Delek Drilling - Limited Partnership
(the "Partnership")

February 19, 2019

Israel Securities Authority
22 Kanfei Nesharim St.
Jerusalem

Tel Aviv Stock Exchange Ltd.
2 Ahuzat Bayit St.
Tel Aviv

Dear Sir/Madam,

Re: **Updated Discounted Cash Flow Figures and Reserve Report in the Tamar Lease**

Further to Section 7.3.9 of the Partnership's periodic report as of December 31, 2017, as released on March 21, 2018 (Ref.: 2018-01-022209) (the "**Periodic Report**"), regarding the evaluation of the reserves in the Tamar project, which includes the Tamar reservoir and the Tamar South-West reservoir ("**Tamar SW**"), in the area of the I/12 Tamar lease (the "**Tamar Project**" and the "**Tamar Lease**", respectively), the Partnership respectfully submits the following updated discounted cash flow figures and reserve report:

a) Quantity Data

According to a report received by the Partnership from Netherland, Sewell & Associates, Inc. ("**NSAI**" or the "**Evaluator**"), which was prepared according to the rules of the Petroleum Resources Management System (SPE-PRMS), as of December 31, 2018 (the "**Reserve Report**"), the condensate and natural gas reserves in the Tamar Project (which includes, as aforesaid, the Tamar reservoir and the Tamar SW reservoir), which are classified as reserves on production, are as specified below[1]:

[1] To the best of the Partnership's knowledge, the Ministry of Energy conducted an independent estimate of the scope of the reserves in the Tamar Project, using outside consultants, *inter alia* for the purpose of calculating the export caps from the Tamar Project, in accordance with the Government Resolution, as specified in Section 7.23.5(a) of the Periodic Report. To the best of the Partnership's knowledge, there is no material difference between the estimate of the Ministry of Energy and the estimate of the reserves published in the Periodic Report (the "**Previous Reserve Report**").

Reserve Category	Total (100%) in the Petroleum Asset (Gross)						Total (Tamar and Tamar SW Reservoirs) Share Attributed to the Holders of the Equity Interests of the Partnership (Net)[2]	
	Tamar Reservoir		Tamar SW Reservoir		Total (Tamar and Tamar SW Reservoirs)			
	Natural Gas BCF	Condensate Million Barrels	Natural Gas BCF	Condensate Million Barrels	Natural Gas BCF	Condensate Million Barrels	In Natural Gas BCF	In Condensate Million Barrels
1P (Proved) Reserves	7,312.4	9.5	796.4	1.0	8,108.9	10.5	1,622.1	2.1
Probable Reserves	2,871.0	3.7	159.1	0.2	3,030.1	3.9	606.2	0.8
Total 2P (Proved+Probable) Reserves	10,183.4	13.2	955.6	1.2	11,139.0	14.5	2,228.3	2.9
Possible Reserves	2,366.0	3.1	102.2	0.1	2,468.3	3.2	493.7	0.6
Total 3P (Proved+Probable+Possible) Reserves	12,549.5	16.3	1,057.8	1.4	13,607.3	17.7	2,722.0	3.5

Warning – possible reserves are the additional reserves which are not expected to be extracted to the same extent as the probable reserves. There is a 10% chance that the quantities that will actually be extracted will be equal to or higher than the quantity of proved reserves, plus the quantity of probable reserves plus the quantity of possible reserves.

[2] The Reserve Report does not state the Partnership's net share but rather the Partnership's gross share. The Partnership's share in the above table is after payment of royalties to the State, to related parties and to third parties. The royalty rate for Delek Group Ltd. and for Delek Royalties (2012) Ltd., which was taken into account in the above figures, is 6.5% (at the wellhead), i.e. the royalty rate after the investment recovery date. The rate attributed to the holders of equity interests of the Partnership was calculated according to the Partnership's holdings in the Tamar Project (directly and indirectly) as of December 31, 2018, assuming that the royalty rate to the State is 12.5% (at the wellhead). For further details with respect to the investment recovery date, see the Partnership's immediate reports of September 5, 2018, November 29, 2018, January 7, 2019 and January 23, 2019 (Ref.: 2018-01-082531, 2018-01-110416, 2019-01-002272 and 2019-01-007177, respectively).

b) In the Reserve Report, NSAI stated, *inter alia*, several assumptions and reservations, including that: (a) The estimates, as customary in reserve appraisals according to the guidelines of the SPE-PRMS, are not adjusted to the risks; (b) NSAI did not visit the oil field, and did not check the mechanical operation of the facilities and the wells or the condition thereof; (c) NSAI did not examine possible exposure deriving from environmental matters. However, NSAI stated that as of the date of the Reserve Report, it is not aware of any potential liability regarding environmental matters which could materially affect the quantity of the reserves estimated in the Reserve Report or the commerciality thereof, and therefore did not include in the Reserve Report costs which may derive from such liability; (d) NSAI assumed that the reservoirs will be developed in accordance with the existing development plans[3], will be reasonably operated, that no regulation will be determined that will affect the ability of the holder of the petroleum rights to produce the reserves, and that its forecasts regarding future production will be similar to the functioning of the reservoirs in practice.

Warning regarding forward-looking information – NSAI's estimates regarding the quantities of condensate and natural gas reserves in the Tamar and Tamar SW reservoirs are forward-looking information, within the meaning thereof in the Securities Law, 5728-1968 (the "Securities Law"). The above estimates are based, *inter alia*, on geological, geophysical, engineering and other information received from the wells and from the operator in the Tamar Project, and constitute estimates and conjectures only of NSAI, and in respect of which there is no certainty. The natural gas and/or condensate quantities that shall actually be extracted may be different to the said estimates and conjectures, *inter alia* as a result of operating and technical conditions and/or regulatory changes and/or supply and demand conditions in the natural gas and/or condensate market and/or commercial conditions and/or as a result of the actual performance of the reservoirs. The said estimates and conjectures may be revised insofar as additional information shall accumulate and/or as a result of a gamut of factors relating to projects of oil and natural gas exploration and production, including as a result of the continued production from the Tamar Project.

c) Discounted cash flow figures

With respect to the calculation of the discounted cash flow specified below, it is noted as follows: (a) The discounted cash flow was calculated, *inter alia,* based on a weighted average of the gas prices stated in the present gas sale agreements, which are based on different price formulas, which include, *inter alia*, linkage to the U.S. CPI, the Brent barrel price or the electricity production tariff[4]. It is noted that the prices may change, *inter alia*, due to a price adjustment according to the mechanism determined in the agreement with the Israel Electric Corp. Ltd. (the "**IEC**")[5], and changes in the indices

[3] With respect to the future development plan of the Tamar field, see Section (c)(2) below.
[4] The weighted electricity production tariff (the "**Electricity Production Tariff**") is a tariff that is supervised by the Electricity Authority, and reflects the costs of the IEC's electricity production component, including the cost of the fuels of the IEC, the capital and operating costs that are attributed to the production component and the cost of purchasing electricity from private electricity producers.
[5] The agreement with the IEC determines two dates on which each party is entitled to request a price adjustment (according to the mechanism determined in the agreement), if such party is of the opinion that the price determined in the contract is no longer appropriate for a long-term contract with an anchor buyer for the consumption of natural gas for use in the Israeli market:

which are the linkage bases in the gas supply agreements[6]. It is clarified that since, as the date of release of this report, it is not possible to estimate the scope of the price adjustment that will be made (if any) on the first adjustment date (i.e. on July 1, 2021), as determined in the agreement with the IEC (the "**First Adjustment Date**"), it was assumed that a reduction will be made of 50% of the maximum adjustment rate, i.e. a reduction of 12.5%. It is noted that in the discounted cash flow, it was assumed that no change will occur in the price on the second adjustment date (i.e. on July 1, 2024). For details regarding changes in the discounted cash flow as a result of a change in price, including as a result of a change in the price adjustment rate as aforesaid, see the sensitivity tables in Sections (d) and (g) below. It is clarified that the said sensitivity analyses were made based on the price reduction assumption as aforesaid. It is further noted that a change in price as a result of the class action certification motion filed by a consumer of the IEC against the partners in the Tamar Project, as specified in Section 7.26.1 of the Periodic Report and in Section 15(a) of the update to Chapter A (Description of the Partnership's Business), which was included in the Partnership's periodic report as of September 30, 2018, as published on November 21, 2018 (Ref.: 2018-01-105874), was not taken into account. The Partnership's legal advisors estimate that chances of the certification motion being granted are lower than 50%. As aforesaid, at this time, the parties are at the stage of the hearing of the class action certification motion. Insofar as a final and non-appealable decision is issued in the context of grant of the said class action (i.e. after the motion for class action certification is granted (if granted) and a non-appealable decision is issued on the class action on the merits thereof (if issued)), this may have an adverse effect on the Partnership's business, including on the discounted cash flow figures and on the prices at which the Partnership, together with the other Tamar partners, shall sell natural gas to its customers, the extent of which will derive from the outcome of the action. The figures regarding the gas prices as aforesaid were provided to NSAI by the Partnership[7]; (b) The demand forecast for the domestic market in Israel, which was used in order to estimate the projected future volume of natural gas sales in the domestic market in Israel, was prepared by an outside consultant, BDO Consulting Group; (c) The discounted cash flow was calculated based on the condensate price which is based on the Brent Crude prices. For the purpose of calculation of the Brent price, use was made of the average of oil price forecasts by third parties that provide long-term price forecasts, including the World Bank and others, for the price of NYMEX ICE Brent Crude and adjusted to quality differences, transportation costs and the price at which condensate is sold in the region; (d) The operating costs that were taken into account are costs that were provided to NSAI by the Partnership. These costs include direct costs at the project level, insurance costs, production well maintenance costs and the estimated G&A and overhead expenses of

---

8 years and 11 years after the date of commercial operation (as defined in the agreement, which occurred on July 1, 2013) from the Tamar Project (i.e.: July 1, 2021 and July 1, 2024, respectively). On the First Adjustment Date (July 1, 2021 – after 8 years) the adjustment that shall be made to the price will be within a range of up to 25% (up or down), and on the second adjustment date (July 1, 2024 – after 11 years) the adjustment that shall be made to the price will be within a range of up to 10% (up or down).

[6] The discounted cash flow was calculated based on the contractual price to be applied from January to the First Adjustment Date, in accordance with the amendment to the IEC agreement (if and to the extent it is signed), as specified in the Partnership's immediate report of February 17, 2019 (Ref.: 2019-01-014973).

[7] For the purpose of calculation of the price forecast, use was made of assumptions that are based on figures that were received from a consulting firm which are based on a weighting of figures of several public and private bodies: (1) annual increase of the U.S. CPI at an average rate of approx. 2% per annum; (2) Brent barrel price of approx. $67 per barrel in 2019, increasing to approx. $80 per barrel in 2024 and to approx. $92 per barrel in 2029, and a gradual rise at an average rate of approx. 2.9% per annum thereafter; (3) an electricity production tariff forecast which is based, *inter alia*, on an ILS-$ exchange rate forecast and on a fuel cost forecast that is based on the price of gas for the IEC.

the operator, which may be directly attributed to the project and together represent the costs of operation of the project. Such costs are divided into expenses at the field level and expenses per output unit. The operating costs provided to NSAI by the Partnership are deemed reasonable thereby, based *inter alia* on NSAI's additional knowledge from similar projects. These costs are not adjusted to inflation changes; (e) The amount of the capital expenditure taken into account for the purpose of preparation of the discounted cash flow exceeds the costs approved by the Partnership, and also includes the estimated costs of future expenses that shall be incurred in the course of production for the purpose of preserving and expanding the production capacity. The capital expenditures taken into account are capital expenditures that may be required, the drilling, development and connection of new wells, the placement of additional infrastructures and production equipment. The capital expenditure provided to NSAI are deemed reasonable thereby, based *inter alia* on development plans for the Tamar Project and on additional knowledge that NSAI has from similar projects, and are not adjusted to inflation changes; (f) Abandonment costs that were taken into account are costs that were provided to NSAI by the Partnership in accordance with its estimates with respect to the cost of abandonment of the wells, the platform and the production facilities. These costs do not take into account the salvage value of the Tamar Lease and the facilities in the Tamar Project and are not adjusted to inflation changes; (g) The tax calculations took into account corporate tax rates pursuant to law. The tax payments and the rate thereof included in the discounted cash flow were calculated from the perspective of the holder of the participation units of the Partnership, which is a company that holds the participation units of the Partnership from the date of commencement of the project. It is noted that the tax payments that shall actually be made in the future by the Partnership on account of the holders of the participation units of the Partnership in each one of the relevant tax years, pursuant to the provisions of the Taxation of Profits from Natural Resources Law, 5771-2011 (in this section: the "**Law**"), may be materially different; (h) The actual rate of production for each one of the reserve categories specified above may be lower or higher than the rate of production that was used for the purpose of estimating the discounted cash flow. In addition, NSAI did not carry out a sensitivity analysis in relation to the production rate of the wells; (i) The discounted cash flow assumes projected sale quantities in each of the project years based on the production capacity of the reservoirs[8] and a forecast in respect of the scope of supply and demand in the domestic market and in the export markets in each of the project years; (j) The calculation of the discounted cash flow assumes revenues from the export of gas to the local markets in Egypt and in Jordan in a total aggregate amount of approx. 42 BCM, until 2040, *inter alia* based on the Partnership's forecasts as to the performance of the agreements for export to Egypt and Jordan specified in Sections 7.11.5(a) of the Periodic Report[9]. Furthermore, it assumes a capital payment by the Tamar partners in respect of the piping of natural gas through the EMG pipeline (see the Partnership's immediate report of September 27, 2018 (Ref.: 2018-01-086332) (the "**Immediate Report of September 27, 2018**"). The price under the agreement for export from the Tamar Project to Dolphinus (for details, see Section 7.11.5(a)(2) of the Periodic Report (the

[8] The current gas supply capacity from the Tamar Project (which includes the Tamar Project's facilities, the compressors systems and the transmission and processing systems of the Yam Tethys project which were upgraded and adapted for use in the Tamar Project) to INGL's transmission system, is approx. 1.1 BCF per day at maximum production.

[9] It is noted that over the course of 2018, the Tamar partners produced and sold a quantity of approx. 10.3 BCM of natural gas to the domestic market and for export as well as approx. 477 thousand barrels of condensate. In addition, the Yam Tethys partners sold a quantity of approx. 0.19 BCM of natural gas of which a quantity of approx. 0.06 BCM of natural gas was sold to customers of the Tamar Project.

"**Dolphinus Agreement**")) was adjusted to the point of delivery, as set forth in the agreement; (k) The calculation of the discounted cash flow takes into account the Partnership's estimate with respect to the actual rate of royalties to the State, related parties and third parties which shall be paid by the Partnership to the State, at the rate of 11.5% and approx. 9.13%, respectively. As of the date of release of this report, the Tamar partners are in discussions with the Ministry of Energy with respect to the manner of calculation of the actual rate of the royalties that shall be paid by the Partnership to the State. Therefore, the actual rate of the said royalties is not final and may change, and there is no certainty that the Partnership will succeed in the negotiations for the determination of a lower rate of royalties in the future. For further details on the matter, see Section 7.25.12(c)(2) of the Periodic Report; (l) The calculation of the discounted cash flow takes into account the petroleum profit levy applicable to the Partnership pursuant to the provisions of the Law. It should be emphasized that the levy calculations were made according to the definitions, the formulas and the mechanisms defined in the Law as understood and interpreted by the Partnership, which are reflected in the reports of the Tamar venture to the Tax Authority. However, in view of the novelty of the Law and the complexity of the calculation formulas and the various mechanisms defined therein, there is no assurance that this interpretation of the manner of calculation of the levy will be the same as that which shall be adopted by the tax authorities and/or the same as the interpretation of the Law by the court. It is noted that, as of the date of release of this report, several interpretive disagreements are being clarified with respect to the implementation of the Law in the reports of the Tamar venture to the Tax Authority, in the framework of the objection and appeal proceedings prescribed by the law. The issues to which the disagreements pertain have not yet been addressed in the case law of the Israeli courts. The levy calculations were made according to the transitional provisions set forth in the Law with respect to a venture, the date of commencement of commercial production of which occurred from the date of commencement of the Law until January 1, 2014, and based on the following assumptions: the venture will choose to report in dollars pursuant to Section 13(b) of the Law, all of the venture's payments (the production costs, the investments, the royalties, etc.) shall be recognized by the tax authorities for the purpose of the levy calculation, and the calculation of the venture's income shall take into account the actual sale prices of the gas; (m) The calculation of the discounted cash flow took into account expenses and investments actually paid and which are expected to be paid by the Partnership as of January 1, 2019 and revenues deriving from sales of natural gas and condensate produced as of January 1, 2019. It is clarified that revenues received in 2019 in respect of sales of natural gas and condensate produced in 2018 were not included in the discounted cash flow.

<u>It is noted that the discounted cash flow was revised in relation to the discounted cash flow as of December 31, 2017 (the "**Previous Discounted Cash Flow**") primarily for the following reasons[10]</u>:

[10] It is noted that the Partnership's total holdings in the Tamar Project (directly and indirectly through Tamar Petroleum Ltd. ("**Tamar Petroleum**")) amount to 25.7855% (compared with a rate of 25.7% in the Previous Discounted Cash Flow).

1. In view of the update of the electricity production tariff forecasts, the U.S. CPI and the Brent barrel price, the forecasts of the relevant sale prices (natural gas and condensate) that are linked thereto have been revised.

2. In view of the update of the venture's expenditure forecast, including the update of the venture's capital expenditure forecast, which chiefly derives from the update of the forecast for the future development plan of the Tamar field, including changes in the dates of drilling of future wells and a change in the cost estimates in respect thereof, along with the addition of a third flowline from the Tamar field to the Tamar platform, the investments in respect of which are expected to be made between the years 2024-2026, with an estimated budget of approx. $370 million (in 100% terms) that is not adjusted to inflation changes, which will allow the gas supply capacity of the Tamar Project to increase to approx. 1.2 BCF per day (approx. 12 BCM per annum), at maximum production. It is noted that such third flowline, construction and placement of which are yet to receive final approval from the Tamar partners, will, subject to associated investments, allow for further expansions of the gas supply capacity of the Tamar Project even beyond a maximum production of 12 BCM per annum.

3. In view of the update of the blend of domestic market and export in the forecast of quantities to be sold, and in view of the possible addition of a third flowline as specified in Section 2 above and in view of the EMG transaction (see the Immediate Report of September 27, 2018), which increases the certainty of performance of the Dolphinus Agreement, the projected quantities for sale were revised as of 2027.

4. For changes that occurred in relation to the quantity of reserves attributed to the petroleum asset, see Section (h) below.

In accordance with various assumptions, the principal among which assumptions are specified above, the following table shows the estimated discounted cash flow as of December 31, 2018 in dollars in thousands (after levy and income tax), attributed to the Partnership's share (directly and indirectly, through its holding in Tamar Petroleum), from the reserves in the Tamar Project, for each one of the reserve categories specified above:

Total discounted cash flow from proved reserves as of December 31, 2018 (in dollars in thousands in relation to the Partnership's share)																	
Cash flow components																	
Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Develop-ment costs	Abandon-ment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Taxes		Total discounted cash flow after tax					
										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	543,380	108,842	-	44,046	31,018	-	359,474	-	60,543	298,931	291,727	288,315	285,020	278,755	272,886
31.12.2020	489	10.65	528,307	105,823	-	40,848	63,546	-	318,091	11,141	71,510	235,440	218,825	211,236	204,076	190,912	179,105
31.12.2021	475	10.34	521,631	104,486	-	39,959	208	-	376,977	102,351	47,938	226,688	200,658	189,194	178,627	159,840	143,706
31.12.2022	489	10.65	540,522	108,270	-	40,056	74,704	-	317,492	112,337	49,579	155,577	131,155	120,786	111,448	95,390	82,189
31.12.2023	489	10.65	546,903	109,548	-	40,056	69,796	-	327,503	136,019	47,927	143,557	115,259	103,678	93,489	76,539	63,199
31.12.2024	490	10.67	552,028	110,575	-	40,056	-	-	401,398	186,497	36,432	178,470	136,466	119,900	105,659	82,742	65,474
31.12.2025	489	10.65	553,775	110,925	-	40,056	-	-	402,795	188,508	36,296	177,991	129,619	111,235	95,796	71,757	54,415
31.12.2026	489	10.65	559,641	112,099	-	40,056	-	-	407,486	190,703	37,412	179,371	124,403	104,277	87,762	62,881	45,697
31.12.2027	534	11.64	624,461	125,083	-	40,056	-	-	459,322	214,963	45,143	199,216	131,588	107,734	88,611	60,729	42,294
31.12.2028	536	11.67	631,608	126,515	-	40,056	-	-	465,038	217,638	48,533	198,867	125,102	100,042	80,414	52,715	35,184
31.12.2029	534	11.64	635,059	127,206	-	40,056	-	-	467,797	218,929	49,078	199,790	119,698	93,494	73,443	46,052	29,456
31.12.2030	534	11.64	649,909	130,181	-	40,056	-	-	479,673	224,487	51,233	203,953	116,373	88,783	68,158	40,879	25,058
31.12.2031	534	11.64	668,438	133,892	-	40,056	-	-	494,490	231,422	54,942	208,127	113,100	84,279	63,229	36,275	21,309
31.12.2032	536	11.67	692,393	138,690	-	40,056	-	-	513,647	240,387	57,285	215,975	111,776	81,356	59,649	32,733	18,427
31.12.2033	534	11.64	712,656	142,749	-	40,056	52,087	-	477,765	223,594	65,962	188,208	92,767	65,950	47,255	24,804	13,382

31.12.2034	519	11.30	703,289	140,873	-	40,056	-	-	522,360	244,465	60,507	217,389	102,048	70,861	49,619	24,913	12,880
31.12.2035	419	9.12	576,059	115,388	-	40,056	-	-	420,615	196,848	48,484	175,283	78,364	53,150	36,371	17,467	8,655
31.12.2036	285	6.22	398,227	79,767	-	40,056	-	-	278,404	130,293	31,651	116,460	49,587	32,850	21,969	10,092	4,792
31.12.2037	285	6.20	402,450	80,613	-	40,056	-	-	281,782	131,874	32,067	117,841	47,785	30,920	20,208	8,879	4,041
31.12.2038	279	6.08	399,767	80,076	-	40,056	-	-	279,636	130,870	31,829	116,938	45,161	28,542	18,230	7,662	3,341
31.12.2039	270	5.87	390,468	78,213	-	40,056	-	-	272,200	127,389	30,959	113,851	41,875	25,850	16,136	6,487	2,711
31.12.2040	253	5.52	370,847	74,283	-	40,056	-	-	256,508	120,046	29,109	107,354	37,605	22,674	13,832	5,319	2,130
31.12.2041	174	3.79	258,160	51,711	-	40,056	-	-	166,394	77,872	18,419	70,102	23,387	13,773	8,211	3,020	1,159
31.12.2042	143	3.12	215,082	43,082	-	40,056	-	-	131,944	61,750	12,635	57,559	18,288	10,520	6,129	2,156	793
31.12.2043	98	2.12	148,014	29,648	-	40,056	-	-	78,310	36,649	6,268	35,393	10,710	6,017	3,426	1,153	406
31.12.2044	78	1.70	119,850	24,007	-	40,056	-	16,412	39,375	18,428	6,560	14,388	4,146	2,275	1,266	408	138
31.12.2045	65	1.42	101,088	20,248	-	40,056	-	16,412	24,372	11,406	4,780	8,186	2,247	1,204	655	202	65
31.12.2046	33	0.71	51,462	10,308	-	40,056	-	16,412	(15,314)	(7,167)	61	(8,208)	(2,146)	(1,123)	(597)	(176)	(55)
31.12.2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

[11] An additional cap rate of 7.5% was applied by the Partnership for calculating purposes and for the benefit of investors.

31.12.2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2057	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**10,542**	**230**	**13,095,475**	**2,623,103**	**-**	**1,126,242**	**291,359**	**49,236**	**9,005,535**	**3,779,697**	**1,073,141**	**4,152,697**	**2,617,571**	**2,167,774**	**1,838,089**	**1,400,583**	**1,132,838**

Total discounted cash flow from probable reserves as of December 31, 2018 (in dollars in thousands in relation to the Partnership's share)																	
Cash flow components																	
										Taxes		Total discounted cash flow after tax					
Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Develop-ment costs[12]	Abandon-ment 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	-	-	-	-	-	-	(75,526)	-	75,526	30,812	(7,087)	51,801	43,669	40,217	37,107	31,761	27,365
31.12.2023	-	-	-	-	-	-	(69,796)	-	69,796	38,528	(7,779)	39,047	31,350	28,200	25,429	20,819	17,190
31.12.2024	-	-	-	-	-	-	75,526	-	(75,526)	(33,988)	11,098	(52,635)	(40,247)	(35,361)	(31,161)	(24,403)	(19,310)
31.12.2025	-	-	-	-	-	-	26,043	-	(26,043)	(12,188)	4,940	(18,795)	(13,687)	(11,746)	(10,116)	(7,577)	(5,746)
31.12.2026	-	-	-	-	-	-	43,753	-	(43,753)	(20,476)	6,840	(30,117)	(20,888)	(17,508)	(14,735)	(10,558)	(7,673)
31.12.2027	-	-	-	-	-	-	-	-	-	-	(62)	62	41	33	28	19	13
31.12.2028	-	-	-	-	-	-	-	-	-	-	(62)	62	39	31	25	16	11
31.12.2029	-	-	-	-	-	-	-	-	-	-	(62)	62	37	29	23	14	9
31.12.2030	-	-	-	-	-	-	-	-	-	-	(62)	62	35	27	21	12	8
31.12.2031	-	-	-	-	-	-	-	-	-	-	(62)	62	34	25	19	11	6
31.12.2032	-	-	-	-	-	-	-	-	-	-	(62)	62	32	23	17	9	5
31.12.2033	-	-	-	-	-	-	(52,087)	-	52,087	24,377	(6,751)	34,461	16,986	12,075	8,652	4,542	2,450

31.12.2034	16	0.34	21,367	4,280	-	-	-	-	17,087	7,997	(54)	9,144	4,292	2,981	2,087	1,048	542
31.12.2035	116	2.53	159,583	31,965	-	-	52,087	-	75,531	35,348	20,815	19,368	8,659	5,873	4,019	1,930	956
31.12.2036	250	5.46	349,352	69,977	-	-	-	-	279,375	130,748	31,399	117,229	49,914	33,066	22,114	10,158	4,823
31.12.2037	250	5.44	353,097	70,727	-	-	-	-	282,370	132,149	34,551	115,670	46,905	30,350	19,836	8,716	3,966
31.12.2038	255	5.56	365,897	73,291	-	-	-	-	292,605	136,939	35,803	119,863	46,291	29,256	18,686	7,854	3,425
31.12.2039	265	5.77	383,588	76,835	-	-	49,482	-	257,271	120,403	42,861	94,007	34,577	21,345	13,323	5,356	2,238
31.12.2040	283	6.16	413,777	82,882	-	-	-	-	330,895	154,859	39,350	136,686	47,880	28,870	17,611	6,772	2,712
31.12.2041	348	7.59	516,282	103,414	-	-	-	-	412,868	193,222	49,380	170,265	56,802	33,453	19,943	7,335	2,815
31.12.2042	304	6.61	455,481	91,236	-	-	-	-	364,246	170,467	45,131	148,648	47,229	27,168	15,828	5,569	2,048
31.12.2043	336	7.31	509,333	102,022	-	-	-	-	407,310	190,621	50,401	166,289	50,318	28,272	16,097	5,417	1,910
31.12.2044	341	7.43	524,124	104,985	-	-	-	(16,412)	435,551	203,838	48,883	182,830	52,689	28,916	16,089	5,179	1,750
31.12.2045	246	5.35	382,301	76,577	-	-	-	(16,412)	322,136	150,760	35,006	136,371	37,429	20,063	10,910	3,359	1,087
31.12.2046	244	5.32	384,201	76,958	-	-	-	(16,412)	323,655	151,471	34,690	137,495	35,940	18,817	10,000	2,945	914
31.12.2047	273	5.94	434,419	87,017	-	40,056	-	-	307,347	143,838	34,769	128,740	32,049	16,390	8,512	2,398	713
31.12.2048	218	4.75	351,877	70,483	-	40,056	-	17,524	223,814	104,745	28,578	90,491	21,455	10,717	5,439	1,466	418
31.12.2049	130	2.83	212,171	42,499	-	40,056	-	17,524	112,092	52,459	14,908	44,725	10,099	4,927	2,444	630	172

[12] Since the degree of certainty required for production of the probable reserves (50%) is lower than the degree of certainty required for the production of the proved reserves (90%), the date of performance of the capital investments required for production of the probable reserves was postponed relative to the date of performance of the capital investments required for production of the proved reserves, in accordance with the production profile. Thus, development costs which are stated as negative in certain years in the table of discounted cash flow figures from probable reserves, are stated as positive in later years in the same table, relative to the development costs in the table of discounted cash flow figures from proved reserves. For details regarding the total capital investments required, see the table of discounted cash flow figures from 2P (proved (1P) + probable) reserves.

[13] See Footnote 11 above.

31.12.2050	64	1.40	106,468	21,326	-	40,056	-	17,524	27,562	12,899	5,703	8,960	1,927	918	445	110	29
31.12.2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2057	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**3,939**	**86**	**5,923,318**	**1,186,476**	**-**	**160,222**	**49,482**	**3,335**	**4,523,802**	**2,119,826**	**553,063**	**1,850,913**	**601,855**	**357,426**	**218,691**	**90,907**	**44,848**

Total discounted cash flow from 2P (proved + probable) reserves as of December 31, 2018 (in dollars in thousands in relation to the Partnership's share)

Cash flow components

Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Develop-ment costs	Abandonment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Taxes		Total discounted cash flow after tax					
										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	543,380	108,842	-	44,046	31,018	-	359,474	-	60,543	298,931	291,727	288,315	285,020	278,755	272,886
31.12.2020	489	10.65	528,307	105,823	-	40,848	63,546	-	318,091	11,141	71,510	235,440	218,825	211,236	204,076	190,912	179,105
31.12.2021	475	10.34	521,631	104,486	-	39,959	208	-	376,977	102,351	47,938	226,688	200,658	189,194	178,627	159,840	143,706
31.12.2022	489	10.65	540,522	108,270	-	40,056	(821)	-	393,018	143,149	42,492	207,378	174,823	161,002	148,555	127,151	109,554
31.12.2023	489	10.65	546,903	109,548	-	40,056	-	-	397,300	174,547	40,147	182,605	146,609	131,879	118,917	97,358	80,389
31.12.2024	490	10.67	552,028	110,575	-	40,056	75,526	-	325,872	152,508	47,530	125,834	96,218	84,538	74,497	58,339	46,164
31.12.2025	489	10.65	553,775	110,925	-	40,056	26,043	-	376,752	176,320	41,236	159,196	115,932	99,489	85,680	64,179	48,669
31.12.2026	489	10.65	559,641	112,099	-	40,056	43,753	-	363,733	170,227	44,252	149,254	103,516	86,769	73,027	52,323	38,025
31.12.2027	534	11.64	624,461	125,083	-	40,056	-	-	459,322	214,963	45,081	199,278	131,629	107,767	88,638	60,747	42,308
31.12.2028	536	11.67	631,608	126,515	-	40,056	-	-	465,038	217,638	48,472	198,928	125,141	100,073	80,439	52,731	35,195
31.12.2029	534	11.64	635,059	127,206	-	40,056	-	-	467,797	218,929	49,016	199,852	119,735	93,523	73,466	46,066	29,465
31.12.2030	534	11.64	649,909	130,181	-	40,056	-	-	479,673	224,487	51,171	204,015	116,408	88,810	68,178	40,892	25,066
31.12.2031	534	11.64	668,438	133,892	-	40,056	-	-	494,490	231,422	54,880	208,188	113,133	84,305	63,248	36,286	21,315
31.12.2032	536	11.67	692,393	138,690	-	40,056	-	-	513,647	240,387	57,223	216,037	111,808	81,379	59,666	32,742	18,432

31.12.2033	534	11.64	712,656	142,749	-	40,056	-	-	529,851	247,970	59,212	222,669	109,753	78,026	55,907	29,346	15,832
31.12.2034	534	11.64	724,656	145,153	-	40,056	-	-	539,447	252,461	60,453	226,533	106,340	73,841	51,706	25,961	13,422
31.12.2035	534	11.64	735,641	147,353	-	40,056	52,087	-	496,146	232,196	69,299	194,651	87,023	59,022	40,390	19,397	9,611
31.12.2036	536	11.67	747,579	149,745	-	40,056	-	-	557,779	261,041	63,049	233,689	99,501	65,916	44,083	20,250	9,615
31.12.2037	534	11.64	755,547	151,341	-	40,056	-	-	564,151	264,023	66,618	233,510	94,690	61,270	40,044	17,595	8,007
31.12.2038	534	11.64	765,664	153,367	-	40,056	-	-	572,241	267,809	67,632	236,801	91,452	57,799	36,917	15,516	6,766
31.12.2039	534	11.64	774,057	155,048	-	40,056	49,482	-	529,470	247,792	73,820	207,859	76,452	47,195	29,459	11,843	4,949
31.12.2040	536	11.67	784,624	157,165	-	40,056	-	-	587,403	274,905	68,459	244,040	85,485	51,544	31,443	12,091	4,842
31.12.2041	523	11.38	774,442	155,125	-	40,056	-	-	579,261	271,094	67,800	240,367	80,189	47,226	28,154	10,356	3,975
31.12.2042	447	9.74	670,563	134,318	-	40,056	-	-	496,190	232,217	57,766	206,207	65,517	37,688	21,957	7,725	2,841
31.12.2043	433	9.43	657,347	131,671	-	40,056	-	-	485,621	227,270	56,669	201,681	61,028	34,289	19,523	6,570	2,316
31.12.2044	419	9.13	643,974	128,992	-	40,056	-	-	474,926	222,265	55,443	197,217	56,835	31,191	17,355	5,587	1,887
31.12.2045	311	6.77	483,389	96,826	-	40,056	-	-	346,508	162,166	39,785	144,557	39,675	21,267	11,565	3,561	1,153
31.12.2046	277	6.03	435,663	87,266	-	40,056	-	-	308,342	144,304	34,751	129,287	33,795	17,694	9,403	2,769	859
31.12.2047	273	5.94	434,419	87,017	-	40,056	-	-	307,347	143,838	34,769	128,740	32,049	16,390	8,512	2,398	713
31.12.2048	218	4.75	351,877	70,483	-	40,056	-	17,524	223,814	104,745	28,578	90,491	21,455	10,717	5,439	1,466	418
31.12.2049	130	2.83	212,171	42,499	-	40,056	-	17,524	112,092	52,459	14,908	44,725	10,099	4,927	2,444	630	172
31.12.2050	64	1.40	106,468	21,326	-	40,056	-	17,524	27,562	12,899	5,703	8,960	1,927	918	445	110	29

[14] See Footnote 11 above.

31.12.2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2057	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**14,478**	**315**	**19,018,792**	**3,809,579**	**-**	**1,286,477**	**340,842**	**52,572**	**13,529,335**	**5,899,523**	**1,626,205**	**6,003,608**	**3,219,427**	**2,525,199**	**2,056,780**	**1,491,492**	**1,177,686**

Total discounted cash flow from possible reserves as of December 31, 2018 (in dollars in thousands in relation to the Partnership's share)																
Cash flow components																
Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Develop-ment costs	Abandon-ment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Taxes		Total discounted cash flow after tax				
										Levy	Income Tax	Discounted at 0%	Discounted at 5%	Discounted at 7.5%[15]	Discounted at 10%	Discounted at 1
31.12.2019	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2021	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2022	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2023	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2024	-	-	-	-	-	-	(75,526)	-	75,526	35,346	(8,130)	48,309	36,939	32,455	28,600	22,3
31.12.2025	-	-	-	-	-	-	-	-	-	-	1,144	(1,144)	(833)	(715)	(616)	(46
31.12.2026	-	-	-	-	-	-	75,526	-	(75,526)	(35,346)	9,274	(49,453)	(34,299)	(28,750)	(24,196)	(17,3
31.12.2027	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

[15] See Footnote 11 above.

Total discounted cash flow from possible reserves as of December 31, 2018 (in dollars in thousands in relation to the Partnership's share)

Cash flow components

Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Develop-ment costs	Abandon-ment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Taxes		Total discounted cash flow after tax				
										Levy	Income Tax	Discounted at 0%	Discounted at 5%	Discounted at 7.5%[15]	Discounted at 10%	Disco d at
31.12.2030	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2031	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2035	-	-	-	-	-	-	(52,087)	-	52,087	24,377	(7,344)	35,054	15,672	10,629	7,274	3,4
31.12.2036	-	-	-	-	-	-	-	-	-	-	647	(647)	(275)	(183)	(122)	(5
31.12.2037	-	-	-	-	-	-	52,087	-	(52,087)	(24,377)	6,805	(34,515)	(13,996)	(9,056)	(5,919)	(2,6
31.12.2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2039	-	-	-	-	-	-	(49,482)	-	49,482	23,158	(5,326)	31,651	11,641	7,186	4,486	1,8
31.12.2040	-	-	-	-	-	-	-	-	-	-	1,138	(1,138)	(399)	(240)	(147)	(5
31.12.2041	12	0.26	17,486	3,503	-	-	49,482	-	(35,499)	(16,614)	8,175	(27,061)	(9,028)	(5,317)	(3,170)	(1,1

Total discounted cash flow from possible reserves as of December 31, 2018 (in dollars in thousands in relation to the Partnership's share)																
Cash flow components																
										Taxes		Total discounted cash flow after tax				
Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Develop-ment costs	Abandon-ment 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%	Disco d at
31.12.2042	87	1.90	130,990	26,238	-	-	-	-	104,752	49,024	12,817	42,911	13,634	7,843	4,569	1,6
31.12.2043	101	2.21	153,947	30,837	-	-	-	-	123,110	57,616	15,064	50,431	15,260	8,574	4,882	1,6
31.12.2044	117	2.55	179,573	35,970	-	-	-	-	143,603	67,206	17,571	58,826	16,953	9,304	5,177	1,6
31.12.2045	224	4.87	347,734	69,653	-	-	-	-	278,081	130,142	34,026	113,913	31,265	16,759	9,113	2,8
31.12.2046	258	5.61	405,551	81,234	-	-	-	-	324,316	151,780	40,186	132,351	34,596	18,113	9,626	2,8
31.12.2047	262	5.70	417,006	83,529	-	-	-	-	333,477	156,067	41,306	136,103	33,882	17,327	8,999	2,5
31.12.2048	318	6.92	512,396	102,636	-	-	-	(17,524)	427,284	199,969	49,952	177,363	42,051	21,005	10,661	2,8
31.12.2049	358	7.79	583,454	116,869	-	-	-	(17,524)	484,109	226,563	56,905	200,640	45,305	22,103	10,963	2,8
31.12.2050	391	8.51	645,125	129,223	-	-	-	(17,524)	533,427	249,644	60,102	223,681	48,102	22,923	11,111	2,7
31.12.2051	390	8.50	652,024	130,604	-	40,056	-	-	481,364	225,278	56,061	200,024	40,967	19,068	9,033	2,1
31.12.2052	325	7.08	549,932	110,155	-	40,056	-	17,524	382,198	178,869	50,796	152,533	29,752	13,526	6,262	1,4
31.12.2053	228	4.96	389,612	78,042	-	40,056	-	17,524	253,991	118,868	35,109	100,014	18,579	8,250	3,733	80

Total discounted cash flow from possible reserves as of December 31, 2018 (in dollars in thousands in relation to the Partnership's share)																
Cash flow components																
Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Develop-ment costs	Abandon-ment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Taxes		Total discounted cash flow after tax				
										Levy	Income Tax	Discounted at 0%	Discounted at 5%	Discounted at 7.5%[15]	Discounted at 10%	Disco d at 1
31.12.2054	140	3.05	243,061	48,687	-	40,056	-	17,524	136,795	64,020	20,769	52,006	9,201	3,991	1,764	36
31.12.2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2057	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**3,209**	**70**	**5,227,891**	**1,047,178**	**-**	**160,222**	**-**	**-**	**4,020,491**	**1,881,590**	**497,048**	**1,641,853**	**384,970**	**194,796**	**102,082**	**32,2**

Total discounted cash flow from 3P (proved + probable + possible) reserves as of December 31, 2018 (in dollars in thousands in relation to the Partnership's share)

Cash flow components

Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Develop-ment costs	Abandon-ment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Taxes		Total discounted cash flow after tax					
										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	543,380	108,842	-	44,046	31,018	-	359,474	-	60,543	298,931	291,727	288,315	285,020	278,755	272,886
31.12.2020	489	10.65	528,307	105,823	-	40,848	63,546	-	318,091	11,141	71,510	235,440	218,825	211,236	204,076	190,912	179,105
31.12.2021	475	10.34	521,631	104,486	-	39,959	208	-	376,977	102,351	47,938	226,688	200,658	189,194	178,627	159,840	143,706
31.12.2022	489	10.65	540,522	108,270	-	40,056	(821)	-	393,018	143,149	42,492	207,378	174,823	161,002	148,555	127,151	109,554
31.12.2023	489	10.65	546,903	109,548	-	40,056	-	-	397,300	174,547	40,147	182,605	146,609	131,879	118,917	97,358	80,389
31.12.2024	490	10.67	552,028	110,575	-	40,056	-	-	401,398	187,854	39,400	174,144	133,158	116,993	103,097	80,736	63,887
31.12.2025	489	10.65	553,775	110,925	-	40,056	26,043	-	376,752	176,320	42,380	158,052	115,098	98,775	85,064	63,718	48,319
31.12.2026	489	10.65	559,641	112,099	-	40,056	119,279	-	288,207	134,881	53,526	99,801	69,217	58,019	48,830	34,986	25,426
31.12.2027	534	11.64	624,461	125,083	-	40,056	-	-	459,322	214,963	45,081	199,278	131,629	107,767	88,638	60,747	42,308
31.12.2028	536	11.67	631,608	126,515	-	40,056	-	-	465,038	217,638	48,472	198,928	125,141	100,073	80,439	52,731	35,195
31.12.2029	534	11.64	635,059	127,206	-	40,056	-	-	467,797	218,929	49,016	199,852	119,735	93,523	73,466	46,066	29,465
31.12.2030	534	11.64	649,909	130,181	-	40,056	-	-	479,673	224,487	51,171	204,015	116,408	88,810	68,178	40,892	25,066
31.12.2031	534	11.64	668,438	133,892	-	40,056	-	-	494,490	231,422	54,880	208,188	113,133	84,305	63,248	36,286	21,315
31.12.2032	536	11.67	692,393	138,690	-	40,056	-	-	513,647	240,387	57,223	216,037	111,808	81,379	59,666	32,742	18,432

[16] See Footnote 11 above.

31.12.2033	534	11.64	712,656	142,749	-	40,056	-	-	529,851	247,970	59,212	222,669	109,753	78,026	55,907	29,346	15,832
31.12.2034	534	11.64	724,656	145,153	-	40,056	-	-	539,447	252,461	60,453	226,533	106,340	73,841	51,706	25,961	13,422
31.12.2035	534	11.64	735,641	147,353	-	40,056	-	-	548,232	256,573	61,955	229,704	102,694	69,651	47,664	22,890	11,342
31.12.2036	536	11.67	747,579	149,745	-	40,056	-	-	557,779	261,041	63,696	233,042	99,225	65,733	43,960	20,194	9,589
31.12.2037	534	11.64	755,547	151,341	-	40,056	52,087	-	512,064	239,646	73,423	198,996	80,694	52,214	34,126	14,995	6,823
31.12.2038	534	11.64	765,664	153,367	-	40,056	-	-	572,241	267,809	67,632	236,801	91,452	57,799	36,917	15,516	6,766
31.12.2039	534	11.64	774,057	155,048	-	40,056	-	-	578,953	270,950	68,493	239,510	88,093	54,381	33,945	13,646	5,703
31.12.2040	536	11.67	784,624	157,165	-	40,056	-	-	587,403	274,905	69,597	242,902	85,087	51,304	31,296	12,034	4,820
31.12.2041	534	11.64	791,928	158,628	-	40,056	49,482	-	543,762	254,481	75,975	213,306	71,161	41,910	24,984	9,190	3,527
31.12.2042	534	11.64	801,553	160,556	-	40,056	-	-	600,942	281,241	70,584	249,117	79,151	45,531	26,526	9,333	3,433
31.12.2043	534	11.64	811,294	162,507	-	40,056	-	-	608,731	284,886	71,733	252,112	76,288	42,863	24,405	8,213	2,895
31.12.2044	536	11.68	823,547	164,961	-	40,056	-	-	618,530	289,472	73,015	256,043	73,788	40,495	22,532	7,253	2,450
31.12.2045	534	11.64	831,123	166,479	-	40,056	-	-	624,589	292,307	73,811	258,470	70,940	38,026	20,678	6,367	2,061
31.12.2046	534	11.64	841,214	168,500	-	40,056	-	-	632,658	296,084	74,937	261,638	68,390	35,807	19,028	5,604	1,739
31.12.2047	534	11.64	851,425	170,546	-	40,056	-	-	640,824	299,905	76,075	264,843	65,932	33,717	17,510	4,933	1,467
31.12.2048	536	11.68	864,273	173,119	-	40,056	-	-	651,098	304,714	78,530	267,854	63,506	31,721	16,100	4,338	1,236
31.12.2049	488	10.62	795,625	159,368	-	40,056	-	-	596,201	279,022	71,813	245,366	55,404	27,031	13,407	3,456	944
31.12.2050	455	9.91	751,593	150,549	-	40,056	-	-	560,989	262,543	65,804	232,642	50,029	23,841	11,556	2,849	746
31.12.2051	390	8.50	652,024	130,604	-	40,056	-	-	481,364	225,278	56,061	200,024	40,967	19,068	9,033	2,130	534

31.12.2052	325	7.08	549,932	110,155	-	40,056	-	17,524	382,198	178,869	50,796	152,533	29,752	13,526	6,262	1,412	339
31.12.2053	228	4.96	389,612	78,042	-	40,056	-	17,524	253,991	118,868	35,109	100,014	18,579	8,250	3,733	805	185
31.12.2054	140	3.05	243,061	48,687	-	40,056	-	17,524	136,795	64,020	20,769	52,006	9,201	3,991	1,764	364	80
31.12.2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2057	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**17,690**	**385**	**24,246,684**	**4,856,758**	**-**	**1,446,687**	**340,841**	**52,571**	**17,549,827**	**7,781,113**	**2,123,252**	**7,645,463**	**3,604,396**	**2,719,997**	**2,158,862**	**1,523,750**	**1,190,986**

Warning – It is clarified that discounted cash flow figures, whether calculated at a specific cap rate or without a cap rate, represent present value but do not necessarily represent fair value.

Warning regarding forward-looking information – The aforesaid discounted cash flow figures are forward-looking information, within the meaning thereof in the Securities Law. The above figures are based on various assumptions, including in relation to the quantities of gas and condensate that shall be produced, the pace and duration of sales of natural gas from the project, operating costs, capital expenditure, abandonment expenses, royalty rates and sale prices, including with respect to the price adjustments according to the agreement with the IEC, and there is no certainty that such assumptions will materialize. It is noted that the quantities of natural gas and/or condensate that shall actually be produced, such expenses and such revenues may materially differ from the above estimates and conjectures, *inter alia* as a result of the competition conditions prevailing on the market and/or operating and technical conditions and/or regulatory changes and/or supply and demand conditions on the natural gas and/or condensate market and/or the actual performance of the project and/or as a result of the actual sale prices and/or as a result of geopolitical changes that shall occur. It is further noted that the price adjustment rate on the First Adjustment Date as set forth in the agreement with the IEC may materially differ from the Partnership's estimate, *inter alia* as a result of the actual natural gas prices on the domestic market on the First Adjustment Date and all according to the adjustment mechanism as stipulated in the agreement with the IEC.

d) Set forth below is an analysis of sensitivity to the main parameters comprising the discounted cash flow (the gas price and the gas sales volume[17]) as of December 31, 2018 (dollars in thousands) which was performed by the Partnership:

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% growth in the gas price					**10% decrease in the gas price**				
1P (Proved) Reserves	4,562,264	1,999,453	1,518,573	1,225,473	1P (Proved) Reserves	3,744,099	1,675,162	1,280,206	1,037,232
Probable Reserves	2,045,261	240,221	98,889	47,920	Probable Reserves	1,659,148	198,814	84,343	43,003
Total 2P (Proved+Probable) Reserves	6,607,524	2,239,674	1,617,462	1,273,393	Total 2P (Proved+Probable) Reserves	5,403,247	1,873,976	1,364,550	1,080,235
Possible Reserves	1,813,112	111,947	34,948	14,089	Possible Reserves	1,469,749	91,720	29,181	12,203
Total 3P (Proved+Probable+Possible) Reserves	8,420,636	2,351,620	1,652,410	1,287,482	Total 3P (Proved+Probable+Possible) Reserves	6,872,996	1,965,696	1,393,731	1,092,438
15% growth in the gas price					**15% decrease in the gas price**				
1P (Proved) Reserves	4,765,600	2,078,329	1,575,693	1,269,891	1P (Proved) Reserves	3,537,521	1,590,594	1,216,778	986,156
Probable Reserves	2,142,758	251,236	103,099	49,649	Probable Reserves	1,563,489	189,057	81,226	42,229
Total 2P (Proved+Probable) Reserves	6,908,358	2,329,565	1,678,792	1,319,540	Total 2P (Proved+Probable) Reserves	5,101,010	1,779,650	1,298,004	1,028,385
Possible Reserves	1,898,741	116,879	36,292	14,484	Possible Reserves	1,383,659	86,613	27,733	11,750
Total 3P (Proved+Probable+Possible) Reserves	8,807,099	2,446,443	1,715,084	1,334,024	Total 3P (Proved+Probable+Possible) Reserves	6,484,670	1,866,263	1,325,738	1,040,135
20% growth in the gas price					**20% decrease in the gas price**				
1P (Proved) Reserves	4,968,029	2,156,080	1,631,645	1,313,123	1P (Proved) Reserves	3,335,739	1,509,352	1,156,207	937,574

[17] Sensitivity to a change in the gas quantity that is sold. It is emphasized that the aforesaid analyses do not take into account changes in the future investment plan pertaining to either an increase or a decrease of the quantity.

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%
Probable Reserves	2,240,203	262,299	107,383	51,466	Probable Reserves	1,467,386	179,058	77,926	41,314
Total 2P (Proved+Probable) Reserves	7,208,233	2,418,379	1,739,027	1,364,588	Total 2P (Proved+Probable) Reserves	4,803,125	1,688,410	1,234,133	978,887
Possible Reserves	1,984,371	121,811	37,637	14,879	Possible Reserves	1,298,246	81,905	26,597	11,543
Total 3P (Proved+Probable+Possible) Reserves	9,192,603	2,540,190	1,776,664	1,379,467	Total 3P (Proved+Probable+Possible) Reserves	6,101,372	1,770,315	1,260,730	990,431

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% growth in the gas sales volume					**10% decrease in the gas sales volume**				
1P (Proved) Reserves	4,200,294	1,968,492	1,514,270	1,230,071	1P (Proved) Reserves	3,755,105	1,663,744	1,268,918	1,026,916
Probable Reserves	1,792,673	241,158	102,797	50,475	Probable Reserves	1,662,544	197,838	83,699	42,553
Total 2P (Proved+Probable) Reserves	5,992,967	2,209,651	1,617,067	1,280,546	Total 2P (Proved+Probable) Reserves	5,417,650	1,861,582	1,352,617	1,069,469
Possible Reserves	1,581,853	117,441	38,610	15,701	Possible Reserves	1,469,965	91,256	29,070	12,208
Total 3P (Proved+Probable+Possible) Reserves	7,574,821	2,327,092	1,655,677	1,296,247	Total 3P (Proved+Probable+Possible) Reserves	6,887,614	1,952,838	1,381,688	1,081,677
15% growth in the gas sales volume					**15% decrease in the gas sales volume**				
1P (Proved) Reserves	4,176,652	2,021,530	1,565,409	1,276,064	1P (Proved) Reserves	3,542,871	1,575,756	1,202,777	973,664
Probable Reserves	1,779,171	256,122	111,256	54,851	Probable Reserves	1,566,872	187,976	80,463	41,655
Total 2P (Proved+Probable) Reserves	5,955,823	2,277,652	1,676,665	1,330,915	Total 2P (Proved+Probable) Reserves	5,109,742	1,763,732	1,283,241	1,015,319
Possible Reserves	1,559,611	127,855	43,330	17,664	Possible Reserves	1,383,819	86,063	27,537	11,676
Total 3P (Proved+Probable+Possible) Reserves	7,515,434	2,405,507	1,719,995	1,348,579	Total 3P (Proved+Probable+Possible) Reserves	6,493,562	1,849,795	1,310,778	1,026,995
20% growth in the gas sales volume					**20% decrease in the gas sales volume**				
1P (Proved) Reserves	4,181,537	2,074,046	1,615,048	1,320,655	1P (Proved) Reserves	3,329,873	1,486,661	1,135,498	919,284
Probable Reserves	1,741,455	268,241	119,211	59,398	Probable Reserves	1,470,835	177,929	77,091	40,658
Total 2P (Proved+Probable) Reserves	5,922,992	2,342,287	1,734,259	1,380,053	Total 2P (Proved+Probable) Reserves	4,800,708	1,664,590	1,212,589	959,942
Possible Reserves	1,538,687	138,807	48,568	19,958	Possible Reserves	1,298,121	81,173	26,255	11,351
Total 3P (Proved+Probable+Possible) Reserves	7,461,679	2,481,094	1,782,827	1,400,011	Total 3P (Proved+Probable+Possible) Reserves	6,098,829	1,745,763	1,238,844	971,293

e) Set forth below is an analysis of sensitivity to the main linkage components of the gas price according to the gas sale agreements in which the Tamar partners have engaged (the U.S. CPI and the electricity production tariff) as of December 31, 2018 (dollars in thousands) which was performed by the Partnership[18]:

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% growth in the CPI forecast					**10% decrease in the CPI forecast**				
1P (Proved) Reserves	4,157,036	1,840,360	1,402,284	1,134,138	1P (Proved) Reserves	4,147,928	1,835,498	1,398,603	1,131,293
Probable Reserves	1,850,920	218,688	90,902	44,842	Probable Reserves	1,850,909	218,690	90,908	44,849
Total 2P (Proved+Probable) Reserves	6,007,956	2,059,048	1,493,187	1,178,980	Total 2P (Proved+Probable) Reserves	5,998,837	2,054,188	1,489,510	1,176,142
Possible Reserves	1,641,853	102,082	32,259	13,300	Possible Reserves	1,641,853	102,082	32,259	13,300
Total 3P (Proved+Probable+Possible) Reserves	7,649,809	2,161,131	1,525,446	1,192,280	Total 3P (Proved+Probable+Possible) Reserves	7,640,690	2,156,270	1,521,770	1,189,442
10% growth in the electricity production tariff forecast					**10% decrease in the electricity production tariff forecast**				
1P (Proved) Reserves	4,235,794	1,886,832	1,440,545	1,166,761	1P (Proved) Reserves	4,103,918	1,814,325	1,382,726	1,118,836
Probable Reserves	1,850,900	218,569	90,764	44,695	Probable Reserves	1,850,924	218,744	90,969	44,912
Total 2P (Proved+Probable) Reserves	6,086,694	2,105,400	1,531,308	1,211,456	Total 2P (Proved+Probable) Reserves	5,954,841	2,033,069	1,473,695	1,163,749
Possible Reserves	1,641,853	102,082	32,259	13,300	Possible Reserves	1,641,853	102,082	32,259	13,300
Total 3P (Proved+Probable+Possible) Reserves	7,728,547	2,207,483	1,563,568	1,224,756	Total 3P (Proved+Probable+Possible) Reserves	7,596,695	2,135,151	1,505,954	1,177,048

[18] Although the electricity production tariff is affected, *inter alia*, by the CPI, such effect was not taken into account in the sensitivity analysis in the table below.

f) <u>Set forth below is an analysis of sensitivity to the sale of quantities exceeding the minimum quantities (take or pay) according to the gas sale agreements in which the Partnership has engaged as of December 31, 2018 (dollars in thousands) which was performed by the Partnership</u>:

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% growth in the gas sales volume in respect of quantities exceeding the take or pay					**10% decrease in the gas sales volume in respect of quantities exceeding the take or pay**				
1P (Proved) Reserves	4,244,034	1,921,254	1,468,782	1,189,387	1P (Proved) Reserves	4,313,034	1,764,169	1,331,419	1,073,024
Probable Reserves	1,812,212	220,445	92,023	45,302	Probable Reserves	1,869,297	212,633	88,771	44,352
Total 2P (Proved+Probable) Reserves	6,056,246	2,141,699	1,560,805	1,234,689	Total 2P (Proved+Probable) Reserves	6,182,331	1,976,802	1,420,190	1,117,376
Possible Reserves	1,619,676	104,169	33,114	13,606	Possible Reserves	1,660,508	97,248	30,583	12,731
Total 3P (Proved+Probable+Possible) Reserves	7,675,922	2,245,868	1,593,919	1,248,295	Total 3P (Proved+Probable+Possible) Reserves	7,842,839	2,074,050	1,450,773	1,130,107

g) Set forth below is an analysis of sensitivity to the price adjustment determined in the agreement with the IEC as of December 31, 2018 (dollars in thousands) which was performed by the Partnership:

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%
0% price reduction					**25% price reduction**				
1P (Proved) Reserves	4,225,138	1,877,195	1,430,528	1,156,295	1P (Proved) Reserves	4,081,890	1,799,617	1,371,037	1,109,630
Probable Reserves	1,850,927	218,620	90,819	44,751	Probable Reserves	1,850,962	218,823	91,053	44,997
Total 2P (Proved+Probable) Reserves	6,076,066	2,095,815	1,521,347	1,201,047	Total 2P (Proved+Probable) Reserves	5,932,852	2,018,440	1,462,090	1,154,627
Possible Reserves	1,641,853	102,082	32,259	13,300	Possible Reserves	1,641,830	102,069	32,249	13,291
Total 3P (Proved+Probable+Possible) Reserves	7,717,919	2,197,898	1,553,607	1,214,346	Total 3P (Proved+Probable+Possible) Reserves	7,574,682	2,120,508	1,494,339	1,167,918

h) <u>Agreement between the report data and data of previous reports in relation to the quantity of reserves attributed to the petroleum asset</u>

The main differences between the present Reserve Report and the Previous Reserve Report derive from the production of approx. 364 BCF and approx. 477 thousand barrels of condensate from the reservoir in the course of 2018, as well as from the update of the mapping of the reservoir, which indicated an increase in the quantity of reserves in the Tamar Project as follows:

Compared with the previous report, the total quantity of condensate and natural gas reserves in the Tamar Lease has increased in the proved reserves (1P) category by approx. 3.5% (from approx. 7.8 TCF and approx. 10.2 million barrels of condensate in the previous report to approx. 8.1 TCF and approx. 10.5 million barrels of condensate in the current reserve report); in the proved and probable (2P) category by approx. 0.7% (from approx. 11 TCF and approx. 14.4 million barrels of condensate in the previous report to approx. 11.1 TCF and approx. 14.5 million barrels of condensate in the current reserve report); and in the proved, probable and possible (3P) category by approx. 3.7% (from approx. 13.1 TCF and approx. 17.1 million barrels of condensate in the reserve report to approx. 13.6 TCF and approx. 17.7 million barrels of condensate in the current reserve report).

i) <u>Production data</u>

Set forth below are production data in the Tamar Project which are attributed to the Partnership in 2016-2018[19]:

Natural Gas[20] [21]

		Y2016	Y2017	Y2018
Total output (attributed to the holders of the equity interests of the Partnership) during the period (in MMCF)		103,028	97,659	92,698
Average price per output unit (attributed to the holders of the equity interests of the Partnership) (dollars per MCF)[22]		5.2	.533	5.49
Average royalties (any payment derived from the output of the producing asset, including from the gross revenues from the petroleum	The State	0.6	0.6	0.61
	Third Parties	0.09	0.1	0.09

[19] It is noted that from the date of commencement of the piping of natural gas from the Tamar Project (i.e. March 30, 2013) until December 31, 2018, natural gas was supplied to customers in a total quantity of approx. 50.5 BCM (the production data for 2018 are based on unaudited financial data). It is further noted that the average daily production volume of natural gas totaled, in the past two years (January 1, 2017 to December 31, 2018), approx. 968 MMCF (0.968 BCF).

[20] The rate attributed to the holders of the equity interest of the Partnership in the production, in royalties that were paid, in the production costs and in the net revenues was rounded off to two digits after the decimal point.

[21] The production data for 2018 are based on unaudited financial data. The financial data include, in addition to the Partnership's direct holding in the Tamar Project, also the Partnership's share in the production data of Tamar Petroleum as of July 2017.

[22] The average price per output unit weights the actual price of the Partnership which includes the framework for the sale of natural gas from the Tamar Project to the Yam Tethys project, as specified in Section 7.4.4(e) of the Periodic Report.

asset) paid per output unit (attributed to the holders of the equity interests of the Partnership) (dollars per MCF)	Interested Parties	0.14	0.15	0.35[23]
Average production costs per output unit (attributed to the holders of the equity interests of the Partnership) (dollars per MCF) [24]		0.4	.036	0.39
Average net revenues per output unit (attributed to the holders of the equity interests of the Partnership) (dollars per MCF)		3.97	4.12	4.05
Petroleum and gas profit levy		-	-	-
Average net income per output unit after the petroleum and gas profit levy (attributed to the holders of the equity interests of the Partnership) (dollars per MCF)		3.97	4.12	4.05
Depletion rate in the reported period relative to the total gas quantities in the project (in %)[25]		3.2	3.44	3.29

Condensate[26] [27]				
		Y2016	**Y2017**	**Y2018**
Total output (attributed to the holders of the equity interests of the Partnership) during the period (in barrels in thousands)		140	129.4	121.51
Average price per output unit (attributed to the holders of the equity interests of the Partnership) (dollars per barrel)		38.1	47.1	63.01
Average royalties (any payment derived from the output of the producing asset, including from the gross revenues from the petroleum asset) paid per output unit (attributed to the holders of the equity interests of the Partnership) (dollars per barrel)	The State	4.2	5.28	7.03
	Third Parties	0.68	0.83	1.05
	Interested Parties	1	1.37	4.12[28]
Average production costs per output unit (attributed to the holders of the equity interests of the Partnership) (dollars per barrel)		2.1	2	2.11
Average net revenues per output unit (attributed to the holders of the equity interests of the Partnership) (dollars per barrel)[29]		30.12	37.62	48.7
Petroleum and gas profit levy		-	-	-
Average net income per output unit after the petroleum and gas profit levy (attributed to the holders of the equity interests of the Partnership) (dollars per barrel)		30.12	37.62	48.7

[23] For the royalty rate taken into account in 2018, see Footnote 2 above.
[24] The data include current production costs only and exclude the exploration and development costs of the reservoir and tax payments to be paid by the Partnership in the future.
[25] The depletion rate is the rate of natural gas produced in the relevant reporting period, out of the balance of proved and probable reserves as of the beginning of such reporting period or as of the date of commencement of production, whichever is later. The said depletion rate is calculated at the end of the year and not in the course thereof.
[26] See Footnote 20 above.
[27] See Footnote 21 above.
[28] See Footnote 23 above.
[29] See Footnote 24 above.

Depletion rate in the reported period relative to the total condensate quantities in the project (in %)[30]	3.3	3.5	3.31

The Partnership declares that all of the above data are SPE-PRMS-compliant.

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

j) Opinion of the evaluator

The reserve report of the Tamar Project (which includes the Tamar and Tamar SW reservoirs) prepared by NSAI as of December 31, 2018, with NSAI's consent to the inclusion thereof in this report, is attached hereto as **Annex A**.

k) Management declaration

(1) Date of the declaration: February 19, 2019;
(2) Name of the corporation: Delek Drilling, Limited Partnership;
(3) Name and position of the resource evaluation officer at the Partnership: Asi Bartfeld, Chairman of the Board of the General Partner;
(4) We confirm that the evaluator was provided with all of the data required for performance of its work;
(5) We confirm that no information has come to our attention which indicates the existence of dependency between the evaluator and the Partnership;
(6) We confirm that, to the best of our knowledge, the resources reported are the best and most current estimates in our possession;
(7) We confirm that the data included in this report were prepared according to the professional terms listed in Chapter G of the Third Schedule to the Securities Regulations (Details of the Prospectus and Draft Prospectus – Structure and Form), 5729-1969 and within the meaning afforded thereto in Petroleum Resources Management System (2007), as published by the SPE, the AAPG, the WPC and the SPEE, as being at the time of release of the report;
(8) We confirm that no change has been made to the identity of the evaluator who performed the last contingent resource or reserve disclosure released by the Partnership;
(9) We agree to the inclusion of the foregoing declaration in this report.

____

Asi Bartfeld

l) Glossary

Lease – Within the meaning thereof in the Petroleum Law, 5712-1952 (the "**Petroleum Law**").

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

SPE-PRMS – (Petroleum Resources Management System 2007) – A petroleum resources and reserves evaluation reporting system, as published by the SPE, the AAPG, the WPC and the SPEE, and as amended from time to time.

Petroleum Asset – The direct or indirect holding of a preliminary permit, license or lease; in another country – the direct or indirect holding of a right of a similar nature that was granted by the competent body. A right to receive benefits deriving from the lease, either directly or indirectly, in a petroleum asset or in a right of a similar nature (as the case may be) shall also be deemed as a petroleum asset.

Petroleum - Any petroleum fluid, whether liquid or gaseous, including oil, natural gas, natural gasoline, condensates and related fluid hydrocarbons, as well as asphalt and other solid petroleum hydrocarbons when dissolved in and producible with fluid petroleum.

Reserves – Defined according to the SPE-PRMS as quantities of petroleum that are expected to be recoverable by implementing a development plan in respect of accumulations discovered from a certain day forth under defined conditions. Reserves must fulfill four conditions: (1) they have to be discovered; (2) recoverable; (3) commercial; and (4) exist, according to the implemented development project.

Condensate – Hydrocarbons which are in a gas state in reservoir conditions, but which condense to a liquid during production from the reservoir to the surface.

License – Within the meaning thereof in the Petroleum Law.

BCF – Billion cubic feet, which are 0.001 TCF or approx. 0.0283 BCM.

BCM – Billion cubic meters.

MMCF – Million cubic feet, which are 0.001 BCF or approx. 0.00003 BCM.

Set forth below are conversion coefficients for the units used in the above report:

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

<u>The partners in the Tamar Project and their holding rates 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 Drilling Management (1993) Ltd.

General Partner of Delek Drilling - Limited Partnership

By Yossi Abu, CEO

and Yossi Gvura, Deputy CEO