensation Committee is comprised of Michael Raynes (chair), David Mitchell, and non-management members of the board of directors. It is required to convene at least annually.

The Compensation Committee exercises general responsibility regarding the overall compensation policy for the senior employees and executive officers of the Corporation. Subject to the approval of the board, it is responsible for: (i) recommending the salary and benefits of the chief executive officer, subject to terms of any existing contractual arrangements; (ii) recommending the general compensation structure and policies and programs for the Corporation and the salary and benefit levels for the senior officers and management; (iii) reviewing the Corporation's stock option plan and Long-Term Incentive Plan and authorizing their use, determining the number of options, and the terms thereof, that may be issued under the stock option plan and Long-Term Incentive Plan of the Corporation during any particular period and issuing or authorizing the issuance of such options in accordance with the plans; (iv) reviewing and making recommendations to the board on issues that arise in relation to any employment contracts in force from time to time; (v) reviewing annually all other benefit programs for salaried personnel; (vi) reviewing and approving severance arrangements for senior officers and management; (vii) reviewing the executive compensation disclosure required to be included in the information circular for the shareholders' annual meeting; (viii) recommending the compensation for members of the board and committee members, including the compensation of the chair of the board and any chair of a board committee; (ix) reviewing and making recommendations on the succession plan for the chief executive officer and for key employees of the Corporation; and (x) reviewing and making recommendations on any material changes in human resources policy, procedure, remuneration, and benefits.

Reserves Committee

The board of directors has adopted a mandate for the Reserves Committee, which is currently comprised of David Mitchell (chair) and Michael Doyle. The Reserves Committee is responsible for meeting with the independent engineering firm commissioned to conduct the reserves evaluation on the Corporation's oil and gas assets and to discuss the results of such evaluation with independent evaluators and management. The Reserves Committee's responsibilities include reviewing management's recommendations for the appointment or proposed changes of independent evaluators, reviewing the Corporation's procedures for providing information to the independent evaluators, meeting with management and the independent evaluator to review the reserves data and report, including any restrictions imposed by management or significant issues on which there has been a disagreement with management and reviewing reserve additions and revisions which occur from one report to the next, recommending to the board of directors whether to approve the content of the independent evaluators' report, reviewing the Corporation's procedures for reporting on other information associated with oil and gas-producing activities and generally reviewing all public disclosure of estimates of the Corporation's reserves. The Reserves Committee meets at least once annually or otherwise as circumstances warrant.

Assessments

The Compensation Committee is responsible for developing an annual assessment of the overall performance of the board and its committees. The objective of this review is to contribute to a process of continuous improvement in the board's execution of its responsibilities. To date, the Compensation Committee and the board have not put into place a formal process for assessing the effectiveness of the board as a whole, its committees, or individual directors, but will consider implementing one in the future should circumstances warrant. Based on the Corporation's size, stage of development, and the number of individuals on the board of directors, the Compensation Committee and the board consider a formal assessment process to be inappropriate at this time. The Compensation Committee and the board plan to continue evaluating the board's effectiveness on an ad hoc basis.

Focused on North Africa

South Disouq: Ibn Yunus, SD-4X and SD-3X discoveries in 2018. First gas targeted H1 2019 at 50-60MMscf/d

9,100boe/d

Production

Combined Egyptian and Moroccan daily average gross production for the year ended December 31, 2018

24.6MMboe

Reserves

Asset reserves (gross) - North West Gemsa, Meseda, South Disouq and Morocco as at December 31, 2018

Management's Discussion & Analysis
for the three and twelve months ended December 31, 2018
(prepared in US$)

Basis of presentation
The following Management's Discussion and Analysis (the "MD&A") dated March 22, 2019 is a review of results of operations and the liquidity and capital resources of SDX Energy Inc. (the "Company" or "SDX"), for the three and 12 months ended December 31, 2018. This MD&A should be read in conjunction with the accompanying Consolidated Financial Statements for the year ended December 31, 2018.

The Company's production and reserves are reported in barrels of oil equivalent ("boe"). Boe may be misleading, particularly if used in isolation. A boe conversion ratio for natural gas of 6 Mcf (6,000 cubic feet): 1 boe has been used, which is based on an energy equivalency conversion method primarily applicable at the burner tip and does not necessarily represent a value equivalency at the wellhead. As the value ratio between natural gas and crude oil based on the current prices of natural gas and crude oil is significantly different from the energy equivalency of 6:1, using a conversion on a 6:1 basis may be misleading as an indication of value.

As discussed in this MD&A and in note 4 to the Consolidated Financial Statements, on January 27, 2017 the Company acquired the Egyptian and Moroccan assets of Circle Oil plc. To provide the reader with a better understanding of the enlarged business, this MD&A contains certain explanations which analyze the performance of the Company as if the acquisition had taken place on January 1, 2017, using pro forma figures. These pro forma figures are clearly identified.

Certain information contained in this report is forward-looking and based upon assumptions and anticipated results that are subject to risks, uncertainties and other factors. Should one or more of these uncertainties materialize, or should the underlying assumptions prove incorrect, actual results may vary materially from those expected. See "Forward-looking statements", below.

All financial references in this MD&A are in thousands of United States dollars, unless otherwise noted.

Additional information on the Company can be found on SEDAR at www.sedar.com.

Forward-looking statements
Certain statements included or incorporated by reference in this MD&A constitute forward-looking statements or forward-looking information under applicable securities legislation. Such forward-looking statements or information are for the purpose of providing information about Management's current expectations and plans relating to the future. Readers are cautioned that reliance on such information may not be appropriate for other purposes, such as making investment decisions. Forward-looking statements or information typically contain statements with words such as "anticipate", "believe", "expect", "plan", "intend", "estimate", "propose", "project" or similar words suggesting future outcomes or statements regarding an outlook. Forward-looking statements or information in this MD&A include, but are not limited to, statements or information with respect to: business strategy and objectives; development plans; exploration plans; acquisition and disposition plans and the timing thereof; reserve quantities and the discounted present value of future net cash flows from such reserves; future production levels; capital expenditures; net revenue; operating and other costs; royalty rates and taxes.

Forward-looking statements or information are based on a number of factors and assumptions that have been used to develop such statements and information but may prove to be incorrect. Although the Company believes that the expectations reflected in such forward-looking statements or information are reasonable, undue reliance should not be placed on forward-looking statements because the Company can give no assurance that such expectations will prove to be correct. In addition to other factors and assumptions that may be identified in this MD&A, assumptions have been made regarding, among other things: the impact of increasing competition; the general stability of the economic and political environment in which the Company operates; the timely receipt of any required regulatory approvals; the ability of the Company to obtain qualified staff, equipment and services in a timely and cost-efficient manner; the ability of the operator of the projects which the Company has an interest in to operate the field in a safe, efficient and effective manner; the ability of the Company to obtain financing on acceptable terms; field production rates and decline rates; the ability to replace and expand oil and natural gas reserves through acquisition, development or exploration; the timing and costs of pipeline, storage and facility construction and expansion and the ability of the Company to secure adequate product transportation; future oil and natural gas prices; currency, exchange and interest rates; the regulatory framework regarding royalties, taxes and environmental matters in the countries in which the Company operates; and the ability of the Company to successfully market its oil and natural gas products. Readers are cautioned that the foregoing list is not exhaustive of all factors and assumptions that may have been used.

Forward-looking statements or information are based on current expectations, estimates and projections that involve a number of risks and uncertainties that could cause actual results to differ materially from those anticipated by the Company and described in the forward-looking statements or information. The risks and uncertainties that may cause actual results to differ materially from the forward-looking statements or information include, among other things: the ability of Management to execute its business plan; general economic and business conditions; the risk of war or instability affecting countries or states in which the Company operates; the risks of the oil and natural gas industry, such as operational risks in exploring for, developing and producing crude oil and natural gas; market demand; the possibility that government policies or laws may change or governmental approvals may be delayed or withheld; risks and uncertainties involving geology of oil and natural gas deposits; the uncertainty of reserves estimates and reserves life; the ability of the Company to add production and reserves through acquisition, development and exploration activities; the Company's ability to enter into or renew production sharing concession; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; the uncertainty of estimates and projections relating to production (including decline rates), costs and expenses; fluctuations in oil and natural gas prices, foreign currency exchange, and interest rates; risks inherent in the Company's marketing operations, including credit risk; uncertainty in amounts and timing of oil revenue payments; health, safety and environmental risks; risks associated with existing and potential future law suits and regulatory actions against the Company; uncertainties as to the availability and cost of financing; and financial risks affecting the value of the Company's investments. Readers are cautioned that the foregoing list is not exhaustive of all possible risks and uncertainties.

Use of estimates

The preparation of Consolidated Financial Statements in conformity with IFRS requires management to make estimates and assumptions based on information available at the time. These estimates and assumptions affect the reported amounts of assets, particularly the recoverability of accounts receivable and the acquisition costs of property, plant, and equipment. Estimates and assumptions also affect the recording of liabilities and contingent liabilities at the date of the Consolidated Financial Statements and the reported amounts of revenues and expenses during the reporting period. Due to various factors affecting future costs and operations, actual results could differ from management's best estimates.

Business combination

On January 27, 2017 the Company acquired the Egyptian and Moroccan assets of Circle Oil plc.

In preparing the Consolidated Financial Statements, the Company must conform with IFRS 3 - Business Combinations. This means that in the Consolidated Financial Statements for the three and 12 months ended December 31, 2018, the 2018 figures in the Consolidated Statement of Comprehensive Income relate to the enlarged entity, whereas the 2017 comparative figures contain one month of revenue and costs for the legacy SDX business only, and 11 months for the enlarged entity.

Non-IFRS measures

The MD&A contains the terms "netback" and "EBITDAX", which are not recognized measures under IFRS. The Company uses these measures to help evaluate its performance.

Netback

EBITDAX is a non-IFRS measure that represents earnings before interest, tax, depreciation, amortization, exploration expense, and impairment, which is operating income/(loss) adjusted for the add-back of depreciation and amortization, exploration expense, and impairment of property, plant, and equipment (if applicable). EBITDAX is presented so that users of the financial statements can understand the cash profitability of the Company, excluding the impact of costs attributable to exploration activity, which tend to be one-off in nature, and the non-cash costs relating to depreciation, amortization, and impairments. EBITDAX may not be comparable to similar measures other companies use. See EBITDAX reconciliation to operating income/(loss) in note 21 to the Consolidated Financial Statements.

EBITDAX

EBITDAX is a non-IFRS measure that represents earnings before interest, tax, depreciation, amortization, exploration expense, and impairment, which is operating income/(loss) adjusted for the add-back of depreciation and amortization, exploration expense, and impairment of property, plant, and equipment (if applicable). EBITDAX is presented so that users of the financial statements can understand the cash profitability of the Company, excluding the impact of costs attributable to exploration activity, which tend to be one-off in nature, and the non-cash costs relating to depreciation, amortization, and impairments. EBITDAX may not be comparable to similar measures other companies use. See EBITDAX reconciliation to operating income/(loss) in note 21 to the Consolidated Financial Statements.

SDX's business strategy and work program

SDX's business

SDX is engaged in the exploration, development and production of oil and gas. Current activities are concentrated in Egypt and Morocco, where the Company has interests in seven concessions with short and long-term potential. The Company's strategy is to develop the potential of its existing concessions while seeking growth opportunities within its North Africa region of focus. The Company intends to create shareholder value by enhancing the value of its assets and through significant growth in production volumes, cash flow, and earnings.

Strategy

The Company's strategy is to create value through organic and inorganic low-cost production growth and low-cost, high-impact exploration success. The Company is underpinned by a portfolio of low-cost, onshore producing assets combined with onshore exploration prospects in Egypt and Morocco.

SDX intends to increase production and cash flow generation organically through an active work program consisting of workover, exploration, and development wells in its existing portfolio in Egypt and Morocco, combined with high impact exploration drilling in both countries. In the pursuit of this strategy, SDX also intends to leverage its balance sheet, early mover advantage, and its regional network to grow through the acquisition of undervalued and/or underperforming producing assets (located principally in onshore North Africa), while maintaining a strict financial discipline to ensure the efficient use of funds. On January 27, 2017, the Company completed the acquisition of the Egyptian and Moroccan assets of Circle Oil plc for US$28.1 million after working capital adjustments and raised US$40.0 million (before expenses) to fund this acquisition and provide additional capital for investment in the enlarged group portfolio.

Further details on this transaction can be found in note 4 to the Consolidated Financial Statements.

The Company currently holds working interests ("WI") in three development/producing concessions and one exploration concession in Egypt, and one development/producing concession and two exploration concessions in Morocco. These are:

- Egypt (development/producing) - The NW Gemsa Concession ("NW Gemsa") - (10% WI up to January 27, 2017, 50% WI thereafter);
- Egypt (development/producing) - The Block-H Meseda production service agreement ("Meseda") - (50% WI);
- Egypt (development) - The South Ramadan Concession ("South Ramadan") - (12.75% WI);
- Egypt (exploration) - The South Disouq Concession ("South Disouq") - (55% WI);
- Morocco (development/producing) - The Sebou Concession ("Sebou") - (75% WI);
- Morocco (exploration) - The Lalla Mimouna Concession ("Lalla Mimouna") - (75% WI); and
- Morocco (exploration) - The Gharb Centre Concession ("Gharb Centre") - (75% WI).

The Moulay Bouchta Ouest exploration licence (SDX 75% working interest and operator), was awarded to the Company in February 2019 and is expected to be granted in Q2 2019.

2019 Work program

The Company's capital expenditure program for 2019 is expected to be approximately US$36.0 million. In Morocco, the Company is planning for a 12-well campaign, with drilling set to begin in late Q3/early Q4 2019 and complete during H1 2020. During this campaign, the LNB-1 and LMS-1 wells in Lalla Mimouna, originally drilled in 2018, will be re-tested, with the remainder of the program's targets coming from the recently acquired Gharb Centre 3D seismic. It is anticipated that three wells from the 12-well program will be drilled in 2019. The 2019 total gross capex is expected to be approximately US$10.0 million, with SDX's share being approximately US$8.0 million. Of this US$8.0 million, US$6.0 million relates to the three planned wells and US$2.0 million to the Company's share of facilities and field maintenance capex. The Company is targeting gross production of 9-11 MMscf/d of conventional natural gas sales by the end of 2019.

In South Disouq the Company is investing approximately US$22.0 million, US$18.5 million of which is for its share of the South Disouq development activities and US$3.5 million is for two exploration wells. During H1 2019, SDX will complete construction of the Central Processing Facility, the 10km export pipeline and the tie-ins for the four existing production wells. First gas is targeted for mid-2019, at a gross plateau production rate of between 50-60 MMscf/d, with the conventional natural gas being sold to the state at a price of US$2.85/Mcf. Prospect inventory for future drilling is expected to increase with the interpretation of the recently acquired 170km² of 3D seismic in the southern section of the concession. The Company is planning to drill two further exploration wells in 2019, with multiple additional conventional gas prospects and a conventional oil prospect also identified for future drilling.

In Meseda, c.US$4.0 million will be contributed to cover the Company's share of the cost of drilling one Rabul well and one Meseda well. The operator also plans to replace up to five electrical submersible pumps ("ESPs") in the wider Meseda area and upgrade water handling capabilities at the field facilities. Gross capex in 2019 is expected to be approximately US$8.0 million (US$4.0 million net to SDX of which US$1.6 million relates to the two planned wells and US$2.4 million to ESP replacements and the facilities upgrade). The Company has 2019 gross production guidance of 4,000-4,200 barrels of oil per day (bbl/d).

In North West Gemsa, the Company will be investing c.US$2.0 million for its share of a 10-well workover program, as the field is now fully developed and no additional wells are required. Given field decline, the Company expects 2019 gross production of 3,400-3,600 boe/d.

In South Ramadan, the Company continues to review technical data from the SRM-3 well result and will provide further updates to the market in due course.

Operational and financial highlights

In accordance with Canadian industry practice, production volumes and revenues are reported on a Company interest basis, before the deduction of royalties.

		Three months ended December 31		Twelve months ended December 31	
US$'000s unless stated	Prior quarter(1)	**2018**	2017	**2018**	2017
NW Gemsa oil sales revenue	12,936	**10,439**	9,087	**42,260**	31,641
Royalties	(5,552)	**(4,480)**	(3,900)	**(18,137)**	(13,580)
Net oil revenue	7,384	**5,959**	5,187	**24,123**	18,061
Block-H Meseda production service fee revenues	4,094	**4,083**	2,276	**14,185**	8,045
Morocco gas sales revenue	3,754	**3,496**	3,646	**14,614**	12,425
Royalties	(216)	**(118)**	-	**(334)**	-
Net Morocco gas sales revenue	3,538	**3,378**	3,646	**14,280**	12,425
Net other products revenue	391	**420**	(105)	**1,091**	635
Total net revenue	15,407	**13,840**	11,004	**53,679**	39,166
Direct operating expense	(3,380)	**(3,392)**	(2,526)	**(11,934)**	(10,254)
Netback: NW Gemsa oil (2)	5,452	**4,085**	3,648	**17,475**	11,563
Netback: Block-H Meseda	3,070	**2,894**	1,619	**10,234**	5,377
Netback: Morocco gas	3,114	**3,049**	3,316	**12,945**	11,337
Netback: Other products (2)	391	**420**	(105)	**1,091**	635
Netback (pre-tax)	12,027	**10,448**	8,478	**41,745**	28,912
EBITDAX	10,995	**7,103**	7,959	**34,306**	21,401
NW Gemsa oil sales (bbl/d)	1,987	**1,808**	1,710	**1,743**	1,733
Block-H Meseda production service fee (bbl/d)	802	**864**	561	**734**	595
Morocco gas sales (boe/d)	615	**648**	680	**646**	596
Other products sales (boe/d)	485	**604**	310	**451**	313
Total sales volumes (boe/d)	3,889	**3,924**	3,261	**3,574**	3,237
NW Gemsa oil sales volumes (bbls)	182,803	**166,296**	157,302	**636,249**	632,592
Block-H Meseda production service fee volumes (bbls)	73,761	**79,530**	51,599	**267,834**	217,135
Morocco gas sales volumes (boe)	56,602	**59,573**	62,543	**235,694**	217,655
Other products sales volumes (boe)	44,575	**55,564**	28,550	**164,468**	114,200
Total sales volumes (boe)	357,741	**360,963**	299,994	**1,304,245**	1,181,582
Brent oil price (US$/bbl)	$75.18	**$67.75**	$61.52	**$71.06**	$54.25
West Gharib oil price ($US/bbl)	$65.36	**$60.09**	$53.59	**$62.05**	$45.37
Realized NW Gemsa oil price (US$/bbl)	$70.76	**$62.77**	$57.77	**$66.42**	$50.02
Realized Block-H Meseda service fee (US$/bbl)	$55.50	**$51.34**	$44.11	**$52.96**	$37.05
Realized oil sales price and service fees (US$/bbl)	$66.38	**$59.07**	$54.39	**$62.43**	$46.70
Realized Morocco gas price (US$/mcf)	$11.05	**$9.78**	$9.72	**$10.33**	$9.51
Total royalties (US$/boe)	$16.88	**$13.53**	$9.89	**$14.86**	$11.28
Operating costs (US$/boe)	$9.45	**$9.40**	$8.42	**$9.15**	$8.68
Netback (US$/boe)	$33.62	**$28.94**	$28.26	**$32.01**	$24.47
Capital expenditures	11,017	**8,316**	15,302	**44,023**	21,040

(1) Three months ended September 30, 2018

(2) When calculating netback for NW Gemsa oil and other products (NW Gemsa natural gas and NGLs), all NW Gemsa operating costs are allocated to oil, as natural gas and NGLs are associated products with assumed nil incremental operating costs.

Operational and financial highlights (continued)

Oil sales and production service fee revenues

		Three months ended December 31		Twelve months ended December 31	
US$'000s	Prior quarter	**2018**	2017	**2018**	2017
Oil sales revenue	12,936	**10,439**	9,087	**42,260**	31,641
Production service fee revenues	4,094	**4,083**	2,276	**14,185**	8,045
Total oil sales and production service fees revenue	17,030	**14,522**	11,363	**56,445**	39,686

Oil sales revenue (relates to NW Gemsa only)

Oil sales volumes

Total oil sales volumes for the three and 12 months ended December 31, 2018 averaged 1,808 bbl/d and 1,743 bbl/d, compared to 1,710 bbl/d and 1,733 bbl/d for the comparative periods of the prior year.

Total sales volumes increased by 3,657 barrels, 1%, to 636,249 barrels in the 12 months ended December 31, 2018 compared to 632,592 barrels in the comparative period of 2017. On a pro forma basis, assuming that the Circle Oil acquisition had occurred on January 1, 2017, sales volumes decreased by 48,920 barrels, from 685,169 barrels, 7%, due to natural reservoir decline, partly mitigated by drilling and well workovers during 2018. The NW Gemsa concession reached its peak production rate in Q4 2014.

Total sales volumes decreased by 16,507 barrels, 9%, in the three months ended December 31, 2018 compared to the previous quarter. This decrease was driven by a number of operational factors, including water breakthrough at one well, increased water cut and pump repairs in several other wells.

Oil sales pricing

The Company is exposed to the volatility of commodity price markets for all its oil sales and service fee volumes and changes in the foreign exchange rate between the Egyptian pound and the US dollar. The Operational and Financial Highlights table in this MD&A outlines the changes in various benchmark commodity prices and the economic parameters that affect the prices received for the Company's oil sales and service fee volumes.

During the 12 months ended December 31, 2018 the Brent price ranged from a high of US$85.63 per barrel on October 2, 2018 to a low of US$50.57 per barrel on December 28, 2018. The Company does not currently hedge any of its production.

For the three and 12 months ended December 31, 2018, the Company's oil sales achieved an average realized price per barrel of oil of US$62.77 and US$66.42 respectively, compared to the average Brent Oil price ("Brent") for the periods of US$67.75 and US$71.06; a discount of US$4.98 and US$4.64, equating to 7% per barrel respectively. The Company receives a discount to Brent due to the quality of the oil produced and a further deduction is reflected in the realized price because of marketing fees. For the three and 12 months ended December 31, 2017, the Company achieved average realized prices of US$57.77 and US$50.02 respectively.

		Three months ended December 31		Twelve months ended December 31	
US$'000s	Prior quarter	**2018**	2017	**2018**	2017
Oil sales revenue (US$'000s)	12,936	**10,439**	9,087	**42,260**	31,641
Realized price per bbl ($/bbl)	70.77	**62.77**	57.77	**66.42**	50.02

Operational and financial highlights (continued)

Oil sales revenue variance from prior year

For the 12 months ended December 31, 2018 (compared to the 12 months ended December 31, 2017) oil sales revenue increased as a result of an increase in sales price of US$10.4 million, 33%, and an increase in sales volume of US$0.2 million, 1%, reflecting the impact of 12 months' increased interest in the concession, versus 11 months in 2017, partly offset by natural reservoir decline.

US$'000s	
Twelve months ended December 31, 2017	31,641
Price variance	10,436
Production variance	183
Twelve months ended December 31, 2018	**42,260**

On a pro forma basis, and assuming that the Circle Oil acquisition had occurred on January 1, 2017, the variance is as follows:

US$'000s	
Twelve months ended December 31, 2017	34,270
Price variance	10,436
Production variance	(2,446)
Twelve months ended December 31, 2018	**42,260**

On this basis, improved pricing resulted in a 30% increase in revenue, partly offset by a 7% reduction in sales volumes, driven by natural reservoir decline.

Oil sales revenue variance from prior quarter

For the three months ended December 31, 2018 (compared to the three months ended September 30, 2018) oil sales revenue decreased by US$2.5 million, 19%, due to a decrease in sales pricing of US$1.3 million, 10%, and a decrease in sales volume of US$1.2 million, 9%, due to a number of operational factors, including water breakthrough at one well, increased water cut, and pump repairs in several other wells.

US$'000s	
Three months ended September 30, 2018	12,936
Price variance	(1,331)
Production variance	(1,166)
Three months ended December 31, 2018	**10,439**

Production service fees (relates to Block-H Meseda (including Rabul))

Production service fee volumes

The Company records service fee revenue relating to the oil production that is delivered to the State Oil Company ("GPC") from the Meseda and Rabul areas of Block H. The Company is entitled to a service fee of between 19.0% and 19.25% of the delivered volumes and has a 50% working/paying interest. The service fee revenue is based on the current market price of West Gharib crude oil, adjusted for a quality differential.

Total production service fee volumes for the three months ended December 31, 2018 increased by 27,931 barrels, 54%, to 79,530 barrels, compared to the three months ended December 31, 2017. This increase in volumes was the result of the Rabul discoveries coming on stream in late Q4 2017/early 2018, the MSD-16 and MSD-15 discoveries in Q2 and Q3 2018, and the continued impact of well workovers. Barrels produced per day increased from Q3 2018 by 62bbl/d, 8%, to 864bbl/d, with strong production from the MSD-15 discovery and workover results being the main factors.

Operational and financial highlights (continued)

Production service fees (relates to Block-H Meseda (including Rabul)) (continued)

Production service fee pricing

For the three and 12 months ended December 31, 2018 the Company received an average service fee per barrel of oil of US$51.34 and US$52.96 respectively, compared to the average West Gharib prices for the periods of US$60.09 and US$62.05, a discount of US$8.75 and US$9.09, equating to 15% per barrel respectively. The Company receives a discount to West Gharib because of the quality of the oil produced. For the three and 12 months ended December 31, 2017, the Company received average service fees per barrel of oil of US$44.11 and US$37.05 respectively.

		Three months ended December 31		Twelve months ended December 31	
US$'000s	Prior quarter	**2018**	2017	**2018**	2017
Production service fee revenues ($'000s)	4,094	**4,083**	2,276	**14,185**	8,045
Realized service fee per bbl ($/bbl)	55.50	**51.34**	44.11	**52.96**	37.05

Production service fee variance from prior year

For the 12 months ended December 31, 2018 (compared to the 12 months ended December 31, 2017) the increase in production service fee revenue of US$6.2 million, 78%, to US$14.2 million is the result of an increase in realized sales price of US$4.3 million, 54%, and increased production from the Rabul discoveries, the recently drilled MSD-16 and MSD-15 wells, and field workovers of US$1.9 million, 23%.

US$'000s	
Twelve months ended December 31, 2017	8,045
Price variance	4,262
Production variance	1,878
Twelve months ended December 31, 2018	**14,185**

Production service fee variance from prior quarter

For the three months ended December 31, 2018 (compared to the three months ended September 30, 2018) production service fee revenue was flat at US$4.1 million. This was because the decrease in realized sales price (US$0.3 million, 7%), was offset by increased production from the recently drilled MSD-15 well and ongoing workover activity (US$0.3 million, 7%).

US$'000s	
Three months ended September 30, 2018	4,094
Price variance	(331)
Production variance	320
Three months ended December 31, 2018	**4,083**

Morocco gas sales revenue

		Three months ended December 31		Twelve months ended December 31	
US$'000s	Prior quarter	**2018**	2017	**2018**	2017
Morocco - Sebou	3,754	**3,496**	3,646	**14,614**	12,425
Realized price per mcf ($/mcf)	11.05	**9.78**	9.72	**10.33**	9.51

The Company sells natural gas to five industrial customers in Kenitra, northern Morocco.

Morocco gas sales variance from prior year

For the 12 months ended December 31, 2018 (compared to the 12 months ended December 31, 2017) the increase in production service fee revenue of US$2.2 million, 18%, to US$14.6 million is the result of an increase in realized sales price of US$1.2 million, 10%, because of higher contract pricing at an existing customer, and increased production reflecting the impact of 12 months' ownership of the business, versus 11 months in 2017. On a pro forma basis, production was stable year on year, with reduced demand from an existing customer offset by new customer connections in Q4.

US$'000s	
Twelve months ended December 31, 2017	12,425
Price variance	1,159
Production variance	1,030
Twelve months ended December 31, 2018	**14,614**

Operational and financial highlights (continued)

Morocco gas sales variance from prior quarter

For the three months ended December 31, 2018 (compared to the three months ended September 30, 2018) a decreased realized sales price of US$0.5 million, 13%, due to a sales tax true up and a weaker Moroccan dirham against the US$. This was partly offset by increased production as the result of new customer connections and higher demand from existing customers following the completion of planned maintenance.

US$'000s	
Three months ended September 30, 2018	3,754
Price variance	(455)
Production variance	197
Three months ended December 31, 2018	**3,496**

Other products sales revenue (relates to NW Gemsa only)

The Company sells associated gas and natural gas liquids ("NGLs") from its NW Gemsa concession to the Egyptian state. In December 2017, the operator of the NW Gemsa concession advised that the invoices it had issued were based on erroneous volumes and prices and that the revised invoices resulted in lower revenues. The adjustment was made during Q4 2017, with the portion relating to the acquired Circle Oil receivables adjusted through the gain on acquisition (US$1.3 million), and the remainder through net revenue, resulting in a net negative US$0.1 million revenue being recognized. A further correction was necessary for Q1 2018, with US$0.2 million being adjusted through the gain on acquisition and US$0.2 million through net revenue.

Royalties

Royalties fluctuate in Egypt (payable on NW Gemsa production only) from quarter to quarter because of changes in production and the impact of commodity prices on the amount of cost oil allocated to the contractors. In turn, there is an impact on the amount of profit oil from which royalties are calculated.

Royalties for crude oil sales per boe by concession are as follows:

		Three months ended December 31		Twelve months ended December 31	
US$'000s	Prior quarter	**2018**	2017	**2018**	2017
NW Gemsa	5,552	**4,480**	3,900	**18,137**	13,580
Total royalties (US$/boe) by concession	30.37	**26.94**	24.79	**28.51**	21.47

The concession agreements allow for the recovery of operating and capital costs through a cost oil allocation. This allocation has an impact on the government share of production as highlighted below (as at December 31, 2018 and December 31, 2017):

Concession	SDX's WI(1)	Cost oil to Contractors(2)	Capital cost recovered(2)	Operating cost recovered(2)	Excess oil to Contractor(3)	Profit oil to Contractor(4)
NW Gemsa (up to 10,000 bopd Gross)	50%	30%	5 years	Immediate	Nil	16.1%
NW Gemsa (10,000 bopd to 25,000 bopd Gross)	50%	30%	5 years	Immediate	Nil	15.4%
NW Gemsa - Gas and LPG	50%	30%	5 years	Immediate	Nil	18.2%

(1) WI denotes the Company's working interest. SDX's WI in the NW Gemsa asset increased to 50% from January 27, 2017 (previously 10%) following the acquisition of Circle Oil's Egyptian assets, which is described elsewhere in this MD&A.

(2) Cost oil is the amount of oil revenue that is attributable to SDX and its joint venture partners (the "Contractor") subject to the limitation of the cost recovery pool. Oil revenue up to a specified percentage is available for recovery by the Contractor for costs incurred in exploring and developing the concession. Operating costs and capital costs are added to a cost recovery pool (the "Cost Pool"). Capital costs for exploration and development expenditures are amortized into the Cost Pool over a specified number of years, with operating costs added to the Cost Pool as they are incurred.

(3) If the costs in the Cost Pool are less than the cost oil attributable to the Contractor, the shortfall, referred to as excess cost oil ("Excess Oil"), reverts 100% to the State.

(4) Profit oil is the amount of oil revenue that is attributable to the Contractor.

For the purposes of the operating and financial highlights disclosure in the MD&A, royalties per boe for the Company are calculated by dividing total royalties by total production for all assets.

In Morocco, sales-based royalties become payable when certain inception-to-date production thresholds are reached, according to the terms of each exploitation concession. During Q3 2018, natural gas production from the Ksiri exploitation concession exceeded such a threshold, resulting in the recognition of royalties amounting to 5% of revenue from this concession from that point forward. US$0.3 million of royalties have been recognized in the Income Statement for the 12 months ended December 31, 2018. Royalty payments are made directly to the Government of Morocco biannually, with the next payment due in Q1 2019.

Operational and financial highlights (continued)

Direct operating expense

The direct operating costs per concession were:

US$'000s	Prior quarter	Three months ended December 31 2018	Three months ended December 31 2017	Twelve months ended December 31 2018	Twelve months ended December 31 2017
NW Gemsa	1,932	**1,874**	1,539	**6,648**	6,498
Block-H Meseda	1,024	**1,189**	657	**3,951**	2,668
Morocco - Sebou	424	**329**	330	**1,335**	1,088
Other	-	**-**	-	**-**	-
Total direct operating expense	3,380	**3,392**	2,526	**11,934**	10,254

The direct operating costs per boe per concession were:

US$/boe	Prior quarter	Three months ended December 31 2018	Three months ended December 31 2017	Twelve months ended December 31 2018	Twelve months ended December 31 2017
NW Gemsa	8.50	**8.45**	8.28	**8.30**	8.70
Block-H Meseda	13.88	**14.95**	12.74	**14.75**	12.29
Morocco - Sebou	7.49	**5.52**	5.28	**5.66**	5.00
Total direct operating costs per concession	9.45	**9.40**	8.42	**9.15**	8.68

Direct operating costs for the three and 12 months ended December 31, 2018 were US$3.4 million and US$11.9 million respectively, compared to US$2.5 million and US$10.3 million respectively for the comparative period of the previous year. Prior quarter direct operating costs were in line with the current quarter.

NW Gemsa

NW Gemsa direct operating costs for the 12 months to December 31, 2018 were US$6.6 million, in line with the comparative period of the prior year. This reflects a full 12 months' costs following the additional interest acquired from Circle Oil, partly offset by cost reductions at the operator.

Block-H Meseda

Direct operating costs for the 12 months to December 31, 2018 for Block-H Meseda were US$1.3 million higher than the prior year owing to increased workover activity and increased production and were US$0.2 million higher than the prior quarter for the same reasons. The increased number of workovers resulted in an increased US$/boe cost of US14.95/boe in Q4 2018.

Morocco - Sebou

Direct operating costs for the 12 months to December 31, 2018 for Morocco were US$0.2 million higher than the comparative period of the prior year, which included only 11 months of the Morocco business following the acquisition of Circle Oil. The costs for 2018 also include the increased allocated costs of operational employees. Direct operating costs were US$0.1 million lower than the prior quarter as the result of higher partner billings, catching up prior periods.

Exploration and evaluation expense

For the 12 months ended December 31, 2018, exploration and evaluation expenses stood at US$5.7 million compared to US$0.2 million in the comparative period. The variance is due to the write-off of non-commercial wells drilled in Morocco (ELQ-1 and KSS-2: US$3.5 million) and South Disouq (Kelvin-1X: US$1.6 million) and increased new venture activity costs of US$0.6 million, which relates to various business development and early stage/pre-license initiatives. There were no wells written off in the comparative period.

Depletion, depreciation and amortization

For the 12 months ended December 31, 2018, depletion, depreciation, and amortization ("DD&A") amounted to US$17.3 million, compared to US$17.8 million in the comparative period. The reduction of US$0.5 million is the result of an upward 2P reserve revision in Morocco, partly offset by production growth in Block-H Meseda and a downward 2P reserve revision at NW Gemsa.

US$'000s	Twelve months ended December 31 2018	Twelve months ended December 31 2017
Depletion, depreciation and amortization	**17,268**	17,824
Per boe	**13.24**	15.08

The DD&A per concession was:

US$'000s	Twelve months ended December 31 2018	Twelve months ended December 31 2017
NW Gemsa	**7,763**	6,758
Block-H Meseda	**1,897**	1,094
Morocco - Sebou	**7,230**	9,885
Other	**378**	87
Total DD&A	**17,268**	17,824

Operational and financial highlights (continued)

Impairment expense

Following the reduction in oil price assumptions during Q4 2018, management tested the NW Gemsa asset for impairment, resulting in an estimated recoverable amount below net book value and an impairment expense of US$3.5 million. Please see note 9 to the Consolidated Financial Statements for further discussion.

General and administrative expenses

	Twelve months ended December 31	
US$'000s	**2018**	2017
Wages and employee costs	**6,433**	6,514
Consultants - inc. PR/IR	**544**	699
Legal fees	**272**	332
Audit, tax and accounting services	**968**	641
Public company fees	**602**	365
Travel	**348**	382
Office expenses	**1,051**	1,091
IT expenses	**426**	303
Service recharges	**(5,829)**	(3,907)
Ongoing general and administrative expenses	**4,815**	6,420
Transaction costs	**2,455**	2,373
Total net G&A	**7,270**	8,793

General and administrative ("G&A") costs for the 12 months ended December 31, 2018 were US$7.3 million, compared to US$8.8 million for the comparative period of the prior year, a decrease of US$1.5 million, or 17%.

The decrease of US$1.5 million is primarily due to the following:

	US$ millions	Analysis
Wages and employee costs	(0.1)	Wages and employee costs have decreased due to a lower bonus payment (US$0.3 million), lower Egyptian severance costs (US$0.3 million) and the absence in 2018 of US$0.5 million of 2016 bonus that was awarded and paid in 2017. These reductions were partly offset by increased headcount in London and Cairo (US$1.0 million), resulting in a net reduction of $0.1 million.
Consultants - inc. PR/IR	(0.2)	Consultant fees have reduced due to lower usage of contract staff and the absence in 2018 of one-off executive remuneration consultancy advice received in 2017.
Audit, tax and accounting services	0.4	Audit, tax and accounting services costs have increased due to required external advisor support with tax audits in both Morocco and Egypt (US$0.3 million) and an increased audit fee (US$0.1 million).
Public company fees	0.2	Public company fees have increased due to higher levels of corporate activity across a number of areas.
Service recharges	(1.9)	The higher service recharges resulted from an overall increase in business activity in 2018 (the drilling campaign in Morocco and drilling/development activity at South Disouq, US$1.8 million) and an increase in the recovery of indirect overhead recharges from concession partners (US$0.1 million).
Other	0.1	
Total decrease	**(1.5)**	

2018 transaction costs relate to a number of business development initiatives, including the proposed acquisition of a package of assets in Egypt from BP and the re-domicile of the Group from Canada to the UK. Transaction costs for 2017 were all associated with the Circle Oil acquisition.

Operational and financial highlights (continued)

Current taxes

Pursuant to the terms of the Company's concession agreements for NW Gemsa, the 40.4% corporate tax liability of the joint venture partners is paid by the Government of Egypt-controlled corporations ("Corporations") out of the profit oil attributable to the Corporations, and not by the Company. For accounting purposes, the corporate taxes paid by the Corporations are "grossed up" in the financial statements and included in net oil revenues and income tax expense, thereby having a net neutral impact on net income.

The Company has a "cash" corporate tax liability in relation to its production service agreement for Block-H Meseda because the Company's Egyptian subsidiary, SDX Energy Egypt (Meseda) Ltd, which is party to this concession, is subject to corporate tax. The Company's Moroccan operations benefit from a 10-year corporation tax holiday from first production. No taxation is due on Moroccan profits as at December 31, 2018.

	Twelve months ended December 31	
US$'000s	**2018**	2017
NW Gemsa	**5,036**	3,551
Block-H Meseda	**1,971**	1,017
Morocco - Sebou	**-**	-
Other	**14**	(27)
Total current taxes	**7,021**	4,541

Current taxes for the year ended December 31, 2018 were US$7.0 million, compared to US$4.5 million for the prior year. The variance is due to the acquisition of an additional 40% share in the NW Gemsa concession and improved profitability at both NW Gemsa and Block-H Meseda.

Net earnings

As per the Consolidated Financial Statements for the year ended December 31, 2018 the Company recorded a Total Comprehensive Income of US$0.1 million, compared to a Total Comprehensive Income of US$28.3 million for the year ended December 31, 2017, a reduction of US$28.2 million.

The main components of this difference are:

	US$ millions	Analysis
Gain on acquisition	(29.8)	Absence in 2018 of gain on acquisition of the Circle Oil assets recorded in the comparative period
Net revenues	14.5	Increase in net revenues in 2018 because of higher commodity prices, 12 months of revenue from the acquired Circle Oil assets versus 11 months in 2017, and higher production at Block-H Meseda.
Direct operating expense	(1.6)	Increase in direct operating expense in 2018 because higher production at Block-H Meseda and 12 months of costs from the acquired Circle Oil assets versus 11 months in 2017.
Depletion, depreciation, and amortization	0.5	Lower DD&A charge in 2018 is the result of an upward 2P reserve revision in Morocco, partly offset by production growth in Block-H Meseda and a downward 2P reserve revision at NW Gemsa.
Impairment expense	(3.5)	The NW Gemsa asset was impaired by US$3.5 million in 2018. No impairment was recognised in 2017.
Ongoing general and administrative expenses	(1.5)	Lower G&A expenses due to increased service recharges (US$1.9 million) driven by higher operational activity in Morocco and South Disouq offset by a net US$0.3 million increase across various other line items within G&A.
Transaction costs	0.1	2018 transaction costs relate to a number of business development initiatives, including the proposed acquisition of a package of assets in Egypt from BP and the re-domicile of the Group from Canada to the UK. Transaction costs for 2017 were all associated with the Circle Oil acquisition.
Exploration and evaluation expense	(5.5)	Increased exploration and evaluation expenditure due to the write off of the ELQ-1 and KSS-2 dry holes in Morocco and Kelvin-1X in South Disouq, and higher new venture spend
Current income tax expense	(2.5)	Increase mainly due to the introduction of the 40% of NW Gemsa from the acquisition from Circle Oil plc and the increased profitability of the Group.
Stock-based compensation	(0.8)	
Foreign exchange	0.1	
Inventory write-off	(0.4)	
Release of historic operational tax provision	0.3	
Other	1.9	
Total decrease	**(28.2)**	

Operational and financial highlights (continued)

Capital expenditures

The following table shows the capital expenditure for the Company. It agrees with notes 9 and 10 to the Consolidated Financial Statements for the three and 12 months ended December 31, 2018, which include discussion therein.

		Three months ended December 31		Twelve months ended December 31	
US$'000s	Prior quarter	**2018**	2017	**2018**	2017
Property, plant and equipment expenditures ("PP&E")	1,815	**2,422**	12,697	**14,288**	15,975
Exploration and evaluation expenditures ("E&E")	9,002	**5,805**	2,237	**29,000**	4,608
Office furniture and fixtures	200	**89**	368	**735**	457
Total capital expenditures	11,017	**8,316**	15,302	**44,023**	21,040

Decommissioning liability

	Carrying amount	
US$'000s	**December 31 2018**	December 31 2017
Decommissioning liability, beginning of period	**4,542**	-
Changes in estimate	**575**	625
Liabilities acquired through business combination	**-**	3,968
Payments for decommissioning	**(23)**	(137)
Accretion	**73**	86
Decommissioning liability, end of period	**5,167**	4,542
Of which:		
Current	**1,125**	1,063
Non-current	**4,042**	3,479

For a discussion of the Company's decommissioning liability, see note 14 to the Consolidated Financial Statements for the year ended December 31, 2018.

Liquidity and capital resources

Share capital

The Company's authorized share capital consists of an unlimited number of common shares and an unlimited number of preferred shares, issuable in one or more series. The common shares of SDX trade on the TSX Venture Exchange and the AIM market of the London Stock Exchange under the symbol SDX.

US$'000s	Prior quarter	**Twelve months ended December 31 2018**	Twelve months ended December 31 2017
High (CAD)	$1.10	**$0.95**	$1.36
Low (CAD)	$0.90	**$0.58**	$0.58
Average volume	140,098	**109,546**	175,512

The following table summarizes the outstanding common shares and options as at March 22, 2019, December 31, 2018, and December 31, 2017.

Outstanding as at:	March 22 2019	December 31 2018	December 31 2017
Common shares	204,723,041	204,723,041	204,493,040
Options (stock option plan)	2,115,000	2,115,000	2,851,667
Options (long-term incentive plan)	7,100,884	7,100,884	3,449,461

The following table summarizes the outstanding stock option plan options as at December 31, 2018:

	Outstanding options		Vested options	
Exercise price range	**Number of options**	**Remaining contractual life**	**Number of options**	**Remaining contractual life**
CAD $0.39 - $0.76	2,115,000	3-5 years	1,795,000	3-5 years

Liquidity and capital resources (continued)

Stock based compensation

Stock option program

The Company has a stock option program that entitles officers, directors, employees, and certain consultants to purchase shares in the Company.

Stock-based compensation expense is the amortization over the vesting period of the fair value of stock options granted to employees, directors, and key consultants of the Company. The fair value of all options granted is estimated using the Black-Scholes option pricing model. Each tranche of options in an award is considered a separate award with its own vesting period and grant date fair value. Compensation cost is expensed over the vesting period with a corresponding increase in contributed surplus. When stock options are exercised, the cash proceeds and the amount previously recorded as contributed surplus are recorded as share capital.

Long-Term Incentive Plan

On July 31, 2017 the Company established a new Long-Term Incentive Plan ("LTIP") and issued awards to its executive directors and certain other key employees. For further details, see note 17 to the Consolidated Financial Statements.

Capital resources

As at December 31, 2018 the Company had working capital of approximately US$29.4 million. The Company expects to fund its 2019 capital program through funds generated from operations and cash on hand.

As at December 31, 2018, the Company had cash and cash equivalents of US$17.3 million, compared to US$25.8 million as at December 31, 2017.

During the 12 months ended December 31, 2018 the Company had a net cash outflow of US$8.5 million (including the effects of foreign exchange on cash and cash equivalents). For further details, please see the sources and uses table below.

As at December 31, 2018, the Company had US$24.3 million in trade and other receivables, compared to US$37.7 million as at December 31, 2017. US$14.8 million is due from a Government of Egypt-controlled corporation ("EGPC") for oil sales, gas, and NGL sales and production service fees, all of which is expected to be received in the normal course of operations. The Company also recorded US$1.8 million receivable related to the joint venture partner account for the South Disouq concession.

US$3.1 million is owed by a Government of Morocco-controlled corporation, Office National Hydrocarbures et des Mines ("ONHYM"), and relates to ONHYM's share of well completion, connection, and production costs.

US$2.7 million is owing from third-party gas customers in Morocco and is expected to be collected within agreed credit terms.

US$0.6 million related to prepayments predominantly associated with technical and business development software subscriptions is recorded in the Consolidated Balance Sheet.

The other receivables of US$1.3 million consist of US$0.8 million for Goods and Services Tax ("GST")/Value Added Tax ("VAT") and US$0.5 million for other items.

Subsequent to December 31, 2018, the Company collected US$14.4 million of trade receivables from those outstanding at December 31, 2018; US$11.6 million from EGPC, and US$2.8 million from third-party gas customers in Morocco. Of the US$11.6 million collected from EGPC, US$1.5 million was in cash and US$10.1 million was offset against South Disouq development costs, South Ramadan drilling costs and amounts owing to joint venture partners.

Liquidity and capital resources (continued)

Capital resources (continued)

The following table outlines the Company's working capital. Working capital is defined as current assets less current liabilities and includes drilling inventory materials that may not be immediately monetized.

US$'000s	December 31 2018	December 31 2017
Current assets		
Cash and cash equivalents	**17,345**	25,844
Trade and other receivables	**24,324**	37,656
Inventory	**5,236**	5,157
Total current assets	**46,905**	68,657
Current liabilities		
Trade and other payables	**14,418**	19,459
Deferred income	**495**	495
Decommissioning liability	**1,125**	1,063
Current income taxes	**1,458**	915
Total current liabilities	**17,496**	21,932
Working capital	**29,409**	46,725

The following table outlines the Company's sources and uses of cash for the years ended December 31, 2018 and 2017:

	Twelve months ended December 31	
US$'000s	**2018**	2017
Sources		
Operating cash flow before working capital movements	**28,744**	16,047
Issuance of common shares	**114**	48,510
Cash balance acquired during the period	**-**	3,108
Changes in non-cash working capital	**8,584**	5,933
Dividends received	**525**	760
Effect of foreign exchange on cash and cash equivalents	**-**	141
Total sources	**37,967**	74,499
Uses		
Property, plant and equipment expenditures	**(21,945)**	(21,132)
Exploration and evaluation expenditures	**(22,865)**	(3,785)
Acquisition of subsidiaries	**-**	(28,056)
Finance costs paid	**(197)**	(43)
Income taxes paid	**(1,091)**	(364)
Effect of foreign exchange on cash and cash equivalents	**(368)**	-
Total uses	**(46,466)**	(53,380)
(Decrease)/increase in cash	**(8,499)**	21,119
Cash and cash equivalents at beginning of period	**25,844**	4,725
Cash and cash equivalents at end of period	**17,345**	25,844

The Company's operating cash flow before working capital movements for the 12 months ended December 31, 2018, compared to the comparative period ended December 31, 2017, has increased by US$12.7 million primarily due to:

i) an increase of US$14.5 million in net revenues because of higher commodity prices, 12 months of revenue from the acquired Circle Oil assets versus 11 months in 2017, and higher production at Block-H Meseda; offset by
ii) an increase of US$1.6 million in operating costs because of the acquisition of the Egyptian and Moroccan assets of Circle Oil and increased production at Block-H Meseda.

Liquidity and capital resources (continued)

Financial instruments

The Company is exposed to financial risks because of the nature of its business and the financial assets and liabilities that it holds. This section outlines material financial risks, quantifies the associated exposures, and explains how these risks and the Company's capital are managed.

Market risk

Market risk is the risk that changes in market prices, such as commodity prices, foreign exchange rates, and interest rates, could affect the Company's income or the value of the financial instruments. The objective of market risk management is to manage and control market risk exposures within acceptable parameters, while optimizing the return.

Commodity price risk

Commodity price risk is the risk that the fair value of future cash flows will fluctuate as the result of changes in commodity prices. Commodity prices for oil and natural gas are affected by not only the relationship between the United States dollar and other currencies, but also world economic events that have an impact on the perceived levels of supply and demand. The Company may hedge some oil and natural gas sales using various financial derivative forward sales contracts and physical sales contracts. In Egypt, the Company's production is sold on the daily average price and in Morocco at contracted prices. The Company may give consideration in certain circumstances to the appropriateness of entering into longer term, fixed price marketing contracts. The Company will not enter into commodity contracts other than to meet the Company's expected sale requirements.

As at December 31, 2018 the Company did not have any outstanding derivatives in place.

Foreign currency risk

Currency risk is the risk that the fair value of future cash flows will fluctuate because of changes in foreign exchange rates. The reporting and functional currency of the Company is United States dollars ("US$"). Most of the Company's operations are in foreign jurisdictions and, as a result, the Company is exposed to foreign currency exchange rate risk on some of its activities, primarily exchange fluctuations between the Egyptian pound ("EGP") and the US$, the Moroccan dirham ("MAD") and the US$, and Sterling ("GBP") and the US$. Most capital expenditures are incurred in US$, EGP and MAD, and oil, natural gas, NGL, and service fee revenues are received in US$, EGP and MAD. The Company can use EGP and MAD to fund its Egyptian and Moroccan office general and administrative expenses and to part-pay cash requirements for both capital and operating expenditure, thereby reducing the Company's exposure to foreign exchange risk during the period.

The table below shows the Company's exposure to foreign currencies for its financial instruments:

	Total per FS[(1)]	US$	EGP	MAD	GBP	Other
As at December 31, 2018			**US$ Equivalent**			
Cash and cash equivalents	17,345	10,645	2,712	1,864	1,983	141
Trade and other receivables[(2)]	23,689	15,979	24	6,750	898	38
Trade and other payables	(14,418)	(6,370)	(1,349)	(4,363)	(2,316)	(20)
Balance sheet exposure	26,616	20,254	1,387	4,251	565	159

(1) FS denotes Financial Statements.

(2) Excludes prepayments.

The average exchange rates during the three months ended December 31, 2018 and 2017 were 1 US$ equals:

Average: October 1, 2018 to December 31, 2018			
	USD/EGP	USD/GBP	USD/MAD
Period average	17.9206	0.7769	9.5089

Average: October 1, 2017 to December 31, 2017			
	USD/EGP	USD/GBP	USD/MAD
Period average	17.7107	0.7537	9.4442

The average exchange rates during the years ended December 31, 2018 and 2017 were 1 US$ equals:

Average: January 1, 2018 to December 31, 2018			
	USD/EGP	USD/GBP	USD/MAD
Period average	17.8191	0.7499	9.3893

Average: January 1, 2017 to December 31, 2017			
	USD/EGP	USD/GBP	USD/MAD
Period average	17.8534	0.7770	9.7047

The exchange rates as at December 31, 2018 and 2017 were 1 US$ equals:

Period end: December 31, 2018			
	USD/EGP	USD/GBP	USD/MAD
Period end	17.8919	0.7812	9.5610

Period end: December 31, 2017			
	USD/EGP	USD/GBP	USD/MAD
Period end	17.7875	0.7398	9.3519

Liquidity and capital resources (continued)

Financial instruments (continued)

Trade and other payables

The foreign currency risk from a trade and other payables perspective arises because the Company's operations are conducted in Egypt and Morocco and its corporate offices are in London and Canada, with G&A and other listing and regulatory costs paid in both jurisdictions.

As at December 31, 2018 and 2017 the Company's trade and other payables were as follows:

	Carrying amount	
US$'000s	December 31 2018	December 31 2017
Trade payables	3,870	2,636
Accruals	3,747	9,536
Joint venture partners	5,409	5,686
Other payables	1,392	1,601
Total trade and other payables	**14,418**	19,459

For a discussion of the Company's trade and other payables, see note 12 to the Consolidated Financial Statements for the year ended December 31, 2018.

Credit risk

Credit risk is the risk of financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its contractual obligations. It arises principally from the Company's receivables from joint operations partners, oil and natural gas marketers, and cash held with banks. The maximum exposure to credit risk at the end of the period was as follows:

	Carrying amount	
US$'000s	December 31 2018	December 31 2017
Cash and cash equivalents	17,345	25,844
Trade and other receivables(1)	23,689	34,781
Total	**41,034**	60,625

(1) Excludes prepayments of US$0.6 million which are included in the Consolidated Balance Sheet as trade and other receivables but which are not categorised as financial assets as summarised above (2017: US$2.9 million).

Trade and other receivables

All the Company's operations as at December 31, 2018 were conducted in Egypt and Morocco. The Company's exposure to credit risk is influenced mainly by the individual characteristics of each counterparty. The Company does not anticipate any default and expects continued payment from customers against invoiced sales. Management has further considered the recoverability of the Company's trade receivables balance alongside confirmations received from EGPC and concession operators of amounts to be settled, as well as the forecast use of EGP in operations, and does not consider it necessary to apply discounting. Receivables due from ONHYM are not expected to be fully recovered during the next 12 months and have been discounted at 5%, with an associated finance expense of US$0.3 million recognized in the Consolidated Statement of Comprehensive Income.

The maximum exposure to credit risk for trade and other receivables at the reporting date by type of customer was:

	Carrying amount	
US$'000s	December 31 2018	December 31 2017
Government of Egypt-controlled corporations	14,846	25,582
Government of Morocco-controlled corporations	3,053	3,597
Third-party gas customers	2,715	3,175
Joint venture partners	1,761	1,586
Other(1)	1,314	841
Total	**23,689**	34,781

(1) Excludes prepayments of US$0.6 million which are included in the Consolidated Balance Sheet as trade and other receivables but which are not categorised as financial assets as summarised above (2017: US$2.9 million).

Liquidity and capital resources (continued)

Financial instruments (continued)

Trade and other receivables (continued)

As at December 31, 2018 and 2017, the Company's trade and other receivables, excluding prepayments, were aged as follows:

	Carrying amount	
US$'000s	**December 31 2018**	December 31 2017
Current (less than 90 days)	**14,805**	21,261
Past due (more than 90 days)	**8,884**	13,520
Total	**23,689**	34,781

For a discussion of the Company's trade and other receivables, see note 6b to the Consolidated Financial Statements for the three and 12 months ended December 31, 2018.

Cash and cash equivalents:

The Company limits its exposure to credit risk by only investing in liquid securities and only with highly rated counterparties. The Company's cash and cash equivalents are currently held in established banks in either countries of operation or the UK, the majority of which have A or AA ratings. Given these credit ratings, management does not expect any counterparty to fail to meet its obligations.

Capital management:

The Company defines and computes its capital as follows:

	Carrying amount	
US$'000s	**December 31 2018**	December 31 2017
Equity	**116,039**	114,619
Working capital[1]	**(29,409)**	(46,725)
Total capital	**86,630**	67,894

(1) Working capital is defined as current assets less current liabilities.

The Company's objective when managing its capital is to ensure that it has sufficient capital to maintain its ongoing operations, pursue the acquisition of interests in producing or near to production oil and gas properties, and to maintain a flexible capital structure that optimizes the cost of capital at an acceptable risk. The Company manages its capital structure and adjusts it, based on the funds available to the Company, to support the exploration and development of its interests in its existing properties and to pursue other opportunities.

Accounting policies and estimates

The Company is required to make judgments, assumptions and estimates in the application of accounting policies that could have a significant impact on its financial results. Actual results may differ from those estimates, and those differences may be material. The estimates and assumptions used are subject to updates based on experience and the application of new information. The accounting policies and estimates are reviewed annually by the Audit Committee of the board. Further information on the basis of presentation and our significant accounting policies can be found in the notes to the Consolidated Financial Statements the year ended December 31, 2018.

Accounting policies

The accounting policies adopted are consistent with those of the previous financial year, except for the adoption of new standards and interpretations effective January 1, 2018.

Further information on the accounting policies and estimates can be found in the notes to the Consolidated Financial Statements for the three and 12 months ended December 31, 2018.

Future changes in accounting policies

There are no updates to future changes in accounting policies in the first 12 months of 2018.

Business risk assessment

There are a number of inherent business risks associated with oil and gas operations and development. Many of these risks are beyond the control of management. The following outlines some of the principal risks and their potential impact to the Company.

Political risk

SDX operates in Egypt and Morocco, countries that have different political, economic and social systems from North America and which subject the Company to a number of risks not within the control of the Company. Exploration or development activities in such countries may require protracted negotiations with host governments, national oil companies and third parties and are frequently subject to economic and political considerations such as taxation, nationalization, expropriation, inflation, currency fluctuations, increased regulation and approval requirements, corruption and the risk of actions by terrorist or insurgent groups, changes in laws and policies governing the operations of foreign-based companies, economic and legal sanctions and other uncertainties arising from foreign governments, any of which could adversely affect the economics of exploration or development projects.

Financial resources

The Company's cash flow from operations may not be sufficient to fund its ongoing activities and implement its business plans. From time to time the Company may enter into transactions to acquire assets or the shares of other companies. Depending on the future exploration and development plans, the Company may require additional financing, which may not be available or, if available, may not be available on favorable terms. Failure to obtain such financing on a timely basis could cause the Company to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate operations. If the revenues from the Company's reserves decrease because of lower oil prices or otherwise, it will affect its ability to expend the necessary capital to replace its reserves or to maintain its production. If cash flow from operations is not sufficient to satisfy capital expenditure requirements, there can be no assurance that additional debt, equity, or asset dispositions will be available to meet these requirements or available on acceptable terms. In addition, cash flow is influenced by factors that the Company cannot control, such as commodity prices, exchange rates, interest rates and changes to existing government regulations and tax and royalty policies.

Exploration, development and production

The long-term success of SDX will depend on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. SDX mitigates these risks through the use of skilled staff, focusing exploration efforts in areas in which the Company has existing knowledge and expertise or access to such expertise, using up-to-date technology to enhance methods, and controlling costs to maximize returns. Despite these efforts, oil and natural gas exploration involves a high degree of risk, which even a combination of experience, knowledge and careful evaluation may not be able to overcome. There is no assurance that SDX will be able to locate satisfactory properties for acquisition or participation or that the Company's expenditures on future exploration will result in new discoveries of oil or natural gas in commercial quantities. It is difficult to accurately project the costs of implementing an exploratory drilling program due to the inherent uncertainties of drilling in unknown formations, the costs associated with encountering various drilling conditions such as over-pressured zones, tools lost in the hole and changes in drilling plans and locations as a result of prior exploratory wells or additional seismic data and interpretations thereof.

Future oil and gas exploration may involve unprofitable efforts, not only from dry wells, but from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion, infrastructure and operating costs. In addition, drilling hazards and/or environmental damage could greatly increase the costs of operations and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-in of wells resulting from extreme weather conditions or natural disasters, insufficient transportation capacity or other geological and mechanical conditions. As well, approved activities may be subject to limited access windows or deadlines, which may cause delays or additional costs. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

The nature of oil and gas operations exposes SDX to risks normally incident to the operation and development of oil and natural gas properties, including encountering unexpected formations or pressures, blow-outs, and fires, all of which could result in personal injuries, loss of life and damage to the property of the Company and others. The Company has both safety and environmental policies in place to protect its operators and employees, as well as to meet the regulatory requirements in those areas where it operates. In addition, the Company has liability insurance policies in place, in such amounts as it considers adequate. The Company will not be fully insured against all of these risks, nor are all such risks insurable.

Business risk assessment (continued)

Oil and natural gas prices

The price of oil and natural gas will fluctuate based on factors beyond the Company's control. These factors include demand for oil and natural gas, market fluctuations, the ability of regional state-owned monopolies to control prices, the proximity and capacity of oil and natural gas pipelines and processing equipment and government regulations, including regulations relating to environmental protection, royalties, allowable production, pricing, importing and exporting of oil and natural gas. Fluctuations in price will have a positive or negative effect on the revenue the Company receives.

Reserve estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids, reserves and cash flows to be derived from them, including many factors beyond the Company's control. In general, estimates of economically recoverable oil and natural gas reserves and the future net cash flows are based on a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and natural gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary from actual results. For those reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues prepared by different engineers, or by the same engineers at different times, may vary. The Company's actual production, revenues and development and operating expenditures with respect to its reserves will vary from estimates and such variations could be material.

Estimates of proved reserves that may be developed and produced in the future are often based on volumetric calculations and comparisons to similar types of reserves rather than actual production history. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based on production history and production practices will result in variations in the estimated reserves and such variations could be material.

The Company's actual future net cash flows, as estimated by independent reserve engineers, will be affected by many factors including, but not limited to: actual production levels; supply and demand for oil and natural gas; curtailments or increases in consumption by oil and natural gas purchasers; changes in governmental regulation; taxation changes; the value of the Moroccan Dirham, British Pound, Egyptian Pound and US$; and the impact of inflation on costs.

Actual production and cash flows will vary from the estimates contained in the applicable engineering reports. The reserve reports are based in part on the assumed success of activities the Company intends to undertake in future years. The reserves and estimated cash flows contained in the engineering reports will be reduced to the extent that such activities do not achieve the level of success assumed in the calculations.

Reliance on operators and key employees

To the extent that SDX is not the operator of its oil and natural gas properties, it will depend on such operators for the timing of activities related to such properties and is largely unable to direct or control the activities of the operators. In addition, the success of the Company will largely depend on the performance of its management and key employees. The Company has no key-man insurance policies, and therefore there is a risk that the death or departure of any member of management or key employee could have a material adverse effect on the Company.

Government regulations

SDX may be subject to various laws, regulations, regulatory actions and court decisions that can have negative effects on it. Changes in the regulatory environment imposed upon the Company could adversely affect its ability to attain its corporate objectives. The current exploration, development and production activities of the Company require certain permits and licenses from governmental agencies and such operations are, and will be, governed by laws and regulations governing exploration, development and production, labor laws, waste disposal, land use, safety, and other matters. There can be no assurance that all licenses and permits that the Company may require to carry out exploration and development of its projects will be obtainable on reasonable terms or on a timely basis, or that such laws and regulation would not have an adverse effect on any project that the Company may undertake.

Environmental factors

All phases of the Company's operations are subject to environmental regulation in Egypt and Morocco. Environmental legislation is evolving in a manner that requires stricter standards and enforcement, increased fines, and penalties for non-compliance, more stringent environmental assessments of proposed projects and a heightened degree of responsibility for companies and their officers, directors and employees.

Insurance

The Company's involvement in the exploration for and development of oil and natural gas properties may result in the Company or its subsidiaries, as the case may be, becoming subject to liability for pollution, blow-outs, property damage, personal injury or other hazards. Prior to drilling, the Company or the operator will obtain insurance in accordance with industry standards to address certain of these risks. However, such insurance has limitations on liability that may not be sufficient to cover the full extent of such liabilities. In addition, such risks may not in all circumstances be insurable or, in certain circumstances, the Company or its subsidiaries, as the case may be, may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The occurrence of a significant event that the Company may not be fully insured against, or the insolvency of the insurer of such event, could have a material adverse effect on the Company's financial position.

Business risk assessment (continued)

Regulatory matters

The Company's operations will be subject to a variety of federal and provincial or state laws and regulations, including income tax laws and laws and regulations relating to the protection of the environment. The Company's operations may require licenses from various governmental authorities and there can be no assurance that the Company will be able to obtain all necessary licenses and permits that may be required to carry out planned exploration and development projects.

Operating hazards and risks

Exploration for natural resources involves many risks, which even a combination of experience, knowledge and careful evaluation may not be able to overcome. Operations in which the Company has a direct or indirect interest will be subject to all the hazards and risks normally incidental to exploration, development and production of resources, any of which could result in work stoppages, damages to persons or property and possible environmental damage.

Although the Company has obtained liability insurance in an amount it considers adequate, the nature of these risks is such that liabilities might exceed policy limits, the liabilities and hazards might not be insurable, or the Company might not elect to insure itself against such liabilities due to high premium costs or other reasons, in which event the Company could incur significant costs that could have a material adverse effect upon its financial condition.

Repatriation of earnings

All of the Company's production and earnings are generated in Egypt and Morocco. Currently there are no restrictions on foreign entities repatriating earnings from Egypt. However, there can be no assurance that restrictions on repatriation of earnings from Egypt will not be imposed in the future. A company can repatriate earnings from Morocco each year up to the limit of its retained earnings.

Disruptions in production

Other factors affecting the production and sale of oil and gas that could result in decreases in profitability include: (i) expiration or termination of permits or licenses, or sales price redeterminations or suspension of deliveries; (ii) future litigation; (iii) the timing and amount of insurance recoveries; (iv) work stoppages or other labor difficulties; (v) changes in the market and general economic conditions, equipment replacement or repair, fires, civil unrest or other unexpected geological conditions that can have a significant impact on operating results.

Foreign investments

All the Company's oil and gas investments are located outside Canada. These investments are subject to the risks associated with foreign investment, including tax increases, royalty increases, re-negotiation of contracts, currency exchange fluctuations and political uncertainty. The jurisdictions in which the Company operates, Egypt and Morocco, have well-established fiscal regimes.

As operations are primarily carried out in US dollars, the main exposure to currency exchange fluctuations is the conversion to equivalent EGP, MAD and GBP.

Competition

SDX operates in the highly competitive areas of oil and gas exploration, development and acquisition with a substantial number of other companies, including U.S.-based and foreign companies doing business in Egypt and Morocco. The Company faces intense competition from both major and other independent oil and gas companies in seeking oil and gas exploration licences and production licences in Egypt and Morocco; and acquiring desirable producing properties or new leases for future exploration.

The Company believes it has significant in-country relationships within the business community and government authorities needed to obtain cooperation to execute projects.

Disclosure controls and procedures

As the Company is classified as a Venture Issuer under applicable Canadian securities legislation, it is required to file basic Chief Executive Officer and Chief Financial Officer Certificates, which it has done for the period ended December 31, 2018. The Company makes no assessment relating to the establishment and maintenance of disclosure controls and procedures and internal controls over financial reporting as defined under Multilateral Instrument 52-109 as at December 31, 2018 .

Summary of quarterly results

Fiscal year	2018				2017			
Financial US$'000s	**Q4**	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Cash, beginning of period	**18,713**	25,234	29,277	25,844	30,469	27,627	21,052	4,725
Cash, end of period	**17,345**	18,713	25,234	29,277	25,844	30,469	27,627	21,052
Working capital	**29,409**	33,190	36,355	43,091	46,725	58,397	43,048	40,039
Comprehensive income/(loss)	**(4,029)**	3,169	640	331	(2,621)	4,408	(427)	26,947
Net income/(loss) per share - basic	**(0.020)**	0.015	0.003	0.002	(0.013)	0.022	(0.005)	0.172
Capital expenditure	**8,316**	11,017	14,742	9,948	15,328	3,423	1,504	811
Total assets	**138,107**	146,239	143,419	140,497	141,057	138,898	132,766	132,794
Shareholders' equity	**116,039**	119,848	116,246	115,282	114,619	116,981	102,559	102,964
Common shares outstanding (000s)	**204,723**	204,706	204,493	204,493	204,493	204,459	186,900	186,900

Fiscal year	2018				2017			
Operational	**Q4**	Q3	Q2	Q1	Q4	Q3	Q2	Q1
NW Gemsa oil sales (bbl/d)	**1,808**	1,987	1,665	1,507	1,710	1,893	1,832	1,493
Block-H Meseda production service fee (bbl/d)	**864**	802	706	558	561	551	623	646
Morocco gas sales (boe/d)	**648**	615	656	664	680	611	651	441
Other products sales (boe/d)	**604**	485	403	307	310	384	419	287
Total boe/d	**3,924**	3,889	3,430	3,036	3,261	3,439	3,525	2,867
NW Gemsa oil sales volumes (bbls)	**166,296**	182,803	151,520	135,630	157,302	174,202	166,693	134,395
Block-H Meseda production service fee volumes (bbls)	**79,530**	73,761	64,286	50,257	51,599	50,674	56,736	58,126
Morocco gas sales volumes (boe)	**59,573**	56,602	59,740	59,779	62,543	56,219	59,246	39,646
Other products sales volumes (boe)	**55,564**	44,575	36,681	27,646	28,550	35,404	38,143	25,832
Total sales and service fee volumes (boe)	**360,963**	357,741	312,227	273,312	299,994	316,499	320,818	257,999
Brent oil price (US$/bbl)	**67.75**	75.18	74.53	66.86	61.52	52.07	49.68	53.64
West Gharib oil price (US$/bbl)	**60.09**	65.36	63.99	58.75	53.59	44.48	41.50	41.93
Realized oil price (US$/bbl)	**62.77**	70.76	68.41	62.81	57.77	48.28	45.56	48.73
Realized service fee (US$/bbl)	**51.34**	55.50	54.37	50.00	44.11	36.41	33.98	34.34
Realised oil sales price and service fees	**59.07**	66.38	64.23	59.34	54.39	45.61	42.62	44.38
Realized Morocco gas price (US$/mcf)	**9.78**	11.05	10.51	10.03	9.72	9.53	9.44	9.29
Royalties (US$/boe)	**13.53**	16.88	14.90	13.92	9.89	11.94	10.97	11.37
Operating costs (US$/boe)	**9.40**	9.45	10.15	7.30	8.42	8.44	9.22	7.94
Netback - (US$/boe)	**28.94**	33.62	33.00	32.80	23.54	21.48	21.64	9.08

South Disouq: Ibn Yunus, SD-4X and SD-3X discoveries in 2018. First gas targeted H1 2019 at 50-60MMscf/d

9,100boe/d

Production
Combined Egyptian and Moroccan daily average gross production for the year ended December 31, 2018

24.6MMboe

Reserves
Asset reserves (gross) - North West Gemsa, Meseda, South Disouq and Morocco as at December 31, 2018

Independent Auditor's Report

To the Shareholders of SDX Energy Inc.

Our opinion

In our opinion, the accompanying consolidated financial statements present fairly, in all material respects, the financial position of SDX Energy Inc. and its subsidiaries (together, the Company) as at December 31, 2018 and 2017, and its financial performance and its cash flows for the years then ended in accordance with International Financial Reporting Standards (IFRS).

What we have audited

The Company's consolidated financial statements comprise:

- the consolidated balance sheets as at December 31, 2018 and 2017;
- the consolidated statements of comprehensive income for the years then ended;
- the consolidated statements of changes in equity for the years then ended;
- the consolidated statements of cash flows for the years then ended; and
- the notes to the consolidated financial statements, which include a summary of significant accounting policies.

Basis for opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the Auditor's responsibilities for the audit of the consolidated financial statements section of our report.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Independence

We are independent of the Company in accordance with the ethical requirements that are relevant to our audit of the consolidated financial statements in Canada. We have fulfilled our other ethical responsibilities in accordance with these requirements.

Other information

Management is responsible for the other information. The other information comprises the Management's Discussion and Analysis and the information, other than the consolidated financial statements and our auditor's report thereon, included in the annual report.

Our opinion on the consolidated financial statements does not cover the other information and we do not express any form of assurance conclusion thereon.

In connection with our audit of the consolidated financial statements, our responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the consolidated financial statements or our knowledge obtained in the audit, or otherwise appears to be materially misstated.

If, based on the work we have performed, we conclude that there is a material misstatement of this other information, we are required to report that fact. We have nothing to report in this regard.

Responsibilities of management and those charged with governance for the consolidated financial statements

Management is responsible for the preparation and fair presentation of the consolidated financial statements in accordance with IFRS, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the consolidated financial statements, management is responsible for assessing the Company's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Company or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Company's financial reporting process.

Auditor's responsibilities for the audit of the consolidated financial statements

Our objectives are to obtain reasonable assurance about whether the consolidated financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these consolidated financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the consolidated financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the consolidated financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Company to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the consolidated financial statements, including the disclosures, and whether the consolidated financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Obtain sufficient appropriate audit evidence regarding the financial information of the entities or business activities within the Company to express an opinion on the consolidated financial statements. We are responsible for the direction, supervision and performance of the group audit. We remain solely responsible for our audit opinion.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

We also provide those charged with governance with a statement that we have complied with relevant ethical requirements regarding independence, and to communicate with them all relationships and other matters that may reasonably be thought to bear on our independence, and where applicable, related safeguards.

The engagement partner on the audit resulting in this independent auditor's report is Richard Spilsbury.

PricewaterhouseCoopers LLP

Chartered Professional Accountants
Aberdeen, United Kingdom

March 22, 2019

Consolidated Balance Sheet
as at December 31, 2018 and 2017

US$'000s	Note	As at December 31 2018	As at December 31 2017
Assets			
Cash and cash equivalents	7	**17,345**	25,844
Trade and other receivables	6b	**24,324**	37,656
Inventory	8	**5,236**	5,157
Current assets		**46,905**	68,657
Investments	11	**3,394**	2,724
Property, plant and equipment	9	**48,680**	54,445
Exploration and evaluation assets	10	**39,128**	15,231
Non-current assets		**91,202**	72,400
Total assets		**138,107**	141,057
Liabilities			
Trade and other payables	12	**14,418**	19,459
Deferred income	13	**495**	495
Decommissioning liability	14	**1,125**	1,063
Current income taxes	15	**1,458**	915
Current liabilities		**17,496**	21,932
Deferred income	13	**240**	737
Decommissioning liability	14	**4,042**	3,479
Deferred income taxes	15	**290**	290
Non-current liabilities		**4,572**	4,506
Total liabilities		**22,068**	26,438
Equity			
Share capital	16	**88,899**	88,785
Contributed surplus		**6,860**	5,666
Accumulated other comprehensive loss		**(917)**	(917)
Retained earnings		**21,197**	21,085
Total equity		**116,039**	114,619
Equity and liabilities		**138,107**	141,057

The notes are an integral part of these Consolidated Financial Statements.

The financial statements on pages 53 to 82 were approved by the board of directors on March 22, 2019 and signed on its behalf by:

Paul Welch
Chief Executive Officer

Mark Reid
Chief Financial Officer

Consolidated Statement of Comprehensive Income
for the years ended December 31, 2018 and 2017

US$'000s	Note	Twelve months ended December 31 2018	2017
Revenue, net of royalties	18	**53,679**	39,166
Revenue			
Direct operating expense		**(11,934)**	(10,254)
Gross profit		**41,745**	28,912
Exploration and evaluation expense	10	**(5,744)**	(187)
Depletion, depreciation and amortisation	9	**(17,268)**	(17,824)
Impairment expense	9	**(3,520)**	-
Stock-based compensation	17	**(1,194)**	(538)
Share of profit from joint venture	11	**1,195**	1,022
Bad debt expense	6b	**(123)**	-
Release of historic operational tax provision	4	**300**	-
(Inventory write-off)/reversal of inventory provision	8	**(370)**	798
Gain on sale of office asset		**23**	-
General and administrative expenses			
- Ongoing general and administrative expenses	19	**(4,815)**	(6,420)
- Transaction costs	19	**(2,455)**	(2,373)
Operating income		**7,774**	3,390
Net finance expense		**(542)**	(129)
Foreign exchange gain		**75**	29
(Loss)/gain on acquisition	4	**(174)**	29,558
Income before income taxes		**7,133**	32,848
Current income tax expense	15	**(7,021)**	(4,541)
Deferred income tax expense	15	**-**	-
Total current and deferred income tax expense		**(7,021)**	(4,541)
Total comprehensive income for the period		**112**	28,307
Net income per share			
Basic	20	**$0.001**	$0.153
Diluted	20	**$0.001**	$0.151

The notes are an integral part of these Consolidated Financial Statements.

Consolidated Statement of Changes in Equity
for the years ended December 31, 2018 and 2017

US$'000s	Note	Twelve months ended December 31 2018	2017
Share capital			
Balance, beginning of period	16	**88,785**	40,275
Issuance of common shares		**114**	49,589
Share issue costs		**-**	(1,079)
Balance, end of period		**88,899**	88,785
Contributed surplus			
Balance, beginning of period		**5,666**	5,128
Stock-based compensation for the period		**1,194**	538
Balance, end of period		**6,860**	5,666
Accumulated other comprehensive loss			
Balance, beginning of period		**(917)**	(917)
Balance, end of period		**(917)**	(917)
Retained earnings/(accumulated loss)			
Balance, beginning of period		**21,085**	(7,222)
Total comprehensive income for the period		**112**	28,307
Balance, end of period		**21,197**	21,085
Total equity		**116,039**	114,619

The notes are an integral part of these Consolidated Financial Statements.

Consolidated Statement of Cash Flows
for the years ended December 31, 2018 and 2017

US$'000s	Note	Twelve months ended December 31 2018	2017
Cash flows generated from/(used in) operating activities			
Income before income taxes		**7,133**	32,848
Adjustments for:			
Depletion, depreciation and amortization	9	**17,268**	17,824
Exploration and evaluation expense	10	**5,103**	187
Impairment expense	9	**3,520**	-
Finance expense		**542**	129
Stock-based compensation	17	**1,194**	538
Loss/(gain) on acquisition	4	**174**	(29,558)
Foreign exchange loss/(gain)		**368**	(141)
Gain on sale of office asset		**(23)**	-
Bad debt expense	6b	**123**	-
Release of historic operational tax provision	4	**(300)**	-
Inventory write-off/(reversal of inventory provision)	8	**370**	(798)
Amortisation of deferred income	13	**(497)**	(380)
Tax paid by state	15	**(5,036)**	(3,551)
Share of profit from joint venture	11	**(1,195)**	(1,022)
Operating cash flow before working capital movements		**28,744**	16,076
Decrease in trade and other receivables	6b	**11,195**	4,871
Increase in trade and other payables	12	**330**	2,988
Increase in inventory	8	**(2,801)**	(1,951)
Payments for decommissioning	14	**(140)**	(4)
Cash generated from operating activities		**37,328**	21,980
Income taxes paid	15	**(1,091)**	(364)
Net cash generated from operating activities		**36,237**	21,616
Cash flows (used in)/generated from investing activities:			
Property, plant and equipment expenditures	9	**(21,945)**	(21,132)
Exploration and evaluation expenditures	10	**(22,865)**	(3,785)
Dividends received	11	**525**	760
Acquisition of subsidiaries	4	**-**	(28,056)
Cash balance acquired during the period	4	**-**	3,108
Net cash used in investing activities		**(44,285)**	(49,105)
Cash flows generated from/(used in) financing activities:			
Issuance of common shares	16	**114**	48,510
Finance costs paid		**(197)**	(43)
Net cash (used in)/generated from financing activities		**(83)**	48,467
(Decrease)/increase in cash and cash equivalents		**(8,131)**	20,978
Effect of foreign exchange on cash and cash equivalents		**(368)**	141
Cash and cash equivalents, beginning of period		**25,844**	4,725
Cash and cash equivalents, end of period		**17,345**	25,844

The notes are an integral part of these Consolidated Financial Statements.

1. Reporting entity

SDX Energy Inc. ("SDX" or "the Company") is a company domiciled in Canada. The address of the Company's registered office is 1900, 520 - 3rd Avenue SW, Centennial Place, East Tower, Calgary, Alberta T2P 0R3. The Consolidated Financial Statements of the Company as at and for the years ended December 31, 2018 and 2017 comprise the Company and its wholly owned subsidiaries and include the Company's share of joint arrangements as explained in note 11 below (together the "Group").

The Company's shares trade on the Toronto Venture Stock Exchange ("TSX-V") in Canada and on the London Stock Exchange's Alternative Investment Market ("AIM") in the United Kingdom under the symbol "SDX".

The Company is engaged in the exploration for, and development and production of, oil and natural gas. The Company's principal properties are in the Arab Republic of Egypt and the Kingdom of Morocco.

As described in note 4 to the Consolidated Financial Statements, on January 27, 2017 the Company acquired the Egyptian and Moroccan assets of Circle Oil plc.

2. Basis of preparation

a) Statement of compliance

The Consolidated Financial Statements of the Company have been prepared in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board ("IASB") and with IFRS Interpretations Committee ("IFRS IC") interpretations. These accounting standards and interpretations are collectively referred to as "IFRS" in this report.

The accounting policies that follow set out those policies that apply in preparing the Consolidated Financial Statements for the year ended December 31, 2018. The policies applied are based on IFRS issued and outstanding as of March 22, 2019.

b) Accounting policies

The Consolidated Financial Statements have been prepared on the historical cost basis.

c) Functional and presentation currency

The functional currency for each entity in the Group, and for joint arrangements and associates, is the currency of the primary economic environment in which that entity operates. Transactions denominated in other currencies are converted to the functional currency at the exchange rate ruling at the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are retranslated at year-end exchange rates.

The Group's financial statements are presented in US dollars, as that presentation currency most reliably reflects the business performance of the Group as a whole. On consolidation, income statement items for each entity are translated from the functional currency into US dollars at average rates of exchange, where the average is a reasonable approximation of rates prevailing on the transaction date. Balance sheet items are translated into US dollars at period-end exchange rates.

d) Use of estimates and judgments

The preparation of financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income, and expenses. Actual results may differ from these estimates and affect the results reported in these Consolidated Financial Statements. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future years affected.

Purchase price allocations, depletion, depreciation and amortization, and amounts used in impairment calculations are based on estimates of crude oil and natural gas reserves. Reserve estimates are based on engineering data, estimated future prices, expected future rates of production, and the timing of future capital expenditures, all of which are subject to many uncertainties, interpretations, and judgements. The Company expects that, over time, its reserve estimates will be revised upward or downward based on updated information such as the results of future drilling, testing, and production levels, and may be affected by changes in commodity prices.

In accounting for property, plant, and equipment, during the drilling of oil and gas wells, at period end it is necessary to estimate the value of work done ("VOWD") for any unbilled goods and services provided by contractors.

The invoicing of produced crude oil, natural gas and natural gas liquids is, for non-operated concessions, performed by the Company's joint venture partners. In certain concessions, the operator relies on production and/or price information from other third parties, which may not be consistently prepared and received on a timely basis. In such instances, the Company may be required to estimate production volumes and/or prices based on the most robust available data.

Provisions recognized for decommissioning costs and related accretion expense, derivative fair value calculations, fair value of share-based payments expense, deferred tax provisions, and fair values assigned to any identifiable assets and liabilities in business combinations are also based on estimates. By their nature, the estimates are subject to measurement uncertainty and the impact on the Consolidated Financial Statements of future periods could be material.

2. Basis of preparation (continued)

e) Brexit

Management has considered the potential impact of the UK vote to leave the European Union and has concluded that, since the Company's business is predominantly conducted in Egypt and Morocco, there are no material uncertainties arising that would have a significant effect on the Company.

f) Going concern

The directors have reviewed the Company's forecast cash flows for the next 21 months from the date of publication of this annual report through to December 31, 2020. The capital expenditure and operating costs used in these forecast cash flows are based on the Company's Board-approved 2019 SDX corporate budget, which reflects approved operating budgets for each of its operating assets and an estimate of 2020 SDX corporate general and administrative expenses. The Company's forecast cash flows also reflect its best estimate of operational and corporate expenditure, including corporate general and administrative costs for the year to December 31, 2020. The directors have made enquiries into and considered the Egyptian and Moroccan business environments, future expectations regarding commodity price risk and, in particular, oil price risk given the volatility in quoted Brent and WTI crude oil prices.

Having considered these sensitivities and potential outcomes relating to:

(i) country and commodity price risks;
(ii) the Company's ability to change the timing and scale of discretionary capital expenditure;
(iii) the Company's ability to manage operating costs; and
(iv) the Company's ability to manage general and administrative costs,

The directors consider that, in a lower cost environment, the Company has sufficient resources at its disposal to continue for the foreseeable future.

The foreseeable future is defined as not being less than 12 months from the date of publication of the 2018 annual report.

Given the above, these Consolidated Financial Statements continue to be prepared under the going concern basis of accounting.

3. Significant accounting policies

The accounting policies set out below have been applied consistently to all years presented in these Consolidated Financial Statements and have been applied consistently by the Company and its subsidiaries.

a) Basis of consolidation

i) Subsidiaries

Subsidiaries are entities controlled by the Company. Control exists where the Company has; power over the entities, that is existing rights that give it the current ability to direct the relevant activities of the entities (those that significantly affect the Companies' returns); exposure, or rights, to variable returns from its involvement with the entities; and the ability to use its power to affect those returns. Subsidiaries are fully consolidated from the date on which control is transferred to the Group. They are deconsolidated from the date that control ceases.

ii) Joint arrangements

A joint arrangement is an arrangement by which two or more parties have joint control. Joint control is the contractually agreed sharing of control such that decisions about the relevant activities of the arrangement (those that significantly affect the Companies' returns) require the unanimous consent of the parties sharing control. The Company has one joint arrangement, its 50% equity interest in Brentford Oil Tools LLC ("Brentford"). As the parties sharing joint control in this entity have rights to its net assets, the arrangement constitutes a joint venture and is accounted for using the equity accounting method. Under the equity method of accounting, the investment in Brentford was initially recognized at cost and adjusted thereafter for the post-acquisition change in the net assets. The Company's Consolidated Statement of Comprehensive Income includes its share of Brentford's profit or loss. The Company's other comprehensive income includes its share of Brentford's other comprehensive income. Dividends received or receivable from Brentford are recognized as a reduction in the carrying amount of the investment.

iii) Investments in associates

An associate is an entity over which the Company has significant influence, and is equity accounted for.

iv) Transactions eliminated on consolidation

Intercompany balances and transactions, and any unrealized income and expenses arising from intercompany transactions, are eliminated in preparing the Consolidated Financial Statements.

b) Foreign currency

Transactions in foreign currencies are translated to United States dollars at exchange rates available on the dates of the transactions. Monetary assets and liabilities denominated in foreign currencies are translated to United States dollars at the period end exchange rate.

Foreign exchange gains and losses resulting from the settlement of such transactions and the translation at exchange rates ruling at the period end date of monetary assets and liabilities denominated in foreign currencies are recognized in the income statement. Previously, such gains and losses were recognized in other comprehensive income. The updated accounting policy has no net effect on prior period total comprehensive income or equity.

3. Significant accounting policies (continued)

c) Financial instruments

i) Non-derivative financial instruments

Non-derivative financial instruments comprise trade and other receivables, cash and cash equivalents, and trade and other payables. Non-derivative financial instruments are recognized initially at fair value. Subsequent to initial recognition, non-derivative financial instruments are measured as described below.

Financial assets and liabilities are recognized when the Company becomes party to the contractual provisions of the instrument. Financial assets are derecognized when the rights to receive cash flows from the assets have expired or been transferred and the Company has transferred substantially all risks and rewards of ownership.

Financial assets and liabilities are off set and the net amount is reported in the balance sheet when there is a legally enforceable right to offset the recognized amounts and there is an intention to settle on a net basis or realize the asset and settle the liability simultaneously.

Cash and cash equivalents

Cash and cash equivalents are comprised of cash in hand, deposits with banks, term deposits, and other short-term highly liquid investments with original maturities of three months or less. Cash and cash equivalents are designated as loans and receivables.

Financial assets at fair value through the Consolidated Statement of Comprehensive Income

An instrument is classified at fair value through the Consolidated Statement of Comprehensive Income if it is held for trading or is designated as such upon initial recognition. Financial instruments are designated at fair value through the Consolidated Statement of Comprehensive Income if the Company manages such investments and makes purchase and sale decisions based on their fair value in accordance with the Company's risk management or investment strategy. Upon initial recognition, attributable transaction costs are recognized in the Consolidated Statement of Comprehensive Income when incurred. Financial instruments are measured at fair value and changes therein are recognized in the Consolidated Statement of Comprehensive Income.

Financial liabilities

Financial liabilities at amortized cost include trade payables. Trade payables are initially recognized at the amount required to be paid, less (when material) a discount to reduce the payables to fair value. Subsequently, trade payables are measured at amortized cost using the effective interest method.

Financial assets

Trade and other receivables, which are non-derivative financial assets that have fixed or determinable payments that are not quoted in an active market, are classified as loans and receivables. They are included in current assets, except for maturities greater than 12 months after the reporting date, which are classified as non-current assets.

ii) Equity instruments

Equity instruments are classified as equity. Incremental costs directly attributable to the issue of common shares and share options are recognized as a deduction from equity, net of any tax effects, if any.

d) Inventory

Inventories consist of tangible drilling materials and other consumables. Inventories are stated at the lower of cost and net realizable value. Cost is determined using the weighted average method. Net realizable value is the estimated selling price less applicable selling expenses.

e) Property, plant and equipment and intangible exploration and evaluation expenses

i) Recognition and measurement

Development and production costs

Property, plant and equipment is stated at cost, less accumulated depletion and depreciation and accumulated impairment losses.

The initial cost of an asset comprises its purchase price or construction cost, any costs directly attributable to bringing the asset into operation, the initial estimate of any decommissioning obligation, if any, and, for qualifying assets, borrowing costs. The purchase price or the construction cost is the aggregate amount paid and the fair value of any other consideration given to acquire the asset.

Expenditures on major maintenance, inspections, or overhauls are capitalized when the item enhances the life or performance of an asset above its original standard. Such capitalized oil and natural gas interests generally represent costs incurred in developing proved and/or probable reserves and bringing in or enhancing production from such reserves, and are accumulated on a field or geotechnical area basis. The carrying amount of any replaced or sold component is derecognized. The costs of the day-to-day servicing of property, plant, and equipment are recognized in the Consolidated Statement of Comprehensive Income as incurred. Where an asset or part of an asset that was separately depreciated is replaced and it is probable that future economic benefits associated with the item will flow to the Company, the expenditure is capitalized and the carrying amount of the replaced asset is derecognized. Inspection costs associated with major maintenance programs are capitalized and amortized over the period to the next inspection. All other maintenance expenditures are expensed as incurred.

3. Significant accounting policies (continued)

e) Property, plant and equipment and intangible exploration and evaluation expenses (continued)

i) Recognition and measurement (continued)

Exploration and evaluation expenditures

Pre-licence costs are recognized in the Consolidated Statement of Comprehensive Income in the period in which they are incurred.

Exploration and evaluation expenditures, including the costs of acquiring licences and directly attributable general and administrative costs, geological and geophysical costs, acquisition of mineral and surface rights, technical studies, other direct costs of exploration (drilling, trenching, sampling, and evaluating the technical feasibility and commercial viability of extraction) and appraisal are accumulated and capitalized as intangible exploration and evaluation ("E&E") assets.

On a quarterly basis, a review of any areas classified and accounted for as E&E is performed to determine whether enough information exists to assess the technical feasibility and commercial viability of the area. Where appropriate, the review may indicate that an area should be further subdivided because a significant portion has already been explored, while a significant undeveloped portion with different traits (i.e. different zone, technical approach, play type, etc.) remains that requires additional E&E activities to assess it for technical feasibility and commercial viability.

The assessment of technical feasibility and commercial viability is performed on an area level basis unless further subdivision is recommended. Depending on the extent and complexity of the prospective play, many wells may need to be drilled and potentially significant E&E costs accumulated prior to obtaining enough information to assess technical feasibility and commercial viability.

E&E costs are not amortized prior to the conclusion of appraisal activities. At the completion of appraisal activities, if technical feasibility is demonstrated and commercial reserves are discovered, then the carrying value of the relevant E&E asset will be reclassified from a development and production asset ("D&P") into the cash generating unit ("CGU") to which it relates, but only after the carrying value of the relevant E&E asset has been assessed for impairment, and where appropriate, its carrying value adjusted. Typically, the technical feasibility and commercial viability of extracting a mineral resource is considered to be demonstrable when proven or probable reserves are determined to exist. However, if the Company determines the area is not technically feasible and commercially viable, accumulated E&E costs are expensed in the period during which the determination is made.

ii) Depletion and depreciation

The net carrying value of development and production assets is depleted using the unit of production method by reference to the ratio of production in the year to the related proven and probable reserves, taking into account the estimated future development costs necessary to bring those reserves into production. Future development costs are estimated taking into account the level of development required to produce the reserves. These estimates are reviewed by independent reserve engineers at least annually.

For other assets (see below), a straight-line basis is used over the assets' estimated useful lives, as follows:

Fixtures and fittings	1 - 5 years
Office equipment	1 - 5 years
Vehicles	1 - 5 years
Software licenses	1 - 3 years

Depreciation methods, useful lives, and residual values are reviewed at each reporting date.

f) Impairment

i) Financial assets

Recognition of impairment provisions under IFRS 9 is based on the expected credit losses ("ECL") model. The ECL model is applicable to financial assets classified at amortized costs and contract assets under IFRS 15: Revenue from Contracts with Customers. The measurement of ECL reflects an unbiased and probability weighted amount that is available without undue cost or effort at the reporting date, about past events, current conditions and forecasts of future economic conditions.

The Group applied the simplified approach to determine impairment of its trade and other receivables. The simplified approach requires expected lifetime losses to be recognized from initial recognition of the receivables. This involves determining the expected loss rates using a provision matrix that is based on the Group's historical default rates observed over the expected life of the receivables and adjusted forward looking estimates. This is then applied to the gross carrying amount of the receivables to arrive at the loss allowance for the period.

3. Significant accounting policies (continued)

f) Impairment (continued)

ii) Non-financial assets

Exploration and evaluation costs are tested for impairment when reclassified as D&P assets or whenever facts and circumstances indicate potential impairment. Exploration and evaluation assets are tested separately for impairment. An impairment loss is recognized for the amount by which the exploration and evaluation expenditure's carrying amount exceeds its recoverable amount. The recoverable amount is the higher of the exploration and evaluation expenditure's fair value less the cost of disposal and its value in use.

Values of oil and gas properties and other property, plant, and equipment are reviewed for impairment when indicators of such impairment exist. If any indication of impairment exists, an estimate of the asset's recoverable amount is calculated. Assets are grouped for impairment assessment purposes at the lowest level at which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets (the CGU). The recoverable amount of a CGU is the greater of its fair value less the cost of disposal and its value in use. Where the carrying amount of a CGU exceeds its recoverable amount, the CGU is considered impaired and is written down to its recoverable amount. An impairment loss is charged to the income statement. In assessing value in use, the estimated future cash flows are adjusted for the risks specific to the CGU and are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money.

For assets excluding goodwill, an assessment is made at each reporting date as to whether there is any indication that previously recognized impairment losses may no longer exist or may have decreased, and if such an indication exists, the Company makes an estimate of the recoverable amount. A previously recognized impairment loss is reversed only if there has been a change in the estimates used to determine the asset's recoverable amount since the last impairment loss was recognized. If that is the case, the carrying amount of the asset is increased to its recoverable amount. That increased amount cannot exceed the carrying amount that would have been determined, net of depreciation, had no impairment loss been recognized for the asset in prior years.

g) Leases

Leased assets are classified as finance leases when the terms of the lease transfer substantially all the risks and rewards incidental to ownership of the leased asset to the lessee. All other leases are classified as operating leases.

Operating lease payments are recognized as an expense on a straight-line basis over the lease term, except where another systematic basis is more representative of the time pattern in which economic benefits from the leased asset are consumed. Contingent rentals arising under operating leases are recognized as an expense in the period in which they are incurred.

IFRS 16 will be applied from January 1, 2019.

h) Share-based payments

The grant date fair value of options granted to employees is recognized as stock-based compensation expense, with a corresponding increase in contributed surplus over the vesting period. Each tranche granted is considered a separate grant with its own vesting period and grant date fair value. A forfeiture rate is estimated on the grant date and is adjusted to reflect the actual number of options that vest.

i) Segment reporting

Operating segments are reported in a manner consistent with the internal reporting provided to the senior operating decision-makers. The senior operating decision-makers have been identified as the Executive directors who, as a group, make strategic decisions regarding the Company.

j) Provisions

A provision is recognized, if, as a result of a past event, the Company has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability. Provisions are not recognized for future operating losses.

k) Decommissioning obligations

The Company's activities can give rise to dismantling, decommissioning and site disturbance remediation activities. Provision is made for the estimated cost of site restoration and capitalized in the relevant asset category.

Decommissioning obligations are measured at the present value of management's best estimate of the expenditure required to settle the present obligation at the balance sheet date. Subsequent to the initial measurement, the obligation is adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as finance costs, whereas increases/decreases due to changes in the estimated future cash flows are capitalized. Actual costs incurred upon settlement of the asset retirement obligations are charged against the provision to the extent the provision is established.

3. Significant accounting policies (continued)

l) Revenue

Revenue is measured at the fair value of the consideration received or receivable for goods in the normal course of business.

i) Sale of goods

Revenue from the sale of hydrocarbons is recognized when the Company has passed control of the hydrocarbons to the buyer, it is probable that economic benefits associated with the transaction will flow to the Company, the sales price can be measured reliably, and the Company has no significant continuing involvement and the costs incurred or to be incurred in respect of the transaction can be measured reliably. This is when insurance risk has passed to the buyer and the goods have been collected at the agreed location.

The performance obligation is satisfied when the hydrocarbons are delivered to the agreed location with the appropriate required documentation and the customer accepts control of the shipment by signature. Prices are based on published indices, with agreed contractual adjustments for quality, marketing fees, and other variables.

ii) Provision of production services

Revenue from the provision of production services is recognized when the Company has passed control of the produced hydrocarbons to the buyer, it is probable that economic benefits associated with the transaction will flow to the Company, the production service fee can be measured reliably, and the Company has no significant continuing involvement and the costs incurred or to be incurred in respect of the transaction can be measured reliably. This is when insurance risk has passed to the buyer and the goods have been collected at the agreed location.

The performance obligation is satisfied when the produced hydrocarbons are delivered to the agreed location with the appropriate required documentation and the customer accepts control of the shipment by signature. Production services fees are based on published indices, with agreed contractual adjustments for quality, marketing fees, and other variables.

iii) Royalties

In the Arab Republic of Egypt, under the terms of the Company's Production Sharing Contracts ("PSCs"), the state is entitled to a percentage in kind of hydrocarbons produced. The Company accounts for this production share as a royalty, netted against gross revenues.

In the Kingdom of Morocco, under the terms of the Company's Petroleum Agreement with the Moroccan state sales-based royalties become payable when certain inception-to-date production thresholds are reached, according to the terms of each exploitation concession. The Company nets these royalties against gross revenues.

iv) Transition from IAS 18 'Revenue'

The only changes to the new accounting policy under IFRS 15 compared with IAS 18 are:

- the performance obligation under IFRS 15 above; and
- control of the items sold under IFRS 15 compared to risk and rewards of ownership being transferred under IAS 18.

Other than that, it is identical to the policy under IAS 18 applied to the comparative data.

m) Income tax

Income tax expense comprises current and deferred tax. Income tax expense is recognized in the Consolidated Statement of Comprehensive Income except to the extent that it relates to items recognized directly in equity, in which case it is recognized in equity.

Current tax is the expected tax payable on the taxable income for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to the tax payable in respect of previous years.

Pursuant to the terms of the Company's Egyptian concession agreements, the corporate tax liability of the joint venture partners is paid by the government-controlled corporations ("Corporations") out of the profit oil attributable to the Corporations, and not by the Company. For accounting purposes, the corporate taxes paid by the Corporations are treated as a benefit earned by the Company; the amount is included in net oil revenues and in income tax expense, therefore having a net neutral impact on reported net income. Income tax expense is recognized in each interim period based on the best estimate of the weighted average annual income tax rate expected for the full financial year.

The Company also has a production service agreement in Egypt relating to Block-H Meseda. The Company's subsidiary, SDX Energy Egypt (Meseda) Ltd, an Egyptian registered entity, is the SDX contracting party in this production service agreement. This entity pays Corporate tax based on its taxable income, according to this production service agreement, for the year using tax rates enacted or substantively enacted at the reporting date.

The Company's Moroccan operations benefit from a 10-year corporation tax holiday from first production and no corporation tax is due on Moroccan profits as at December 31, 2018.

3. Significant accounting policies (continued)

m) Income tax (continued)

Deferred tax is recognized using the balance sheet method, providing for temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred tax is not recognized on the initial recognition of assets or liabilities in a transaction that is not a business combination. Deferred tax is also not recognized for taxable temporary differences arising on the initial recognition of goodwill. Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the reporting date. Deferred tax assets and liabilities are offset if there is a legally enforceable right to offset, and they relate to income taxes levied by the same tax authority on the same taxable entity, or on different tax entities, but they intend to settle current tax liabilities and assets on a net basis or their tax assets and liabilities will be realized simultaneously.

A deferred tax asset is recognized to the extent that it is probable that future taxable profits will be available against which the temporary difference can be used.

n) Earnings per share

Basic earnings per share is calculated by dividing the profit or loss attributable to common shareholders of the Company by the weighted average number of common shares outstanding during the period. Diluted earnings per share is determined by adjusting the profit or loss attributable to common shareholders and the weighted average number of common shares outstanding for the effects of dilutive instruments, such as options granted to employees.

0) Business combinations

Business combinations are accounted for using the acquisition method. Assets and liabilities assumed in a business combination are recognized at their fair value at the date of the acquisition. Any excess of the consideration paid over the fair value of the net assets acquired is recognized as an asset. Any excess of the fair value of the net assets acquired over the consideration paid is recognized in the Consolidated Statement of Comprehensive Income.

p) New standards and interpretations

The Company has adopted IFRS 15 Revenue from Contracts with Customers and IFRS 9 Financial Instruments effective January 1, 2018. Adoption of these standards has not materially affected the way SDX accounts for its revenues or financial instruments. However, the Company will be including the new disclosures required by IFRS 15 and IFRS 9.

IFRS 9 (revised) "Financial Instruments: Classification and Measurement"

Effective January 1, 2018, the Company adopted IFRS 9 Financial Instruments, which replaced IAS 39 Financial Instruments: Recognition and Measurement. The new standard covers three distinct areas as follows:

Classification and measurement of financial assets and liabilities

Under the new standard, financial assets are classified as either at amortised cost or fair value through other comprehensive income ("FVOCI"); or fair value through profit and loss ("FVTPL"). The approach is based on how an entity manages its financial instruments in the context of its business model and the contractual cash flow characteristics of its financial assets. All of the Company's financial assets as at January 1, 2018 (trade and other receivables (excluding prepayments) and cash and cash equivalents) satisfied the conditions for classification at amortised cost under IFRS 9.

As for financial liabilities, they are classified as at amortised cost, with some exceptions. Financial liabilities are not reclassified at any point of time. The Company's financial liabilities which includes accounts payables and accrued liabilities and decommissioning liabilities are classified at amortised cost.

As the impact of IFRS 9 in relation to the classification and measurement of financial assets and liabilities was immaterial on the transition date, no retrospective adjustments have been posted on adoption of this standard.

Impairment of financial assets

IFRS 9 incorporates a new expected credit loss model for calculation impairment on financial assets, which will result in more timely recognition of expected credit losses. A review of the Company's historical credit losses has confirmed that annual credit losses are wholly immaterial to the Consolidated Financial Statements therefore no retrospective adjustments have been posted on adoption of IFRS 9.

Hedge accounting

IFRS 9 includes a simplified hedge accounting model, aligning hedge accounting more closely with risk management. The Company does not apply hedge accounting.

3. Significant accounting policies (continued)

p) New standards and interpretations (continued)

IFRS 15 "Revenue from Contracts with Customers"

Effective January 1, 2018, the Company adopted IFRS 15 Revenue from Contracts with Customers, which replaced IAS 18 Revenue, IAS 11 Construction Contracts and related interpretations. IFRS 15 establishes a comprehensive framework for determining whether, how much, and when revenue from contracts with customers is recognized. Under IFRS 15, revenue is recognized when a customer obtains control of the goods or services as stipulated in a performance obligation. Determining whether the timing of the transfer of control is at a point in time or over time requires judgement and can significantly affect when revenue is recognized. In addition, the entity must also determine the transaction price and apply it correctly to the goods or services contained in the performance obligation.

The Company's revenue is derived exclusively from contracts with customers, except for immaterial amounts related to interest and other income. Royalties are considered to be part of the price of the sale transaction and are therefore presented as a reduction to revenue. Revenue associated with the sale of crude oil, natural gas, and natural gas liquids ("NGLs") is measured based on the consideration specified in contracts with customers. Revenue from contracts with customers is recognized when or as the Company satisfies a performance obligation by transferring a good or service to a customer. A good or service is transferred when the customer obtains control of the good or service. The transfer of control of oil, natural gas, and NGLs usually coincides with title passing to the customer and the customer taking physical possession. SDX mainly satisfies its performance obligations at a point in time and the amounts of revenue recognized relating to performance obligations satisfied over time are not significant.

Revenues associated with the sales of the Company's crude oil, natural gas, and NGLs in Egypt are recognized by reference to actual volumes sold and quoted market prices in active markets (Dated Brent), adjusted according to specific terms and conditions as applicable according to the sales contracts. Revenue is measured at the fair value of the consideration received or receivable. For reporting purposes, the Company records the government's share of production as royalties and taxes as all royalties and taxes are paid out of the government's share of production.

Revenues from the sale of natural gas in Morocco are recognized by reference to actual volumes delivered at contracted delivery points and contracted prices. Certain contracted prices are fixed, and others are determined by reference to quoted market prices in active markets (Dated Brent). Revenues are measured at the fair value of the consideration received. SDX pays royalties to the Moroccan government in accordance with the established royalty regime.

The Company reviewed its sales contracts with customers and determined that IFRS 15 did not have a material impact on its revenue recognition and, accordingly, no material impact on the Consolidated Financial Statements. SDX adopted this standard using the modified retrospective approach, whereby the cumulative effect of initial adoption of the standard is recognized as an adjustment to retained earnings. There was no effect on the Company's retained earnings or prior period amounts as a result of adopting this standard.

Revenue segregated by product type and geographical market is found in notes 18 and 21 respectively.

At the date of authorization of these Consolidated Financial Statements, the International Accounting Standards Board ("IASB") has issued the following new and revised standards, which are not yet effective for the relevant periods:

IFRS 16 "Leases"

This is a new accounting standard which will result in almost all leases being recognised on the balance sheet, since the distinction between operating and finance leases is removed. Under the new standard, an asset (that is, the right to use the leased item) and a financial liability to pay rentals are recognised. The only exceptions are short-term and low-value leases.

As at December 31, 2018, the Company holds a small number of operating leases that are expensed over the lease term. The adoption of IFRS 16 would not have had a material impact on the net assets, operating income, and finance expense of the Company in the current period. However, in the future should the Group contract equipment on longer term contracts to develop its assets there may be a material impact.

The Group intends to adopt IFRS 16 on the following basis (a) prospectively, (b) right of use assets will be measured at an amount equal to the lease liability and (c) leases entered into prior to January 1, 2019 will not be reflected as leases under IFRS 16. The Group has made the following application policy choice: short term leases (less than 12 months) and leases of low value assets will not be reflected in the balance sheet but will be expensed as incurred.

(tabular amounts are in thousands of United States dollars except where stated)

4. Business Combination

On January 27, 2017, the Company announced the acquisition, through two of its wholly-owned subsidiaries, of the entire issued share capital of Circle Oil Egypt Limited ("COEL") and Circle Oil Morocco Limited ("COML") for a cash purchase price of US$28.1 million. The acquisition was funded by means of a conditional placing of new common shares in SDX at a placing price of 30 pence (C$0.50) per placing share, amounting to US$40.0 million before costs.

COEL holds a 40% interest in the NW Gemsa concession, Eastern Desert, Egypt. Prior to the acquisition, SDX held a 10% interest in this concession, bringing the post-acquisition holding to 50%.

COML holds a 75% interest and operatorship in certain licenses, onshore Morocco, with L'Office National des Hydrocarbures et des Mines ("ONHYM") holding a 25% interest.

The acquisition is in accordance with the Company's strategy to pursue value adding production and development opportunities in North Africa to complement its organic growth strategy.

The fair value of the identifiable assets and liabilities of COEL and COML as at the date of acquisition were:

US$ million	Fair value as at January 27, 2017
Non-current assets	
Property, plant & equipment	43.2
Current assets	
Cash and cash equivalents	3.1
Trade and other receivables	32.7
Inventory	1.1
Current tax	0.1
Non-current liabilities	
Decommissioning liability	(2.8)
Deferred income	(0.7)
Current liabilities	
Trade and other payables	(17.1)
Decommissioning liability	(1.2)
Deferred income	(0.9)
Total identifiable net assets at fair value	57.5
Total consideration	(28.1)
Excess of fair value over cost (bargain purchase)	29.4

Prior to the acquisition, the parent company of COEL and COML, Circle Oil Jersey Limited, was placed into administration. The excess of fair value over cost arises because COEL and COML were distressed businesses and purchased out of administration. A bargain purchase gain amounting to US$29.4 million was recognized in the Consolidated Statement of Comprehensive Income for periods subsequent to the acquisition, after recording the following adjustments:

- A provision of US$2.6 million has been recognized against certain aged receivables due from ONHYM relating to its share of historic construction costs, and a further US$0.5 million of additional deferred income was recognized. These amounts have been partially offset by additional billings for well completions in Morocco of US$1.0 million (US$0.8 million net of VAT). Management has further considered the recoverability of the trade receivables balance alongside confirmations received from EGPC and concession operators of amounts to be settled, as well as forecasted uses of Egyptian pounds in operations, and do not consider it necessary to apply discounting. The trade receivables balance and any updates to the conclusion over discounting will be monitored over the coming months.
- Ahead of the drilling campaign that began in the second half of 2017, an assessment was made of the acquired inventory. Certain items were identified as being unfit for use and an obsolescence provision of US$0.2 million was recognized. Aged working capital of US$0.9 million associated with legacy suppliers was eliminated.
- A further US$1.9 million has been recorded for additional liabilities acquired, relating to potential tax and legal claims. During Q2 2018, a settlement was reached in relation to a historic operational tax issue, resulting in a provision release of US$0.3 million to the Consolidated Statement of Comprehensive Income.
- An accrued payable relating to back-dated tariff charges and other costs of US$4.8 million at NW Gemsa has been released following the agreement of a payment plan with the operator. The estimate of natural gas and NGL receivable acquired has been revised down by US$1.5 million following the receipt of additional information from the operator and EGPC (see note 17) to US$6.7 million.

COEL and COML contributed US$23.2 million in revenue and US$5.1 million in net loss, and US$14.6 million in revenue and US$0.7 million in net loss respectively for the 12 months ended December 31, 2018.

5. Determination of fair values

A number of the Company's accounting policies and disclosures require the determination of fair value, for both financial and non-financial assets and liabilities. Fair values have been determined for measurement and/or disclosure purposes based on the following methods. When applicable, further information about the assumptions made in determining fair values is disclosed in the notes specific to that asset or liability.

The different levels of financial instrument valuation methods have been defined as:

Level 1 fair value measurements are based on unadjusted quoted market prices.
Level 2 fair value measurements are based on valuation models and techniques where the significant inputs are derived from quoted indices.
Level 3 fair value measurements are based on unobservable information.

The carrying value of cash and cash equivalents, trade and other receivables, trade and other payables, and loans and borrowings included in the consolidated balance sheet approximate to their fair value due to the short-term nature of those instruments.

The fair value of employee stock options is measured using Black-Scholes (non-market-based performance conditions) and Monte Carlo (market-based performance conditions) option pricing models. Measurement inputs include the share price on the measurement date, exercise price of the instrument, expected volatility based on the weighted average historic volatility (adjusted for changes expected as the result of publicly available information), the weighted average expected life of the instruments based on historical experience and general option holder behavior, expected dividends, anticipated achievement of performance conditions, and the risk-free interest rate.

6. Financial risk management

a) Overview

The Company's activities expose it to a variety of financial risks that arise as a result of its exploration, development, production, and financing activities such as:

- credit risk;
- liquidity risk;
- market risk;
- foreign currency risk; and
- other price risk.

This note presents information about the Company's exposure to each of the above risks, the Company's objectives, policies and processes for measuring and managing risk, and the Company's management of capital. Further quantitative disclosures are included throughout these Consolidated Financial Statements.

The Board of Directors oversees management's establishment and execution of the Company's risk management framework. Management implements and monitors compliance with risk management policies. The Company's risk management policies are established to identify and analyze the risks faced by the Company, to set appropriate risk limits and controls, and to monitor risks and adherence to market conditions and the Company's activities.

b) Credit risk

Credit risk is the risk of financial loss to the Company if a customer, partner, or counterparty to a financial instrument fails to meet its contractual obligations and arises principally from the Company's receivables from joint venture partners, oil and natural gas customers, and cash held with banks. The maximum exposure to credit risk at the end of the period is as follows:

	Carrying amount	
US$'000s	**December 31 2018**	December 31 2017
Cash and cash equivalents	**17,345**	25,844
Trade and other receivables[1]	**23,689**	34,781
Total	**41,034**	60,625

(1) Excludes prepayments of US$0.6 million which are included in the Consolidated Balance Sheet as trade and other receivables but which are not categorised as financial assets as summarised above (2017: US$2.9 million).

6. Financial risk management (continued)
(b) Credit risk (continued)
Trade and other receivables

Following the acquisition described in note 4, all of the Company's operations are conducted in Egypt and Morocco. The Company's exposure to credit risk is influenced mainly by the individual characteristics of each counter-party.

The Company applies IFRS 9 simplifies model for measuring the expected credit losses which uses a lifetime expected loss allowance and are measured on the days past due criterion. Having reviewed past payments combined with the credit profile of its existing trade debtors in order to assess the potential for impairment, the Company has concluded that this is insignificant as there has been no history of default or disputes arising on invoiced amounts since inception and as such the credit loss percentage is assumed to be almost zero. No provision for doubtful accounts against these sales has been recorded as at December 31, 2018 and December 31, 2017.

The maximum exposure to credit risk for loans and receivables at the reporting date by type of customer was:

	Carrying amount	
US$'000s	**December 31 2018**	December 31 2017
Government of Egypt-controlled corporations	**14,846**	25,582
Government of Morocco-controlled corporations	**3,053**	3,597
Third-party gas customers	**2,715**	3,175
Joint venture partners	**1,761**	1,586
Other[(1)]	**1,314**	841
Total	**23,689**	34,781

(1) Excludes prepayments of US$0.6 million which are included in the Consolidated Balance Sheet as trade and other receivables but which are not categorised as financial assets as summarised above (2017: US$2.9 million).

US$14.8 million of current receivables relates to oil, gas, and NGL sales and production service fees that are due from EGPC (2017: US$25.6 million), a Government of Egypt-controlled corporation. The Company expects to collect outstanding receivables of US$10.0 million for NW Gemsa (2017: US$22.7 million) and US$4.8 million for Block-H Meseda (2017: US$2.9 million), in the normal course of operations. As part of the Government of Egypt's commitment to reduce amounts owing to international oil companies, the Company received US$16.1 million in lump-sum payments during the 12 months ended December 31, 2018.

ONHYM, a Government of Morocco-controlled corporation, owes US$3.1 million, which relates to its outstanding share of well completion and connection and production costs. These receivables are not expected to be fully recovered during the next 12 months and have been discounted at 5%, with an associated finance expense of US$0.3 million recognized in the Consolidated Statement of Comprehensive Income. During 2018, the Company received US$0.5 million from ONHYM.

US$2.7 million is owing from third-party gas customers in Morocco and is expected to be collected within agreed credit terms.

Subsequent to December 31, 2018, the Company collected US$14.4 million of trade receivables from those outstanding at December 31, 2018; US$11.6 million from EGPC, and US$2.8 million from third-party gas customers in Morocco. Of the US$11.6 million collected from EGPC, US$1.5 million was in cash and US$10.1 million was offset against South Disouq development costs, South Ramadan drilling costs and amounts owing to joint venture partners.

The joint venture partner current accounts represent the net of monthly cash calls paid less billings received. At December 31, 2018, US$1.8 million was receivable from the joint venture partner in the South Disouq concession (2017: South Disouq - US$1.6 million), representing both billed and unbilled amounts.

The other receivables of US$1.3 million consist of US$0.8 million for Goods and Services Tax ("GST")/ Value Added Tax ("VAT") and US$0.5 million for other items.

US$0.6 million related to prepayments predominantly associated with technical and business development software subscriptions is recorded in the Consolidated Balance Sheet.

6. Financial risk management (continued)

(b) Credit risk (continued)

Trade and other receivables (continued)

As at December 31, 2018 and December 31, 2017, the Company's trade and other receivables, other than prepayments, are aged as follows:

	Carrying amount	
US$'000s	**December 31 2018**	December 31 2017
Current		
Current (less than 90 days)	**14,805**	21,261
Past due (more than 90 days)	**8,884**	13,520
Total	**23,689**	34,781

Current trade and other receivables are unsecured and non-interest-bearing. The balances that are past due are not considered impaired.

Current trade and other receivables past due (more than 90 days old) have decreased by US$2.7 million compared to December 31, 2017. This decrease is primarily due to the collection of NW Gemsa natural gas and NGL invoices issued by the operator in Q4 2017, amounting to US$9.2 million, which were current as at December 31, 2017, and became aged during 2018.

Cash and cash equivalents

The Company limits its exposure to credit risk by investing only in liquid securities and only with highly rated counterparties. The Company's cash and cash equivalents are currently held in established banks in either countries of operation or the UK, the majority of which have A or AA ratings. Given these credit ratings, management does not expect any counterparty to fail to meet its obligations.

c) Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they fall due. The Company's approach to managing liquidity is to ensure, as far as possible, that it will always have sufficient liquidity to meet its liabilities when due, under both normal and stressed conditions, without incurring unacceptable losses or risking damage to the Company's reputation.

The Company typically ensures that it has sufficient cash on demand to meet expected operational expenses, including the servicing of financial obligations and excluding the potential impact of extreme circumstances that cannot reasonably be predicted, such as natural disasters and political unrest. To achieve this objective, the Company prepares annual capital expenditure budgets, which are regularly monitored and updated as considered necessary. Further, the Company uses authorizations for expenditures on projects to further manage capital expenditure and has a Board of Director-approved signing authority matrix. The Company also strives to match its payment cycle with the collection of oil and service fee revenue to the extent possible.

As at December 31, 2018, other than the non-current elements of the deferred income and decommissioning liabilities, the Company's financial liabilities are due within one year.

d) Market risk

Market risk is the risk that changes in market prices, such as commodity prices, foreign exchange rates, and interest rates will affect the Company's income or the value of the financial instruments. The objective of market risk management is to manage and control market risk exposures within acceptable parameters, while optimizing the return.

The Company may use both financial derivatives and physical delivery sales contracts to manage market risks. All such transactions are conducted within risk management tolerances that are reviewed by the board of directors.

(tabular amounts are in thousands of United States dollars except where stated)

6. Financial risk management (continued)

e) Foreign currency risk (continued)

Currency risk is the risk that the fair value of future cash flows will fluctuate because of changes in foreign exchange rates. The reporting and functional currency of the Company is United States dollars ("US$"). Most of the Company's operations are in foreign jurisdictions and, as a result, the Company is exposed to foreign currency exchange rate risk on some of its activities, primarily on exchange fluctuations between the Egyptian pound ("EGP") and the US$, the Moroccan dirham ("MAD") and the US$, and Sterling ("GBP") and the US$. The majority of capital expenditures are incurred in US$, EGP and MAD, and oil, natural gas, NGL and service fee revenues are received in US$, EGP and MAD. The Company can use EGP and MAD to fund its Egyptian and Moroccan office general and administrative expenses and to part-pay cash requirements for both capital and operating expenditure, thereby reducing the Company's exposure to foreign exchange risk during the period.

The table below shows the Company's exposure to foreign currencies for its financial instruments:

	Total per FS[1]	US$	EGP	MAD	GBP	Other
As at December 31, 2018			**US$ Equivalent**			
Cash and cash equivalents	17,345	10,645	2,712	1,864	1,983	141
Trade and other receivables[2]	23,689	15,979	24	6,750	898	38
Trade and other payables	(14,418)	(6,370)	(1,349)	(4,363)	(2,316)	(20)
Balance sheet exposure	26,616	20,254	1,387	4,251	565	159

(1) FS denotes Financial Statements

(2) Excludes prepayments

The average exchange rates during the three months ended December 31, 2018 and 2017 were 1 US$ equals:

Average: October 1, 2018 to December 31, 2018			
	USD/EGP	USD/GBP	USD/MAD
Period average	17.9206	0.7769	9.5089

Average: October 1, 2017 to December 31, 2017			
	USD/EGP	USD/GBP	USD/MAD
Period average	17.7107	0.7537	9.4442

The average exchange rates during the years ended December 31, 2018 and 2017 were 1 US$ equals:

Average: January 1, 2018 to December 31, 2018			
	USD/EGP	USD/GBP	USD/MAD
Period average	17.8191	0.7499	9.3893

Average: January 1, 2017 to December 31, 2017			
	USD/EGP	USD/GBP	USD/MAD
Period average	17.8534	0.7770	9.7047

The exchange rates as at December 31, 2018 and 2017 were 1 US$ equals:

Period end: December 31, 2018			
	USD/EGP	USD/GBP	USD/MAD
Period end	17.8919	0.7812	9.5610

Period end: December 31, 2017			
	USD/EGP	USD/GBP	USD/MAD
Period end	17.7875	0.7398	9.3519

f) Other price risk

Other price risk is the risk that the fair value of future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for oil and natural gas are affected by not only the relationship between the US dollar and other currencies, but also macro-economic events that affect the perceived levels of supply and demand.

The Company may hedge some oil and natural gas sales through the use of various financial derivative forward sales contracts and physical sales contracts. The Company's production is sold on the daily average price. The Company, however, may give consideration in certain circumstances to the appropriateness of entering into long-term, fixed-price marketing contracts.

As at December 31, 2018 the Company did not have any outstanding derivatives in place.

6. Financial risk management (continued)

g) Capital management

The Company defines and computes its capital as follows:

	Carrying amount	
US$'000s	**December 31 2018**	December 31 2017
Equity	**116,039**	114,619
Working capital[1]	**(29,409)**	(46,725)
Total capital	**86,630**	67,894

(1) Working capital is defined as current assets less current liabilities.

The Company's objective when managing its capital is to ensure that it has sufficient funds to maintain its ongoing operations, to pursue the acquisition of interests in producing (or near to production) oil and gas properties, and to maintain a flexible capital structure that optimizes the cost of capital at an acceptable risk. The Company manages its capital structure and adjusts it according to the funds available to the Company, to support the exploration and development of its interests in its existing oil and gas properties and to pursue other opportunities.

7. Cash and cash equivalents

	Carrying value	
US$'000s	**December 31 2018**	December 31 2017
Cash and bank balances	**15,809**	24,248
Restricted cash[1]	**1,536**	1,596
Total cash and cash equivalents	**17,345**	25,844

(1) Cash collateral of US$1.5 million is held at the bank to cover bank guarantees for minimum work commitments on the Company's Moroccan concessions. These guarantees are subject to forfeiture in certain circumstances if the Company does not fulfil its minimum work obligations.

8. Inventory

Following the completion of the Company's drilling campaign in Morocco in 2018, the Company undertook a review of on-hand drilling inventory. It was concluded that a number of items should be written off based on several factors, including condition, operational failure, future utility, and the limited resale market in Morocco. A charge of US$0.4 million has been recognized in the Consolidated Statement of Comprehensive Income, resulting in a closing inventory balance as at December 31, 2018 of US$5.2 million, of which US$3.3 million is held in South Disouq and US$1.9 million in Morocco.

9. Property, plant and equipment

US$'000s	Oil and gas properties	Furniture and fixtures	Total
Cost:			
Balance at December 31, 2016	**32,368**	**188**	**32,556**
Additions	15,975	457	16,432
Acquisitions	43,232	-	43,232
Balance at December 31, 2017	**91,575**	**645**	**92,220**
Additions	14,288	735	15,023
Balance at December 31, 2018	**105,863**	**1,380**	**107,243**
Accumulated depletion, depreciation, amortization and impairment:			
Balance at December 31, 2016	**(19,862)**	**(89)**	**(19,951)**
Depletion, depreciation and amortization for the year	(17,737)	(87)	(17,824)
Balance at December 31, 2017	**(37,599)**	**(176)**	**(37,775)**
Depletion, depreciation and amortization for the year	(16,890)	(378)	(17,268)
Impairment expense	(3,520)	-	(3,520)
Balance at December 31, 2018	**(58,009)**	**(554)**	**(58,563)**
NBV Property, plant and equipment as at December 31, 2017	53,976	469	54,445
NBV Property, plant and equipment as at December 31, 2018	**47,854**	**826**	**48,680**

During the 12 months ended December 31, 2018, the PP&E additions of US$15.0 million were predominantly related to the Morocco drilling campaign and new customer connections (US$4.5 million), the drilling of the AASE-25, AASE-27 and Al-Ola 4 wells and well workovers in the NW Gemsa concession (US$7.9 million), the Rabul-4, MH-16, and MH-15 wells in Block-H Meseda and well workovers (US$1.9 million), the acquisition of additional technical software (US$0.5 million), and the fit-out of the new Cairo office in Egypt (US$0.2 million).

The difference between the US$15.0 million disclosed above and the US$22.0 million property, plant and equipment expenditure in the Consolidated Statement of Cash Flows is because payments to billed and accrued creditors associated with Moroccan drilling which were outstanding as at December 31, 2017 were paid in the 12 months ended December 31, 2018.

In the table above, the Company has also recorded the assets acquired from Circle Oil plc at fair value of US$43.2 million.

Impairment assessment
At the reporting date, management performed an impairment indicator assessment and concluded that due to a reduction in the proved and probable reserves for the NW Gemsa concession, caused predominantly by reduced oil price assumptions from Q4 2018 onwards, the asset should be tested for impairment.

The impairment test was carried out in accordance with the Company's accounting policy stated in note 3. The recoverable amount of the field has been determined based on a value-in-use calculation. This calculation requires the use of estimates. The present values of future cash flows were computed by applying forecast prices for oil and gas reserves to estimated future production of proved and probable reserves. The present value of estimated future net revenues is computed using a discount factor of 12.5%. The discount rate used reflects the specific risks relating to the underlying cash generating unit.

Based on this calculation for NW Gemsa an impairment of US$3.5 million has been recorded.

The value in use calculation assumes Brent oil sales prices in US$/bbl as follows:

2019	2020	2021	2022	2023	2024
67.0	70.0	71.0	74.0	70.0	78.0

A 10% reduction in the Brent oil sales price would increase the impairment by US$3.4 million. A 10% increase in the Brent oil sales price would reduce the impairment by US$3.3 million.

A 10% reduction in forecast production would increase the impairment by US$3.5 million. A 10% increase in forecast production would reduce the impairment by US$3.4 million.

10. Exploration and evaluation assets

US$'000s	
Balance at December 31, 2016	**10,623**
Additions	4,608
Balance at December 31, 2017	**15,231**
Additions	29,000
Exploration and evaluation expense	(5,103)
Balance at December 31, 2018	**39,128**

During the twelve months ended December 31, 2018, E&E additions amounted to US$29.0 million.

Of this, US$8.5 million was invested at South Disouq for the drilling of the Ibn Yunus-1X, Kelvin-1X, SD-4X, and SD-3X wells. Following the interpretation of well logs, Kelvin-1X was deemed non-commercial and the associated costs (US$1.6 million) were expensed to the Consolidated Statement of Comprehensive Income. A further US$2.1 million was capitalized, representing the costs of the 3D seismic acquisition that began in Q4 2018.

Additions in Morocco relate to the drilling of the ELQ-1, KSS-2, LNB-1, and LMS-1 wells (US$9.4 million) and US$6.4 million for the current 3D seismic campaign. Following sub-commercial results at the ELQ-1 and KSS-2 wells, the full costs of these two wells (US$3.5 million) were expensed.

US$2.6 million of costs relating to the South Ramadan SRM-3 well were incurred during the year.

11. Investments

The Company owns a 50% equity interest in Brentford Oil Tools LLC ("Brentford"), an oilfield services business incorporated in Egypt, over which it exercises joint control. Brentford owns all the assets it uses to provide its services and is legally responsible for settling its liabilities. In the current and comparative year, Brentford has provided services only to its shareholders, but it is not contractually obliged to do so. In the past, it has contracted with third parties and continues to seek future opportunities. On the balance of facts, the Company has concluded that Brentford is a joint venture under IFRS 11 - "Joint Arrangements" and the Company's interest is equity accounted for. The investment is reviewed regularly for indicators of impairment and no impairment was identified for the years ended December 31, 2018 and December 31, 2017.

The following table summarizes the changes in investments for the years ended December 31, 2018 and December 31, 2017:

	Carrying value	
US$'000s	**December 31 2018**	December 31 2017
Investments, beginning of period	**2,724**	2,503
Dividends received	**(525)**	(801)
Share of operating income	**1,195**	1,022
Investments, end of period	**3,394**	2,724

11. Investments (continued)

The following table summarizes the Company's 50% interest in the assets, liabilities, revenue, and operating income of Brentford as at December 31, 2018 and December 31, 2017:

SDX share (50%) of Brentford (US$'000s)	December 31 2018	December 31 2017
Total assets	2,454	2,235
Total liabilities	9	14
Revenue	1,787	1,448
Net income	1,195	1,022

During the year ended December 31, 2018 50% (December 31, 2017: 50%) of Brentford's revenue was earned from fees charged to the Company, and 50% (2017: 50%) to the Company's partner in the Block-H concession.

12. Trade and other payables

	Carrying amount	
US$'000s	December 31 2018	December 31 2017
Current		
Trade payables	3,870	2,636
Accruals	3,747	9,536
Joint venture partners	5,409	5,686
Other payables	1,392	1,601
Total trade and other payables	14,418	19,459

Trade payables comprises billed services and goods and, as at December 31, 2018, consisted predominantly of creditors associated with the Moroccan 3D seismic campaigns and the South Disouq development and 3D seismic campaign (US$2.0 million) and G&A creditors.

The US$1.3 million increase in trade payables as at December 31, 2018, is due to Moroccan and South Disouq 3D seismic costs, South Disouq development costs, and billed transaction costs.

Accruals include amounts for products and services received which have yet to be invoiced. The US$5.8 million decrease period- on-period reflects the fact that unbilled Morocco drilling campaign costs as at December 31, 2017 were significantly higher than corresponding capital accruals, primarily for South Disouq, as at December 31, 2018.

Joint venture partners comprise partner current accounts of US$0.6 million for NW Gemsa (2017:US$1.0 million), US$1.3 million for Block-H Meseda (2017: US$1.2 million), US$3.3 million for the Morocco concessions (2017: US$3.5 million) and US$0.2 million for South Ramadan (2017: US$nil). The joint venture partner current accounts represent the net of monthly cash calls paid less billings received.

Other payables of US$1.4 million comprise an estimated liability of US$0.5 million related to the relinquishment of the Shukheir Marine concession (2017: US$0.5 million), and employee costs accrued, VAT payable, and other sundry creditors of US$0.9 million (2017: US$1.1 million).

The difference between the decrease of US$5.1 million in trade and other payables in the Consolidated Balance Sheets as at December 31, 2018 and December 31, 2017 and the line item in the Consolidated Statement of Cash Flows relating to the implied increase in trade and other payables of US$0.3 million as the balance sheet movement includes payments to capital creditors which are included in PP&E and E&E expenditure in the Consolidated Statement of Cash Flows.

13. Deferred income

Deferred income relates to an advance receipt for gas sales from a customer in Morocco. This payment was used to fund the tie-in of the customer's manufacturing premises to the Company's operated gas pipeline. The amount will be credited to the Consolidated Statement of Comprehensive Income under the terms of an agreement with the customer by which the selling price of gas is discounted by 5% until the advance payment is fully recouped (expected during the year ended December 31, 2020).

14. Decommissioning liability

Upon the acquisition of Circle Oil's Moroccan assets, the Company assumed responsibility for the decommissioning of these assets and has drilled further wells since acquisition that will require decommissioning in the future.

As at December 31, 2018, the total future undiscounted cash flows relating to Moroccan assets amounted to US$5.1 million, to be incurred between the years 2019 and 2023, and the liability was discounted using a risk-free rate of 3.0%. Decommissioning expenditure of US$1.1 million is anticipated within the next 12 months.

Following the drilling of the exploration and appraisal wells at South Disouq, the Company has a present obligation to decommission these assets under the terms of the concession agreement. The total future undiscounted cash flows amounted to US$0.6 million, to be incurred in 2025, and the liability was discounted using a risk-free rate of 8.0%.

The discounted value of the cash flows above amounts to US$5.2 million as at December 31, 2018, as shown below:

	Carrying amount	
US$'000s	**December 31 2018**	December 31 2017
Decommissioning liability, beginning of period	**4,542**	-
Changes in estimate	**575**	625
Liabilities acquired through business combination	**-**	3,968
Payments for decommissioning	**(23)**	(137)
Accretion	**73**	86
Decommissioning liability, end of period	**5,167**	4,542
Of which:		
Current	**1,125**	1,063
Non-current	**4,042**	3,479

No decommissioning liabilities are recorded for the Company's other Egyptian assets, under the terms of the respective concession agreements.

15. Income tax - current and deferred

According to the terms of the Company's Egyptian Production Sharing Contracts ("PSCs"), the corporate tax liability of the joint venture partners is paid by the government-controlled corporations ("Corporations") that participate in these PSCs, out of the profit oil attributable to the Corporations, and not by the Company. For accounting purposes however, the corporate taxes paid by the Corporations are treated as a benefit earned by the Company, with the amount being "grossed up" and included in net oil revenues and the income tax expense of the Company.

The Company also has a Production Services Agreement ("PSA") related to Block-H Meseda, with the legal title held by SDX Energy Egypt (Meseda) Limited ("SDX Meseda"), an Egyptian incorporated entity. The Company is governed by the laws and tax regulations of the Arab Republic of Egypt and pays corporate taxes on the adjusted profit of SDX Meseda.

The current income tax expense in the Consolidated Statement of Comprehensive Income for the year ended December 31, 2018 relates to income tax on North West Gemsa's PSC and income tax relating to the Company's PSA in Block-H Meseda.

The current income tax liability of US$1.5 million in the Consolidated Balance Sheet relates to the Company's PSA in Block-H Meseda.

The Company's Moroccan operations benefit from a 10-year corporation tax holiday from first production and no such taxation is due on Moroccan profits as at December 31, 2018.

Income tax expense differs from that which would be expected from applying the effective Canadian federal and provincial income tax rates of 27% (2017: 27%) to income before income taxes as follows:

Consolidated Statement of Comprehensive Income

	Twelve months ended December 31	
US$'000s except per unit amounts	**2018**	2017
Income before income taxes	**7,133**	32,848
Canadian statutory income tax rate	**27%**	27%
Expected income taxes	**1,926**	8,869
Adjustments:		
Non-deductible items	**528**	518
Non-taxable gain on acquisition	**47**	(7,981)
Unrecognized income tax benefit	**2,116**	510
Foreign tax differential	**(1,257)**	1,291
Expenses incurred with no recognised tax benefit	**3,661**	1,334
Total current and deferred income tax	**7,021**	4,541

The components of the deferred income tax assets and liabilities at December 31, 2018 and 2017 include the following:

Consolidated Balance Sheet

	Twelve months ended December 31	
US$'000s except per unit amounts	**2018**	2017
Deferred tax assets/(liabilities)		
Investments	**(14)**	(10)
Property, plant and equipment	**(448)**	(324)
Other	**172**	44
Deferred income tax liability	**(290)**	(290)

The Company has US$68.4 million of non-capital losses available at December 31, 2017 (2017: US$61.5 million) to shelter future taxable income, the majority of which were incurred in Canada and expire between 2026 and 2035. The Company has not recognized any deferred tax assets as at December 31, 2018 and 2017 primarily relating to its Canadian business as it has determined that its deferred tax assets are not probable to be realized from current operations.

16. Share capital

The Company is authorized to issue unlimited common shares with no-par value and unlimited preferred shares with no-par value. The table below shows the number and stated value of the common shares issued as at December 31, 2018 and 2017:

	December 31, 2018		December 31, 2017	
	Number of Shares (000s)	Stated Value (US$'000s)	Number of Shares (000s)	Stated Value (US$'000s)
Balance, beginning of period	204,493	88,785	79,844	40,275
Issue of common shares (less share issue costs)	230	114	124,649	48,510
Balance, end of period	204,723	88,899	204,493	88,785
Weighted average shares outstanding	204,565		184,422	

17. Stock-based compensation

The stock-based compensation expense of US$1.3 million recorded in the Consolidated Statement of Comprehensive income represents the IFRS 2 charge associated with both the stock option plan and the Long-Term Incentive Plan described below.

Stock option plan

The Company has a stock option plan that entitles officers, directors, employees, and certain consultants to purchase shares in the Company.

Stock-based compensation expense is the amortization over the vesting period of the fair value of stock options granted to employees, directors, and key consultants of the Company. The fair value of all options granted is estimated using the Black-Scholes option pricing model. Each tranche of options in an award is considered a separate award with its own vesting period and grant date fair value. Compensation costs are expensed over the vesting period, with a corresponding increase in contributed surplus. When stock options are exercised, the cash proceeds and the amount previously recorded as contributed surplus are recorded as share capital.

In the year to December 31, 2018, 400,000 and 106,667 options previously awarded lapsed and were cancelled respectively. During 2018, 213,333 options were exercised by a former director of the Company, in accordance with the 90 day post leaving exercise period stipulated by the stock option plan, and 16,668 options were exercised by an employee. In the 12 months ended December 31, 2017, 640,000 stock options were issued to four non-executive directors of the Company, 100,000 options lapsed, 100,000 options were cancelled due to employees leaving the Company, and 33,332 options were exercised.

The number and weighted average exercise price of stock options for the Company's stock option plan is as follows:

	Number of Options (000s)	Weighted average exercise price (CAD$)
Outstanding January 1, 2017	**2,445**	**0.61**
Lapsed during the year	(100)	0.54
Cancelled during the year	(100)	0.45
Exercised during the year	(33)	0.36
Issued during the year	640	0.76
Outstanding December 31, 2017	**2,852**	**0.65**
Exercisable December 31, 2017	**2,395**	**0.64**
Lapsed during the period	(400)	0.63
Cancelled during the period	(107)	0.76
Exercised during the period	(230)	0.66
Outstanding December 31, 2018	**2,115**	**0.65**
Exercisable December 31, 2018	**1,795**	**0.64**

The exercise price of the outstanding options under the stock option plan as at December 31, 2018 is as follows:

	Outstanding options		Vested options	
Exercise price range	Number of options	Remaining contractual life	Number of options	Remaining contractual life
CAD $0.39 - $0.76	2,115,000	3-5 years	1,795,000	3-5 years

(tabular amounts are in thousands of United States dollars except where stated)

17. Stock-based compensation (continued)

Stock option plan (continued)

Key assumptions relating the options issued to December 31, 2018 are as follows:

	2017	2016	2015
Fair value at grant date (CAD)	**$0.26**	$0.28	$0.61
Share price (CAD)	**$0.76**	$0.36	$0.63
Exercise price (CAD)	**$0.76**	$0.36	$0.63
Volatility (%)	**70**	70	70
Forfeiture (%)	**0**	0	0
Option life	**5 years**	5 years	5 years
Dividends (%)	**0**	0	0
Risk-free interest rate (%)	**0.8**	0.8	0.8

Long-Term Incentive Plan ("LTIP")

On July 31, 2017 the Company established a new Long-Term Incentive Plan and issued awards to its executive directors and certain other key employees. The Company recognizes the need to ensure that executive directors and key employees from its operational, commercial, technical, and financial divisions, who are critical to executing the Company's strategy over the next phase of its development, are retained and incentivized to generate long-term value for shareholders.

The LTIP Awards and CSOP Options granted under the Plan take the form of a base award over a number of common shares. These awards will normally vest on the third anniversary of the date of grant of the awards, subject to meeting certain strategic, operational, financial, and shareholder return performance criteria and the continued employment of the participant. The awards for the executive directors are subject to a further two-year holding period from the date of vesting. There are clawback provisions contained in the rules of the Plan that can be applied to awards made to all participants.

The number of common shares granted to executive directors, over which the LTIP Awards and CSOP Options may vest, can be increased by a multiple of up to one times, depending on the level of share price growth over the three-year period from the date of grant. The potential level of increased share awards is calculated as follows:

- If the share price growth in the three-year period is less than 11% pa, there will be no increase in the base award number of shares set out above; and
- If the share price growth in the three-year period is between 11% pa and 20% pa, the additional number of shares that vest will increase proportionately within this range up to a cap of a multiple of one times the base award number of shares. This cap will be triggered at share price growth of 20% pa or more.

For the avoidance of doubt, the maximum number of shares that can vest for the CEO and CFO is 3,005,674 and 2,234,707 respectively.

Based on grants to March 22, 2019, the maximum potential number of common shares that can vest to the executive directors and other selected employees under the LTIP was in aggregate 7,100,884. All these options are outstanding as at December 31, 2018 and March 22, 2019 but none have vested.

The number of ordinary shares that may be issued or reserved for issuance under the awards granted in accordance with the LTIP, together with all common shares that may be issued under options granted pursuant to the Company's stock option plan, may not exceed 10% of the Company's issued and outstanding common shares at the time of granting.

18. Revenue, net of royalties

	Twelve months ended December 31	
US$'000s	**2018**	2017
NW Gemsa oil sales revenue	**42,260**	31,641
Royalties	**(18,137)**	(13,580)
Net oil revenue	**24,123**	18,061
Block-H Meseda production service fee revenues	**14,185**	8,045
Morocco gas sales revenue	**14,614**	12,425
Royalties	**(334)**	-
Net Morocco gas sales revenue	**14,280**	12,425
Net other products revenue	**1,091**	635
Total net revenue before tax	**53,679**	39,166

The oil sales revenue and royalties and net other products revenue relate to the NW Gemsa concession, which is governed by an Egyptian PSC. The royalties are those attributable to the government, taken in accordance with the fiscal terms of the PSC.

The Company sells associated gas and natural gas liquids ("NGLs") from its NW Gemsa concession to the Egyptian state. In December 2017, the operator of the NW Gemsa concession advised that the invoices it had issued were based on erroneous volumes and prices and that the revised invoices resulted in lower revenues. The adjustment was made during Q4 2017, with the portion relating to the acquired Circle Oil receivables adjusted through the gain on acquisition (US$1.3 million), and the remainder through net revenue, resulting in a net negative US$0.1 million revenue being recognized. A further correction was necessary for Q1 2018, with US$0.2 million being adjusted through the gain on acquisition and US$0.2 million through net revenue.

The production service fees relate to Block-H Meseda, which is governed by an Egyptian PSA.

The Moroccan gas sales revenue is derived from a Petroleum Agreement with the Moroccan state. Sales-based royalties become payable when certain inception-to-date production thresholds are reached, according to the terms of each exploitation concession. During Q3 2018, natural gas production from the Ksiri exploitation concession exceeded such a threshold, resulting in the recognition of royalties amounting to 5% of revenue from this concession from that point forward. Royalty payments are made directly to the Government of Morocco biannually, with the next payment due in Q1 2019.

19. General and administrative expenses

	Twelve months ended December 31	
US$'000s	**2018**	2017
Wages and employee costs	**6,433**	6,514
Consultants - inc. PR/IR	**544**	699
Legal fees	**272**	332
Audit, tax and accounting services	**968**	641
Public company fees	**602**	365
Travel	**348**	382
Office expenses	**1,051**	1,091
IT expenses	**426**	303
Service recharges	**(5,829)**	(3,907)
Ongoing general and administrative expenses	**4,815**	6,420
Transaction costs	**2,455**	2,373
Total net G&A	**7,270**	8,793

2018 transaction costs relate to a number of business development initiatives, including the proposed acquisition of a package of assets in Egypt from BP and the re-domicile of the Group from Canada to the UK. Transaction costs for 2017 were all associated with the Circle Oil acquisition.

20. Income per share

	Twelve months ended December 31	
US$'000s	**2018**	2017
Net income before comprehensive income for the period	**112**	28,307
Weighted average amount of shares		
Basic	**204,565**	184,422
Diluted	**205,222**	187,389
Per share amount		
Basic	**$0.001**	$0.153
Diluted	**$0.001**	$0.151

Basic income per share is calculated by dividing the income attributable to shareholders of the Company by the weighted average number of ordinary shares in issue during the year. Diluted per share information is calculated by adjusting the weighted average number of ordinary shares outstanding to assume conversion of all dilutive potential ordinary shares. The Company computes the dilutive impact of common shares by assuming that the proceeds received from the pro forma exercise of in-the-money stock options or warrants are used to purchase common shares at average market prices.

(tabular amounts are in thousands of United States dollars except where stated)

21. Segmental reporting

Following the acquisition of the Egyptian and Moroccan assets of Circle Oil plc, the Company's operations are managed on a geographic basis, by country.

The Company is engaged in one business of upstream oil and gas exploration and production. The executive directors are the Company's chief operating decision maker within the meaning of IFRS 8.

	Twelve months ended December 31, 2018				Twelve months ended December 31, 2017			
	Egypt	Morocco	Unallocated[(1)]	Total	Egypt	Morocco	Unallocated[(1)]	Total
Revenue	39,399	14,280	-	53,679	26,741	12,425	-	39,166
Direct operating expense	(10,599)	(1,335)	-	(11,934)	(9,166)	(1,088)	-	(10,254)
Netback (pre tax)	28,800	12,945	-	41,745	17,575	11,337	-	28,912
General and administrative expenses	(389)	(1,375)	(5,506)	(7,270)	(1,053)	(957)	(6,783)	(8,793)
Stock-based compensation	-	-	(1,194)	(1,194)	-	-	(538)	(538)
Share of profit from joint venture	1,195	-	-	1,195	1,022	-	-	1,022
Bad debt expense	-	(123)	-	(123)	-	-	-	-
Release of historic operational tax provision	-	300	-	300	-	-	-	-
Inventory write-off	-	(370)	-	(370)	798	-	-	798
Gain on sale of office asset	23	-	-	23	-	-	-	-
EBITDAX	29,629	11,377	(6,700)	34,306	18,342	10,380	(7,321)	21,401
Exploration and evaluation expense	(1,727)	(3,478)	(539)	(5,744)	(2)	-	(185)	(187)
Depletion, depreciation and amortization	(9,489)	(7,269)	(510)	(17,268)	(7,797)	(9,898)	(129)	(17,824)
Impairment expense	(3,520)	-	-	(3,520)	-	-	-	-
Operating income/(loss)	14,893	630	(7,749)	7,774	10,543	482	(7,635)	3,390

(1) Unallocated expenditure, assets and liabilities include amounts of a corporate nature and not specifically attributable to a geographical segment.

The segment assets and liabilities as at December 31, 2018 and December 31, 2017 are as follows:

	December 31, 2018				December 31, 2017			
	Egypt	Morocco	Unallocated[(1)]	Total	Egypt	Morocco	Unallocated[(1)]	Total
Segment assets	74,442	48,399	15,266	138,107	74,046	51,277	15,734	141,057
Segment liabilities	(7,229)	(11,227)	(3,612)	(22,068)	(4,703)	(19,523)	(2,212)	(26,438)

(1) Unallocated expenditure, assets and liabilities include amounts of a corporate nature and not specifically attributable to a geographical segment.

22. Commitments and contingencies

In accordance with the concession and production service fee agreements in Egypt and Morocco, the Company is required to perform certain minimum exploration and development activities, including the drilling of exploration and development wells. These obligations have not been provided for in the Consolidated Financial Statements.

In Morocco, the commitment is for one exploration well in Gharb Centre. The estimated cost of this commitment is approximately US$2.0 million.

In Egypt, the commitments are for the drilling of one appraisal well and a facilities upgrade for South Ramadan (remaining commitment of US$0.7 million) and no less than 100km^2 of 3D for the second exploration phase commitment for South Disouq. The Company estimates that its remaining share of this committed exploration cost on South Disouq is $1.1 million, which will be incurred within the next 12 months.

The anticipated timing of the expenditure associated with the above commitments is shown in the table below.

US$'000s	December 31 2018	December 31 2017
Less than one year	3,800	31,000
Between one and five years	-	-
Total	**3,800**	31,000

The Company has a lease commitment for its office premises in London under a non-cancellable operating lease. Commitments for minimum lease payments in relation to non-cancellable operating leases are payable as follows:

US$'000s	December 31 2018	December 31 2017
Less than one year	163	172
Between one and five years	192	375
Total	**355**	547

There are no contingencies as at December 31, 2018.

23. Related party transactions

All subsidiaries and joint arrangements (Brentford Oil Tools) are listed below. A list of the investments in subsidiary undertakings (all of whose operations comprise one class of business, being oil and gas exploration, development and production), including the name, proportion of ownership interest, country of operation and country of registration, is given below.

Name	Percentage	Country of operation	Country of registration
Sea Dragon Energy (UK) Ltd	100%	U.K.	U.K.
SDX Energy Investments (UK) Ltd	100%	U.K.	U.K.
SDX Energy Morocco (UK) Ltd	100%	U.K.	U.K.
Sea Dragon Cooperatieve U.A.	100%	Netherlands	Netherlands
Sea Dragon Energy Holding B.V.	100%	Netherlands	Netherlands
SDX Energy Egypt (Nile Delta) B.V.	100%	Egypt	Netherlands
Sea Dragon Energy (GOS) B.V.	100%	Egypt	Netherlands
Sea Dragon Energy (Nile) B.V.	100%	Egypt	Netherlands
Sea Dragon Energy (NW Gemsa) B.V.	100%	Egypt	Netherlands
Sea Dragon Energy Holding Ltd.	100%	British Virgin Islands	British Virgin Islands
NPC (Shukheir Marine) Ltd	100%	Egypt	British Virgin Islands
NPC (South Ramadan) Ltd	100%	Egypt	British Virgin Islands
Madison International Oil & Gas Ltd	100%	Barbados	Barbados
Madison Egypt Oil & Gas Ltd	100%	Egypt	Barbados
Madison Cameroon Oil & Gas Ltd	100%	Cameroon	Barbados
SDX Energy Egypt (Meseda) Ltd	100%	Egypt	Egypt
SDX Energy Morocco (Jersey) Ltd	100%	Morocco	Jersey
Limerick Services SARL	100%	Morocco	Morocco
SDX Energy Egypt (Jersey) Ltd	100%	Egypt	Jersey
Brentford Oil Tools	50%	Egypt	Egypt

(tabular amounts are in thousands of United States dollars except where stated)

24. Compensation of key management personnel

The remuneration of directors and other key management personnel during the years ended December 31, 2018 and 2017 was as follows:

	Twelve months ended December 31	
	2018	2017
Salaries, incentives and short term benefits	**892**	2,489
Directors' fees	**214**	173
Stock based compensation	**996**	417
Total compensation	**2,102**	3,079

Key management personnel have been identified as the non-executive directors and executive officers of the Company. The executive officers include the president and CEO and CFO.

In the year ended December 31, 2017, termination benefits of $383k were paid to Ahmed Moaaz, the former Egypt country manager. No such benefits were paid during 2018.

25. Post-balance sheet events

On January 14, 2019, the Company announced that the South Disouq development lease application had been approved by the relevant authorities. Construction of the pipeline and central processing facility has begun.

On January 28, 2019, the Company announced its intention to de-list from the TSX-V in conjunction with a move of its corporate residence to the UK from Canada.

On February 7, 2019, the Company announced that it has been awarded the Moulay Bouchta Ouest exploration licence (SDX 75% working interest and operator), covering an area of 458km^2, for a period of eight years. The Company has a commitment to reprocess 150km^2 of 2D seismic data, acquire 100km^2 of new 3D seismic and drill one exploration well within the first three-and-a-half-year period. The Company also announced that it has been re-awarded the Lalla Mimouna Sud licence (SDX 75% working interest and operator), covering an area of 857km^2, for a period of eight years. The Company has a commitment to acquire 50km^2 of 3D seismic and drill one exploration well within the first three-year period. Both licences are expected to be granted in Q2 2019.

Corporate information

Executive Officers
Paul Welch
President &
Chief Executive Officer &
Chief Operating Officer

Mark Reid
Chief Financial Officer

Independent Directors
Michael Doyle
Non-Executive Chairman

Timothy Linacre
David Mitchell
Michael Raynes

Stock Exchange Listing
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Symbol: SDX

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