Revised Reserves Evaluation Report and Discounted Cash Flow Data for Tamar Lease

Tel Aviv, January 10, 2020. Delek Group (TASE: DLEKG, US ADR: DGRLY) (“the Company”) announces that, further to section 1.7.4 (I) of the Company's periodic report as at March 31, 2018, as published on March 31, 2018 (Ref. No. 2019-01-029344) (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 (the “Tamar Project” and “Tamar Lease”, respectively), the Company is pleased to issue an updated reserves evaluation report and discounted cash flow information, as follows.

A. **Quantitative data**

According to the report Delek Drilling, Limited Partnership (the “Partnership”) received from Netherland, Sewell & Associates Inc. ("NSAI” or "the Evaluator”), which was prepared in accordance with the guidelines set out in the Petroleum Resources Management System approved by the Society of Petroleum Engineers (SPE-PRMS), as of December 31, 2019 "the Reserves Report"), the natural gas and condensate reserves in the Tamar Project (which includes the Tamar and Tamar SW Reservoirs) are classified as on production reserves and are as follows:

Reserve category	Total (100%) in the oil asset (gross)						Total (Tamar and Tamar SW reservoirs) share attributable to equity holders of the Company (net)[1]	
	Tamar Reservoir		Tamar SW Reservoir[2]		Total (Tamar and Tamar SW reservoir)			
	Natural gas BCF	Condensate M barrels	Natural gas BCF	Condensate M barrels	Natural gas BCF	Condensate M barrels	Natural gas BCF	Condensate M barrels
P1 Reserves (Proved Reserves)	6,944.5	9.0	796.4	1.0	7,741.0	10.1	952.2	1.2
Probable reserves (Probable reserves)	2,871.0	3.7	159.1	0.2	3,030.1	3.9	372.7	0.5
Total P2 Reserves (Proved + Probable Reserves)	9,815.5	12.8	955.6	1.2	10,771.1	14.0	1,324.9	1.7
Possible reserves (Possible Reserves)	2,366.0	3.1	102.2	0.1	2,468.3	3.2	303.6	0.4
Total P3 Reserves (Proved + Probable + Possible Reserves)	12,181.6	15.8	1,057.8	1.4	13,239.4	17.2	1,628.6	2.1

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 volumes produced will be equivalent to or higher than the proved reserves, with the addition of the volume of the probable reserves and volume of the possible reserves.

1 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 attributable to the equity holders of the Company is calculated according to the Company's holdings in the Tamar Project (direct and indirect) and under the assumption that the rate of royalties to the State is 12.5% (at wellhead). The Company's share, direct and indirect, in the Tamar Project includes the Company's holdings in the participating units of the Partnership, the Company's holdings in Delek Energy Systems Ltd and in Cohen Gas and Oil Development Ltd., and in their holdings in the participating units of the Partnership, and the Partnership's holdings in Tamar Petroleum Ltd. The Company's share also includes the rights of Cohen Gas and Oil Development Ltd. to overriding royalties from the Partnership. For further information concerning the date of return on investment see section 1.7.36(J) and Notes 23A4(3) and 23A4(4) to the Periodic Report, and section 14 of the revised chapter on the Description of the Company's Businesses of the quarterly report as at June 30, 2019, as published on August 29, 2019 (Ref. No.: 2019-01-090004) and Note 7C to the financial statements as at September 30, 2019, as published on November 28, 2019 (Ref. No.: 2019-01-103617) ("Second Quarter Report" and "Third Quarter Report", respectively).

2 The resources indicated in the table that are contained in the Tamar SW reservoir do not include resources located in the area of License 353/Eran. See Section 6 of the revised chapter on the Description of the Company's Businesses in the quarterly report as at March 31, 2019, as published on May 30, 2019 (Ref. No.: 2019-01-053317) (the First Quarter Report).

B. In its reserves report NSAI noted, among other things, 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 and according to the Partnership's estimates concerning the required future developments in order to meet the projected production, that the reservoirs will be operated reasonably, that no new regulation will be adopted that will affect the oil rights holders' ability to produce the reserves and forecasts for future production will be similar to actual performance of the reservoirs.

Forward-looking information: The estimates of NSAI in respect of the quantities of natural gas reserves 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 partially based on geological, geophysical , engineering and other information received from the drilling and from the Tamar project Operator, and are the estimates and assumptions only of NSAI and there can be no certainty in respect of them. Actual quantities of natural gas and/or condensate consumed 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.

C. **Discounted cash flows**

With regard to the calculation of the discounted cash flows described below, the following is noted: (a) Discounted cash flow is calculated, among other things, based on average weighted prices of gas according to the price formulas in existing sales agreements for natural gas from the Tamar Project, in accordance with the Partnership's assumptions regarding prices in future agreements, and based on price formulas as set out in the provisions of the Gas Outline Plan. Such price formulas include, inter alia, partial or full linkage to the cost of electricity generation[3], to the NIS/USD exchange rate, the US CPI, and Brent price per barrel. It is noted that price changes may arise, among other things, due to price adjustments based on a mechanism set in the agreement with the Israel Electric Corp. Ltd. ("IEC") [4]and

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

4 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 production (as defined in the agreement) from the Tamar Project or within three months after the commencing gas supply from the Tamar Project (i.e. July 1, 2021 and July 1, 2024, respectively). At the first adjustment date (after 8 years - on July 1, 2021) the price adjustment will be up to 25% (increase or reduction), and at the second adjustment date (after 11 years - on July 1, 2024) the adjustment will be up to 10% (increase or reduction).

in agreement with Dolphinus Holdings Limited [5](see the Company's Immediate Reports dated October 2, 2019 and December 24, 2019 (Ref. No.: 2019-01-084633 and 2019-01-112980, respectively). (the " Egypt Export Agreement") and due to changes in the indices on which the price formula in the gas agreements are based. For the discounted cash flow, it was assumed that the price in the IEC agreement will be reduced by 25% on the first adjustment date (i.e. on July 1, 2021) and that no further adjustment will be made on the second adjustment date (i.e. on July 1, 2024). The foregoing price reduction was incorporated in the cost of electricity generation forecast. For information about changes in the discounted cash flows due to the change in the natural gas price, including due to a change in the rate of the price adjustment, see the sensitivity tables in sections (d) and (g) below. It should further be noted that no change in price was taken into account as a result of the motion for the certification of a class action that was filed by an IEC consumer against the Tamar Project partners, as set out in Note 23A3(2) and section 12(A) to the Third Quarter 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, the parties are currently at the hearing stage of the motion for certification of a class action. If a final and absolute ruling is handed down regarding certification of the class action (meaning, after the motion for certification as a class action is accepted (if it will be accepted) and an absolute ruling on the class action itself will be handed (if such will be handed)) against the Tamar partners, this may have a material adverse effect on the Partnership's business, including on the discounted cash flow data and the prices at which the Partnership, together with the other Tamar partners, will sell natural gas to its customers, the scope of which will be derived from the results of the claim. The information concerning the foregoing gas prices was given to NSAI by the Partnership[6]; (b) the projected local market demand in Israel, which was used for estimating the projected volume of future natural gas sales for the local market in Israel, was estimated by the external consultancy firm, BDO Consulting Group; (c) the discounted cash flow was calculated according to the Brent Crude price-based condensate price. For the purpose of calculating the Brent price, average oil price forecasts by third parties that provide long-term price projections were used, among them the World Bank and others, for the NYMEX ICE Brent Crude price, and were adjusted for differences in quality, transportation costs and the price at which condensate is sold in the region. The Partnership provided the information regarding the condensate price to NSAI; (d) the operating costs taken into account are costs provided by the Partnership to NSAI. These costs include direct project costs, insurance costs, production well maintenance costs and the estimated overheads and general and administrative expenses of the Operator, which can be directly attributed to the project and together form the project operating expenses. These costs are divided into expenses on the field level and expenses per production unit and are not adjusted for inflation. The operating costs that NSAI received from the Partnership are deemed by them to be reasonable based on, among other things, additional information that NSAI has accrued from similar projects; (e) the capital expenses taken into account when preparing the discounted cash flows exceed the costs approved by the Partnership, and also include 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, such as drilling, development and connecting of new

5 The agreement for export to Egypt includes a mechanism for updating the price by up to 10% (up or down) after the fifth year and again after the tenth year of the agreement, in accordance with certain conditions stipulated in the agreement. It should be noted that no price updates were assumed for these dates. It should also be noted that the price under the export agreement to Egypt was adjusted to the delivery point, as stipulated in the agreement.

6 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 of 2.3% in the US-CPI; (2) Brent price of USD 61 per barrel in 2020, rising to USD 75 per barrel in 2025 and USD 91 per barrel in 2030, and a gradual average annual increase of 4% per subsequent year; (3) projected electricity generation price based, among other things, on a projected USD-NIS exchange rate and projected IEC costs for purchasing fuels.

wells, laying of infrastructures and additional production equipment, including participation in the pipeline construction costs of Israel National Gas Lines ("INGL") [7]. The capital expenditure data given to NSAI by the Partnerships are deemed by them to be reasonable, based on, among other things, the Tamar project development plan and on NSAI's additional knowledge from similar projects, and are not adjusted for inflation changes; (f) the abandonment costs that were taken into account are costs given to NSAI by the Partnership that are based on its assessments of the costs involved in abandoning wells, platforms and production facilities. These costs do not take into account salvage value of the Tamar Project facilities and are not adjusted to inflation changes; (g) the tax calculations take due corporate tax rates into account. Costs involved in depreciation for tax purposes were calculated according to the depreciation rates set by law; (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. Furthermore, NSAI did not conduct a sensitivity analysis with respect to the well production rates; (i) for calculating the discounted cash flows, projected volumes were assumed for sales in each of the project years based on the Tamar Project production capacity.[8], and based on the Partnership's estimates that were based on supply and demand forecasts for the domestic and export markets by independent consulting firms, for each of the project years; (j) for calculating the discounted cash flows, domestic market sales in Egypt and Jordan were assumed at total aggregate volume of BCM 50 by 2040[9], among other things, based on the Partnership's forecasts of exports to Egypt and Jordan, as set out in section 1.7.15(e) of the Periodic Report and the Immediate Reports dated October 2, 2019 and December 24, 2019[10]; (k) for calculating the discounted cash flows, the Partnership estimated that the actual rate of royalties to the State, and to related and third parties, that will be paid by the Partnership, to be 11.5% and 9.13%, respectively. It should be noted that the discounted cash flow does not include the Company's share in royalties since it sold its right to third parties as aforesaid, and the Company's share of royalties that Delek Royalties (2012) Ltd. will receive, have not been included. To the best of the Partnership's knowledge, after discussions between Tamar Partners and the Ministry of Energy regarding the method for calculating the rate of royalties to be paid by the Partnership to the State , the Ministry of Energy intends to publish guidelines for calculating the royalty rate at wellhead. Accordingly, the actual rate of royalties is not final and may change[11]. For further information on this matter and for arrangements between the parties until completion of these discussions, see section 1.7.36(i) to the Periodic Report; (l) the calculation of the discounted cash flow took into account the oil profits levy applicable to the Partnership and the Company under the Law. It should be emphasized that the calculations for this levy were based on the definitions, formulas and mechanisms defined by law, as the Partnership and the Company understands and interprets them, and which are reflected in the Tamar Project reports to the tax authority. However, given the resourcefulness of the law and the complexity of the various calculation formulas and mechanisms defined therein, there is no assurance that this interpretation of the method for calculating the levy will be the same as the interpretation adopted by

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7 In order to increase the streaming capacity via the EMG pipeline, it is necessary to expand the delivery capacity to the INGL pipeline. For further information see section 1.7.16(B)(2) of the Periodic Report.

8 The current gas delivery capacity from the Tamar Project to the INGL pipeline is 1.1 BCF per day, at maximum production.

9 It was assumed that the total expected volume of sales for the Egyptian and Jordanian domestic markets will be higher than the contractual volume as set out in the existing export agreements.

10 It should be noted that during 2019, the Tamar partners and Yam Tethys partners produced and sold a total volume of natural gas of BCM 10.5. Of this amount, the Tamar partners produced and sold on the domestic market and for export, a total volume of BCM 10.43 natural gas and 480 thousand barrels of condensate. The Yam Tethys partners also produced and sold a volume of BCM 0.07 natural gas, and the Tamar Project provided the Yam Tethys partners with an additional volume of BCM 0.07.

11 It is noted that, in March 2019, a letter was received from the Ministry of Energy regarding advance payments on royalties for 2019, stating that the effective rate of royalties to be paid as advance payments for 2019 will be 11.3%.

the tax authorities and/or the same as the interpretation of the law by the courts. It should be noted that, as of the date of publication of this report, a number of interpretative disputes are being clarified with the tax authority, with regard to the implementation of the law in the Tamar Project reports according to the procedures provided in the law for presenting them. To date, these issues have not yet been discussed in the rulings of 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 developer will choose to report in USD according to section 13(B) of the Law, all of the developer's payments (such as production costs, investments, and royalties) will be recognized by the tax authorities for calculation of the levy, and calculation of the developers revenues will take into account actual selling prices of the gas; (m) the calculation of the discounted cash flows include expenses and investments that were paid in practice and which are expected to be paid by the Partnership as of January 1, 2020, as well as revenues from sales of natural gas and condensate produced as of January 1, 2020. It is hereby clarified that revenues received in 2020 for sales of natural gas and condensate produced in 2019 were not included in the cash flows. It should also be noted that revenues from sales of natural gas and condensate in any given year were taken into account for that year.

It is further noted that the discounted cash flows have been adjusted compared to the discounted cash flows as at December 31, 2018 (the “Previous Discounted Cash Flow”) due to the following main reasons:

1. Revision of selling prices (natural gas and condensate) for the following reasons: (A) revising of forecasts for electricity generation cost, the US CPI and Brent per barrel price; (B) revising of forecasts of prices for future customers in the domestic market and for export; (C) updating the projected rate of the price reduction on the first adjustment date as per the IEC agreement.
2. Updating of sales volume forecasts due to, among other things, the revised forecast for natural gas demand in the domestic market, the signing of the export agreement to Egypt, as set out in the immediate reports dated October 2, 2019 and December 24, 2019, and the gas supply agreement signed between the IEC and the Leviathan partners, as set out in the immediate reports dated June 12, 2019 and October 29, 2019 (Ref. No.: 2019-01-057961 and 2019-01-091608, respectively).
3. Updating of the forecasted Tamar Project expenses, including updated forecast of the Tamar Project capital expenditure, which is mainly due to the revision of the expected future development plan of the Tamar Field, including changes to the drilling dates of future wells and capital costs with respect to the export transaction to Egypt.

   Based on various assumptions, as described above, below is the estimated discounted cash flows as at December 31, 2019, in USD thousands (net of the levy and income tax) attributable to the Company's share [12]in the Tamar Project reserves, for each of the reserve categories set out above:

[12] Directly and indirectly, including through the Company’s holdings in Delek Energy Systems Ltd and in Cohen Gas and Oil Development Ltd., and in the participating units of the Partnership and its holdings in Tamar Petroleum Ltd. The Company's share also includes the rights of Cohen Gas and Oil Development Ltd. to overriding royalties from the Partnership.

Total discounted cash flow from Proved Reserves at December 31, 2019 (in USD thousands for the Company's share)																	
Cash flow items																	
At	Condensate sales volume (K barrels) (100% of oil asset)	Sales volume (BCM) (100% of oil asset)	Revenue	Royalties payable	Royalties receivable	Operating 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%[13]	Discounted at 10%	Discounted at 15%	Discounted at 20%
Dec 31, 2020	427	9.30	266,140	53,309	3,690	25,845	17,189	-	173,487	5,910	35,940	131,636	128,464	126,961	125,510	122,751	120,167
Dec 31, 2021	409	8.90	242,559	48,586	3,363	25,481	42,566	-	129,290	31,297	25,545	72,448	67,335	65,000	62,797	58,746	55,113
Dec 31, 2022	459	10.00	273,182	54,720	3,788	24,997	43,384	-	153,869	46,664	26,401	80,804	71,526	67,439	63,673	56,976	51,225
Dec 31, 2023	489	10.65	299,088	59,909	4,147	24,997	28,670	-	189,660	69,648	26,174	93,838	79,107	72,853	67,221	57,536	49,573
Dec 31, 2024	489	10.66	305,106	61,115	4,231	24,997	-	-	223,225	97,296	20,959	104,970	84,278	75,810	68,360	55,966	46,212
Dec 31, 2025	489	10.65	310,702	62,235	4,308	24,997	-	-	227,777	106,600	19,868	101,309	77,465	68,062	59,978	46,969	37,167
Dec 31, 2026	489	10.65	314,104	62,917	4,355	24,997	-	-	230,545	107,895	20,539	102,111	74,360	63,814	54,956	41,166	31,217
Dec 31, 2027	535	11.65	349,326	69,972	4,844	24,997	-	-	259,201	121,306	24,847	113,047	78,405	65,720	55,312	39,630	28,801
Dec 31, 2028	535	11.65	352,801	70,668	4,892	24,997	-	-	262,028	122,629	26,898	112,501	74,310	60,839	50,040	34,295	23,884
Dec 31, 2029	535	11.65	355,812	71,271	4,934	24,997	15,581	-	248,896	116,483	28,995	103,418	65,058	52,025	41,818	27,414	18,297
Dec 31, 2030	535	11.65	360,050	72,120	4,993	24,997	-	-	267,926	125,389	27,541	114,995	68,896	53,813	42,272	26,506	16,954
Dec 31, 2031	535	11.65	363,755	72,862	5,044	24,997	-	-	270,940	126,800	28,268	115,872	66,115	50,441	38,722	23,225	14,236
Dec 31, 2032	535	11.65	368,632	73,839	5,112	24,997	-	-	274,907	128,657	30,101	116,150	63,118	47,034	35,287	20,244	11,892
Dec 31, 2033	534	11.63	372,989	74,712	5,172	24,997	29,605	-	248,847	116,461	34,099	98,288	50,868	37,024	27,146	14,896	8,386
Dec 31, 2034	512	11.15	361,860	72,483	5,018	24,997	-	-	269,398	126,078	30,437	112,883	55,640	39,555	28,342	14,877	8,026
Dec 31, 2035	390	8.49	278,356	55,756	3,860	24,997	-	-	201,463	94,285	22,583	84,595	39,711	27,575	19,309	9,695	5,012
Dec 31, 2036	326	7.11	236,162	47,305	3,275	24,997	-	-	167,135	78,219	18,550	70,366	31,459	21,337	14,601	7,012	3,474
Dec 31, 2037	306	6.67	223,641	44,797	3,101	24,997	-	-	156,948	73,452	17,357	66,140	28,161	18,656	12,476	5,731	2,721
Dec 31, 2038	247	5.39	182,452	36,546	2,530	24,997	-	-	123,439	57,769	13,412	52,258	21,191	13,712	8,962	3,938	1,792
Dec 31, 2039	235	5.11	175,101	35,074	2,428	24,997	-	-	117,458	54,970	12,714	49,774	19,223	12,149	7,760	3,261	1,422
Dec 31, 2040	226	4.93	170,670	34,186	2,367	24,997	-	-	113,854	53,283	12,653	47,917	17,624	10,880	6,791	2,730	1,141
Dec 31, 2041	218	4.74	165,808	33,212	2,299	24,997	-	-	109,898	51,432	10,968	47,498	16,638	10,032	6,120	2,353	942
Dec 31, 2042	211	4.59	162,241	32,498	2,250	24,997	-	-	106,996	50,074	10,630	46,292	15,443	9,095	5,422	1,994	765
Dec 31, 2043	206	4.49	160,369	32,123	2,224	24,997	-	12,340	93,133	43,586	11,784	37,763	11,998	6,902	4,021	1,415	520
Dec 31, 2044	130	2.83	102,139	20,459	1,416	24,997	-	12,340	45,759	21,415	6,862	17,482	5,290	2,972	1,692	569	201
Dec 31, 2045	63	1.37	50,044	10,024	694	24,997	-	12,340	3,377	1,580	1,848	(52)	(15)	(8)	(5)	(1)	(0)

[13] An additional discount rate of 7.5% for calculation purposes and as a tool for the investor.

Dec 31, 2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec 31, 2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec 31, 2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec 31, 2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec 31, 2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec 31, 2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec 31, 2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec 31, 2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec 31, 2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec 31, 2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec 31, 2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec 31, 2057	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**10,064**	**219**	**6,803,089**	**1,362,700**	**94,333**	**651,251**	**176,994**	**37,020**	**4,669,457**	**2,029,181**	**545,973**	**2,094,304**	**1,311,667**	**1,079,693**	**908,583**	**679,894**	**539,141**

Total discounted cash flow from Probable Reserves at December 31, 2019 (in USD thousands for the Company's share)																	
Cash flow items																	
At	Condensate sales volume (K barrels) (100% of oil asset)	Sales volume (BCM) (100% of oil asset)	Revenue	Royalties payable	Royalties receivable	Operating costs	Development costs[14]	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%[15]	Discounted at 10%	Discounted at 15%	Discounted at 20%
Dec 31, 2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec 31, 2021	-	-	-	-	-	-	(26,800)	-	26,800	7,497	(1,724)	21,027	19,543	18,865	18,226	17,050	15,996
Dec 31, 2022	-	-	-	-	-	-	(43,472)	-	43,472	17,207	(2,970)	29,234	25,877	24,399	23,036	20,613	18,533
Dec 31, 2023	-	-	-	-	-	-	(28,670)	-	28,670	17,083	(2,569)	14,155	11,933	10,990	10,140	8,679	7,478
Dec 31, 2024	-	-	-	-	-	-	11,998	-	(11,998)	(750)	2,504	(13,752)	(11,041)	(9,932)	(8,956)	(7,332)	(6,054)
Dec 31, 2025	-	-	-	-	-	-	43,472	-	(43,472)	(20,345)	6,554	(29,681)	(22,695)	(19,940)	(17,572)	(13,761)	(10,889)
Dec 31, 2026	-	-	-	-	-	-	43,472	-	(43,472)	(20,345)	6,111	(29,238)	(21,292)	(18,272)	(15,736)	(11,787)	(8,939)
Dec 31, 2027	-	-	-	-	-	-	-	-	-	-	(125)	125	87	73	61	44	32
Dec 31, 2028	-	-	-	-	-	-	-	-	-	-	(77)	77	51	42	34	23	16
Dec 31, 2029	-	-	-	-	-	-	(15,581)	-	15,581	7,292	(1,802)	10,092	6,348	5,077	4,081	2,675	1,785
Dec 31, 2030	-	-	-	-	-	-	-	-	-	-	233	(233)	(140)	(109)	(86)	(54)	(34)
Dec 31, 2031	-	-	-	-	-	-	-	-	-	-	160	(160)	(91)	(70)	(53)	(32)	(20)
Dec 31, 2032	-	-	-	-	-	-	-	-	-	-	(704)	704	383	285	214	123	72
Dec 31, 2033	1	0.02	641	128	9	-	(29,605)	-	30,126	14,099	(4,200)	20,228	10,469	7,620	5,587	3,066	1,726
Dec 31, 2034	23	0.50	16,226	3,250	225	-	-	-	13,201	6,178	198	6,825	3,364	2,392	1,714	899	485
Dec 31, 2035	145	3.16	103,596	20,751	1,436	-	-	-	84,281	39,444	9,352	35,485	16,658	11,567	8,100	4,067	2,103
Dec 31, 2036	208	4.54	150,786	30,203	2,091	-	15,581	-	107,092	50,119	16,170	40,803	18,242	12,372	8,467	4,066	2,015
Dec 31, 2037	229	4.98	166,964	33,444	2,315	-	29,605	-	106,231	49,716	20,488	36,026	15,339	10,162	6,796	3,122	1,482
Dec 31, 2038	287	6.26	211,890	42,443	2,938	-	-	-	172,385	80,676	21,045	70,664	28,655	18,541	12,118	5,325	2,423
Dec 31, 2039	300	6.54	224,089	44,886	3,107	-	-	-	182,310	85,321	22,307	74,682	28,842	18,228	11,643	4,893	2,134
Dec 31, 2040	309	6.72	232,626	46,596	3,226	-	29,605	-	159,650	74,716	25,985	58,948	21,682	13,384	8,355	3,359	1,404
Dec 31, 2041	317	6.91	241,704	48,415	3,352	-	-	-	196,641	92,028	24,256	80,357	28,148	16,972	10,353	3,981	1,595

14 As the appropriate level of certainty to produce the probable reserves (50%) is lower than the appropriate level of certainty to produce the proven reserves (90%), the date of execution of the capital investments required to produce the probable reserves has been postponed to the date of execution of the capital investments required to produce the proven reserves. 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 further information concerning the total capital investments required, see the table of discounted cash flows from P2 reserves (proved reserves (P1) + probable reserves).

15 An additional discount rate of 7.5% for calculation purposes and as a tool for the investor.

Dec 31, 2042	310	6.76	238,933	47,860	3,313	-	-	-	194,386	90,973	23,980	79,434	26,500	15,607	9,304	3,422	1,313
Dec 31, 2043	229	4.99	178,222	35,699	2,471	-	(51)	(12,289)	157,335	73,633	16,608	67,094	21,317	12,263	7,144	2,514	925
Dec 31, 2044	241	5.25	189,479	37,954	2,627	-	(51)	(12,289)	166,493	77,918	17,050	71,524	21,643	12,160	6,924	2,330	821
Dec 31, 2045	281	6.12	223,117	44,692	3,094	-	(51)	(12,289)	193,859	90,726	20,399	82,734	23,843	13,085	7,281	2,344	792
Dec 31, 2046	329	7.17	264,237	52,928	3,664	24,997	-	-	189,976	88,909	20,177	80,890	22,201	11,901	6,471	1,993	645
Dec 31, 2047	303	6.60	245,788	49,233	3,408	24,997	-	-	174,967	81,884	18,697	74,385	19,444	10,180	5,410	1,593	494
Dec 31, 2048	255	5.56	209,237	41,912	2,901	24,997	55	13,160	132,015	61,783	17,160	53,073	13,212	6,757	3,509	989	294
Dec 31, 2049	130	2.83	107,623	21,557	1,492	24,997	55	13,160	49,346	23,094	7,044	19,208	4,554	2,275	1,154	311	89
Dec 31, 2050	41	0.88	33,903	6,791	470	24,997	55	13,160	(10,629)	(4,975)	-	(5,655)	(1,277)	(623)	(309)	(80)	(22)
Dec 31, 2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec 31, 2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec 31, 2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec 31, 2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec 31, 2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec 31, 2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec 31, 2057	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**3,939**	**86**	**3,039,061**	**608,742**	**42,140**	**124,984**	**29,615**	**2,613**	**2,315,245**	**1,083,883**	**282,306**	**949,056**	**331,799**	**206,250**	**133,409**	**64,435**	**38,694**

Total discounted cash flow from Proved + Probable Reserves (P2) at December 31, 2019 (in USD thousands for the Company's share)																	
Cash flow items																	
At	Condensate sales volume (K barrels) (100% of oil asset)	Sales volume (BCM) (100% of oil asset)	Revenue	Royalties payable	Royalties receivable	Operating 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%
Dec 31, 2020	427	9.30	266,140	53,309	3,690	25,845	17,189	-	173,487	5,910	35,940	131,636	128,464	126,961	125,510	122,751	120,167
Dec 31, 2021	409	8.90	242,559	48,586	3,363	25,481	15,766	-	156,090	38,794	23,821	93,475	86,878	83,865	81,023	75,796	71,109
Dec 31, 2022	459	10.00	273,182	54,720	3,788	24,997	(88)	-	197,341	63,871	23,431	110,039	97,403	91,839	86,709	77,589	69,758
Dec 31, 2023	489	10.65	299,088	59,909	4,147	24,997	-	-	218,329	86,731	23,605	107,994	91,041	83,843	77,361	66,215	57,051
Dec 31, 2024	489	10.66	305,106	61,115	4,231	24,997	11,998	-	211,227	96,546	23,463	91,219	73,237	65,879	59,404	48,634	40,158
Dec 31, 2025	489	10.65	310,702	62,235	4,308	24,997	43,472	-	184,306	86,255	26,422	71,628	54,770	48,121	42,406	33,208	26,278
Dec 31, 2026	489	10.65	314,104	62,917	4,355	24,997	43,472	-	187,073	87,550	26,651	72,872	53,068	45,542	39,220	29,378	22,278
Dec 31, 2027	535	11.65	349,326	69,972	4,844	24,997	-	-	259,201	121,306	24,722	113,173	78,491	65,793	55,373	39,674	28,832
Dec 31, 2028	535	11.65	352,801	70,668	4,892	24,997	-	-	262,028	122,629	26,821	112,578	74,361	60,881	50,074	34,318	23,901
Dec 31, 2029	535	11.65	355,812	71,271	4,934	24,997	-	-	264,478	123,776	27,193	113,509	71,406	57,102	45,899	30,089	20,082
Dec 31, 2030	535	11.65	360,050	72,120	4,993	24,997	-	-	267,926	125,389	27,775	114,762	68,756	53,704	42,186	26,453	16,920
Dec 31, 2031	535	11.65	363,755	72,862	5,044	24,997	-	-	270,940	126,800	28,428	115,712	66,024	50,371	38,669	23,193	14,217
Dec 31, 2032	535	11.65	368,632	73,839	5,112	24,997	-	-	274,907	128,657	29,397	116,854	63,500	47,319	35,500	20,367	11,964
Dec 31, 2033	535	11.65	373,630	74,840	5,181	24,997	-	-	278,974	130,560	29,899	118,515	61,337	44,644	32,732	17,962	10,112
Dec 31, 2034	535	11.65	378,086	75,733	5,243	24,997	-	-	282,599	132,256	30,634	119,708	59,004	41,947	30,056	15,776	8,511
Dec 31, 2035	535	11.65	381,952	76,507	5,296	24,997	-	-	285,744	133,728	31,935	120,081	56,369	39,142	27,409	13,761	7,115
Dec 31, 2036	535	11.65	386,948	77,508	5,365	24,997	15,581	-	274,227	128,338	34,720	111,169	49,701	33,709	23,068	11,078	5,489
Dec 31, 2037	535	11.65	390,605	78,241	5,416	24,997	29,605	-	263,179	123,168	37,845	102,166	43,501	28,818	19,272	8,853	4,204
Dec 31, 2038	535	11.65	394,342	78,989	5,468	24,997	-	-	295,824	138,446	34,457	122,922	49,846	32,253	21,080	9,262	4,215
Dec 31, 2039	535	11.65	399,190	79,960	5,535	24,997	-	-	299,768	140,291	35,021	124,455	48,064	30,377	19,402	8,155	3,556
Dec 31, 2040	535	11.65	403,296	80,783	5,592	24,997	29,605	-	273,504	128,000	38,638	106,866	39,306	24,264	15,146	6,089	2,545
Dec 31, 2041	535	11.65	407,513	81,627	5,651	24,997	-	-	306,539	143,460	35,223	127,855	44,787	27,005	16,473	6,335	2,537
Dec 31, 2042	521	11.35	401,174	80,358	5,563	24,997	-	-	301,382	141,047	34,610	125,725	41,943	24,702	14,726	5,417	2,079
Dec 31, 2043	435	9.48	338,591	67,822	4,695	24,997	-	-	250,467	117,219	28,392	104,857	33,316	19,164	11,165	3,928	1,445
Dec 31, 2044	371	8.08	291,617	58,413	4,044	24,997	-	-	212,251	99,334	23,912	89,006	26,933	15,132	8,616	2,899	1,022
Dec 31, 2045	344	7.49	273,161	54,716	3,788	24,997	-	-	197,236	92,306	22,247	82,683	23,828	13,077	7,276	2,342	791

16 An additional discount rate of 7.5% for calculation purposes and as a tool for the investor.

Dec 31, 2046	329	7.17	264,237	52,928	3,664	24,997	-	-	189,976	88,909	20,177	80,890	22,201	11,901	6,471	1,993	645
Dec 31, 2047	303	6.60	245,788	49,233	3,408	24,997	-	-	174,967	81,884	18,697	74,385	19,444	10,180	5,410	1,593	494
Dec 31, 2048	255	5.56	209,237	41,912	2,901	24,997	-	13,215	132,015	61,783	17,160	53,073	13,212	6,757	3,509	989	294
Dec 31, 2049	130	2.83	107,623	21,557	1,492	24,997	-	13,215	49,346	23,094	7,044	19,208	4,554	2,275	1,154	311	89
Dec 31, 2050	41	0.88	33,903	6,791	470	24,997	-	13,215	(10,629)	(4,975)	-	(5,655)	(1,277)	(623)	(309)	(80)	(22)
Dec 31, 2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec 31, 2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec 31, 2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec 31, 2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec 31, 2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec 31, 2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec 31, 2057	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**14,002**	**305**	**9,842,150**	**1,971,441**	**136,473**	**776,239**	**206,600**	**39,645**	**6,984,702**	**3,113,062**	**828,280**	**3,043,360**	**1,643,468**	**1,285,944**	**1,041,990**	**744,328**	**577,836**

Total discounted cash flow from Possible Reserves at December 31, 2019 (in USD thousands for the Company's share)																	
Cash flow items																	
At	Condensate sales volume (K barrels) (100% of oil asset)	Sales volume (BCM) (100% of oil asset)	Revenue	Royalties payable	Royalties receivable	Operating 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%[17]	Discounted at 10%	Discounted at 15%	Discounted at 20%
Dec 31, 2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec 31, 2021	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec 31, 2022	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec 31, 2023	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec 31, 2024	-	-	-	-	-	-	(11,998)	-	11,998	5,702	(1,132)	7,427	5,963	5,364	4,837	3,960	3,270
Dec 31, 2025	-	-	-	-	-	-	(2,805)	-	2,805	1,313	154	1,338	1,023	899	792	620	491
Dec 31, 2026	-	-	-	-	-	-	14,802	-	(14,802)	(6,927)	1,934	(9,809)	(7,143)	(6,130)	(5,279)	(3,954)	(2,999)
Dec 31, 2027	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec 31, 2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec 31, 2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec 31, 2030	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec 31, 2031	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec 31, 2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec 31, 2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec 31, 2034	-	-	-	-	-	-	-	-	-	-	(180)	180	89	63	45	24	13
Dec 31, 2035	-	-	-	-	-	-	-	-	-	-	(419)	419	197	137	96	48	25
Dec 31, 2036	-	-	-	-	-	-	(15,581)	-	15,581	7,292	(2,018)	10,307	4,608	3,125	2,139	1,027	509
Dec 31, 2037	-	-	-	-	-	-	(14,023)	-	14,023	6,563	(1,151)	8,611	3,667	2,429	1,624	746	354
Dec 31, 2038	-	-	-	-	-	-	29,605	-	(29,605)	(13,855)	3,868	(19,617)	(7,955)	(5,147)	(3,364)	(1,478)	(673)
Dec 31, 2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec 31, 2040	-	-	-	-	-	-	(29,605)	-	29,605	13,855	(3,187)	18,936	6,965	4,300	2,684	1,079	451
Dec 31, 2041	-	-	-	-	-	-	29,605	-	(29,605)	(13,855)	3,876	(19,625)	(6,875)	(4,145)	(2,529)	(972)	(389)
Dec 31, 2042	14	0.30	10,487	2,101	145	-	-	-	8,532	3,993	1,052	3,487	1,163	685	408	150	58
Dec 31, 2043	99	2.17	77,382	15,500	1,073	-	-	-	62,955	29,463	7,711	25,780	8,191	4,712	2,745	966	355
Dec 31, 2044	164	3.57	128,716	25,783	1,785	-	-	-	104,719	49,008	12,822	42,889	12,978	7,292	4,152	1,397	492
Dec 31, 2045	191	4.16	151,584	30,363	2,102	-	-	-	123,322	57,715	15,098	50,509	14,556	7,988	4,445	1,431	483

[17] An additional discount rate of 7.5% for calculation purposes and as a tool for the investor.

Dec 31, 2046	206	4.48	164,969	33,044	2,287	-	-	-	134,212	62,811	17,775	53,626	14,718	7,890	4,290	1,321	428
Dec 31, 2047	227	4.95	184,230	36,902	2,555	-	-	-	149,882	70,145	19,335	60,402	15,789	8,266	4,393	1,294	401
Dec 31, 2048	232	5.06	190,368	38,132	2,640	-	(55)	(13,160)	168,090	78,666	18,202	71,222	17,730	9,067	4,709	1,327	394
Dec 31, 2049	325	7.08	269,274	53,937	3,734	-	(55)	(13,160)	232,285	108,710	26,735	96,840	22,960	11,469	5,821	1,568	447
Dec 31, 2050	382	8.32	319,766	64,051	4,434	-	(55)	(13,160)	273,364	127,934	31,467	113,962	25,733	12,555	6,227	1,605	438
Dec 31, 2051	390	8.50	329,874	66,076	4,574	24,997	-	-	243,376	113,900	29,099	100,377	21,586	10,287	4,986	1,229	322
Dec 31, 2052	325	7.08	277,768	55,639	3,852	24,997	-	-	200,984	94,060	23,248	83,675	17,137	7,977	3,779	891	223
Dec 31, 2053	260	5.66	224,535	44,976	3,113	24,997	-	-	157,676	73,792	17,949	65,934	12,861	5,847	2,707	611	147
Dec 31, 2054	195	4.25	170,161	34,084	2,359	24,997	55	13,160	100,224	46,905	13,959	39,361	7,312	3,247	1,469	317	73
Dec 31, 2055	130	2.83	114,626	22,960	1,589	24,997	55	13,160	55,044	25,760	8,431	20,853	3,689	1,600	707	146	32
Dec 31, 2056	70	1.52	62,118	12,443	861	24,997	55	13,160	12,325	5,768	3,204	3,353	565	239	103	20	4
Dec 31, 2057	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**3,209**	**70**	**2,675,858**	**535,991**	**37,104**	**149,981**	**-**	**-**	**2,026,990**	**948,719**	**247,832**	**830,439**	**197,508**	**100,014**	**51,986**	**15,372**	**5,350**

Total discounted cash flow from P3 Reserves (Proved + Probable + Possible Reserves) at December 31, 2019 (in USD thousands for the Company's share)																	
Cash flow items																	
At	Condensate sales volume (K barrels) (100% of oil asset)	Sales volume (BCM) (100% of 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%)	Taxes		Total discounted cash flow after tax					
										Levy	Income tax	Discounted at 0%	Discounted at 5%	Discounted at 7.5%[18]	Discounted at 10%	Discounted at 15%	Discounted at 20%
Dec 31, 2020	427	9.30	266,140	53,309	3,690	25,845	17,189	-	173,487	5,910	35,940	131,636	128,464	126,961	125,510	122,751	120,167
Dec 31, 2021	409	8.90	242,559	48,586	3,363	25,481	15,766	-	156,090	38,794	23,821	93,475	86,878	83,865	81,023	75,796	71,109
Dec 31, 2022	459	10.00	273,182	54,720	3,788	24,997	(88)	-	197,341	63,871	23,431	110,039	97,403	91,839	86,709	77,589	69,758
Dec 31, 2023	489	10.65	299,088	59,909	4,147	24,997	-	-	218,329	86,731	23,605	107,994	91,041	83,843	77,361	66,215	57,051
Dec 31, 2024	489	10.66	305,106	61,115	4,231	24,997	-	-	223,225	102,248	22,331	98,645	79,200	71,242	64,241	52,594	43,427
Dec 31, 2025	489	10.65	310,702	62,235	4,308	24,997	40,667	-	187,110	87,568	26,576	72,966	55,793	49,020	43,198	33,829	26,769
Dec 31, 2026	489	10.65	314,104	62,917	4,355	24,997	58,274	-	172,271	80,623	28,584	63,064	45,925	39,412	33,941	25,424	19,280
Dec 31, 2027	535	11.65	349,326	69,972	4,844	24,997	-	-	259,201	121,306	24,722	113,173	78,491	65,793	55,373	39,674	28,832
Dec 31, 2028	535	11.65	352,801	70,668	4,892	24,997	-	-	262,028	122,629	26,821	112,578	74,361	60,881	50,074	34,318	23,901
Dec 31, 2029	535	11.65	355,812	71,271	4,934	24,997	-	-	264,478	123,776	27,193	113,509	71,406	57,102	45,899	30,089	20,082
Dec 31, 2030	535	11.65	360,050	72,120	4,993	24,997	-	-	267,926	125,389	27,775	114,762	68,756	53,704	42,186	26,453	16,920
Dec 31, 2031	535	11.65	363,755	72,862	5,044	24,997	-	-	270,940	126,800	28,428	115,712	66,024	50,371	38,669	23,193	14,217
Dec 31, 2032	535	11.65	368,632	73,839	5,112	24,997	-	-	274,907	128,657	29,397	116,854	63,500	47,319	35,500	20,367	11,964
Dec 31, 2033	535	11.65	373,630	74,840	5,181	24,997	-	-	278,974	130,560	29,899	118,515	61,337	44,644	32,732	17,962	10,112
Dec 31, 2034	535	11.65	378,086	75,733	5,243	24,997	-	-	282,599	132,256	30,454	119,888	59,092	42,010	30,101	15,800	8,524
Dec 31, 2035	535	11.65	381,952	76,507	5,296	24,997	-	-	285,744	133,728	31,516	120,500	56,566	39,279	27,504	13,809	7,140
Dec 31, 2036	535	11.65	386,948	77,508	5,365	24,997	-	-	289,809	135,631	32,702	121,476	54,308	36,834	25,206	12,105	5,998
Dec 31, 2037	535	11.65	390,605	78,241	5,416	24,997	15,581	-	277,202	129,731	36,694	110,778	47,167	31,247	20,897	9,599	4,558
Dec 31, 2038	535	11.65	394,342	78,989	5,468	24,997	29,605	-	266,220	124,591	38,324	103,305	41,891	27,106	17,716	7,784	3,542
Dec 31, 2039	535	11.65	399,190	79,960	5,535	24,997	-	-	299,768	140,291	35,021	124,455	48,064	30,377	19,402	8,155	3,556
Dec 31, 2040	535	11.65	403,296	80,783	5,592	24,997	-	-	303,108	141,855	35,452	125,802	46,271	28,564	17,829	7,168	2,996
Dec 31, 2041	535	11.65	407,513	81,627	5,651	24,997	29,605	-	276,935	129,605	39,099	108,230	37,912	22,859	13,945	5,362	2,148
Dec 31, 2042	535	11.65	411,661	82,458	5,708	24,997	-	-	309,914	145,040	35,662	129,212	43,107	25,387	15,134	5,567	2,137
Dec 31, 2043	535	11.65	415,973	83,322	5,768	24,997	-	-	313,422	146,682	36,104	130,637	41,507	23,876	13,910	4,894	1,800
Dec 31, 2044	535	11.65	420,334	84,195	5,828	24,997	-	-	316,970	148,342	36,734	131,894	39,911	22,424	12,767	4,297	1,515
Dec 31, 2045	535	11.65	424,745	85,079	5,890	24,997	-	-	320,558	150,021	37,345	133,192	38,384	21,065	11,721	3,773	1,275

18 An additional discount rate of 7.5% for calculation purposes and as a tool for the investor.

Dec 31, 2046	535	11.65	429,206	85,973	5,951	24,997	-	-	324,188	151,720	37,951	134,517	36,920	19,790	10,761	3,313	1,073
Dec 31, 2047	530	11.55	430,018	86,135	5,963	24,997	-	-	324,849	152,029	38,032	134,787	35,232	18,447	9,803	2,887	896
Dec 31, 2048	488	10.62	399,605	80,043	5,541	24,997	-	-	300,106	140,450	35,362	124,295	30,943	15,824	8,218	2,315	688
Dec 31, 2049	455	9.91	376,896	75,495	5,226	24,997	-	-	281,631	131,803	33,779	116,048	27,514	13,743	6,975	1,880	536
Dec 31, 2050	423	9.20	353,669	70,842	4,904	24,997	-	-	262,734	122,960	31,467	108,307	24,456	11,932	5,918	1,525	417
Dec 31, 2051	390	8.50	329,874	66,076	4,574	24,997	-	-	243,376	113,900	29,099	100,377	21,586	10,287	4,986	1,229	322
Dec 31, 2052	325	7.08	277,768	55,639	3,852	24,997	-	-	200,984	94,060	23,248	83,675	17,137	7,977	3,779	891	223
Dec 31, 2053	260	5.66	224,535	44,976	3,113	24,997	-	-	157,676	73,792	17,949	65,934	12,861	5,847	2,707	611	147
Dec 31, 2054	195	4.25	170,161	34,084	2,359	24,997	-	13,215	100,224	46,905	13,959	39,361	7,312	3,247	1,469	317	73
Dec 31, 2055	130	2.83	114,626	22,960	1,589	24,997	-	13,215	55,044	25,760	8,431	20,853	3,689	1,600	707	146	32
Dec 31, 2056	70	1.52	62,118	12,443	861	24,997	-	13,215	12,325	5,768	3,204	3,353	565	239	103	20	4
Dec 31, 2057	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**17,212**	**375**	**12,518,008**	**2,507,431**	**173,575**	**926,221**	**206,599**	**39,645**	**9,011,693**	**4,061,782**	**1,076,111**	**3,873,798**	**1,840,974**	**1,385,957**	**1,093,974**	**759,701**	**583,189**

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

Notice regarding 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, among others, 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 quantities of natural gas and/or condensate produced, the above expenses and revenues may differ from these assumptions and estimates, among other things, as a result of competition that may develop in the market and/or due to technical and operational conditions and/or regulatory changes and/or the conditions for supply and demand of natural gas and/or condensate in the domestic market and/or the natural gas and condensate export 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 adjustments at the price adjustment dates 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 price adjustment dates, all in accordance with the adjustment mechanism set out in the IEC agreement.

D. **Sensitivity analysis for the main parameters of the discounted cash flow (gas price and volume of gas sold[19]) at December 31, 2019 (USD thousands)**

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				
Proved Reserves (P1)	2,320,322	1,002,483	749,465	594,048
Probable Reserves	1,050,142	145,271	68,746	40,159
Total Proved + Probable Reserves (P2)	3,370,464	1,147,754	818,211	634,207
Possible Reserves	919,493	57,296	16,865	5,814
Total Proved + Probable + Possible Reserves (P3)	4,289,957	1,205,050	835,077	640,021
15% increase in the price of gas				
Proved Reserves (P1)	2,434,154	1,050,158	784,946	622,176
Probable Reserves	1,100,739	151,300	70,987	40,965
Total Proved + Probable Reserves (P2)	3,534,893	1,201,457	855,933	663,141
Possible Reserves	964,087	59,939	17,599	6,034
Total Proved + Probable + Possible Reserves (P3)	4,498,980	1,261,396	873,533	669,176
20% increase in the price of gas				
Proved Reserves (P1)	2,545,966	1,095,679	818,242	648,101
Probable Reserves	1,151,314	157,361	73,275	41,826
Total Proved + Probable Reserves (P2)	3,697,280	1,253,039	891,516	689,928
Possible Reserves	1,008,676	62,578	18,331	6,253
Total Proved + Probable + Possible Reserves (P3)	4,705,956	1,315,618	909,847	696,180

Sensitivity/category	Total	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%
10% decrease in the price of gas				
Proved Reserves (P1)	1,869,439	815,408	610,936	484,774
Probable Reserves	847,975	121,717	60,294	37,390
Total Proved + Probable Reserves (P2)	2,717,414	937,125	671,231	522,164
Possible Reserves	741,434	46,628	13,839	4,855
Total Proved + Probable + Possible Reserves (P3)	3,458,848	983,754	685,070	527,020
15% decrease in the price of gas				
Proved Reserves (P1)	1,756,509	767,928	575,448	456,498
Probable Reserves	797,871	116,251	58,578	37,070
Total Proved + Probable Reserves (P2)	2,554,381	884,179	634,027	493,567
Possible Reserves	696,965	43,980	13,100	4,633
Total Proved + Probable + Possible Reserves (P3)	3,251,345	928,159	647,127	498,201
20% decrease in the price of gas				
Proved Reserves (P1)	1,644,302	720,930	540,375	428,590
Probable Reserves	746,963	110,032	56,137	36,050
Total Proved + Probable Reserves (P2)	2,391,265	830,962	596,512	464,639
Possible Reserves	652,608	41,406	12,423	4,462
Total Proved + Probable + Possible Reserves (P3)	3,043,873	872,368	608,934	469,101

[19] It is hereby emphasized that the sensitivity analyses to change in the volume of gas sold do not take into account changes in the future investment plan, for neither an increase or decrease in volume.

Sensitivity/category	Total	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%
Increase in gas sales volume of 10%				
Proved Reserves (P1)	2,112,563	978,275	740,831	591,013
Probable Reserves	930,958	145,382	70,594	41,432
Total Proved + Probable Reserves (P2)	3,043,521	1,123,656	811,425	632,446
Possible Reserves	815,844	62,524	19,689	7,011
Total Proved + Probable + Possible Reserves (P3)	3,859,364	1,186,180	831,114	639,456
Increase in gas sales volume of 15%				
Proved Reserves (P1)	2,120,991	1,010,303	769,978	616,549
Probable Reserves	923,262	151,902	74,325	43,315
Total Proved + Probable Reserves (P2)	3,044,253	1,162,205	844,302	659,864
Possible Reserves	791,767	67,347	22,081	8,061
Total Proved + Probable + Possible Reserves (P3)	3,836,020	1,229,552	866,384	667,924
Increase in gas sales volume of 20%				
Proved Reserves (P1)	2,119,187	1,036,529	794,885	638,752
Probable Reserves	915,809	159,446	78,928	45,827
Total Proved + Probable Reserves (P2)	3,034,996	1,195,975	873,813	684,579
Possible Reserves	796,206	74,182	25,265	9,463
Total Proved + Probable + Possible Reserves (P3)	3,831,202	1,270,156	899,078	694,042

Sensitivity/category	Total	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%
Decrease in gas sales volume of 10%				
Proved Reserves (P1)	1,869,452	815,416	610,942	484,779
Probable Reserves	847,982	121,718	60,295	37,390
Total Proved + Probable Reserves (P2)	2,717,434	937,133	671,237	522,169
Possible Reserves	741,440	46,629	13,839	4,855
Total Proved + Probable + Possible Reserves (P3)	3,458,875	983,762	685,076	527,025
Decrease in gas sales volume of 15%				
Proved Reserves (P1)	1,756,529	767,939	575,457	456,505
Probable Reserves	797,882	116,252	58,579	37,070
Total Proved + Probable Reserves (P2)	2,554,410	884,191	634,036	493,575
Possible Reserves	696,974	43,980	13,100	4,633
Total Proved + Probable + Possible Reserves (P3)	3,251,384	928,171	647,136	498,208
Decrease in gas sales volume of 20%				
Proved Reserves (P1)	1,644,327	720,943	540,385	428,598
Probable Reserves	746,977	110,034	56,137	36,050
Total Proved + Probable Reserves (P2)	2,391,304	830,977	596,523	464,648
Possible Reserves	652,620	41,407	12,423	4,462
Total Proved + Probable + Possible Reserves (P3)	3,043,924	872,384	608,946	469,110

E. **Sensitivity analysis of the main linkage components of gas price according to the Tamar partners agreements for gas sales (US-CPI and Electricity Generation Price as at December 31, 2019 (USD thousands), performed by the Company** [20]

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%
Increase in the projected CPI of 10%					**Decrease in the projected CPI of 10%**				
Proved Reserves (P1)	2,104,631	911,968	682,099	540,670	Proved Reserves (P1)	2,084,235	905,263	677,728	537,636
Probable Reserves	955,546	134,173	64,729	38,813	Probable Reserves	942,839	132,674	64,151	38,578
Total Proved + Probable Reserves (P2)	3,060,177	1,046,142	746,828	579,483	Total Proved + Probable Reserves (P2)	3,027,074	1,037,937	741,879	576,215
Possible Reserves	836,981	52,364	15,475	5,380	Possible Reserves	824,239	51,625	15,273	5,321
Total Proved + Probable + Possible Reserves (P3)	3,897,159	1,098,506	762,303	584,862	Total Proved + Probable + Possible Reserves (P3)	3,851,313	1,089,563	757,152	581,535

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%
Increase in projected electricity generation price of 10%					**Decrease in projected electricity generation price of 10%**				
Proved Reserves (P1)	2,174,872	939,436	701,892	555,910	Proved Reserves (P1)	2,043,279	893,881	670,806	533,120
Probable Reserves	990,634	138,292	66,252	39,364	Probable Reserves	902,731	128,160	62,436	37,878
Total Proved + Probable Reserves (P2)	3,165,506	1,077,728	768,144	595,273	Total Proved + Probable Reserves (P2)	2,946,011	1,022,041	733,243	570,999
Possible Reserves	868,788	54,259	16,011	5,549	Possible Reserves	776,203	48,887	14,525	5,099
Total Proved + Probable + Possible Reserves (P3)	4,034,294	1,131,987	784,155	600,822	Total Proved + Probable + Possible Reserves (P3)	3,722,213	1,070,928	747,768	576,097

[20] 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.

F. **Sensitivity analysis for sales volumes that exceed the minimum (take or pay) volumes under the Partnership's gas sales agreements as at December 31, 2019 (USD thousand), which was prepared 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%
Increase in gas sales volumes exceeding take or pay volumes by 10%					**Decrease in gas sales volumes exceeding take or pay volumes by 10%**				
Proved Reserves (P1)	2,116,530	945,157	708,783	561,716	Proved Reserves (P1)	1,937,798	858,905	647,591	516,512
Probable Reserves	935,206	142,639	69,276	40,981	Probable Reserves	847,586	121,166	59,719	36,811
Total Proved + Probable Reserves (P2)	3,051,736	1,087,795	778,059	602,698	Total Proved + Probable Reserves (P2)	2,785,383	980,071	707,310	553,323
Possible Reserves	820,500	60,228	18,660	6,583	Possible Reserves	741,570	46,702	13,895	4,899
Total Proved + Probable + Possible Reserves (P3)	3,872,236	1,148,023	796,719	609,280	Total Proved + Probable + Possible Reserves (P3)	3,526,953	1,026,773	721,206	558,222

G. **Sensitivity analysis for the price adjustment set out in the IEC agreement as at December 31, 2019 (USD thousands), 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%
Reduced price at a rate of 0%					**Reduced price at a rate of 12.5%**				
Proved Reserves (P1)	2,387,254	1,021,563	761,391	602,007	Proved Reserves (P1)	2,301,233	970,471	720,487	568,571
Probable Reserves	1,116,469	152,992	71,685	41,329	Probable Reserves	1,116,566	153,237	71,964	41,627
Total Proved + Probable Reserves (P2)	3,503,723	1,174,555	833,076	643,336	Total Proved + Probable Reserves (P2)	3,417,800	1,123,708	792,451	610,198
Possible Reserves	989,962	61,363	17,980	6,144	Possible Reserves	989,931	61,343	17,964	6,131
Total Proved + Probable + Possible Reserves (P3)	4,493,685	1,235,918	851,056	649,480	Total Proved + Probable + Possible Reserves (P3)	4,407,731	1,185,051	810,415	616,328

H. **Adjustment of the data in the report compared with the data in previous reports relating to the extent of the reserves attributed to the oil asset**

The major differences between the current reserves report and the previous reserves report that was published as part of the Periodic Report are due to production of 368 BCF of natural gas and 480,000 barrels of condensate during 2019.

I. **Production data**

Breakdown of production data for the Tamar Project, attributable to the Company in 2017-2019[21]:

Natural gas [22] [23]

		2017	2018	2019
Total output (attributable to equity holders of the Company) in the period (on MMcf)		54,926	52,925	48,490
Average price per production unit (attributable to equity holders of the Company) (USD per MCF) [24]		5.33	5.49	5.49
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 Partnership) (USD per MCF)	The State	0.6	0.61	0.61
	Third parties	0.1	0.09	0.10
	Interested parties	0.15	0.35[25]	0.38
Average income 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)		0.2	0.4[26]	0.27[27]
Average production costs per production unit (attributable to equity holders of the Company) (USD per MCF)[28]		0.36	0.39	0.45
Average net intake per production unit (attributable to equity holders of the Company) (USD per MCF)		4.32	4.45	4.22
Oil and gas profits levy:		-	-	-
Average net intake per production unit after oil and gas		4.32	4.45	4.22

21 It should be noted that since the streaming of natural gas began from the Tamar Project (i.e. March 30, 2013) through December 31, 2019, a total volume of 60 BCM natural gas and 85.2 million barrels of condensate were supplied to customers (production data for 2019 are based on unaudited financial data). It is further noted that the average daily production of natural gas in the last two years (January 1, 2016 through December 31, 2017) was 1 BCF.

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

23 Production data for 2019 is based on unaudited financial data and on the Partnership's direct holdings in the Tamar Project of 22%. The production data for 2017 and 2018 include, in addition to the Partnership's direct holding in the Tamar Project, the Partnership's share in the production data of Tamar Petroleum Ltd. as of July 2017.

24 The average price of a production unit weighs out the effective price of the Partnership, which includes the outline for the sale of natural gas between the Tamar Project and the Yam Tethys Project, as set out in section 1.7.5(D)(5) of the Periodic Report.

25 The rate of royalties taken into account in this figure is 6.5% (at wellhead), i.e. the rate of royalty after return on investment.

26 Income for royalties include Delek Energy Systems Ltd.'s share of the overriding royalty from the project through to June 7, 2018; the date of transfer of the rights to Delek Royalties Ltd. and at a rate of 6.5%.

27 Income for royalties include the Company's share of the overriding royalty from the project up through to the date on which the rights to royalties were transferred to the study funds for teachers and kindergarten teachers, as set out in the immediate reports dated July 21, 2019 (Ref. No.: 2019-01-074494), and December 26, 2019 (Ref. No.: 2019-01-114384).

28 The data includes only ongoing production costs and does not include the exploration and development costs for the reservoir and tax payments that will be paid by the Company in the future.

profits tax (attributable to equity holders of the Company) (USD per MCF)			
Depletion rate in the reporting period in relation to the overall quantity of gas in the project (%)29	3.44	3.29	3.31

Condensate [30] [31]				
		2017	**2018**	**2019**
Total output (attributable to equity holders of the Company) in the period (thousands of barrels)		73	69.2	63.2
Average price per production unit (attributable to equity holders of the Company) (USD per barrel)		47.1	63.0	55.79
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	5.3	7.0	6.18
	Third parties	0.8	1.1	1.22
	Interested parties	1.4	4.1[32]	3.66
Average income 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 barrel)		2	4.6[33]	2.69[34]
Average production costs per production unit (attributable to equity holders of the Company) (USD per barrel)[35]		2	2.1	2.47
Average net intake per production unit (attributable to equity holders of the Company) (USD per barrel)		39.6	53.3	44.95
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)		39.6	53.3	44.95
Depletion rate in the reporting period in relation to the overall volume of condensate in the project (%)[36]		3.5	3.31	3.33

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

29 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.

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

31 Production data for 2019 is based on unaudited financial data and on the Partnership's direct holdings in the Tamar Project of 22%.

32 The rate of royalties taken into account in this figure is 6.5% (at wellhead), i.e. the rate of royalty after return on investment.

33 Income for royalties include Delek Energy Systems Ltd.'s share of the overriding royalty from the project through to June 7, 2018; the date of transfer of the rights to Delek Royalties Ltd. and at a rate of 6.5%.

34 Income for royalties include the Company's share of the overriding royalty from the project up through to the date on which the rights to royalties were transferred to the study funds for teachers and kindergarten teachers, as set out in the immediate reports dated July 21, 2019 (Ref. No.: 2019-01-074494), and December 26, 2019 (Ref. No.: 2019-01-114384).

35 The data includes only ongoing production costs and does not include the exploration and development costs for the reservoir and tax payments that will be paid by the Company in the future.

36 The volume of condensate produced from the Tamar Project is directly derived from the volume of natural gas produced from the Project.

J. **Opinion of the appraiser**

A reserves report prepared by NSAI for the Tamar Project (which includes the Tamar and Tamar SW reservoirs) as of December 31, 2019 is attached to this report by way of reference to the Reserves Report which is attached as Appendix A to the Immediate Report issued by the Partnership on January 10, 2020 (Ref. No.: 2020-01-004515) and attached to this report as Appendix A is NSAI's consent to include the report in this report by way of reference.

K. **Glossary**

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

BCM – billion cubic meters

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

Commercial quantities – volumes of oil and/or gas that are economically viable.

Hydrocarbons – carbons; compounds of carbon and hydrogen, including gas, oil and condensate.

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

License – as defined in the Petroleum Law

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

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

Petroleum Resources Management System (2018) - (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

Porosity – the ratio of the volume of the voids in a rock to the total volume of the rock

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.

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.

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**

Partners in the Tamar Project and the rate of their holdings are as follows:

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%

This is a convenience translation of the original HEBREW immediate report issued to the Tel Aviv Stock Exchange by the Company on January 10, 2020

About The Delek Group

Delek Group is an independent E&P and the pioneering visionary behind the development of the East Med. With eight consecutive finds in the Levant Basin, 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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