Delek Group

Revised Reserves Evaluation Report and Discounted Cash Flows for the Tamar Lease

Tel Aviv, February 27, 2019. Delek Group (TASE: DLEKG, US ADR: DGRLY) The Company hereby respectfully issues a revised assessment report of reserves and a revised discounted cash flow for the Tamar field for year-end 2018.

The following reserves evluation and DCF projection report is a convenience translation of the original HEBREW immediate report issued to the Tel Aviv Stock Exchange by the Company on February 19, 2019.

About The Delek Group

Delek Group is an independent E&P and the pioneering visionary behind the development of the East Med. With major finds in the Levant Basin, including the Leviathan (21.4 TCF) and Tamar (11.2 TCF) reservoirs and others, Delek is leading the region's development into a major natural gas export hub. In addition, Delek has embarked on an international expansion with a focus on high-potential opportunities in the North Sea and North America. Delek Group is one of Israel's largest and most prominent companies with a consistent track record of growth. Its shares are traded on the Tel Aviv Stock Exchange (TASE:DLEKG) and are part of the TA 35 Index.

For more information on Delek Group please visit www.delek-group.com

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Delek Group Ltd.
("the Company")

February 19, 2019

Atn:	To
Israel Securities Authority	Tel Aviv Stock Exchange Ltd.
22 Kanfei Nesharim St.	2 Ahuzat Beit Street
Jerusalem	Tel Aviv

Dear Sir/Madam,

re: **Revised Reserves Evaluation Report and Discounted Cash Flows for the Tamar Lease**

Further to section 1.7.4 (I) of the Company's periodic report as at December 31, 2017, as published on March 28, 2018 (Ref. No. 2018-01-031177) (the "Periodic Report") concerning the evaluation of reserves in the Tamar project, which includes the Tamar and Tamar South-West reservoirs ("Tamar SW") in the area covered by the I/12 Tamar lease ("**Tamar Project**" and "**Tamar Lease**", respectively) , the Company hereby respectfully issues a revised assessment report of reserves and revised discounted cash flow, as follows:

1. Quantitative data

   According to a report Delek Drilling – Limited Partnership (the "Partnership") received from Netherland, Sewell and Associates, Inc. ("NSAI" or the "Evaluator"), which was prepared according to the guidelines of the Petroleum Resources Management System (SPE-PRMS), as of December 31, 2018 (the "Reserves Report") the natural gas and condensate reserves in the Tamar Project (including, as aforesaid, the Tamar Reservoir and Tamar SW Reservoir), classified as on-production reserves, are as set out below[1]:

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1 To the best of the Partnership's knowledge, the Ministry of Energy has conducted an independent evaluation of the volume of reserves in the Tamar Reservoir, by external consultants, among other things, for the purpose of calculating export quotas from the Tamar Project, pursuant to the Government Decision as set out in section 1.7.29(a)(5)B.1 of the Periodic Report. To the best of the Company's knowledge, there is no material difference between the Ministry of Energy's evaluation and the estimated reserves published in the Periodic Report ("the Previous Reserves Report").

Reserve category	Total (100%) in the oil asset (gross)						Total (Tamar and Tamar SW reservoirs) rate attributable to equity holders of the Company (net)[2]	
	Tamar Reservoir		Tamar SW reservoir		Total (Tamar and Tamar SW reservoir)			
	Natural gas BCF	Condensate (million barrels)	Natural gas BCF	Condensate (million barrels)	Natural gas BCF	Condensate Million barrels	of natural gas BCF	of condensate Million barrels
Proved reserves 1P (Proved Reserves)	7,312.4	9.5	796.4	1.0	8,108.9	10.5	1,030.5	1.3
Probable Reserves (Probable reserves)	2,871.0	3.7	159.1	0.2	3,030.1	3.9	385.1	0.5
Total 2P reserves (Proved+Probable Reserves)	10,183.4	13.2	955.6	1.2	11,139.0	14.5	1,415.6	1.8
Possible Reserves (Possible Reserves)	2,366.0	3.1	102.2	0.1	2,468.3	3.2	313.7	0.4
Total 3P reserves (proved + probable + possible reserves)	12,549.5	16.3	1,057.8	1.4	13,607.3	17.7	1729.3	2.2

Forward-looking information: Possible reserves are the additional reserves that are not expected to be produced to the same extent as probable reserves. There is a 10% chance that actual quantities produced will be equivalent to or higher than the proved reserves, with the addition of the quantity of the probable and possible reserves.

2 The Partnership's share (gross), instead of the Company's share (net) is included in the resources report. The Company's share in the above table is after royalties The rate of royalties payable to the Company and Delek Royalties (2012) Ltd., as taken into account in the foregoing figures, is 6.5% (at wellhead), the rate of royalties after ROI date. The rate attributable to the equity holders of the Partnership is calculated according to the Partnership's holdings in the Tamar Project (direct and indirect) as at December 31, 2018 and under the assumption that the rate of royalties payable to the State is 12.5%. With regard to the ROI date and the dispute in this regard, see immediate reports dated September 5, 2018 (Ref No.: 2018-01-085299), November 29, 2018 (Ref. No.: 2018-01-115659), January 7, 2019 (Ref. No.: 2019-01-002622).

2. The NSAI evaluation report noted, inter alia, a number of assumptions and reservations, including: (A) The estimate in the report, as is standard in estimating reserves based on the guidelines set out in the Petroleum Resources Management System approved by the Society of Petroleum Engineers (SPE-PRMS), are not adjusted to the risks. (B) NSAI did not visit the oil field or check the mechanical operation of the wells or their state. (C) NSAI did not examine the possible exposure arising from environmental matters. However, according to NSAI, as of the date of the reserves report, it is unaware of any possible environmental liability that could have a material effect on the amount of estimated reserves in the reserves report, or on whether they are commercial, therefore the reserves report does not include the costs that could arise from such liability. (D) NSAI assumed that the reservoirs will be developed in accordance with existing development plans[3], which will be operated reasonably, that no regulation will be set that will affect the ability of the holder of the oil rights to produce the reserves, and that and forecasts for future production will be similar to actual performance of the reservoirs.

   Forward-looking information: the NSAI estimates of the volume of reserves of natural gas and condensate in the Tamar and Tamar SW reservoirs are forward-looking information as defined in the Securities Law, 1968 **("the Securities Law").** These estimates are based, among other things, on geological, geophysical, engineering and other information received from the wells and from the Tamar Project Operator, and are NSAI estimates and assumptions only and there can be no certainty in respect thereof. **The actual volumes of natural gas and/or condensate produced may be different from these estimates and assumptions, partly due to technical and operational conditions and/or regulatory changes and/or the supply and demand conditions in the natural gas and/or condensate market and/or commercial conditions and/or as a result of actual performance of the reservoirs.** The foregoing estimates and assumptions may be updated if additional information becomes available and/or as the result of a range of factors related to oil and natural gas exploration and production, including due to the continued production from the Tamar Project.

3. <u>Discounted cash flows</u>

   With regard to calculation of the discounted cash flows described below, the following is noted: (A) The discounted cash flow is based, among other things, on the weighted average gas prices in the gas sales agreements, which are based on various price formulae that include linkage to the US CPI, the Brent price per barrel, or the electricity generation price.[4] It should be noted that

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[3] For further information regarding the plan for future development of the Tamar field see section (c)(2) below.

[4] The weighted electricity generation price ("the **Electricity Generation Price"**) is the price controlled by the Electricity Authority, and reflects the costs of the electricity generation segment of the IEC, including the cost

price changes may arise, among other things, due to adjustment of prices based on the mechanism set out in the agreement with the Israel Electric Corporation Ltd. ("the IEC")[5], and changes in the indices on which linkage in gas supply agreements is based[6]. It should be clarified that as of the publication date of this report, it is not possible to estimate the extent of such price adjustment (if adjusted at all) on the first adjustment date (namely, July 1, 2021) as set out in the IEC agreement ("First Adjustment Date"), and it is assumed that an adjustment will be made at 50% of the maximum rate of adjustment, i.e. a price reduction of 12.5%. It should be noted that in the discounted cash flow, it was assumed that there will be no change in the price on the second adjustment date (namely, on July 1, 2024). For further information regarding discounted cash flow changes resulting from price adjustments, including as a result of the foregoing change in price adjustment rate, see the sensitivity tables in sections (d) and (g) below. It should be clarified that these sensitivity tests were based on the assumption of the foregoing price reduction. It should further be noted that no price adjustments were taken into account for the result of the motion for the certification of a class action filed by an IEC consumer against the Tamar Project partners, as set out in section 23A5 of the Periodic Report . In the opinion of the legal counsel of the Partnership, it is more likely than not that the motion for certification will be dismissed. As aforesaid, at the present time the parties are at the hearing stage of the motion for certification of a class action. If a final and absolute ruling is handed certifying the foregoing class action suit (i.e. if after the motion for certification of a class action is certified (if it is certified) and a final ruling is handed in a subsequent action class action suit (if one is handed)), this may have an adverse effect on the Partnership's business, as well as on the prices at which it, together with the other Tamar partners, will sell natural gas to their customers, the scope of which depends on the outcome of the claim. The information about the gas price was provided to NSAI by the Partnership [7]; (b) The forecast of demand in the domestic market in Israel, which was used for assessing the estimated volume of future natural gas sales to the domestic market in Israel, was

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of IEC fuels, capital, and operating costs associated with the generation segment, and the cost of purchasing electricity from independent power producers.

5 The agreement with IEC stipulates two dates when each party may request an adjustment of the price (based on the mechanism set out in the agreement) if that party believes that the contract price is no longer appropriate for a long-term contract with a significant buyer for consumption of natural gas in the Israeli market: After 8 years and 11 years from the date of commercial operation (as defined in the agreement as from July 1, 2013) from the Tamar Project (namely, July 1, 2021 and July 1, 2024). At the first adjustment date (July 1, 2021 - after 8 years), the adjustment to the price will be up to 25% (increase or reduction), and at the second adjustment date (July 1, 2024 - after 11 years), the adjustment will be up to 10% (increase or reduction).

6 The discounted cash flow calculation is based on the contractual price that will apply as of January through to the date of the first adjustment, in accordance with the amendment to the agreement with the Israel Electric Corporation (if and when it is signed), as set out in the Company's immediate report dated February 17, 2019 (Ref. No.: 2019-01-013606).

7 To calculate the projected prices, assumptions were made based on information received from a consultation company based on the weighted data of several public and private entities: (1) Annual increase in the US-CPI of average 2%; (2) Brent price of USD 67 per barrel in 2019, rising to USD 80 per barrel in 2024 and USD 92 per barrel in 2029, and a gradual annual increase of 2.9% in subsequent years; (3) Projected electricity generation price based on an average long-term NIS to USD exchange rate and a forecast of fuel costs based on the price of gas to the IEC.

prepared by an external consultant, BDO Consulting Group; (c) the discounted cash flow is based on the price of condensate derived from the Brent prices. The Brent price was calculated using average oil price forecasts by third parties that provide long term price forecasts, including the World Bank and others, the NYMEX ICE Brent Crude price with adjustments for quality differences, transportation costs and the price at which condensates are sold in the region; (d) the operating costs taken into account were costs that NSAI received from the Partnerships. These costs include direct costs relating to the Project, insurance expenses and the Partnership's estimate of the overheads, and general and administrative expenses which can be attributed directly to the Project, and which together make up the operating costs of the Project. These costs are divided into expenses on the field level and expenses for a production unit. The operating costs that the Partnerships provided to NSAI, and which they believe are reasonable, are based, among other things, on NSAI's additional knowledge from similar projects. These costs are not adjusted to inflation fluctuations ;(e) the capital expenses taken into account when preparing the discounted cash flow exceed the costs approved by the Partnership, and it also includes estimated costs of future investments during production with the aim of maintaining and expanding production output. The capital expenses taken into account are capital expenditures that may be required, drilling, development and connection of new wells, laying of infrastructures and other production equipment. The capital expenses provided to NSAI, seem to be reasonable, are based, inter alia, on the Tamar Project development plan and on NSAI's additional knowledge from similar projects, and have not been adjusted for inflation changes; (f) The abandonment costs that were taken into account are costs that the Partnerships provided to NSAI, based on its assessment of the cost of abandoning wells, platforms and production facilities. These costs do not take into account salvage value of the Tamar Lease and Tamar Project facilities and are not adjusted to inflation changes; (g) The tax calculations take due corporate tax rates into account; (h) Actual production capacity for each of the reserve categories described above could be lower or higher than the production capacity used to estimate the discounted cash flows. In addition, NSAI did not prepare a sensitivity analysis for the production capacity of the wells. (i) Calculation of the discounted cash flow assumed projected sales quantities for each of the project years, based on the production capacity from the reservoirs[8] and an estimate of demand and supply in the domestic and export markets for each project year. (j) For calculating the discounted cash flow assumptions were taken into account regarding the scope of revenue from the export of gas to the domestic markets in Egypt and Jordan in a total aggregate quantity of 42 BCM, until 2040, based on the Partnership's forecasts regarding materialization of the export agreements to Egypt

[8] The supply capacity of gas from the Tamar project (which includes the Tamar project facilities, compression systems, and handling and transmission systems of the Yam Tethys project, which were upgraded and adapted for use by the Tamar project) to the INGL pipeline, is 1.1 BCF per day at maximum production.

and Jordan as described in section 1.7.12(E) of the Periodic Report.[9] Furthermore, a capital payment by the Tamar Partners was assumed with regard to the transmission of natural gas in the EMG pipeline (see the Company's immediate report dated September 27, 2018, Ref. No.: 2018-01-090483) (the "Immediate Report of 27.9.18"). The price under the export agreement from the Tamar Project to Dolphinus (for details see section (for details see section 1.7.12(E)(1)b to the Periodic Report (the "Dolphinus Agreement") was adjusted to delivery point, as set out in the agreement; (k) For calculating the discounted cash flow the Partnership's estimate of the actual rate of royalties to the State, related parties and third parties, that were paid to the State were taken into account at a rate of 11.5% and 9.13%, respectively. As at the publication date of this report, the Tamar partners are holding discussions with the Ministry of Energy regarding the calculation method of the actual rate of royalties payable by the Partnership to the state. Therefore, the actual rate of the royalties is not final and may change, and there is no certainty that the Partnership will succeed in negotiations to set a lower royalty rate in the future. For further information on this matter, see Note 23A6 to the financial statements that appear in the Periodic Report; (l) The calculation of the discounted cash flow takes into account the oil profit levy applicable to the Partnership and the Company in accordance with the provisions of the Law. It should be emphasized that the levy was calculated according to the definitions, formulas and mechanisms defined in the law as the Company and the Partnership understand and interpret them, and which are reflected in the Tamar Project reports to the Tax Authority. Nonetheless, in view of the law's innovation and the complexity of the calculation formulas and the various mechanisms defined therein, it is not certain that this interpretation of the calculation for the levy will be the same as that adopted by the tax authorities and/or the same as the interpretation of the law by the court. It should be noted that as at the date of publication of this report, several interpretative disputes regarding the implementation of the Law are being clarified in the Tamar Project's reports with the Tax Authority, as part of the of the appeal procedures prescribed by law. The disputed issues have not been brought before the courts in Israel. The levy was calculated according to the transitional provisions in the law for a project that started commercial production before the Law came into effect, and through to January 1, 2014, based on the following assumptions: The Project will choose to report in USD pursuant to section 13(B) of the Law, all of the Project's payments (such as production costs, investments, and royalties) will be recognized by the tax authorities for calculating the levy, and calculation of the Project revenues will take into account actual selling prices of the gas; (m) The calculation of the discounted cash flows included expenses and investments that were actually paid and which are expected to be paid by the Partnership as of January 1, 2019, as well as revenues from sales of natural gas and

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[9] It should be noted that in 2018 the Tamar Partners produced and sold a volume of 10.3 BCM natural gas on the domestic market and for export, and 477 thousand barrels of condensate. The Yam Tethys partners also sold natural gas in a volume of 0.19 BCM of which a volume of0.06 BCM was sold to Tamar Project customers.

condensate produced as of January 1, 2019. It is clarified that revenues received in 2019 for sales of natural gas and condensate produced in 2018 were not included in the cash flows.

<u>It is noted that there is a change in the discounted cash flow compared to the discounted cash flow as of December 31, 2017, ("The previous discounted cash flow") for the following main reasons [10] :</u>

1. Following the adjusted projections for the Electricity Generation Price, the US-CPI, and the price of a Brent barrel, projections were adjusted for the relevant selling prices (natural gas and condensate) that are linked to them.
2. In view of the revision of the Project's expenditure forecast, including revision of the Project's capital expenditure forecast, which is mainly due to revising the forecast of the Tamar field future development plan, including changes in dates of future drilling of wells and a change in the estimated cost involved, together with the addition of a third pipeline from the Tamar field to the Tamar platform, expected to be executed between 2024 - 2026, at an estimated budget of USD 370 million (for 100%) and that are not adjusted for inflation, and which will increase the gas supply capacity from the Tamar Project to 1.2 BCF per day (12 BCM per year), at maximum production . It should be noted that such third pipeline, for which construction and laying have not yet been finally approved by the Tamar partners, will allow further expansion of the gas supply capacity from the Tamar project, with a maximum production even exceeding 12 BCM per year.
3. Following revision of the components of the forecast of future volumes expected to be sold, whether on the domestic market or for export, and in view of the feasibility of adding a third pipeline as set out in section 2 above, as well as the EMG transaction (see immediate report dated September 27, 2018) increasing certainty regarding realization of the Dolphinus sale, we updated the forecast of sales volumes as of 2027.
4. For information concerning changes that have occurred concerning the volume of reserves attributed to the oil asset, see section **Error! Reference source not found.** below.

Based on different assumptions, which are described above, following is the estimated discounted cash flow as at December 31, 2018, in thousands of USD (after the levy and income tax) attributable to the Company's share (including through the Partnership's holding in Tamar Petroleum and the overriding royalties paid to the Company and companies under its control from Tamar Petroleum and from the Partnership), from the reserves in the Tamar Project, for each of the reserve categories described above:

10 It should be noted that the Partnership's total holdings in the Tamar Project (directly and indirectly held through Tamar Petroleum Ltd. ("**Tamar Petroleum"**) comes to 25.7855% (compared with 25.7% in the previous discounted cash flow) .

Total discounted cash flow from Proved Reserves at December 31, 2018 (in USD thousands, relating to the Company's share)																	
Cash flow items																	
										Taxes		Total discounted cash flow after tax					
to	Quantity of condensate sales (thousands of barrels) (100% of the oil asset)	Sales volume (BCM) (100% of the oil asset)	Revenue	Royalties payable	Royalties receivable	Operating costs	Development costs	Abandonment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Levy	Income tax	Discounted at -0%	Discounted at 5%	Discounted at -7.5%[11]	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2019	489	10.65	325,096	65,119	14,353	26,352	18,557	-	229,421	-	39,523	189,898	185,321	183,154	181,060	177,080	173,352
31.12.2020	489	10.65	316,078	63,312	13,955	24,439	38,018	-	204,263	7,154	45,880	151,229	140,557	135,682	131,083	122,628	115,044
31.12.2021	475	10.34	312,083	62,512	13,778	23,907	125	-	239,318	64,976	30,989	143,353	126,892	119,643	112,960	101,079	90,877
31.12.2022	489	10.65	323,386	64,776	14,277	23,965	44,694	-	204,228	72,261	31,784	100,183	84,456	77,780	71,766	61,426	52,925
31.12.2023	489	10.65	327,204	65,541	14,446	23,965	41,758	-	210,386	87,378	30,616	92,392	74,179	66,726	60,168	49,260	40,674
31.12.2024	490	10.67	330,270	66,155	14,581	23,965	-	-	254,732	118,353	23,592	112,787	86,242	75,772	66,773	52,290	41,377
31.12.2025	489	10.65	331,315	66,364	14,628	23,965	-	-	255,614	119,627	23,505	112,481	81,912	70,295	60,538	45,347	34,388
31.12.2026	489	10.65	334,824	67,067	14,782	23,965	-	-	258,575	121,013	24,192	113,370	78,628	65,908	55,469	39,743	28,883
31.12.2027	534	11.64	373,605	74,835	16,495	23,965	-	-	291,300	136,328	29,027	125,945	83,190	68,110	56,020	38,393	26,739
31.12.2028	536	11.67	377,881	75,692	16,683	23,965	-	-	294,908	138,017	31,078	125,813	79,146	63,291	50,874	33,350	22,259
31.12.2029	534	11.64	379,946	76,105	16,775	23,965	-	-	296,650	138,832	31,415	126,403	75,730	59,152	46,466	29,136	18,636
31.12.2030	534	11.64	388,831	77,885	17,167	23,965	-	-	304,148	142,341	32,753	129,054	73,637	56,179	43,128	25,867	15,856
31.12.2031	534	11.64	399,916	80,106	17,656	23,965	-	-	313,502	146,719	35,032	131,752	71,596	53,352	40,026	22,963	13,489
31.12.2032	536	11.67	414,248	82,976	18,289	23,965	-	-	325,596	152,379	36,510	136,707	70,751	51,496	37,756	20,719	11,664
31.12.2033	534	11.64	426,371	85,405	18,824	23,965	31,163	-	304,663	142,582	41,768	120,313	59,302	42,159	30,208	15,856	8,554
31.12.2034	519	11.30	420,767	84,282	18,577	23,965	-	-	331,097	154,953	38,473	137,670	64,626	44,875	31,423	15,777	8,157
31.12.2035	419	9.12	344,647	69,035	15,216	23,965	-	-	266,863	124,892	30,869	111,102	49,671	33,689	23,054	11,072	5,486
31.12.2036	285	6.22	238,253	47,724	10,519	23,965	-	-	177,084	82,875	20,223	73,985	31,502	20,869	13,956	6,411	3,044
31.12.2037	285	6.20	240,780	48,230	10,630	23,965	-	-	179,216	83,873	20,486	74,857	30,355	19,642	12,837	5,641	2,567
31.12.2038	279	6.08	239,175	47,908	10,560	23,965	-	-	177,861	83,239	20,335	74,288	28,690	18,132	11,581	4,868	2,123
31.12.2039	270	5.87	233,611	46,794	10,314	23,965	-	-	173,167	81,042	19,784	72,340	26,607	16,425	10,253	4,122	1,723
31.12.2040	253	5.52	221,872	44,442	9,796	23,965	-	-	163,261	76,406	18,614	68,241	23,904	14,413	8,792	3,381	1,354
31.12.2041	174	3.79	154,453	30,938	6,819	23,965	-	-	106,370	49,781	11,854	44,734	14,924	8,789	5,240	1,927	740
31.12.2042	143	3.12	128,680	25,775	5,681	23,965	-	-	84,621	39,603	8,255	36,764	11,681	6,719	3,915	1,377	507
31.12.2043	98	2.12	88,554	17,738	3,910	23,965	-	-	50,762	23,756	4,229	22,777	6,892	3,872	2,205	742	262
31.12.2044	78	1.70	71,704	14,363	3,166	23,965	-	9,819	26,723	12,507	4,312	9,905	2,854	1,566	872	281	95
31.12.2045	65	1.42	60,479	12,114	2,670	23,965	-	9,819	17,251	8,074	3,186	5,991	1,644	881	479	148	48
31.12.2046	33	0.71	30,789	6,167	1,359	23,965	-	9,819	(7,803)	(3,652)	203	(4,354)	(1,138)	(596)	(317)	(93)	(29)
31.12.2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**10,542**	**230**	**7,834,818**	**1,569,360**	**345,906**	**673,823**	**174,315**	**29,457**	**5,733,777**	**2,405,309**	**688,487**	**2,639,980**	**1,663,751**	**1,377,975**	**1,168,585**	**890,791**	**720,794**

[11] An additional discount rate of 7.5% was made by the Company for calculation purposes and as a tool for the investor.

Total discounted cash flow from probable reserves as of December 31, 2018 (in USD thousands for the Company's share)

Cash flow items

										Taxes		Total discounted cash flow after tax					
until	Quantity of condensate sales (thousands of barrels) (100% of the oil asset)	Sales volume (BCM) (100% of the oil asset)	Revenue	Royalties payable	Royalties receivable	Operating costs	Development costs[12]	Abandonment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Levy	Income tax	Discounted at -0%	Discounted at 5%	Discounted at -7.5%[13]	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2019	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2021	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2022	-	-	-	-	-	-	(45,186)	-	45,186	18,583	(4,274)	30,877	26,030	23,972	22,119	18,932	16,312
31.12.2023	-	-	-	-	-	-	(41,758)	-	41,758	23,398	(4,734)	23,094	18,542	16,679	15,040	12,313	10,167
31.12.2024	-	-	-	-	-	-	45,186	-	(45,186)	(20,285)	6,628	(31,529)	(24,108)	(21,182)	(18,666)	(14,617)	(11,567)
31.12.2025	-	-	-	-	-	-	15,581	-	(15,581)	(7,292)	2,955	(11,245)	(8,189)	(7,027)	(6,052)	(4,533)	(3,438)
31.12.2026	-	-	-	-	-	-	26,177	-	(26,177)	(12,251)	4,092	(18,018)	(12,497)	(10,475)	(8,816)	(6,317)	(4,590)
31.12.2027	-	-	-	-	-	-	-	-	-	-	(37)	37	24	20	16	11	8
31.12.2028	-	-	-	-	-	-	-	-	-	-	(37)	37	23	19	15	10	7
31.12.2029	-	-	-	-	-	-	-	-	-	-	(37)	37	22	17	14	9	5
31.12.2030	-	-	-	-	-	-	-	-	-	-	(37)	37	21	16	12	7	5
31.12.2031	-	-	-	-	-	-	-	-	-	-	(37)	37	20	15	11	6	4
31.12.2032	-	-	-	-	-	-	-	-	-	-	(37)	37	19	14	10	6	3
31.12.2033	-	-	-	-	-	-	(31,163)	-	31,163	14,584	(4,039)	20,617	10,162	7,225	5,177	2,717	1,466
31.12.2034	16	0.34	12,783	2,561	564	-	-	-	10,787	5,048	37	5,702	2,677	1,859	1,301	653	338
31.12.2035	116	2.53	95,476	19,124	4,215	-	31,163	-	49,404	23,121	12,969	13,314	5,952	4,037	2,763	1,327	657
31.12.2036	250	5.46	209,012	41,866	9,228	-	-	-	176,374	82,543	19,915	73,916	31,472	20,849	13,943	6,405	3,041
31.12.2037	250	5.44	211,252	42,315	9,327	-	-	-	178,264	83,428	21,812	73,024	29,612	19,161	12,523	5,502	2,504
31.12.2038	255	5.56	218,910	43,849	9,665	-	-	-	184,726	86,452	22,603	75,671	29,224	18,470	11,797	4,958	2,162
31.12.2039	265	5.77	229,495	45,969	10,132	-	29,605	-	164,053	76,777	26,883	60,394	22,213	13,713	8,559	3,441	1,438
31.12.2040	283	6.16	247,557	49,587	10,930	-	-	-	208,899	97,765	24,880	86,254	30,214	18,218	11,113	4,273	1,712
31.12.2041	348	7.59	308,883	61,871	13,637	-	-	-	260,649	121,984	31,212	107,453	35,848	21,112	12,586	4,629	1,777

12 As the level of certainty required to produce the probable reserves (50%) is lower than the level of certainty required to produce the proved reserves (90%), the date of execution of the capital investments required to produce the probable reserves was postponed to the date of execution of the capital investments required to produce the proved reserves, according to the production profile. Thus, the development costs are stated as negative amounts for certain years in the table of discounted cash flow from probable reserves, and are stated as positive amounts for later years in the same table, compared with the development costs in the table of discounted flow from proved reserves. For information about the total capital investments required, see the table of discounted cash flow from 2P reserves (proved reserves (1P) + probable reserves).

13 An additional discount rate of 7.5% was made by the Company for calculation purposes and as a tool for the investor.

Total discounted cash flow from probable reserves as of December 31, 2018 (in USD thousands for the Company's share)																	
Cash flow items																	
										Taxes		Total discounted cash flow after tax					
until	Quantity of condensate sales (thousands of barrels) (100% of the oil asset)	Sales volume (BCM) (100% of the oil asset)	Revenue	Royalties payable	Royalties receivable	Operating costs	Development costs[12]	Abandonment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Levy	Income tax	Discounted at -0%	Discounted at 5%	Discounted at -7.5%[13]	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2042	304	6.61	272,507	54,585	12,031	-	-	-	229,954	107,618	28,473	93,862	29,822	17,155	9,995	3,516	1,293
31.12.2043	336	7.31	304,726	61,038	13,454	-	-	-	257,141	120,342	31,800	104,999	31,772	17,852	10,164	3,420	1,206
31.12.2044	341	7.43	313,575	62,811	13,844	-	-	(9,819)	274,428	128,432	30,940	115,055	33,157	18,197	10,125	3,259	1,101
31.12.2045	246	5.35	228,725	45,815	10,098	-	-	(9,819)	202,827	94,923	22,179	85,725	23,528	12,612	6,858	2,112	684
31.12.2046	244	5.32	229,862	46,043	10,148	-	-	(9,819)	203,786	95,372	21,996	86,418	22,589	11,827	6,285	1,851	574
31.12.2047	273	5.94	259,906	52,061	11,475	23,965	-	-	195,356	91,426	22,206	81,724	20,345	10,404	5,403	1,522	453
31.12.2048	218	4.75	210,522	42,169	9,295	23,965	-	10,484	143,199	67,017	18,235	57,947	13,739	6,862	3,483	939	267
31.12.2049	130	2.83	126,938	25,427	5,604	23,965	-	10,484	72,667	34,008	9,605	29,054	6,560	3,201	1,588	409	112
31.12.2050	64	1.40	63,698	12,759	2,812	23,965	-	10,484	19,302	9,034	3,756	6,513	1,401	667	324	80	21
31.12.2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**3,939**	**86**	**3,543,827**	**709,850**	**156,459**	**95,860**	**29,605**	**1,995**	**2,862,979**	**1,342,027**	**349,907**	**1,171,043**	**380,194**	**225,489**	**137,690**	**56,840**	**27,722**

Total discounted cash flow from 2P Reserves (Proved+Probable Reserves) as of December 31, 2018 (in USD thousands, relating to the Company's share)																	
Cash flow items																	
										Taxes		Total discounted cash flow after tax					
until	**Quantity of condensate sales (thousands of barrels) (100% of the oil asset)**	**Sales volume (BCM) (100% of the oil asset)**	**Revenue**	**Royalties payable**	**Royalties receivable**	**Operating costs**	**Development costs**	**Abandonment and restoration costs**	**Total cash flow before levy and income tax (discounted at 0%)**	**Levy**	**Income tax**	**Discounted at -0%**	**Discounted at 5%**	**Discounted at -7.5%[14]**	**Discounted at 10%**	**Discounted at 15%**	**Discounted at 20%**
31.12.2019	489	10.65	325,096	65,119	14,353	26,352	18,557	-	229,421	-	39,523	189,898	185,321	183,154	181,060	177,080	173,352
31.12.2020	489	10.65	316,078	63,312	13,955	24,439	38,018	-	204,263	7,154	45,880	151,229	140,557	135,682	131,083	122,628	115,044
31.12.2021	475	10.34	312,083	62,512	13,778	23,907	125	-	239,318	64,976	30,989	143,353	126,892	119,643	112,960	101,079	90,877
31.12.2022	489	10.65	323,386	64,776	14,277	23,965	(491)	-	249,414	90,844	27,510	131,060	110,486	101,752	93,885	80,358	69,237
31.12.2023	489	10.65	327,204	65,541	14,446	23,965	-	-	252,144	110,776	25,882	115,486	92,721	83,405	75,208	61,573	50,841
31.12.2024	490	10.67	330,270	66,155	14,581	23,965	45,186	-	209,546	98,067	30,220	81,258	62,133	54,591	48,107	37,673	29,810
31.12.2025	489	10.65	331,315	66,364	14,628	23,965	15,581	-	240,032	112,335	26,461	101,237	73,724	63,268	54,486	40,813	30,950
31.12.2026	489	10.65	334,824	67,067	14,782	23,965	26,177	-	232,398	108,762	28,284	95,352	66,132	55,433	46,653	33,427	24,292
31.12.2027	534	11.64	373,605	74,835	16,495	23,965	-	-	291,300	136,328	28,990	125,982	83,214	68,130	56,036	38,404	26,746
31.12.2028	536	11.67	377,881	75,692	16,683	23,965	-	-	294,908	138,017	31,041	125,850	79,169	63,310	50,889	33,360	22,265
31.12.2029	534	11.64	379,946	76,105	16,775	23,965	-	-	296,650	138,832	31,378	126,440	75,752	59,169	46,479	29,145	18,642
31.12.2030	534	11.64	388,831	77,885	17,167	23,965	-	-	304,148	142,341	32,716	129,091	73,658	56,195	43,140	25,874	15,860
31.12.2031	534	11.64	399,916	80,106	17,656	23,965	-	-	313,502	146,719	34,995	131,789	71,616	53,367	40,038	22,970	13,493
31.12.2032	536	11.67	414,248	82,976	18,289	23,965	-	-	325,596	152,379	36,473	136,744	70,770	51,510	37,766	20,725	11,667
31.12.2033	534	11.64	426,371	85,405	18,824	23,965	-	-	335,826	157,167	37,729	140,931	69,464	49,384	35,384	18,573	10,020
31.12.2034	534	11.64	433,550	86,843	19,141	23,965	-	-	341,884	160,002	38,510	143,372	67,302	46,734	32,725	16,430	8,495
31.12.2035	534	11.64	440,123	88,159	19,431	23,965	31,163	-	316,268	148,013	43,838	124,416	55,623	37,726	25,817	12,398	6,143
31.12.2036	536	11.67	447,265	89,590	19,747	23,965	-	-	353,457	165,418	40,138	147,902	62,974	41,718	27,900	12,816	6,086
31.12.2037	534	11.64	452,032	90,545	19,957	23,965	-	-	357,480	167,301	42,298	147,881	59,967	38,802	25,360	11,143	5,071
31.12.2038	534	11.64	458,085	91,757	20,224	23,965	-	-	362,587	169,691	42,938	149,959	57,914	36,602	23,378	9,826	4,285
31.12.2039	534	11.64	463,106	92,763	20,446	23,965	29,605	-	337,220	157,819	46,667	132,734	48,820	30,138	18,812	7,563	3,161
31.12.2040	536	11.67	469,428	94,029	20,725	23,965	-	-	372,160	174,171	43,494	154,495	54,118	32,631	19,905	7,654	3,066
31.12.2041	523	11.38	463,337	92,809	20,456	23,965	-	-	367,019	171,765	43,066	152,188	50,772	29,901	17,826	6,557	2,517
31.12.2042	447	9.74	401,188	80,360	17,712	23,965	-	-	314,575	147,221	36,728	130,626	41,503	23,874	13,909	4,894	1,800
31.12.2043	433	9.43	393,280	78,776	17,363	23,965	-	-	307,903	144,098	36,029	127,776	38,664	21,724	12,369	4,162	1,467
31.12.2044	419	9.13	385,279	77,174	17,010	23,965	-	-	301,151	140,939	35,252	124,960	36,012	19,763	10,997	3,540	1,196

[14] See footnote 8 above.

Total discounted cash flow from 2P Reserves (Proved+Probable Reserves) as of December 31, 2018 (in USD thousands, relating to the Company's share)																	
Cash flow items																	
										Taxes		Total discounted cash flow after tax					
until	Quantity of condensate sales (thousands of barrels) (100% of the oil asset)	Sales volume (BCM) (100% of the oil asset)	Revenue	Royalties payable	Royalties receivable	Operating costs	Development costs	Abandonment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Levy	Income tax	Discounted at -0%	Discounted at 5%	Discounted at -7.5%14	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2045	311	6.77	289,204	57,929	12,768	23,965	-	-	220,078	102,997	25,365	91,716	25,173	13,493	7,337	2,259	731
31.12.2046	277	6.03	260,651	52,210	11,508	23,965	-	-	195,984	91,720	22,199	82,064	21,451	11,231	5,968	1,758	545
31.12.2047	273	5.94	259,906	52,061	11,475	23,965	-	-	195,356	91,426	22,206	81,724	20,345	10,404	5,403	1,522	453
31.12.2048	218	4.75	210,522	42,169	9,295	23,965	-	10,484	143,199	67,017	18,235	57,947	13,739	6,862	3,483	939	267
31.12.2049	130	2.83	126,938	25,427	5,604	23,965	-	10,484	72,667	34,008	9,605	29,054	6,560	3,201	1,588	409	112
31.12.2050	64	1.40	63,698	12,759	2,812	23,965	-	10,484	19,302	9,034	3,756	6,513	1,401	667	324	80	21
31.12.2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**14,478**	**315**	**11,378,646**	**2,279,210**	**502,363**	**769,683**	**203,921**	**31,452**	**8,596,756**	**3,747,337**	**1,038,395**	**3,811,027**	**2,043,947**	**1,603,464**	**1,306,275**	**947,632**	**748,512**

Total discounted cash flow from possible reserves as of December 31, 2018 (in USD thousands regarding the Company's share)																
Cash flow items																
										Taxes		Total discounted cash flow after tax				
until	Quantity of condensate sales (thousands of barrels) (100% of the oil asset)	Sales volume (BCM) (100% of the oil asset)	Revenue	Royalties payable	Royalties receivable	Operating costs	Development costs	Abandonment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Levy	Income tax	Discounted at -0%	Discounted at 5%	Discounted at -7.5%[15]	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2019	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2021	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2022	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2023	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2024	-	-	-	-	-	-	(45,186)	-	45,186	21,147	(4,864)	28,903	22,100	19,417	17,111	13,400	10,603
31.12.2025	-	-	-	-	-	-	-	-	-	-	684	(684)	(498)	(428)	(368)	(276)	(209)
31.12.2026	-	-	-	-	-	-	45,186	-	(45,186)	(21,147)	5,548	(29,587)	(20,520)	(17,200)	(14,476)	(10,372)	(7,538)
31.12.2027	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2030	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2031	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2035	-	-	-	-	-	-	(31,163)	-	31,163	14,584	(4,394)	20,972	9,376	6,359	4,352	2,090	1,036
31.12.2036	-	-	-	-	-	-	-	-	-	-	387	(387)	(165)	(109)	(73)	(34)	(16)
31.12.2037	-	-	-	-	-	-	31,163	-	(31,163)	(14,584)	4,071	(20,650)	(8,374)	(5,418)	(3,541)	(1,556)	(708)
31.12.2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2039	-	-	-	-	-	-	(29,605)	-	29,605	13,855	(3,187)	18,936	6,965	4,300	2,684	1,079	451
31.12.2040	-	-	-	-	-	-	-	-	-	-	681	(681)	(239)	(144)	(88)	(34)	(14)
31.12.2041	12	0.26	10,462	2,096	462	-	29,605	-	(20,777)	(9,723)	4,948	(16,001)	(5,338)	(3,144)	(1,874)	(689)	(265)
31.12.2042	87	1.90	78,369	15,698	3,460	-	-	-	66,131	30,949	8,092	27,090	8,607	4,951	2,885	1,015	373
31.12.2043	101	2.21	92,104	18,449	4,066	-	-	-	77,721	36,374	9,510	31,838	9,634	5,413	3,082	1,037	366
31.12.2044	117	2.55	107,436	21,520	4,743	-	-	-	90,659	42,428	11,093	37,138	10,703	5,874	3,268	1,052	355
31.12.2045	224	4.87	208,044	41,672	9,185	-	-	-	175,557	82,160	21,481	71,915	19,738	10,580	5,753	1,771	573

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[15] See footnote 8 above.

Total discounted cash flow from possible reserves as of December 31, 2018 (in USD thousands regarding the Company's share)																	
Cash flow items																	
										Taxes		Total discounted cash flow after tax					
until	Quantity of condensate sales (thousands of barrels) (100% of the oil asset)	Sales volume (BCM) (100% of the oil asset)	Revenue	Royalties payable	Royalties receivable	Operating costs	Development costs	Abandonment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Levy	Income tax	Discounted at -0%	Discounted at 5%	Discounted at -7.5%[15]	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2046	258	5.61	242,635	48,601	10,712	-	-	-	204,746	95,821	25,353	83,572	21,845	11,437	6,078	1,790	555
31.12.2047	262	5.70	249,488	49,974	11,015	-	-	-	210,529	98,528	26,061	85,941	21,395	10,941	5,682	1,601	476
31.12.2048	318	6.92	306,559	61,406	13,535	-	-	(10,484)	269,172	125,972	31,542	111,658	26,473	13,223	6,711	1,808	515
31.12.2049	358	7.79	349,072	69,921	15,411	-	-	(10,484)	305,046	142,762	35,931	126,353	28,531	13,920	6,904	1,780	486
31.12.2050	391	8.51	385,969	77,312	17,040	-	-	(10,484)	336,181	157,333	38,043	140,806	30,280	14,430	6,994	1,724	451
31.12.2051	390	8.50	390,096	78,139	17,223	23,965	-	-	305,215	142,841	35,648	126,727	25,955	12,081	5,723	1,350	338
31.12.2052	325	7.08	329,016	65,904	14,526	23,965	-	10,484	243,189	113,813	32,168	97,209	18,961	8,620	3,991	900	216
31.12.2053	228	4.96	233,099	46,691	10,291	23,965	-	10,484	162,250	75,933	22,264	64,053	11,899	5,284	2,391	516	119
31.12.2054	140	3.05	145,420	29,128	6,420	23,965	-	10,484	88,263	41,307	13,211	33,745	5,970	2,589	1,145	236	52
31.12.2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**3,211**	**70**	**3,127,769**	**626,511**	**138,089**	**95,860**	**-**	**-**	**2,543,487**	**1,190,353**	**314,271**	**1,038,866**	**243,298**	**122,976**	**64,334**	**20,188**	**8,215**

Total discounted cash flow from 3P Reserves (Proved+Probable+Possible Reserves) at December 31, 2018 (in USD thousands, relating to the Company's share)																		
Cash flow items																		
										Taxes		Total discounted cash flow after tax						
until	Quantity of condensate sales (thousands of barrels) (100% of the oil asset)	Sales volume (BCM) (100% of the oil asset)	Revenue	Royalties payable	Royalties receivable	Operating costs	Development costs	Abandonment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Levy	Income tax	Discounted at -0%	Discounted at 5%	Discounted at -7.5%[16]	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2019	489	10.65	325,096	65,119	14,353	26,352	18,557	-	229,421	-	39,523	189,898	185,321	183,154	181,060	177,080	173,352
31.12.2020	489	10.65	316,078	63,312	13,955	24,439	38,018	-	204,263	7,154	45,880	151,229	140,557	135,682	131,083	122,628	115,044
31.12.2021	475	10.34	312,083	62,512	13,778	23,907	125	-	239,318	64,976	30,989	143,353	126,892	119,643	112,960	101,079	90,877
31.12.2022	489	10.65	323,386	64,776	14,277	23,965	(491)	-	249,414	90,844	27,510	131,060	110,486	101,752	93,885	80,358	69,237
31.12.2023	489	10.65	327,204	65,541	14,446	23,965	-	-	252,144	110,776	25,882	115,486	92,721	83,405	75,208	61,573	50,841
31.12.2024	490	10.67	330,270	66,155	14,581	23,965	-	-	254,732	119,214	25,357	110,161	84,234	74,008	65,218	51,073	40,414
31.12.2025	489	10.65	331,315	66,364	14,628	23,965	15,581	-	240,032	112,335	27,145	100,552	73,225	62,840	54,118	40,537	30,741
31.12.2026	489	10.65	334,824	67,067	14,782	23,965	71,363	-	187,212	87,615	33,832	65,765	45,611	38,232	32,177	23,055	16,755
31.12.2027	534	11.64	373,605	74,835	16,495	23,965	-	-	291,300	136,328	28,990	125,982	83,214	68,130	56,036	38,404	26,746
31.12.2028	536	11.67	377,881	75,692	16,683	23,965	-	-	294,908	138,017	31,041	125,850	79,169	63,310	50,889	33,360	22,265
31.12.2029	534	11.64	379,946	76,105	16,775	23,965	-	-	296,650	138,832	31,378	126,440	75,752	59,169	46,479	29,145	18,642
31.12.2030	534	11.64	388,831	77,885	17,167	23,965	-	-	304,148	142,341	32,716	129,091	73,658	56,195	43,140	25,874	15,860
31.12.2031	534	11.64	399,916	80,106	17,656	23,965	-	-	313,502	146,719	34,995	131,789	71,616	53,367	40,038	22,970	13,493
31.12.2032	536	11.67	414,248	82,976	18,289	23,965	-	-	325,596	152,379	36,473	136,744	70,770	51,510	37,766	20,725	11,667
31.12.2033	534	11.64	426,371	85,405	18,824	23,965	-	-	335,826	157,167	37,729	140,931	69,464	49,384	35,384	18,573	10,020
31.12.2034	534	11.64	433,550	86,843	19,141	23,965	-	-	341,884	160,002	38,510	143,372	67,302	46,734	32,725	16,430	8,495
31.12.2035	534	11.64	440,123	88,159	19,431	23,965	-	-	347,430	162,597	39,444	145,388	64,999	44,085	30,168	14,488	7,179
31.12.2036	536	11.67	447,265	89,590	19,747	23,965	-	-	353,457	165,418	40,525	147,515	62,809	41,609	27,827	12,783	6,070
31.12.2037	534	11.64	452,032	90,545	19,957	23,965	31,163	-	326,317	152,717	46,370	127,231	51,593	33,384	21,819	9,587	4,363
31.12.2038	534	11.64	458,085	91,757	20,224	23,965	-	-	362,587	169,691	42,938	149,959	57,914	36,602	23,378	9,826	4,285
31.12.2039	534	11.64	463,106	92,763	20,446	23,965	-	-	366,825	171,674	43,480	151,670	55,785	34,437	21,496	8,642	3,611
31.12.2040	536	11.67	469,428	94,029	20,725	23,965	-	-	372,160	174,171	44,175	153,814	53,880	32,487	19,818	7,621	3,052
31.12.2041	534	11.64	473,798	94,905	20,918	23,965	29,605	-	346,243	162,042	48,014	136,187	45,433	26,757	15,951	5,867	2,252
31.12.2042	534	11.64	479,557	96,058	21,172	23,965	-	-	380,706	178,171	44,820	157,716	50,110	28,825	16,794	5,908	2,173
31.12.2043	534	11.64	485,384	97,225	21,430	23,965	-	-	385,624	180,472	45,539	159,613	48,298	27,137	15,451	5,200	1,833
31.12.2044	536	11.68	492,715	98,694	21,753	23,965	-	-	391,810	183,367	46,345	162,098	46,714	25,637	14,265	4,592	1,551

[16] See footnote 8 above.

Total discounted cash flow from 3P Reserves (Proved+Probable+Possible Reserves) at December 31, 2018 (in USD thousands, relating to the Company's share)																	
Cash flow items																	
										Taxes		Total discounted cash flow after tax					
until	Quantity of condensate sales (thousands of barrels) (100% of the oil asset)	Sales volume (BCM) (100% of the oil asset)	Revenue	Royalties payable	Royalties receivable	Operating costs	Development costs	Abandonment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Levy	Income tax	Discounted at -0%	Discounted at 5%	Discounted at -7.5%[16]	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2045	534	11.64	497,248	99,602	21,953	23,965	-	-	395,635	185,157	46,846	163,631	44,911	24,074	13,091	4,031	1,305
31.12.2046	534	11.64	503,285	100,811	22,220	23,965	-	-	400,730	187,541	47,552	165,636	43,296	22,668	12,046	3,548	1,101
31.12.2047	534	11.64	509,394	102,035	22,490	23,965	-	-	405,885	189,954	48,266	167,664	41,739	21,345	11,085	3,123	928
31.12.2048	536	11.68	517,081	103,574	22,829	23,965	-	-	412,371	192,990	49,777	169,605	40,212	20,086	10,194	2,747	783
31.12.2049	488	10.62	476,010	95,348	21,016	23,965	-	-	377,713	176,770	45,536	155,407	35,091	17,120	8,492	2,189	598
31.12.2050	455	9.91	449,667	90,071	19,853	23,965	-	-	355,484	166,366	41,799	147,318	31,681	15,097	7,318	1,804	472
31.12.2051	390	8.50	390,096	78,139	17,223	23,965	-	-	305,215	142,841	35,648	126,727	25,955	12,081	5,723	1,350	338
31.12.2052	325	7.08	329,016	65,904	14,526	23,965	-	10,484	243,189	113,813	32,168	97,209	18,961	8,620	3,991	900	216
31.12.2053	228	4.96	233,099	46,691	10,291	23,965	-	10,484	162,250	75,933	22,264	64,053	11,899	5,284	2,391	516	119
31.12.2054	140	3.05	145,420	29,128	6,420	23,965	-	10,484	88,263	41,307	13,211	33,745	5,970	2,589	1,145	236	52
31.12.2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**17,685**	**385**	**14,506,413**	**2,905,721**	**640,454**	**865,543**	**203,921**	**31,452**	**11,140,244**	**4,937,691**	**1,352,667**	**4,849,889**	**2,287,242**	**1,726,439**	**1,370,609**	**967,822**	**756,730**

Note: It is clarified that the discounted cash flow figures, whether calculated at a specific discount rate or without a discount rate, represent the present value but not necessarily the fair value.

Forward-looking information: The discounted cash flows set out above are forward-looking information as defined in the Securities Law. The information above is based on various assumptions, including the rate and duration of natural gas and condensate sales from the project, operational costs, capital expenditure, abandonment expenses, rates of royalties, and selling prices, including price adjustments according to the agreement with IEC, and there is no certainly whether these will materialize. It is noted that actual volume of natural gas and/or condensate produced, and these expenses and revenues may be different from these estimates and assumptions, partly due to the prevailing competition in the market and/or technical and operational conditions and/or regulatory changes and/or the supply and demand conditions in the natural gas and/or condensate market and/or actual performance of the project and/or as a result of actual selling prices and/or due to geo-political changes. **It should also be noted that price adjustment at the first adjustment date as set out in the IEC agreement may differ materially from the Partnership's assessment, among other things, due to actual natural gas prices in the domestic market on the first adjustment date, all in accordance with the adjustment mechanism set out in the IEC agreement.**

4. Sensitivity analysis of the main discounted cash flow items (gas price and quantity of gas sold[17]) as at December 31, 2018 (USD thousands) carried out by the Company:

Sensitivity/category	Total	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%	Sensitivity/category	Total	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%
10% increase in the price of gas					**10% decrease in the price of gas**				
Proved reserves 1P (Proved Reserves)	2,898,038	1,270,067	964,931	778,962	Proved reserves 1P (Proved Reserves)	2,382,696	1,066,109	815,117	660,715
Probable Reserves (Probable reserves)	1,293,920	151,405	61,984	29,747	Probable Reserves (Probable Reserves)	1,049,670	125,026	52,607	26,480
Total 2P reserves (Proved+Probable Reserves)	4,191,958	1,421,471	1,026,914	808,709	Total 2P reserves (Proved+Probable Reserves)	3,432,366	1,191,135	867,724	687,194
Possible Reserves (Possible Reserves)	1,146,981	70,560	21,886	8,716	Possible Reserves (Possible Reserves)	930,154	57,757	18,219	7,504
Total 3P reserves (Proved + probable + possible reserves)	5,338,938	1,492,031	1,048,800	817,425	Total 3P reserves Proved + probable + possible reserves)	4,362,520	1,248,892	885,943	694,699
15% increase in the price of gas					**15% decrease in the price of gas**				
Proved reserves 1P (Proved Reserves)	3,026,184	1,319,685	1,000,831	806,858	Proved reserves 1P (Proved Reserves)	2,252,526	1,012,888	775,216	628,591
Probable Reserves (Probable reserves)	1,355,534	158,402	64,678	30,869	Probable Reserves (Probable Reserves)	989,239	118,832	50,609	25,964
Total 2P reserves (Proved+Probable Reserves)	4,381,718	1,478,087	1,065,510	837,728	Total 2P reserves (Proved+Probable Reserves)	3,241,765	1,131,721	825,825	654,555
Possible Reserves (Possible Reserves)	1,201,040	73,674	22,734	8,965	Possible Reserves (Possible Reserves)	875,734	54,492	17,273	7,194
Total 3P reserves (Proved + probable + possible reserves)	5,582,758	1,551,761	1,088,244	846,693	Total 3P reserves (Proved + probable + possible reserves)	4,117,500	1,186,213	843,098	661,748
20% increase in the price of gas					**20% decrease in the price of gas**				
Proved reserves 1P (Proved Reserves)	3,153,776	1,368,604	1,036,003	834,012	Proved reserves 1P (Proved Reserves)	2,125,421	961,794	737,141	598,060
Probable Reserves (Probable reserves)	1,417,098	165,419	67,410	32,040	Probable Reserves (Probable reserves)	928,540	112,495	48,501	25,364
Total 2P reserves (Proved+Probable Reserves)	4,570,874	1,534,023	1,103,413	866,053	Total 2P reserves (Proved+Probable Reserves)	3,053,962	1,074,288	785,642	623,424
Possible Reserves (Possible Reserves)	1,255,099	76,787	23,583	9,214	Possible Reserves (Possible Reserves)	821,746	51,482	16,526	7,040
Total 3P reserves (Proved + probable + possible reserves)	5,825,973	1,610,810	1,126,996	875,267	Total 3P reserves (Proved + probable + possible reserves)	3,875,707	1,125,770	802,168	630,464

[17] Sensitivity to changes in the volume of gas being sold. It should be emphasized that these analyses do not take into account changes in the future investment plan, in relation to both the increase or the decrease in volume.

Sensitivity/category	Total	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%	Sensitivity/category	Total	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%
10% increase in the quantity of gas sales					**10% decrease in the quantity of gas sales**				
Proved reserves 1P (Proved Reserves)	2,665,091	1,250,128	962,107	781,852	Proved reserves 1P (Proved Reserves)	2,388,546	1,058,738	807,894	654,131
Probable Reserves (Probable reserves)	1,134,893	152,154	64,509	31,376	Probable Reserves (Probable Reserves)	1,051,710	124,446	52,225	26,213
Total 2P reserves (Proved+Probable Reserves)	3,799,984	1,402,282	1,026,616	813,228	Total 2P reserves (Proved+Probable Reserves)	3,440,256	1,183,184	860,119	680,345
Possible Reserves (Possible Reserves)	1,001,357	74,139	24,237	9,748	Possible Reserves (Possible Reserves)	930,308	57,494	18,164	7,517
Total 3P reserves (Proved + probable + possible reserves)	4,801,341	1,476,421	1,050,854	822,976	Total 3P reserves (Proved + probable + possible reserves)	4,370,564	1,240,678	878,283	687,861

15% increase in the quantity of gas sales					**15% decrease in the quantity of gas sales**				
Proved reserves 1P (Proved Reserves)	2,649,703	1,283,430	994,251	810,771	Proved reserves 1P (Proved Reserves)	2,254,748	1,003,320	766,250	620,608
Probable Reserves (Probable reserves)	1,126,195	161,632	69,883	34,168	Probable Reserves (Probable Reserves)	991,281	118,196	50,160	25,627
Total 2P reserves (Proved+Probable Reserves)	3,775,898	1,445,062	1,064,134	844,939	Total 2P reserves (Proved+Probable Reserves)	3,246,029	1,121,517	816,410	646,235
Possible Reserves (Possible Reserves)	987,315	80,735	27,226	10,991	Possible Reserves (Possible Reserves)	875,870	54,184	17,172	7,161
Total 3P reserves (Proved + probable + possible reserves)	4,763,213	1,525,797	1,091,361	855,930	Total 3P reserves (Proved + probable + possible reserves)	4,121,899	1,175,701	833,582	653,396
20% increase in the quantity of gas sales					**20% decrease in the quantity of gas sales**				
Proved reserves 1P (Proved Reserves)	2,651,333	1,316,236	1,025,378	838,775	Proved reserves 1P (Proved Reserves)	2,120,484	947,213	723,892	586,377
Probable Reserves (Probable reserves)	1,103,205	169,480	75,009	37,098	Probable Reserves (Probable Reserves)	930,628	111,832	48,012	24,979
Total 2P reserves (Proved+Probable Reserves)	3,754,538	1,485,716	1,100,386	875,873	Total 2P reserves (Proved+Probable Reserves)	3,051,112	1,059,045	771,904	611,356
Possible Reserves (Possible Reserves)	974,106	87,672	30,544	12,444	Possible Reserves (Possible Reserves)	821,710	51,064	16,337	6,936
Total 3P reserves (Proved + probable + possible reserves)	4,728,643	1,573,387	1,130,930	888,317	Total 3P reserves (Proved + probable + possible reserves)	3,872,822	1,110,109	788,241	618,292

5. Sensitivity analysis of the main linkage components to the gas price based on the Tamar partners agreements for gas sales (US-CPI and Electricity Generation Price as at December 31, 2018 (USD thousands), performed by the Company: [18]:

Sensitivity/category	Total	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%
10% increase in the projected CPI				
Proved reserves 1P (Proved Reserves)	2,642,715	1,170,017	891,861	721,609
Probable Reserves (Probable reserves)	1,171,052	137,690	56,840	27,718
Total 2P reserves (Proved+Probable Reserves)	3,813,766	1,307,706	948,701	749,328
Possible Reserves (Possible Reserves)	1,038,863	64,332	20,188	8,218
Total 3P reserves (Proved + probable + possible reserves)	4,852,629	1,372,039	968,889	757,545
10% increase in the projected Electricity Generation Price				
Proved reserves 1P (Proved Reserves)	2,692,296	1,199,249	915,922	742,122
Probable Reserves (Probable reserves)	1,171,094	137,652	56,784	27,651
Total 2P reserves (Proved+Probable Reserves)	3,863,390	1,336,901	972,706	769,774
Possible Reserves (Possible Reserves)	1,038,863	64,332	20,188	8,218
Total 3P reserves (Proved + probable + possible reserves)	4,902,253	1,401,234	992,894	777,991

Sensitivity/category	Total	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%
10% decrease in the projected CPI				
Proved reserves 1P (Proved Reserves)	2,636,969	1,166,950	889,539	719,815
Probable Reserves (Probable Reserves)	1,171,042	137,689	56,842	27,721
Total 2P reserves (Proved+Probable Reserves)	3,808,011	1,304,639	946,381	747,536
Possible Reserves (Possible Reserves)	1,038,863	64,332	20,188	8,218
Total 3P reserves (Proved + probable + possible reserves)	4,846,874	1,368,971	966,569	755,754
10% decrease in the projected Electricity Generation Price				
Proved reserves 1P (Proved Reserves)	2,609,212	1,153,602	879,532	711,965
Probable Reserves (Probable Reserves)	1,171,035	137,712	56,871	27,753
Total 2P reserves (Proved+Probable Reserves)	3,780,247	1,291,314	936,403	739,718
Possible Reserves (Possible Reserves)	1,038,863	64,332	20,188	8,218
Total 3P reserves (Proved + probable + possible reserves)	4,819,109	1,355,646	956,591	747,936

[18] Although the Electricity Generation Price is affected, among other things, by the CPI, the sensitivity analysis in the table below does not take this into account.

6. Sensitivity analysis for sales of volumes exceeding the minimum volumes (take or pay) based on the Partnerships' gas sales agreements as at December 31, 2018 (USD thousand), as performed by the Company:

Sensitivity/category	**Total**	**Present value discounted at 10%**	**Present value discounted at 15%**	**Present value discounted at 20%**	Sensitivity/category	**Total**	**Present value discounted at 10%**	**Present value discounted at 15%**	**Present value discounted at 20%**
An increase in the sales quantity of gas for quantities that are beyond the take of pay, at 10%					**A decrease in the sales quantity of gas for quantities that are beyond the take of pay, at 10%**				
Proved reserves 1P (Proved Reserves)	2,695,470	1,220,766	933,637	756,328	Proved reserves 1P (Proved Reserves)	2,741,948	1,122,136	847,294	683,172
Probable Reserves (Probable reserves)	1,147,666	138,941	57,618	28,053	Probable Reserves (Probable Reserves)	1,182,570	133,801	55,444	27,367
Total 2P reserves (Proved+Probable Reserves)	3,843,135	1,359,707	991,255	784,382	Total 2P reserves (Proved+Probable Reserves)	3,924,518	1,255,936	902,738	710,539
Possible Reserves (Possible Reserves)	1,025,292	65,675	20,734	8,413	Possible Reserves (Possible Reserves)	1,050,630	61,269	19,124	7,855
Total 3P reserves (Proved + probable + possible reserves)	4,868,427	1,425,382	1,011,989	792,794	Total 3P reserves (Proved + probable + possible reserves)	4,975,148	1,317,205	921,862	718,394

7. Sensitivity analysis for the price adjustment as set out in the IEC contract as at December 31, 2018 (in thousands of dollars), as performed by the Company:

Sensitivity/category	**Total**	**Present value discounted at 10%**	**Present value discounted at 15%**	**Present value discounted at 20%**	**Sensitivity/category**	**Total**	**Present value discounted at 10%**	**Present value discounted at 15%**	**Present value discounted at 20%**
Reduced price at a rate of 0%					**Reduced price at a rate of 25%**				
Proved reserves 1P (Proved Reserves)	2,685,664	1,193,241	909,666	735,577	Proved reserves 1P (Proved Reserves)	2,595,324	1,144,328	872,162	706,161
Probable Reserves (Probable reserves)	1,171,087	137,667	56,805	27,675	Probable Reserves (Probable Reserves)	1,171,046	137,753	56,917	27,801
Total 2P reserves (Proved+Probable Reserves)	3,856,751	1,330,908	966,471	763,252	Total 2P reserves (Proved+Probable Reserves)	3,766,370	1,282,082	929,079	733,962
Possible Reserves (Possible Reserves)	1,038,863	64,332	20,188	8,218	Possible Reserves (Possible Reserves)	1,038,847	64,323	20,181	8,212
Total 3P reserves (Proved + probable + possible reserves)	4,895,614	1,395,241	986,659	771,469	Total 3P reserves (Proved + probable + possible reserves)	4,805,217	1,346,405	949,261	742,174

8. Reconciliation of the information in the Report and information in previous reports with regard to the volume of reserves attributed to the oil asset

The main differences between the current reserves report and the previous reserves report are due to the production of 364 BCF and 477 thousand barrels of condensate from the reservoir during 2018, as well as the mapping of the reservoir, which indicated an increase in the Tamar Project reserves, as follows:

Compared with the previous report, the volumes of the natural gas and condensate in the Tamar Lease increased in the proved reserves (1P) category by 3.5% (from 7.8 TCF and 10.2 million barrels of condensate in the Previous Reserves Report to 8.1 TCF and 10.5 million barrels of condensate in the current Reserves Report); in the Proved + Probable (2P) category by 0.7% (from 11 TCF and 14.4 million barrels of condensate in the Previous Reserves Report to 11.1 TCF and 14.5 million barrels of condensate in the current Reserves Report); in the Proved + Probable + Possible (3P) category by 3.7% (from 13.1 TCF and 17.1 million barrels of condensate in the Previous Reserves Report to 13.6 TCF and 17.7 million barrels of condensate in the current Reserves Report).

9. Production Information

Below is informaton regarding Tamar Project production relating to the Company in 2016-2018[19]:

Natural gas[20][21]				
		2016	**2017**	**2018**
Total output (attributable to equity holders of the Company) in the period (on MMcf)		58,280	54,926	
Average price per production unit (attributable to equity holders of the Company) (USD per MCF)[22]		5.2	5.34	
Average royalties (every payment derived from the output of the producing asset, including from the gross income from the oil asset) paid per production unit (attributable to equity	The State	0.6	0.6	
	Third parties	0.1	0.1	

19 It should be noted that as from the start of flow of natural gas from the Tamar Project (i.e. on March 30, 2013) through to December 31, 2018, a total volume of 50.5 BCM natural gas was supplied to customers (production figures for 2018 are based on unaudited financial information). It is further noted that the average per day production of natural gas in the past two years (January 1, 2017 through December 31, 2018) is 968 MMCF (0.968 BCF).

20 The rate attributable to the Company's equity holders in production, royalties paid, production costs and net intake is rounded up to two decimal points.

21 The output data for 2018 are based on unaudited financial data. Production figures are based on unaudited financial information and include, in addition to the Partnership's direct holdings of the Tamar Project, the Partnership's share in Tamar Petroleum's production data as at July 2017.

22 The average price of a production unit weighs the effective price of the Partnership, which includes the outline plan for the sale of natural gas from the Tamar Project to the Yam Tethys project, as set out in section 1.7.4(ד)(5 of the Periodic Report.

Natural gas[20][21]				
		2016	2017	2018
holders of the Company) (USD per MCF)	Interested parties	0.1	0.1	[23]
Average intake for royalties (all compensation arising from the output of the producing asset, including from the gross income from the oil asset) received per production unit (attributable to the Company's share) (USD per MCF and BBL)		0.2	0.2	
Average production costs per production unit (attributable to equity holders of the Company) (USD per MCF) [24]		0.4	0.37	
Average net intake per production unit (attributable to equity holders of the Company) (USD per MCF)		4.2	4.32	
Oil and gas profits levy		-	-	-
Average net intake per production unit after oil and gas profits tax (attributable to equity holders of the Company) (USD per MCF)		4.3	4.2	4.32
Depletion rate in the reporting period in relation to the overall quantity of gas in the project (%)[25]		2.8	3.2	3.44

Condensate[26] [27]				
		2016	2017	2018
Total output (attributable to equity holders of the Company) in the period (thousands of barrels)		79	73	
Average price per production unit (attributable to equity holders of the Company) (USD per barrel)		38.1	47.1	
Average royalties (every payment derived from the output of the producing asset, including from the gross income from the oil asset) paid per production unit (attributable to equity holders of the Company) (USD per barrel)	The State	4.2	5.3	
	Third parties	0.6	0.8	
	Interested parties	1	1.4	[28]
Average intake for royalties (all compensation arising from the output of the producing asset, including from the gross income from the oil asset) received per production unit (attributable to the Company's share) (USD per MCF and BBL)		1.3	2	

[23] For information concerning the royalty rate taken into account in 2018, see footnote 2 above.

[24] The figures include current production costs only and do not include reservoir exploration and development costs and tax payments to be paid in the future by the Partnership .

[25] The depletion rate is the rate of natural gas produced in the relevant reporting period from the balance of the proved and expected reserves at the beginning of the reporting period or at the date production started, whichever is later. The depletion rate is calculated at the end of the year and not during the year.

[26] The rate attributable to the Company's equity holders for production, royalties , production costs and net intake is rounded up to two decimal points.

27 The output data for 2018 are based on unaudited financial data. Production figures are based on unaudited financial information and include, in addition to the Partnership's direct holdings of the Tamar Project, the Partnership's share in Tamar Petroleum's production data as at July 2017.

[28] For information concerning the royalty rate taken into account in 2018, see footnote 2 above.

Condensate[26] [27]			
	2016	**2017**	**2018**
Average production costs per production unit (attributable to equity holders of the Company) (USD per barrel)[29]	2.1	2.1	
Average net intake per production unit (attributable to equity holders of the Company) (USD per barrel)	31.5	39.5	
Oil and gas profits levy	-	-	
Average net intake per production unit after oil and gas profits tax (attributable to equity holders of the Company) (USD per barrel)	31.5	39.5	
Depletion rate in the reporting period in relation to the overall quantity of condensate in the project (%)[30]	3.3	3.5	

The Company declares that all of the above information has been prepared in compliance with the Petroleum Resources Management System (SPE-PRMS).

10. Expert opinion of the assessor:

Attached to this report by way of reference to Appendix A of the Partnership's immediate report of February 19, 2019 (Ref. No.: 2019-01-015717), is the reserves report of the Tamar Project (which includes the Tamar and Tamar SW reservoirs), prepared by NSAI as at December 31, 2018. Attached as A**ppendix A** to this report is NSAI's consent to include it in the report.

11. Glossary

Lease – as defined in the Petroleum Law, 1952 ("the Petroleum Law").

Reservoir – A layer or layers of rock characterized by porosity and relatively high permeability, enabling acceptance and flow of liquids and gas. Sometimes also used to describe an oil and/or gas field.

Petroleum Resources Management System (2007) - (SPE-PRMS) – a system for reporting assessments of oil reserves and resources, as published by the Society of Petroleum Engineers, the American Association of Petroleum Geologists (AAPG), the World Petroleum Council (WPC) and the Society of Petroleum Evaluation Engineers (SPEE) and as revised from time to time

Oil asset – the lease, direct or indirect, in a preliminary permit, license or lease; in another country – the lease, direct or indirect, in a similar right granted by a competent party. The oil asset is also regarded as the right to receive benefits arising from the lease, direct or indirect, in the oil asset or in a similar right (as the case may be).

Oil – any petroleum fluid, whether liquid or gaseous and includes oil, natural gas, natural

[29] The figures include current production costs only and do not include reservoir exploration and development costs and tax payments to be paid in the future by the Partnership .

[30] The quantity of condensate produced from the Tamar project is derived directly from the quantity of natural gas produced from the project.

gasoline, condensates and (carbons) hydrocarbons and also asphalt and other solid petroleum hydrocarbons when dissolved in and producible with fluid petroleum

Reserves – defined under the Petroleum Resources Management System (SPE-PRMS) as the volumes of oil estimated to be recoverable by executing a development plan for discovered deposits from a certain date onwards, under defined conditions. Reserves are required to meet four conditions: (1) they must be discoverable; (2) recoverable; (3) commercially viable; (4) sustainable, based on the executed development project.

Condensate – gaseous hydrocarbons found in the reservoir conditions, but which liquefy when transmitted from the reservoir to the surface.

License – as defined in the Petroleum Law

BCF – billions of cubic feet, which is 0.001 TCF or 0.0283 BCM

BCM – billion cubic meters

MMCF – millions of cubic feet, which is 0.001 BCF or 0.0003 BCM

Conversion table for units used in the report:

MMCF	BCF	BCM
35310.7	35.3107	1
BCM	**MMCF**	**BCF**
0.0283	1000	1
BCM	**BCF**	**MMCF**
0.00003	0.001	1

<u>Partners in the Tamar Project and the rate of their holdings are as follows:</u>

Noble Energy Mediterranean Ltd.	25.00%
Isramco Negev 2 Limited Partnership	28.75%
Delek Drilling Limited Partnership	22.00%
Tamar Petroleum Ltd	16.75%
Dor Gas Exploration Limited Partnership	4.00%
Everest Infrastructures Limited Partnership	3.50%

Sincerely,

Delek Group Ltd.

Gabriel Last, Chairman of the board of directors

Asi Bartfeld, CEO