THIRD QUARTER REPORT FOR THE PERIOD ENDED 30 SEPTEMBER 2018

23 October 2018

Oil Search

ASX: OSH | ADR: OISHY | POMSOX: OSH

STRONG START TO SECOND HALF, DRIVEN BY RECOVERY IN PRODUCTION AND HIGHER GLOBAL OIL AND GAS PRICES

THREE MONTHS ENDED	SEP 2018	JUN 2018	% CHANGE
Total production (mmboe)	**7.53**	5.40	*+39%*
Total sales (mmboe)	**7.44**	4.65	*+60%*
Total revenue (US$m)	**474.9**	262.8	*+81%*

HIGHLIGHTS

- **Total production in the third quarter of 2018 was 7.5 million barrels of oil equivalent (mmboe), 39% higher than in the second quarter and close to the pre-earthquake level of 7.6 mmboe produced in the fourth quarter of 2017. The PNG LNG Project achieved annualised production rates of 8.9 MTPA for the quarter, 9.0 MTPA for September and a daily rate of 9.2 MTPA, the highest rates since the Project came onstream in 2014. Oil Search-operated production continued to improve and is expected to be progressively restored over the coming months.**
- **Based on the strong performance by the PNG LNG Project since the recommencement of production post the earthquake, 2018 full year production is now expected to be between 25 - 26 mmboe (previously 24 – 26 mmboe) while guidance for full year unit operating costs has been narrowed, to US$11.50 – 12.50 per boe, from US$11 – 13 per boe previously.**
- **Total revenue rose by 81% to US$474.9 million, the highest quarterly revenue achieved since the fourth quarter of 2014. This was underpinned by a 68% lift in LNG and gas sales and a 31% increase in liquids sales, combined with higher realised LNG and gas prices (up 18%) and oil and condensate prices (up 5%).**
- **Mid-term LNG sales and purchase agreements (SPAs) were signed by the PNG LNG Project with PetroChina and BP, increasing total contracted volumes from the PNG LNG Project to 7.5 MTPA. Negotiations continue to contract the final mid-term tranche of 0.45 MTPA.**
- **During the quarter, activities related to the development of additional LNG capacity in PNG advanced. Discussions took place between the PNG LNG Project, P'nyang (PRL 3) and Papua LNG (PRL 15) joint ventures to mature technical definition for the developments, project financing and the remaining agreements required to enable integration of the projects. Gas agreement discussions between the PRL 3 and PRL 15 joint ventures and the PNG Government also progressed, with the aim of agreeing key terms by the APEC Economic Leaders' Meeting in November.**
- **In the Forelands region of PNG, the Barikewa 3 appraisal well successfully intersected gas, confirming good reservoir quality in the target intervals. This followed positive results from the Kimu 2 appraisal well, which proved up an extension of the Kimu gas reservoir in May. Evaluation of the data from both wells will assist in delineating the resource base of these fields and the optimal route for potential commercialisation.**
- **In the PNG Highlands, construction of the Muruk 2 appraisal well pad was completed, with rig mobilisation underway in preparation to commence drilling in November 2018.**

- **In the onshore Gulf, Oil Search completed its farm-in to four highly prospective licences adjacent to the Elk-Antelope fields in PRL 15, enhancing its exploration acreage and joint venture alignment in this important gas hub. A 330 kilometre seismic acquisition programme over these licences and in PRL 15 will be followed by the acquisition of an additional 250 kilometres of seismic, to help mature identified leads and prospects for potential future drilling.**
- **In Alaska, preparations for the 2018/19 drilling programme, comprising two appraisal wells in the Pikka Unit, continued. These wells are expected to confirm the continuity, and establish the deliverability, of the reservoir and if successful, could add approximately 250 million barrels to Oil Search's current 2C resource estimate of 500 million barrels. Work also continued on how to optimise the value of the Company's fixed price option to buy the balance of Armstrong's interests in the key Alaskan assets.**
- **The Company ended the third quarter with liquidity of US$1.44 billion (compared to US$1.26 billion at the end of June), reflecting strong operating cash flows, underpinned by the recovery in production post the earthquake and higher realised oil and gas prices.**

COMMENTING ON THE THIRD QUARTER OF 2018, OIL SEARCH MANAGING DIRECTOR, PETER BOTTEN, SAID:

"Oil Search reported a strong third quarter result, delivering the Company's highest quarterly revenue since the fourth quarter of 2014, and approached the end of 2018 in a robust financial position.

Total oil and gas production was 7.5 mmboe, a significant improvement on the previous two quarters and in line with levels achieved prior to the February 2018 earthquake. This took production for the nine months to 30 September 2018 to 17.8 mmboe.

Oil Search's operated production increased 69% during the quarter, to 0.8 mmboe, largely reflecting the resumption of production from the Moran and Agogo fields and a full quarter of contribution from the other fields. Production from our operated oil and gas fields is expected to ramp up progressively as remedial work continues and flow lines in remote locations, damaged by the earthquake, are restored, enabling wells to be brought back online.

The PNG LNG Project achieved record production levels following modifications undertaken on the Hides Gas Conditioning Plant and maintenance work on the LNG trains in March while production was shut-in due to the earthquake. The Project averaged 8.9 MTPA in the third quarter, 9.0 MTPA in September and reached daily rates of 9.2 MTPA, the highest quarterly, monthly and daily annualised production rates achieved since the Project came onstream in 2014. Current production is approximately 30% above nameplate capacity and has been achieved with little additional expenditure, delivering significant incremental value to all Project stakeholders. These production levels are underpinned by the Project's strong reserve position, which was upgraded materially following recertification of the PNG LNG fields in 2016. No significant downtime is scheduled for plant maintenance in the second half of the year. In August, the PNG LNG plant site celebrated five years without a lost time incident, equivalent to 13 million work hours, a highly commendable milestone, reflecting the operator's robust safety culture.

During the quarter, the Company benefited from higher global oil and gas prices, achieving an average realised oil and condensate price of US$76.17 per barrel, up 5% on the second quarter, and an average realised LNG and gas price of US$10.45/mmBtu, 18% higher than in the previous period. This, together with a rebound in production and sales volumes, drove an 81% increase in total revenue to US$474.9 million. Strong operating cash flows resulted in an improvement in our liquidity position, from US$1.26 billion at mid-year to US$1.44 billion at the end of September, confirming the Company's sound financial position."

Discussions on the proposed Papua LNG and additional PNG LNG train developments advancing

"During the quarter, discussions continued between the PNG LNG Project, the P'nyang (PRL 3) and Papua LNG (PRL 15) joint ventures on the proposed development of three new LNG trains at the PNG LNG plant site, two underwritten by Papua LNG and one by the PNG LNG and P'nyang gas fields. Formal negotiations are continuing between Papua LNG and PNG LNG on the terms for access to the PNG LNG plant site. In addition, the parties continue to mature the technical definition for the developments, explore options for managing FEED studies, advance project financing and progress the remaining agreements required to enable integration of the projects.

Discussions between the P'nyang (PRL 3) and Papua LNG (PRL 15) joint ventures and the State Negotiation Team (SNT) on key terms for the gas agreements also made progress, with the joint ventures providing project and economic information to the SNT. We are aiming to have the key terms agreed by the November APEC Economic Leaders' Meeting, subject to progress over the next few weeks."

LNG marketing

"The PNG LNG Project entered into two mid-term LNG sale and purchase agreements (SPAs) with PetroChina and BP during the quarter, broadening the customer base for LNG from PNG and increasing total contracted volumes to approximately 7.5 MTPA.

Under the PetroChina SPA, the Project will supply 0.45 MTPA of LNG for three years, while the BP SPA involves the supply of approximately 0.45 MTPA of LNG for three years and approximately 0.9 MTPA for two years thereafter. Sales under the PetroChina and BP SPAs commenced in July and August, respectively. These SPAs are in addition to the 6.6 MTPA already committed under long-term contracts to JERA, Osaka Gas, Sinopec and CPC. ExxonMobil, on behalf of the PNG LNG Project participants, is negotiating the sale of the final mid-term tranche of 0.45 MTPA, which is expected to be completed in the near term.

Oil Search's equity marketing team continued to engage with LNG buyers in key Asian markets, on potential offtake agreements from the Company's share of high heating value LNG from the next phase of LNG development in PNG. There has been significant interest from LNG customers, with formal negotiations with selected parties expected to commence early in 2019."

Good progress on PNG LNG Project landowner identification

"During the quarter, the PNG Government, in collaboration with its partners, made significant progress on resolving outstanding issues related to the identification and verification of landowner beneficiaries from the PNG LNG Project. Of the 15 licences covering PNG LNG Project areas, 13 licences are either receiving or close to receiving benefits, with more than US$250 million of landowner benefits held in trust pending the completion of landowner identification and verification. On the back of the momentum gained, further substantial efforts are being put into ensuring that the remaining licences are progressed to completion. Oil Search continues to support the Government, to ensure a speedy release of these funds to the rightful beneficiaries."

Exploration, appraisal and near-field activity in PNG

"In the Highlands, construction of the Muruk 2 appraisal well pad was completed and rig mobilisation to site is currently underway ahead of an expected November 2018 spud. Located 11 kilometres north-west of the discovery well, Muruk 2 will assist in narrowing the joint venture's gas resource estimates for the field.

As previously announced, in July Oil Search completed the acquisition of a 25% interest in four highly prospective exploration licences, located adjacent to the Elk-Antelope fields in the onshore Papuan Gulf Basin, from ExxonMobil. Positive results from preliminary processing of the first, 330 kilometre, phase of seismic data over these licences and over PRL 15 have encouraged the joint ventures to conduct a second phase of 2D seismic acquisition in early 2019, covering approximately 250 kilometres. Data from these surveys, both of which are being operated by Oil Search on behalf of ExxonMobil and Total, will help to mature leads and prospects located near planned Papua LNG infrastructure for potential drilling in 2019 onwards.

The maturation of a number of drilling and workover opportunities focused on optimising production from our PNG oil fields continued during the quarter. Subject to final technical and commercial review, these opportunities have the potential to add significant volumes to oil production over the 2019 to 2023 period and help mitigate the decline from our mature oil fields. This programme is expected to commence with workover and drilling activity at Moran in the first quarter of 2019, with subsequent operations to take place at Kutubu later in the year."

Preparing for the Alaskan drilling season

"Planning for the 2018/19 drilling programme continued during the quarter. Two appraisal wells, which are expected to spud in January and March 2019, respectively, will be drilled in the Pikka Unit. The objective of these wells is to constrain the continuity of the Pikka B and C reservoirs and to establish reservoir deliverability. If the appraisal programme is successful and continuity of the reservoir is confirmed, approximately 250 million barrels could be added to our current 2C resource estimate of 500 million barrels, as additional resource is migrated into the 2C category. Two high-quality, modular rigs have been contracted and the Company is currently waiting for final approvals for the drilling plans. The results from these wells will help define the final configuration of the Pikka Unit development, with entry into Front-end Engineering and Design (FEED) expected in mid-2019.

During the quarter, Oil Search progressed planning and permitting activities for the development. The Environmental Impact Statement process, which commenced in 2015, and studies to optimise the development concept continued during the period. Activities included assessing opportunities for cooperation with adjacent operators, reducing well numbers and therefore drilling costs by applying proven drilling and completions technology, reviewing contracting strategies, reducing the facilities' footprints and assessing the scope for early works. Following consultation with local communities, the Company proposed enhancements to the project concept through the permitting process that address community concerns.

Work also took place on optimising the value of Oil Search's US$450 million, fixed price option with Armstrong to increase our interests in the key Alaskan leases. Our objectives are to capture value, diversify risk and establish an aligned joint venture, focused on maximising the potential of the assets. Oil Search anticipates this will involve exercising the option and, at the same time, selling a portion of the interest to introduce one or two third parties into the joint venture, with our desired final equity being 30 – 35%."

GUIDANCE FOR THE 2018 FULL YEAR

"As a result of the excellent performance from the PNG LNG Project since it recommenced production following the earthquake, the lower end of the 2018 full year production guidance range has been increased, with production now expected to be between 25 and 26 mmboe. The unit production cost guidance range has been narrowed, to US$11.50 – 12.50 per boe, while guidance for other operating costs and depreciation and amortisation is unchanged. The upper end of the capital cost guidance range has been reduced, due to the re-phasing of activities."

2018 FULL YEAR	UPDATED GUIDANCE[1]	PREVIOUS GUIDANCE[1]
Total production (mmboe)[2]	25.0 – 26.0	24.0 – 26.0
Operating costs		
Production costs (US$ per boe)	11.50 – 12.50	11.00 – 13.00
Other operating costs[3] (US$m)	140 – 150	140 – 150
Depreciation and amortisation (US$ per boe)	12.00 – 13.00	12.00 – 13.00
Capital costs		
Production (US$m)	20 – 25	25 – 30
Development – oil and gas (US$m)	35 – 40	40 – 50
Exploration and evaluation[4] (US$m)	270 – 300	270 – 330
Other plant and equipment[5] (US$m)	45 – 50	50 – 55
Power[6] (US$m)	55 - 60	50 - 65
Total (US$m)	**425 – 475**	**435 – 530**

1. Numbers may not add due to rounding.
2. Gas volumes have been converted to barrels of oil equivalent using an Oil Search specific conversion factor of 5,100 scf = 1 boe, which represents a weighted average, based on Oil Search's reserves portfolio, using the actual calorific value of each gas volume at its point of sale.
3. Includes Hides GTE gas purchase costs, royalties and levies, selling and distribution costs, rig operating costs, corporate administration costs (including business development), expenditure related to power activities, inventory movements and other expenses.
4. Excludes Alaska acquisition costs of US$415 million.
5. Excludes finance leased assets.
6. Includes capital expenditure related to the Port Moresby power project. Project expenditure to date has been recorded as a receivable pending the execution of certain agreements that will convert the receivable to investment expenditure.

PRODUCTION SUMMARY[1]

	QUARTER END			YEAR TO DATE		FULL YEAR
	SEP 2018	JUN 2018	SEP 2017	SEP 2018	SEP 2017	DEC 2017
PNG LNG Project[2]						
LNG (mmscf)	**29,404**	21,382	27,813	68,346	79,693	106,266
Gas to power (mmscf)[3]	**170**	173	174	503	494	665
Condensate ('000 bbls)	**816**	617	820	1,907	2,399	3,157
Naphtha ('000 bbls)	**83**	63	81	196	234	312
PNG crude oil production ('000 bbls)						
Kutubu	**415**	356	679	1,164	1,981	2,630
Moran	**58**	0	333	194	910	1,267
Gobe Main	**4**	4	6	11	15	20
SE Gobe	**11**	6	16	25	45	56
Total oil production ('000 bbls)	**489**	366	1,033	1,394	2,951	3,973
SE Gobe gas to PNG LNG (mmscf)[4]	**313**	192	887	1,025	2,439	3,265
Hides GTE Refinery Products[5]						
Sales gas (mmscf)	**1,300**	412	1,452	2,631	4,341	5,843
Liquids ('000 bbls)	**27**	8	30	55	86	118
Total barrels of oil equivalent ('000 boe)[6]	**7,529**	**5,399**	**7,910**	**17,769**	**22,722**	**30,314**

1. Numbers may not add due to rounding.
2. Production net of fuel, flare, shrinkage and SE Gobe wet gas.
3. Gas to power had previously been accounted for as losses within the PNG LNG Plant.
4. SE Gobe wet gas reported at inlet to plant, inclusive of fuel, flare and naphtha.
5. Hides GTE production is reported on a 100% basis for gas and associated liquids purchased by the Hides (GTE) Project Participant (Oil Search 100%) for processing and sale to the Porgera power station. Sales gas volumes are inclusive of approximately 2% unrecovered process gas.
6. Gas and LNG volumes have been converted to barrels of oil equivalent using an Oil Search specific conversion factor of 5,100 scf = 1 boe, which represents a weighted average, based on Oil Search's reserves portfolio, using the actual calorific value of each gas volume at its point of sale. Minor variations to the conversion factors may occur over time.

SALES SUMMARY[1]

	QUARTER END			YEAR TO DATE		FULL YEAR
	SEP 2018	**JUN 2018**	**SEP 2017**	**SEP 2018**	**SEP 2017**	**DEC 2017**
Sales data						
PNG LNG PROJECT						
LNG (Billion Btu)	**33,504**	20,313	32,851	76,223	91,898	123,239
Condensate ('000 bbls)	**786**	593	951	1,834	2,385	3,145
Naphtha ('000 bbls)	**61**	80	89	202	239	335
PNG oil ('000 bbls)	**483**	350	1,134	1,348	2,844	3,909
HIDES GTE						
Gas (Billion Btu)[2]	**1,393**	442	1,557	2,818	4,658	6,266
Condensate & refined products ('000 bbls)[3]	**23**	7	30	51	88	115
Total barrels of oil equivalent sold ('000 boe)[4]	**7,440**	4,647	8,191	17,205	22,370	30,044
Financial data (US$ million)						
LNG and gas sales	**364.8**	183.4	257.4	763.2	734.0	993.1
Oil and condensate sales	**98.1**	68.9	110.8	235.9	279.4	395.0
Other revenue[5]	**12.0**	10.5	12.6	33.6	43.5	58.0
Total operating revenue	**474.9**	262.8	380.8	1,032.6	1,057.0	1,446.0
Average realised oil and condensate price (US$ per bbl)[6]	**76.17**	72.55	52.75	73.34	53.11	55.68
Average realised LNG and gas price (US$ per mmBtu)	**10.45**	8.83	7.48	9.65	7.60	7.67
Cash (US$m)	**728.1**	412.1	1,119.2	728.1	1,119.2	1,015.2
Debt (US$m)[7]						
PNG LNG financing	**3,459.7**	3,459.7	3,786.0	3,459.7	3,786.0	3,625.5
Corporate revolving facilities[8]	**140.0**	-	-	140.0	-	-
Net debt (US$m)	**2,871.6**	3,047.6	2,666.9	2,871.6	2,666.9	2610.2

1. Numbers may not add due to rounding.
2. Relates to gas delivered under the Hides GTE Gas Sales Agreement.
3. Relates to refined products delivered under the Hides GTE Gas Sales Agreement or sold in the domestic market and condensate.
4. Gas and LNG sales volumes have been converted to barrels of oil equivalent using an Oil Search specific conversion factor of 5,100 scf = 1 boe, which represents a weighted average, based on Oil Search's reserves portfolio, using the actual calorific value of each gas volume at its point of sale and asset specific heating values. Minor variations to the conversion factors may occur over time.
5. Other revenue consists largely of rig lease income, infrastructure tariffs and electricity, refinery and naphtha sales.
6. Average realised price for Kutubu Blend including PNG LNG condensate.
7. Excludes finance leases recorded as borrowings.
8. At the end of September 2018, the Company had drawn US$140.0 million under its revolving facilities.

❖ PRODUCTION PERFORMANCE

2018 third quarter production net to Oil Search was 7.529 million barrels of oil equivalent (mmboe), comprising the following:

- LNG produced at the PNG LNG plant, net of SE Gobe sales, fuel, flare and shrinkage, of 29,404 mmscf.
- Gas produced for domestic market power generation of 170 mmscf.
- PNG LNG liquids production of 0.90 mmbbl, comprising condensate produced during gas processing at the Hides Gas Conditioning Plant (HGCP) and naphtha at the PNG LNG plant.
- PNG oil field production and gas and liquids production from the Hides GTE Project of 0.8 mmboe. These fields produced at an average rate of 15,849 barrels of oil equivalent per day (gross), including 1.401 mmscf of gas (gross) exported to the PNG LNG Project from the SE Gobe field.

PNG LNG Project (29.0%)

Third quarter production from the PNG LNG Project, net to Oil Search, was 6.7 mmboe, comprising 29.404 bcf of LNG, 0.170 bcf of gas for power generation and 0.9 mmbbl of liquids.

During the quarter, an average of 136 mmscf/day of gas was supplied to the PNG LNG Project by Oil Search from the Associated Gas (Kutubu and Gobe Main) and SE Gobe fields, representing approximately 12.1% of the total gas delivered to the LNG plant.

At Angore, fieldwork remained suspended following community unrest, due to political and inter-tribal tensions, earlier in the year. While work inside the Hides Gas Conditioning Plant related to the Angore tie-in continues, all other work near Angore remains on hold. As the Angore field is not yet tied in, there has been no impact on PNG LNG production.

Kutubu (PDL 2 – 60.0%, operator)

Third quarter oil production net to Oil Search from the Kutubu complex was 0.42 mmbbl, 17% higher than in the second quarter. Gross production rates averaged 7,521 bopd during the period, compared to 6,508 bopd in the previous quarter.

While oil production was materially higher than in the prior quarter, output from the Kutubu and Agogo fields continued to be impacted by earthquake-related damage to a number of flow lines and the high-pressure compression systems at the Agogo Processing Facility, as well as by ongoing remedial work.

Moran Unit (49.5%, based on PDL 2 – 60.0%, PDL 5 – 40.7% and PDL 6 – 71.1%, operator)

Oil Search's share of Moran third quarter oil production was 0.058 mmbbl. Production from the Moran field resumed in August and is expected to progressively ramp up over the coming months.

The high-pressure compression systems at the Agogo Processing Facility remained offline due to earthquake-related damage. This has limited the amount of oil and gas that can be processed from the Agogo and Moran fields.

Gobe (PDL 3 - 36.4% and PDL 4 - 10%, operator)

Oil Search's share of oil production from the Gobe fields in the third quarter of 2018 was 0.015 mmbbl, up 53% on the previous quarter.

The gross average production rate for Gobe Main was 10% higher than in the second quarter, at 469 bopd, while the gross average production rate at SE Gobe was 78% higher than in the previous quarter, at 536 bopd. Both fields benefited from stable and reliable facility performance.

During the quarter, Oil Search's share of SE Gobe gas exported net to the PNG LNG Project was 313 mmscf. Work continued to evaluate options to reinstate the G7X well, which was impacted by the earthquake.

Hides Gas-to-Electricity Project (PDL 1 - 100%)

Gas production for the Hides Gas-to-Electricity Project in the third quarter of 2018 was 1,300 mmscf, produced at an average rate of 14.1 mmscf per day. 27,388 barrels of condensate were produced for use within the Hides facility or transported by truck to the Hides Gas Conditioning Plant for export.

❖ EXPLORATION AND APPRAISAL ACTIVITY

Gas

Highlands

Preparations to drill the Muruk 2 appraisal well in PDL 9 (Oil Search – 24.4%) continued, with construction of the well pad completed and mobilisation of the rig from the Muruk 1 site currently underway. The well is expected to spud in November 2018. Located 11 kilometres north-west of the discovery well, Muruk 2 will assist in narrowing the joint venture's gas resource estimates for the field. The second phase of a 2D seismic acquisition programme covering approximately 100 kilometres over Muruk and an adjacent prospect has been deferred, to enable results from Muruk 2 to be incorporated into planning of the programme.

Forelands/Gulf

The Barikewa 3 appraisal well in PRL 9 (Oil Search – 45.1%, operator) reached total depth in July and successfully encountered gas in the target Toro and Hedinia Sandstone reservoirs at depths in line with pre-drill expectations. Both reservoirs were well developed and of good quality. A Drill Stem Test (DST) was conducted over the Toro interval from a depth of 1,729 metres to 1,743 metres, flowing gas at a continuous rate of 35.5 mmscf/day over a 75-hour period through a 68/64" choke. Preliminary analysis has indicated a clean, dry gas comprising approximately 20% nitrogen, which is a similar composition to that tested at Barikewa 1. Following completion of the DST, Barikewa 3 was plugged and abandoned, as planned. Evaluation of the well results is underway. This information will be used in conjunction with the results from Kimu 2 to help delineate the resource base of the Kimu and Barikewa gas fields and assist in determining the optimal route for potential commercialisation.

In the onshore Papuan Gulf Basin, Oil Search continued to acquire seismic in and around the Elk-Antelope fields, including over ExxonMobil-operated PPLs 475, 476 and PRL 39 (Oil Search – 25% following farm-in completed in July 2018) and Total-operated PRL 15 (Oil Search – 22.835%). The seismic information from this 330 kilometre survey and an additional 250 kilometres of seismic acquisition planned for early in 2019, will help mature identified leads and prospects surrounding the world-class Elk-Antelope gas fields for potential future drilling.

In the fourth quarter of 2018, the Company plans to acquire seismic over the Gobe Footwall exploration prospect, located west of the Gobe field in PDL 4, and over the Iehi discovery in PRL 14. This will provide information to help delineate these prospects for potential future drilling.

Offshore Gulf of Papua

During the quarter, reprocessing of the offshore shallow water 3D seismic continued and the Company completed the acquisition of a large gravity gradiometry and magnetics survey, with data delivery expected in the fourth quarter of 2018.

In the deepwater Gulf, evaluation of recently acquired 2D seismic continued, with consideration being made for the acquisition of 3D seismic in 2019.

Alaska

During the quarter, preparations continued to deliver the 2018/19 appraisal programme, with two high-quality, modular rigs and associated services contracted to drill two appraisal wells on the Pikka Unit. Planning and permitting activities to optimise the development also took place.

Additional experienced staff with strong Alaskan experience were recruited over the quarter. There are now 65 people in the Anchorage-based team, which is expected to grow to 100 by the end of 2018. Engagement with key stakeholders on the North Slope progressed, with the focus on building mutually beneficial partnerships and maximising cooperation and alignment in the coming exploration, appraisal and development programme.

Middle East

Work with the Kurdistan Regional Government on a relinquishment agreement for the Taza PSC in Kurdistan continued during the quarter.

DRILLING CALENDAR

Subject to joint venture and government approvals, the 2H18/1H19 exploration and appraisal programme is as follows:

WELL	WELL TYPE	LICENCE	OSH INTEREST	EXPECTED SPUD DATE
PNG				
Muruk 2	Appraisal	PDL 9	24.4%	4Q 2018
ALASKA				
Pikka B	Appraisal	Pikka Unit	25.5%	1Q 2019
Pikka C	Appraisal	Pikka Unit	25.5%	1Q 2019

Note: Wells, location and timing subject to change.

FINANCIAL PERFORMANCE

Sales revenue

During the quarter, 33,504 billion Btu of LNG was sold, 65% higher than sales volumes in the second quarter of 2018, reflecting an excellent performance by the PNG LNG Project. Three LNG cargoes were on the water at the end of the third quarter, the same as at the end of the second quarter. Thirty LNG cargoes were delivered during the period, of which nine were spot sales. This compared to 18 LNG cargoes delivered in the second quarter. Oil, condensate and naphtha sales volumes for the period totaled 1.33 mmbbl, 30% higher than liquids sales in the previous quarter. Six cargoes of Kutubu Blend and two naphtha cargoes were sold during the period.

The average oil and condensate price realised during the quarter was US$76.17 per barrel, 5% higher than in the second quarter of 2018, reflecting strength in global oil prices. The average price realised for LNG and gas sales was US$10.45 per mmBtu, 18% higher than in the second quarter, reflecting the approximate three-month lag between the spot oil price and LNG contract prices, as well as strong North Asian LNG demand which supported the spot LNG price. The Company did not undertake any hedging transactions during the period and remains unhedged.

Total sales revenue from LNG, gas, oil and condensate rose 83% to US$462.9 million, driven by higher sales volumes and stronger realised oil and gas prices compared to the previous quarter. Other revenue, comprising rig lease income, infrastructure tariffs, electricity, refinery and naphtha sales, was US$12.0 million.

Capital management

At 30 September 2018, Oil Search had liquidity of US$1.44 billion, comprising US$728.1 million in cash (US$412.1 million at the end of the second quarter) and US$710 million in undrawn corporate credit facilities (US$850 million at the end of the second quarter). The higher cash balance reflected the generation of strong operating cash flows, which more than offset the payment of the Company's interim dividend and investment in exploration and appraisal activities in PNG (see 'Capital expenditure' section below). Oil Search ended the period with US$3.60 billion of debt outstanding, including US$3.46 billion under the PNG LNG project finance facility (unchanged) and US$140 million drawn from the Company's corporate facilities (nil at the end of June). The corporate credit facility drawdown is expected to be repaid in the fourth quarter.

Based on the Company's oil price outlook, which assumes prices below current levels, Oil Search continues to expect that it will have sufficient financial capacity, including existing liquidity and ongoing cash flow from Oil Search's operations and PNG LNG, to fund its major growth projects – Papua LNG and PNG LNG expansion in PNG and the Pikka Unit development in Alaska – as well as scheduled debt repayments and future dividends over the 2018 – 2023 period.

Capital expenditure

During the quarter, exploration and evaluation expenditure totaled US$107.1 million. A large portion of this spend reflected the completion of the farm-in to four licences and the acquisition of seismic in the onshore Papuan Gulf. Other key expenditure items included preparations to drill Muruk 2 (US$5.9 million), drilling of the Kimu 2 and Barikewa 3 appraisal wells in the Forelands (US$14.2 million) and pre-FEED activities for further LNG development in PNG (US$4.4 million).

US$25.0 million of exploration costs were expensed, mainly reflecting seismic acquisition costs as well as geological, geophysical and general and administration expenses in PNG.

Development expenditure for the second quarter totaled US$11.6 million, which included US$9.0 million spent on the PNG LNG Project and US$2.6 million on the PNG Biomass power project. Expenditure on producing assets was US$4.4 million, while expenditure on property, plant and equipment was US$13.1 million, primarily related to implementation of a new enterprise resource planning system.

SUMMARY OF INVESTMENT EXPENDITURE AND EXPLORATION AND EVALUATION EXPENSED[1]

	QUARTER END			YEAR TO DATE		FULL YEAR
	SEP 2018	JUN 2018	SEP 2017	SEP 2018	SEP 2017	DEC 2017
Investment Expenditure						
Exploration & Evaluation						
PNG	**96.8**	49.1	32.1	185.1	119.0	158.8
USA	**10.3**	8.8	-	436.1	-	7.9
MENA	**-**	0.2	0.8	1.0	2.4	2.9
Total Exploration & Evaluation	**107.1**	58.1	32.8	622.2	121.5	169.5
Development						
PNG LNG	**9.0**	12.0	9.0	26.2	19.6	30.1
Biomass	**2.6**	3.4	2.4	8.4	6.5	9.8
Total Development	**11.6**	15.4	11.4	34.6	26.1	39.9
Production	**4.4**	1.8	8.5	11.2	31.2	40.7
PP&E	**13.1**	8.2	2.5	29.5	4.9	27.6
Total	**136.3**	**83.4**	**55.3**	**697.4**	**183.7**	**277.6**
Exploration & Evaluation Expenditure Expensed[2,3]						
PNG	**23.4**	4.4	6.4	32.6	29.7	27.0
USA	**1.6**	1.9	-	3.6	-	6.2
MENA	**-**	0.2	0.7	1.1	2.4	2.7
Total current year expenditures expensed	**25.0**	6.4	7.1	37.3	32.1	35.9
Prior year expenditures expensed	**-**	-	-	-	-	-
Total	**25.0**	**6.4**	**7.1**	**37.3**	**32.1**	**35.9**

1. Numbers may not add up due to rounding.
2. Exploration costs expensed includes unsuccessful wells, exploration seismic and certain costs related to administration costs and geological and geophysical activities. Costs related to permit acquisitions, the drilling of wells that have resulted in a successful discovery of potentially economically recoverable hydrocarbons and appraisal and evaluation of discovered resources are capitalised.
3. Numbers do not include expensed business development costs of US$0.6 million in the third quarter of 2018 (US$0.5 million in the first half of 2018).

Gas/LNG Glossary and Conversion Factors Used[1,2]

Mmscf	Million (10^6) standard cubic feet
mmBtu	Million (10^6) British thermal units
Billion Btu	Billion (10^9) British thermal units
MTPA (LNG)	Million tonnes per annum
Boe	Barrel of oil equivalent
1 mmscf LNG	Approximately 1.10 - 1.14 billion Btu
1 boe	Approximately 5,100 standard cubic feet
1 tonne LNG	Approximately 52 mmBtu

1. Minor variations in conversion factors may occur over time, due to changes in gas composition.
2. Conversion factors used for forecasting purposes only.

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DISCLAIMER

This report contains some forward-looking statements which are subject to particular risks associated with the oil and gas industry. Actual outcomes could differ materially due to a range of operational, cost and revenue factors and uncertainties including oil and gas prices, changes in market demand for oil and gas, currency fluctuations, drilling results, field performance, the timing of well workovers and field development, reserves depletion and fiscal and other government issues and approvals.