Delek Group

ANNUAL REPORT 2020

IMPORTANT

This document is an unofficial translation for convenience only of the Hebrew original of the December 31, 2020 financial report of Delek Group Ltd. that was submitted to the Tel-Aviv Stock Exchange and the Israeli Securities Authority on March 31, 2021.

The Hebrew version submitted to the TASE and the Israeli Securities Authority shall be the sole legally binding version.

ANNUAL REPORT 2020

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<u>Key:</u>

In this report the following abbreviations have the following meanings:

The Company	–	Delek Group Ltd.
Delek GOM	–	Delek GOM Investments LLC
Ithaca	–	Ithaca Energy Limited
Delek Ashkelon	–	I.P.P. Delek Ashkelon Ltd.
Delek Sorek	–	IPP Delek Sorek Ltd.
Delek Energy	–	Delek Energy Systems Ltd.
Delek Israel	–	Delek The Israel Fuel Corporation Ltd.
Delek Petroleum	–	Delek Petroleum Ltd.
Delek Infrastructure	–	Delek Infrastructure Ltd.
Delek Power Plants	–	Delek Power Plants - Limited Partnership
The Phoenix	–	The Phoenix Holdings Ltd.
Delek Drilling Partnership or the Partnership	–	Delek Drilling - Limited Partnership
Delek Financial Investments	–	Delek Financial Investments Limited Partnership
IOGL	–	Ithaca Oil and Gas Limited
DKL	–	DKL Investments Limited
DKL Energy	–	DKL Energy Limited
DNSL	–	Delek North Sea Limited

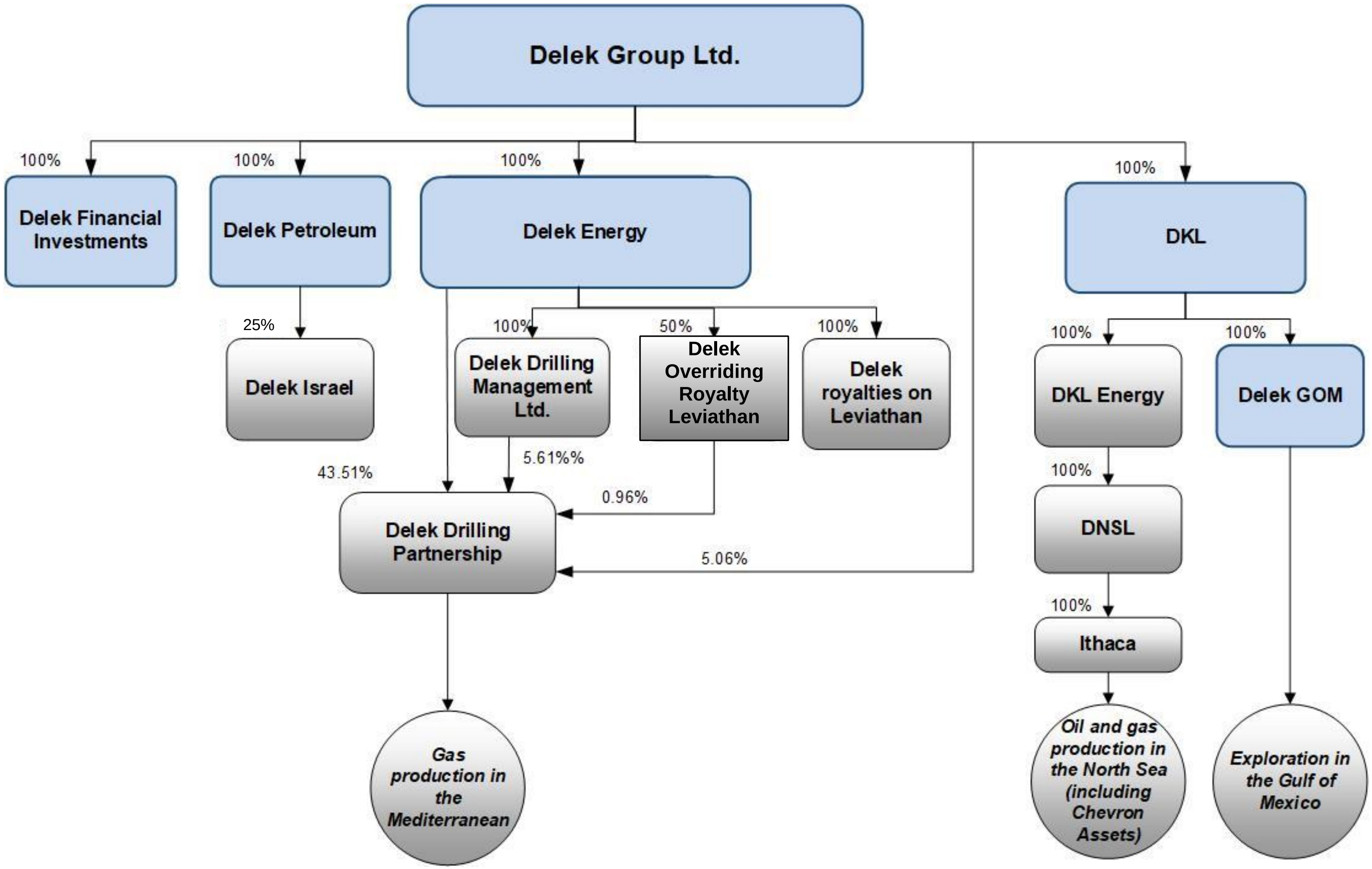
Part One – Description of the General Development of the Company's Business

1.1. General

The Company deals in oil and gas exploration and production in Israel and abroad through investee companies. The Company also markets fuel products in Israel through its holdings in Delek Israel. For the sake of convenience, the Company and those companies under its control will hereinafter be referred to as "the Group" or "the Delek Group".

The Company was incorporated on October 26, 1999. The Company's controlling shareholder is Mr. Yitzhak Sharon (Tshuva) ("the Controlling Shareholder") who, as of the reporting date, holds through companies under his control 48.64% of the Company's issued capital and 50.34% of its voting rights.

The following chart illustrates the Group's major holdings as of the publication date of this report:



1. - Staff companies.

2. Delek Group shares and debentures held by Delek Financial Investment. For more information, see Section 1.3 below.

1.2. The Group's Operating Segments

1.2.1. As of the reporting date, the Group operates in three main segments, as follows:

Energy in Israel - These operations are conducted mainly through the Company's direct and indirect holdings in the Delek Drilling partnership, which holds rights to offshore oil assets in the Mediterranean, where significant gas reservoirs have been discovered. These include, among others, the Leviathan reservoir, the Tamar reservoir, and the Aphrodite reservoir in Cyprus. The Company also holds rights to royalties from the Karish and Tanin oil assets. Under the Gas Framework, Delek Drilling must transfer all of its rights in the Tamar Project, one of its two most material assets, no later than December 17, 2021. For more information, see Section 1.7.1(g) below.

The Group's strategy in this segment is to focus on the development, production, and sale of natural gas and exploration of oil and natural gas in the Partnership's existing oil assets in the Mediterranean Sea. As of the report's approval date, the Company holds the entire share capital of the general partner in the Partnership (100%) and 54.7% of the participation units issued by the limited partner in the Partnership.

For details about this segment, see Section 1.7 below.

Energy Abroad - These operations are mainly conducted through Ithaca, which holds the rights to actively-producing oil and gas reservoirs on the continental shelf in the North Sea off the coast of England. Ithaca also holds production, treatment, and storage facilities, and has proven operator experience. Ithaca's principal oil assets were purchased from a Chevron subsidiary, in a transaction which was completed in December 2019.

For details about this segment, see Section 1.8 below.

Fuel Products - These operations are conducted through shareholdings in Delek Israel, which mainly deals in sales of fuels and lubricants, the operation of gas stations with on-site convenience stores, and the provision of fuel storage and distribution services in Israel.

Until October 25, 2020, the Company held 100% of Delek Israel's issued and paid-up share capital. On October 26, 2020, the Company completed the sale of 70% of Delek Israel's issued and paid-up share capital, fully-diluted, for a consideration of NIS 525 million. Part of this amount was set as deferred consideration, and the buyers were also given an option to buy another 5% of Delek Israel's share capital. On February 15, 2021, the Company announced that payment of one half of the deferred consideration had been advanced, and that 1.666% of the option granted to the buyers had been exercised. On February 24, 2021, the buyers announced that they would exercise another 3.334% of their option in Delek Israel's share capital. For more information, see the immediate reports of October 18, 2020 (ref. no. 2020-01-113067), October 26, 2020, (ref. no. 2020-01-116238), February 15, 2021(ref. no. 2020-01-018478), and February 25, 2021 (ref. no. 2021-01-045036), included herein by way of reference. As of the report's approval date, the Company (indirectly) held 25% of Delek Israel's share capital. Shares accounting for 5% of Delek Israel's share capital are in escrow, and will be transferred to the buyers against payment of the remaining balance of the deferred consideration.

On February 22, 2020, Delek Israel completed the sale of two wholly-owned power generation plants. For more information, see the immediate reports of July 23, 2020 (ref. no. 2020-01-078138), October 21, 2020, (ref. no. 2020-01-114678), November 15, 2020, (ref. no. 2020-01-122937) and XXX (ref. no. 2020-01-021270), included herein by way of reference.

On July 6, 2020, Delek Israel completed the sale of all of its holdings in Pi Gliloth Limited Partnership ("Pi Gliloth"), and the land on which Pi Gliloth operates its fuel terminals in Haifa, Ashdod, Be'er Sheva, and Jerusalem. For more information, see the Company's immediate reports of May 7, 2020 (ref. no. 2020-01-045153), June 7, 2020, (ref. no. 2020-01-057975) and July 7, 2020 (ref. no. 2020-01-072168), included herein by way of reference.

For details about this segment, see Section 1.9 below.

1.2.2. Sales of assets and holdings in 2020 and until immediately prior to the publication date

In addition to the sale of 70% of Delek Israel's issued and paid-up share capital as aforesaid, in 2020 and until the report's approval date, the Group disposed of several additional holdings and assets, as follows:

On March 26, 2020, the Company completed the sale of its remaining 20% stake in IDE Holdings Limited, a company engaged in desalination operations ("IDE"), in consideration for NIS 164 million. For more information, see the immediate reports of March 16, 2020 (ref. no. 2020-01-025203) and March 26, 2020 (ref. no. 2020-01-030114), included herein by way of reference. As of the publication date of this report, the Company does not hold any shares in IDE.

On April 19, 2020, the Company completed the sale of its entire 51.7% stake in the share capital of Cohen Gas and Oil Development Ltd. ("Cohen Development"), for a consideration of NIS 207 million. Cohen Development is a public company holding rights to royalties from Delek Drilling's oil assets and from the Karish and Tanin oil assets. Cohen Development also holds 50% of the share capital of Avner Oil and Gas Ltd. (in this Section - "Avner Management"), which holds 0.96% of Delek Drilling's participation units. Avner Management's remaining shares are held by Delek Energy. For more information about this transaction, see the immediate report of April 19, 2020 (ref. no. 2020-01-039303), included herein by way of reference, and Note 10K to the financial statements. As of the publication date of this report, the Company does not hold any shares in Cohen Development.

On July 8, 2020, the Group completed the sale of rights to royalties from the Karish and Tanin leases, for a total consideration of NIS 318 million. For more information about this transaction, see the immediate reports of May 25, 2020 and July 8, 2020 (ref. no. 2020-01-052266 and 2020-01-073059, respectively), and Note 12H.2 to the financial statements.

On March 25, 2021, the Company signed a detailed agreement to sell all of a Company subsidiary's rights in 430,000 square meters of land located in Acre, as-is, for a total consideration of NIS 200 million. For more information, see the Company's immediate reports of January 14, 2021 (ref. no. 2021-01-113067), February 10, 2021 (ref. no. 2021-01-017248), February 28, 2021 (ref. no. 2021-01-024300), March 16, 2021 (ref. no. 2021-01-036285), and March 25, 2021 (ref. no. 2021-01-046893), included herein by way of reference, and Section 1.10(b) below.

On May 13, 2020, the Company sold all of its holdings in Mehadrin Ltd. for a total consideration of NIS 74 million. For more information, see the Company's immediate report of May 14, 2020 (ref. no. 2020-01-047682), included herein by way of reference, and Note 10.E.3 to the financial statements.

1.2.3. Operating segments - materiality and description in the report

In recent years, the Group's strategy has been to focus on energy operations in Israel and abroad. As a result, and following the sale of other material operations in recent years, Energy in Israel and Energy Abroad have become the Group's principal operating segments. This is reflected, among other things, in the administrative resources allocated by the Company's management, and by the managements of the Company's investees in these segments, toward developing operations, and toward operational and financial decision-making.

Disclosure on the Group's operating segments in the chapter entitled Description of the Company's Business is made bearing in mind the relative material importance of each operating segment.

1.2.4. COVID-19 pandemic and its effects on the Group and its business

Following the COVID-19 outbreak and additional factors, in the first half of 2020 global markets saw sharp drops in oil and natural gas prices. These drops were mirrored in the prices of shares and other securities issued by the Company and Delek Drilling. As a result, in 2020, the conditions were met for calls for immediate repayment of certain loans taken by the Group. Actions were taken against the Company by banks and by holders of Company debentures which, among other things, required the Company to dispose of holdings and assets and to shore up its collateral to these lenders, as detailed above. As part of these developments, in June 2020 the Company and its debenture-holders signed an arrangement to amend the terms of the Company's debentures. Under the amended arrangement, the Company undertook various restrictions and obligations, including an obligation to raise capital according to the schedule set forth in said amendment. For more information concerning the COVID-19 pandemic and its effects, see Section 1.6.6 below. For more information on the Company's loans and debentures, see the chapter entitled Financing, in Section 1.14 below.

1.3. Equity investments in the Company and transactions in its shares

(A) On August 8, 2019, the Company and Delek Financial Investments issued a purchase offer to buy 135,904 Company shares. The purchase offer was accepted in full, and 135,904 Company shares were purchased. These shares account for 1.13% of the Company's share capital, and were purchased at a price of NIS 544.5 per share, for a total consideration of NIS 74 million. For more information, see the Company's immediate reports of August 8, 2019 (ref. no. 2019-01-082552), September 4, 2019, (ref. no. 2019-01-092437), and September 10, 2019 (ref. no. 2019-01-094822), included herein by way of reference. Buyback of the Company's shares under the purchase offer was made in accordance with the buyback plan for Company shares and debentures in 2019, as approved by the Company's Board of Directors on December 27, 2018. For more information about the Company's buyback plan, see Section E1to the Company's Board of Directors' Report in Chapter B to this report.

(B) On October 6, 2019, the Company's Board of Directors approved the plan to buy back up to NIS 100 million in Company shares and debentures over a one-year period up to October 6, 2020. In accordance with said buyback plan, Delek Financial Investments has bought 164,295 Company shares, 5,024,413 Debentures (Series B34), 153,082 Debentures (Series B33), and 15,661,666 Debentures (Series B31). Furthermore, the Company has bought, under the buyback plan, 1,650,000 Debentures (Series B34), 4,154,141 Debentures (Series B31), 435,000 Debentures (Series B18), and 370,000 Debentures (Series B19), which were delisted from the TASE. For more information about the buyback plan, see the Company's immediate report of October 6, 2019 (ref. no. 2019-01-086409), included in this section by way of reference.

(C) On May 17, 2020, the Company offered to the public, by way of a shelf offering, between 500,000 and 2,000,000 ordinary shares in the Company; between 120,000 and 480,000 warrants (Series 7) exercisable into ordinary shares; and between 120,000 and 480,000 warrants (Series 8) exercisable into ordinary shares ("the Offered Securities"). Between 20,000 units and 80,000 units were offered in the Offered Securities, by way of a tender on the unit price. Each unit was composed of 25 ordinary shares at a price of NIS 100 per share, 6 warrants (Series 7), and 6 warrants (Series 8), for no consideration. Following the results of the tender for these units, the Company allocated 1,371,350 ordinary shares, 329,124 warrants (Series 7) and 329,124 warrants (Series 8). The Company's total gross proceeds amounted to NIS 137 million. For more information, see the Company's immediate reports of May 17, 2020 (ref. no. 2020-01-048828) and May 18, 2020 (ref. no. 2020-01-049647), included here by way of reference.

(D) On August 2, 2020, the Company offered to the public, by way of a shelf offering, up to 2,198,200 ordinary shares in the Company; up to 758,000 warrants (Series 9); up to 379,000 warrants (Series 10); up to 758,000 warrants (Series 11); and up to 379,000 warrants (Series 12). All warrants (Series 9-12) are exercisable into ordinary shares in the Company ("the Offered Securities"). Based on the results of the tender for purchasing the Offered Securities, the Company issued all of the Offered Securities for a total (gross) consideration of NIS 175,856 thousand. For more information, see the Company's immediate reports of August 2, 2020 (ref. no. 2020-01-081795) and August 4, 2020 (ref. no. 2020-01-083622), included here by way of reference.

(E) On December 16, 2020, the Company offered to the public, by way of a shelf offering, 361,000 ordinary shares in the Company. The Company allocated all of the offered shares. In consideration for this issuance, the Company recorded immediate (gross) proceeds of NIS 39.7 million. For more information, see the Company's immediate reports of December 16, 2020 (ref. no. 2020-01-128635) and (ref. no. 2020-01-129052), included here by way of reference.

(F) As of the publication date of this report, a total of 1,351,863 warrants (Series 7-12) have been exercised (including by principal shareholders as detailed in Section 1.3.7 below) into Company shares, for a total consideration of NIS 116 million.

(G) Information, to the best of the Company's knowledge, concerning off-TASE transactions in Company shares, conducted by the Company's principal shareholders between December 31, 2018 and the reporting date:

Principal shareholder	Transaction date	Type of transaction	Number of shares	Share price in NIS	Total consideration (NIS thousands)
Yitzhak (Sharon) Tshuva	February 20, 2020	Purchase	101,200	435	44,022
Gabriel Last	December 9, 2020	Exercise of warrants	150	100	15
Yitzhak (Sharon) Tshuva	December 13, 2020	Exercise of warrants	124,544	75	9,341
Yitzhak (Sharon) Tshuva	December 15, 2020	Exercise of warrants	80,096	75	6,007

Principal shareholder	Transaction date	Type of transaction	Number of shares	Share price in NIS	Total consideration (NIS thousands)
Yitzhak (Sharon) Tshuva	December 23, 2020	Sale	42,970	98.45	4,230

1.4. Dividends

1.4.1. Distribution of dividends in the past two years and balance of distributable profits

Dividends declared by the Company in 2019-2020 until shortly prior to the report approval date:

Declaration date	Payout date	Dividend per share (NIS)	Total dividend (NIS millions)
May 29, 2019	June 27, 2019	10.0137	120
March 31, 2019	April 29, 2019	11.6826	140

In all, in 2019 the Company distributed a total of NIS 260 million in dividends. These payouts did not require Court approval under the Companies Law, 1999 "the Companies Law").

In 2020 and until immediately prior to the publication date of this report, the Company did not make any dividend payments.

As of December 31, 2020, the Company's distributable earnings, under Section 302 of the Companies Law totaled NIS 915 million.

1.4.2. Dividend distribution policy

As of the reporting date, the Company does not have a dividend distribution policy. The Company is restricted from making dividend distributions under the amended deeds of trust for its debenture series, as detailed below.

1.4.3. Restrictions on dividend distributions

Restrictions under the amendment to the Company's deeds of trust

On June 17, 2020, a meeting of the holders of the Company's various debenture series approved an amendment to the deed of trust for each of the Company's debenture series. This amendment included, among other things, a restriction on dividend distributions, whereby the Company would not make a distribution including dividend distributions and would not buy back its shares and would not make any payments to holders of senior shares until 7 days had passed from the Company's publication of an immediate report announcing that it had met the "Expiration Condition" whereby:

the Company's equity as presented in its most recently-published financial statements (annual or quarterly), and in the statements published in the preceding quarter exceeded the higher of either: (a) NIS 2.8 billion, less any cash amount raised by the Company as equity in excess of the amounts raised after publication of the amended deed of trust; and (b) NIS 2.1 billion. However, in order to meet the Expiration Condition for the purpose of making a distribution (dividend distribution, buyback of shares, and payment to holders of senior shares), said equity will not be less than NIS 3 billion after such distribution is made (including by way of dividend or buyback of shares).

The ratio of the Company's equity to its balance sheet total as presented in the most recent separate financial statements (annual or quarterly) published by the Company, and as presented in the financial statements published in the preceding quarter, will not be less than 22.5%.

The most recent rating for the Company's debentures will be at least an A rating on S&P Maalot's rating scale.

For more information on the amended deed of trust, see Section 1.14.3 below.

Part Two – Other Information

1.5. Financial information concerning the Group's operating segments

The following table details financial information concerning the Group's operating segments:

2020 (NIS millions) -

2020 (NIS millions)		Energy in Israel	Energy Abroad	Delek Israel	Others	Consolidation adjustments	Consolidated
Revenues	Revenues from externals	2,667	4,052	-	8	(56)	6,671
	Revenues from other segments	-	-	-	-	-	-
	Total	**2,667**	**4,052**	**-**	**8**	**(56)**	**6,671**
Total attributable costs	Costs constituting revenues for another segment	-	-	-	-	-	-
	Other costs	1,962	4,786	-	(16)	34	6,766
	Total	**1,962**	**4,786**	**-**	**(16)**	**34**	**6,766**
	Fixed costs attributed to segment	-	-	-	-	-	-
	Variable costs attributed to segment	1,962	4,786	-	(16)	34	6,766
Profit (loss) from operating activities attributed to owners of the parent		382	(734)	-	24	90	(48)
Share in profit from operating activities attributed to non-controlling interest		323	-	-	-	-	323
Total assets attributed to segment		19,448	13,470	-	509	851	34,278
Total liabilities attributed to segment		13,433	9,706	-	43	5,910	29,002

2019 (NIS millions) -

2019 (NIS millions)		Energy in Israel	Energy Abroad	Delek Israel	Others	Consolidation adjustments	Consolidated
Revenues	Revenues from externals	1,332	2,062	-	22	(60)	3,356
	Revenues from other segments	-	-	-	-		-
	Total	**1,332**	**2,062**	**-**	**22**	**(60)**	**3,356**
Total attributable costs	Costs constituting revenues for another segment	-	-	-	-	-	-
	Other costs	683	2,166	-	85	(5)	2,929
	Total	**683**	**2,166**	**-**	**85**	**(5)**	**2,929**
	Fixed costs attributed to segment	-	-	-	-	-	-
	Variable costs attributed to segment	683	2,166		85	(5)	2,929
Profit (loss) from operating activities attributed to owners of the parent		391	391	(104)	-	(63)	(55)
Share in profit from operating activities attributed to non-controlling interest		258	258	-	-	-	-
Total assets attributed to segment		22,889	22,889	16,635	-	392	7,047
Total liabilities attributed to segment		15,401	15,401	11,293	-	132	12,560

(*) Revenue, cost, and profit data have been reclassified following the sale of control in Delek Israel. For more information, see Note 10K to the financial statements.

2018 (NIS millions) -

2018 (NIS millions)		Energy in Israel	Energy Abroad	Delek Israel	Others	Consolidation adjustments	Consolidated
Revenues	Revenues from externals	1,412	1,174	-	55	(43)	2,598
	Revenues from other segments	_	-	-	-	_	-
	Total	**1,412**	**1,174**		**55**	**(43)**	**8,128**
Total attributable costs	Costs constituting revenues for another segment	-	-	-	-	-	-
	Other costs	298	664	-	138	37	1,137
	Total	**298**	**664**	**-**	**138**	**37**	**1,137**
	Fixed costs attributed to segment	-	-	-	-	-	-
	Variable costs attributed to segment	298	664	-	138	37	1,137
Profit (loss) from operating activities attributed to owners of the parent		640	640	510	-	(83)	(80)
Share in profit from operating activities attributed to non-controlling interest		474	474	-	-	-	-
Total assets attributed to segment		22,204	22,204	7,479	-	419	96,940
Total liabilities attributed to segment		13,436	13,436	4,463	-	94	96,789

(*) Revenue, cost, and profit data have been reclassified following the sale of control in Delek Israel. For more information, see Note 10K to the financial statements.

For details about the main developments in the financial data, see the Board of Directors' explanations regarding the Corporation's affairs.

1.6. General environment and impact of external factors

1.6.1. General

The Company's investees, through which the Company conducts its energy operations in Israel and abroad, are controlled by the Company, with holdings of more than 50%. The Company's fuel product operations in Israel are carried out through Delek Israel. As of the report's approval date, the Company held a 33.34% interest in Delek Israel.

The Company's financial data and its operating results are affected by the financial data and operating results of its investee companies, and by its sale or acquisition of holdings. The Company's cash flow is affected, among other things, by dividends and management fees paid by investees, by proceeds earned from the sale of Company holdings and assets, and the Company's ability to raise financing that depends, among other things, on the value of its holdings and assets.

1.6.2. Market developments and volatility

Market developments and fluctuations may have a significant effect on the results of the Company and its investee companies, on their liquidity, the valuation of their assets, their ability to dispose of such assets, the state of their business, their financial covenants, their credit rating, their ability to distribute dividends, and their ability to raise funds to finance their ongoing operations and their long-term operations, as well as the terms of such financing. The Group's results are materially affected by developments and volatility in each segment's relevant markets and the underlying factors, as detailed below.

For information concerning extreme changes in energy prices on international markets in 2020 due, among other things, to the COVID-19 outbreak, see Section 1.6.6 below.

1.6.3. Exchange rates

The Company’s functional currency and the presentation currency of the Company’s financial statements is the NIS. However, the functional currency for the Delek Drilling partnership and for Ithaca, is the USD. Thus, the Group's results and the equity attributable to the Company's shareholders are materially affected by changes in exchange rates against the NIS.

1.6.4. Regulation

The Company and several of its investees are subject to statutory restrictions and the directives of various regulatory bodies, in Israel and abroad, such as the Gas Framework, anti-trust provisions, and provisions relating to the supervision of product and service prices. Furthermore, the Group's ability to raise funds is affected, among other things, by regulation, such as the Proper Conduct of Banking Business provisions (see below) and regulation of off-bank credit, such as the regulation adopted by the Ministry of Finance Capital Market, Insurance and Savings Commissioner ("the Capital Market Commissioner") following the Hodek Committee's recommendations.

The Company is affected by changes in competition laws or their application, primarily in those fields in which it has significant operations. For more information on applicable regulation in Energy in Israel operations, see Sections 1.7.27 and 1.7.28 below; for regulation applicable to Energy Abroad operations, see Section 1.8.22; and for Fuel in Israel operations, see Sections 1.9.15 and 1.9.16 below.

On December 11, 2013, the Promotion of Competition and Reduction of Market Concentration Law, 2013 was published in the Official Gazette ("the Market Concentration Law"). On December 11, 2014, the chapter in the Market Concentration Law concerning the application of market-wide concentration considerations and industry-specific competition considerations in rights allocations went into effect. On March 2, 2021, the Committee for Reducing Market Concentration issued, pursuant to the Market Concentration Law's provisions, a list of concentration-promoting entities in the Israeli market, a list of significant non-financial entities, and a list of significant financial entities. The Group is included in the list of entities promoting market concentration. For information on the Market Concentration Law's effects on the Company and/or its subsidiaries, and the implications of the Company's inclusion in the list of market concentration promoting entities, see Section 1.17 below.

The Company and several of its investee companies are affected by the Proper Conduct of Banking Business Regulations issued by the Supervisor of Banks in Israel. These regulations include, among other things, restrictions on the scope of the loans that Israeli banks can grant to "single borrowers", and the largest "borrower group" in the bank (as these terms are defined in the aforesaid regulations). Accordingly, the scope of the loans issued to the Group's companies and the controlling shareholder in the Company may, under certain circumstances, affect the ability of the Group's companies to borrow additional amounts from banks in Israel.

The Company and its investee companies are also affected by the Government of Israel's policies in various matters (e.g. – monetary policies), and by the requirements of authorities monitoring environmental quality.

1.6.5. Developments in the Israeli economy

Economic developments in Israel materially affect the results of operations. These developments stem, inter alia, from economic, political and security conditions in Israel.

For more information concerning the general economic environment and external factors that specifically affected the Delek Group's operating segments, see the description for each operating segment below.

1.6.6. COVID-19 pandemic and its impact on the Group

At the end of 2019 and in the first quarter of 2020, the COVID-19 coronavirus began spreading in China and then around the world (including in Israel). In March 2020, the World Health Organization declared the virus a global pandemic ("the COVID-19 Pandemic").

Due to the COVID-19 Pandemic, as well as other factors, in the first half of 2020 extremely sharp drops were recorded in oil and natural gas prices on the global markets.

Following this sharp drop in energy product prices, in the first three quarters of 2020 Israel and many other countries also saw high volatility and sharp drops in the prices of securities issued by energy companies. These include securities issued by the Company and the Delek Drilling partnership, which are traded on the Tel Aviv Stock Exchange. It is, however, noted that, toward the end of 2020 and in the initial months of 2021, energy product prices regained ground on the global markets. These increases were also seen in oil and LNG prices.

Due to the drop in the prices of energy products and of the Company's and Delek Drilling's securities, actions were taken against the Company as aforesaid by banks and by holders of Company debentures. These required the Company, among other things, to dispose of holdings and assets, to repay its main bank loans, and to reach an arrangement with its debenture-holders whereby the Company undertook certain obligations and restrictions. For more information, see Section 1.14 – Financing, below.

As of the report's approval date, it is difficult to estimate how the COVID-19 Pandemic will develop and play out over the coming years, what its impact will be on the global economy, and how it will effect demand, supply and prices for oil and natural gas produced and sold by the Group's companies. Under these circumstances, the COVID-19 Pandemic constitutes a global macro-economic risk creating uncertainty concerning future economic activity worldwide and concerning the expected impact on financial markets, interest rate margins, currency prices, and energy commodity prices. Thus, the COVID-19 Pandemic may adversely affect numerous industries, including those segments in which the Group operates.

Following the Coronavirus Crisis, many countries, including Israel, are enacting various measures to try and prevent the virus from spreading. These include restricting movement and public gatherings, restricting transport (of people and goods), border closings, and more. Besides the adverse effects of these measures on economic growth, both locally and globally, these restrictions may have a material adverse effect on the operations of investee companies, including on the regular production of oil and natural gas from their oil assets in the Mediterranean and the North Sea. These effects may cause delays in work plans for the various projects.

For more information on the effect of the COVID-19 Pandemic and the risks affecting the Group's core segments, see Sections 1.7.33(b), 1.8.26(c)-(d) and 1.9.20(a) below.

Warning concerning forward-looking information - The Company's assessments concerning the possible implications of the Coronavirus Crisis and the global economic crisis for the Company and its investees constitute forward-looking information as defined in Section 32A to the Securities Law. This information is based on the Company's assessments, as of the

report's approval date, concerning global macro-economic factors outside the Company's control, and so there is no certainty that the Company's assessments will materialize.

1.6.7. The Group's and its subsidiaries' financial position

As of December 31, 2020, the Company, separately, had a working capital deficit of NIS 5.2 billion, while the Group had a consolidated working capital deficit of NIS 4.3 billion. For more information, see Note 1C to the financial statements.

Part Three – Description of the Company's Business by Operating Segment

Below is a separate description of the Group's business in each of its operating segments:

1.7. Energy in Israel

1.7.1. General

The Company's operations in the energy sector in Israel are carried out through its holdings in Delek Drilling – Limited Partnership ("Delek Drilling" or "the Partnership"), which holds the rights in oil assets in the Mediterranean Sea where significant gas reservoirs were discovered, including the Tamar reservoir, the Leviathan reservoir, and the Aphrodite reservoir in Cyprus.

For information about the oil assets in the Mediterranean Sea in Israel and Cyprus in which the Company holds rights, see sections 1.7.4 to 1.7.10 below.

The Group's strategy in this area of activity is to focus on the development, production, and sale of natural gas in the existing oil assets of the Partnership, and oil and natural gas exploration in the Mediterranean Sea.

For definitions of some of the professional terminology used in this section, see the definitions appendix at the end of the chapter.

(A) The Company's holdings in Delek Drilling

(1) Delek Drilling is a public limited partnership, within its meaning in the Partnerships Ordinance [New Version], 1975 ("Partnership Ordinance"), which was established under a partnership agreement signed on July 1, 1993 (as amended from time to time) ("the Partnership Agreement") between Delek Drilling Management (1993) Ltd. ("the General Partner") as the general partner of the first part and Delek Drilling Trusts Ltd. as the limited partner of the second part ("the Limited Partner"). The Partnership was registered on July 25, 1993 under the Partnerships Ordinance. In accordance with the Partnership Agreement, the Limited Partner holds 99.99% of the capital rights in the Partnership.

In accordance with the provisions of the Partnerships Ordinance and the Partnership Agreement, the ongoing management of the Partnership is performed by the General Partner. Delek Energy, a wholly-owned private subsidiary of the Company (100%), holds all the issued share capital (100%) of the General Partner.

(2) On May 17, 2017, the merger between the Partnership and Avner Oil Exploration - Limited Partnership ("Avner" or "the Avner Partnership") was completed , such that all the assets and liabilities of Avner were transferred as is to the Partnership, the limited partner issued participating units to the holders of the participating units in Avner Partnership, and Avner Partnership was liquidated without dissolution and was struck off from the records of the Registrar of Partnerships ("the Merger" or "the Merger of the Partnerships").

(3) As at the approval date of the report, the Company holds, directly and indirectly, 54.7% of the unit capital issued by the Limited Partner ("the Issued Unit Capital"), as follows: (A) The Company directly holds 5.1% of the Issued Unit Capital. (B) Delek Energy holds 43.5% of the Issued Unit Capital as at the approval date of the report. (C) The General Partner holds 5.6% of the Issued Unit Capital as at the approval date of the report. (D) Delek Energy holds 50% of the share capital of Avner Oil and Gas Ltd.,[1] which, as at the approval date of the report, holds 0.96% of the Issued Unit Capital (the share of Delek Energy – 0.48%).[2]

(4) On October 5, 2020, Chevron Corporation ("Chevron") announced the completion of the merger transaction between Chevron and Noble Energy Inc. ("Noble Inc."), the parent company of Noble Energy Mediterranean Ltd. ("Noble"), the operator in the Tamar and Leviathan oil assets, and of Noble Cyprus, the operator in the Block 12 project in Cyprus. As at the reporting date, Noble Inc. is a wholly-owned company of Chevron. Chevron is a foreign public company and its shares are traded on the NYSE. To the best of the Company's knowledge, there is no single shareholder holding more than 10% of the issued share capital of Chevron.

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1 Up to the completion date of the merger between the Delek Drilling and Avner Oil and Gas Exploration partnerships on May 17, 2017, Avner Oil and Gas Ltd. served as the general partner in Avner Oil Exploration Limited Partnership.

2 For information about the Partnership's units pledged in favor of the Company's debenture holders, see section 1.14.3(A) below.

(5) The Partnership’s main business is exploration, development, and production of natural gas, condensate, and oil in Israel and Cyprus, and promotion of various natural gas-based projects, with the aim of increasing natural gas sales from the Partnership's assets. At the same time, the Partnership is assessing business opportunities with similar characteristics to those in which the Partnership is already active in exploration, development, and production of natural gas and oil.

(6) As at the approval date of the report, the main oil assets of the Partnership are as follows:

A. Leviathan project: The Partnership holds rights at a rate of 45.34% (out of 100%) in the I/14 Leviathan South and the I/15 Leviathan North leases ("the Leviathan South Lease" and "the Leviathan North Lease", respectively, and collectively: the Leviathan Leases”) The Leviathan natural gas reservoir was discovered in the area of the Leviathan Lease, including a 2P natural gas discovery, as at December 31, 2020, in a total volume of 13.09 TCF (100%). Commercial production from the Leviathan reservoir began in December 2019. For information about the Leviathan project, see section 1.7.4 below.

B. Tamar project: The Partnership holds rights at a rate of 22.0% in the I/12 Tamar and I/13 Dalit leases (“the Tamar Lease” and “the Dalit Lease”), respectively, and collectively: "the Tamar Leases"). The Tamar natural gas reservoir was discovered in the area of the Tamar Lease, including a 2P natural gas discovery, as at December 31, 2020, in a total volume of 10.48 TCF (100%). Commercial production from the Tamar reservoir began in March 2013. For information about the Tamar project, see section 1.7.5 below. The Dalit natural gas reservoir was discovered in the area of the Dalit Lease, including 2C contingent resources, as at December 31, 2020, in a total volume of 0.27 TCF (100%). For information about the Dalit oil asset, see section 1.7.5 below.

C. Block 12 in Cyprus: The Partnership holds rights at a rate of 30% in an oil asset in the exclusive economic zone of the Republic of Cyprus, in an area known as Block 12 (“Block 12”). The Aphrodite natural gas reservoir was discovered in the area of the Block 12 oil asset, including 2C contingent resources, as at December 31, 2020, in a total volume of 3.48 TCF (100%). For information about the Block 12 oil asset, see section 1.7.6 below.

D. Karish and Tanin leases: In August 2016, the Partnership and Avner Partnership sold their rights in the I/16 Tanin and I/17 Karish leases “the Tanin Lease” and “the Karish Lease”, respectively) to Energean Israel Ltd. ("the Energean Transaction"). In this transaction, as part of the consideration for the sale of the rights, the sellers received a right to royalties from the Karish and Tanin Leases at a rate of 5.12% before payment of the oil profits tax under the Taxation of Profits from Natural Resources Law, 2011 (“the Levy") and before the investment recovery date; 2.47% before payment of the Levy and after the investment recovery date; and 3.22% upon the start of payment of the Levy and after the investment recovery date. According to information published by Energean Oil and Gas PLC, which, to the best of the Company’s knowledge, is the parent company of Energean Israel Ltd. (jointly below: "Energean"), as at the approval date of the report, among other things, 2P natural gas reserves amounting to98.2 BCM and hydrocarbon reserves amounting to 99.6 million barrels are attributable to the reservoirs discovered in the area of the Karish and Tanin Leases. For further information about the Energean Transaction, see section 1.7.29(Q) below, and for information about the Karish and Tanin Leases, see section 1.7.10 below.

E. In addition to rights in oil assets, as at the approval date of the report, the Partnership holds shares conferring 22.6% of the capital rights and 13.42% of the voting rights in Tamar Petroleum Ltd. ("Tamar Petroleum"), as part of the consideration received by the Partnership in the transaction in July 2017 for the sale of 9.25% (out of 100%) of the rights in the Tamar and Dalit Leases. For further information about the transaction, see section 1.7.29(R) below.

In accordance with the provisions of the Gas Framework (as defined in section 1.7.1(G)(1) below), the Partnership is required to transfer its full rights in the holdings of Tamar and Dalit, as well as its holdings in Tamar Petroleum, by December 17, 2021.

In the past year, the Partnership has taken steps to advance a possible framework for splitting its assets. For further information, see section 1.7.31 below.

(B) The Company's holding in rights to royalties from oil assets in Israel and Cyprus

The Company holds, directly and indirectly, the rights to royalties from the Partnership's oil assets and from the Karish and Tanin oil assets (“the Rights to Royalties”), as follows:[3]

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[3] As set out in section 1.2.2(B) above, on April 19, 2020, the Company sold all its holdings in the shares of Cohen Development, which held the rights to royalties from all of the Partnership's oil assets.

(1) Under the 1993 agreement for the transfer of oil rights to the Partnership described in section 1.7.29(N)(2) below ("the 1993 Agreement"), the Company and Delek Energy hold the rights to royalties from the Partnership (the Company's share, 25% and Delek Energy's share, 75%), at a rate of 1.5% before the investment recovery date and 6.5% after the investment recovery date, of the Partnership’s share in all the oil assets it holds. For a description of the rights to royalties of the Company and Delek Energy under the 1993 Agreement, see section 1.7.29(N)(2) below.

(2) Under the Energean Transaction, Energean Israel Ltd. assumed the Partnership’s undertaking to pay royalties to the Company and Delek Energy (under the 1993 Agreement) for the rights in the Karish and Tanin Leases that were sold to it by the Partnership in this transaction. For information about the Energean Transaction, see section 1.7.29(Q) below. As at the approval date of the report, the Company is reviewing the option of exercising its right to overriding royalties from the Karish and Tanin Leases.

(3) In June 2018, Delek Energy sold its right to royalties from the Tamar and Dalit Leases to Delek Royalties Ltd., as described in section (C) below. In July 2019, the Company sold its right to royalties from the Tamar and Dalit Leases to the Study Funds for Teachers and Kindergarten Teachers, as set out in the Immediate Reports of July 21, 2019 (Ref. No. 2019-01-074494) and December 26, 2019 (Ref. No. 2019-01-114384).

(4) Up to April 19, 2020, the Company held 51.7% of the share capital of Cohen Development. Cohen Development holds 50% of the share capital of Avner Oil and Gas Ltd. (together with Delek Energy, which also holds 50%). The main operation of Avner Oil and Gas Ltd. is a holding of 0.96% of the unit capital of Delek Drilling. On April 19, 2020, the Company completed the sale of all its holdings in Cohen Development. For further information, see Note 10L to the Company’s financial statements and the immediate report of April 19, 2020 (Ref. No. 2020-01-039303). The information in this report is included as a reference.

(5) In July 2020, the Company and Delek Energy sold their rights to royalties from the Karish and Tanin leases for a consideration of NIS 318 million plus VAT.

(6) In October 2020, a transaction was completed for the transfer of the rights of the Company and Delek Energy in the royalty on Leviathan and the rights related to the royalty to Delek Leviathan Overriding Royalty Ltd., a special purpose company (100%) of Delek Energy (“Delek Leviathan”), which issued debentures to classified foreign and Israeli investors guaranteed by the lien on the right to royalties from Leviathan. For further information, see section 1.7.22(B) below.

(C) <u>Disposal of the Company's holdings in the shares of Delek Royalties</u>

Delek Royalties (2012) Ltd. (above and below: (“Delek Royalties”) is a public company whose shares are listed on the Tel Aviv Stock Exchange.

Until December 29, 2020, the Company held Delek Royalty shares through Delek Energy. On December 29, 2020, the Company completed the sale of its entire holdings in Delek Royalties, as described below:

(1) On June 7, 2018, Delek Energy completed a transaction for the sale to Delek Royalties Ltd. of its right to royalties from the Partnership and from Tamar Petroleum for their share in the Tamar project (“the Delek Royalties Transaction”). As part of the consideration for the sale, Delek Energy received, in this transaction, shares representing 39.93% of the issued capital of Delek Royalties. Shortly before the completion date of the transaction, Delek Energy undertook an irrevocable obligation, whereby all the shares that it holds or will hold, directly, or by another corporation controlled by it, and for as long as they are held by them, will not confer on it voting rights and the right to appoint directors. It is clarified that all the capital rights underlying these shares remained in effect, and that if the shares of Delek Royalties are transferred or sold to a third party, they will confer on the transferee the full voting rights attached to them.

For further information about the Delek Royalties Transaction, see section 1.7.26(A)(3)b to the Company's Periodic Report for 2019 as published on May 3, 2020 (Ref. No. 2020-01-043356) (“The Company’s Periodic Report for 2019”) and section 1.7.36(A) to the Company's Periodic Report for 2018, as published on March 31, 2019 (Ref. No. 2019-01-029344) (“the Company’s Periodic Report for 2018”).

(2) On September 13, 2020, the Company, through Delek Energy, entered into an agreement with a third party for the sale of the entire holdings of Delek Energy (39.3%) in Delek Royalties, in which it was determined that part of the consideration will be paid in cash, and part under a special tender offer to be published by the buyer (“the Tender Offer"). On September 17, 2020, the buyer published the Tender Offer, which was revised from time to time. On November 16, 2020, the results of the

Tender Offer were published, such that according to the response rate, the percentage of acquisitions from each offeree that responded was 74.39%. Subsequent to completion of the Tender Offer, Delek Energy held 7.07% of the share capital of Delek Royalties. For further information, see section A.2 of the third part of the update to Chapter A in the Company's quarterly report for the period ended September 30, 2020, which was published on November 26, 2020 (Ref. No: 2020-01-127563) ("the Third Quarter Report for 2020"), the information in which is included as a reference.

(3) On December 29, 2020, the Company sold the balance of all its holdings in Delek Royalties (7.07%) in an off-floor transaction. For further information, see the Company's immediate report dated December 30, 2020 (Ref. No. 2020-01-141972). The information in this report is included as a reference.

(D) <u>Company's share of reserves and contingent resources attributed to the oil assets in the Mediterranean sea</u>

The tables below present information about the share attributable to the Company as at December 31, 2020, in 2P reserves and 2C contingent resources attributed to the oil assets in the Mediterranean Sea in which the Company holds direct and indirect rights, through its holdings of 54.7% of the Partnership's units and rights to royalties (the holdings are as at the approval date of the report).

The following information about the resources is based on information obtained from NSAI, the Company's independent reserves valuator.

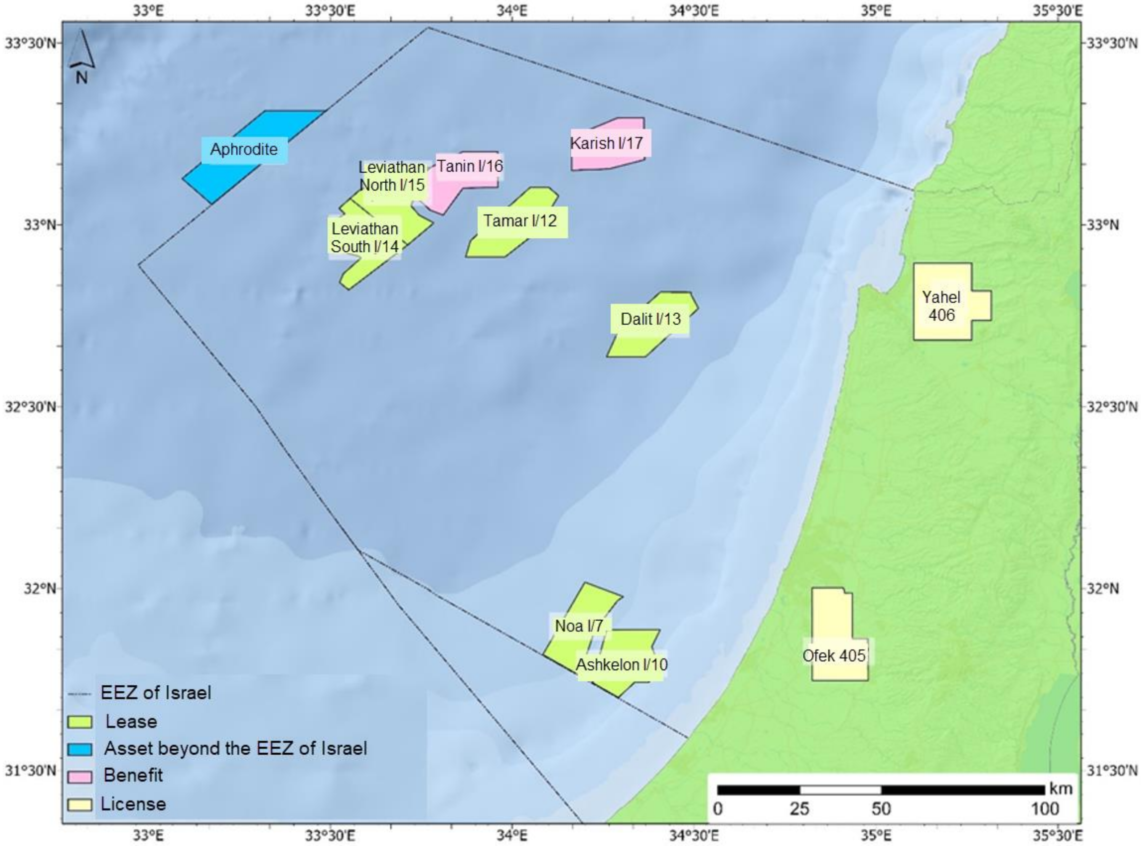
	2P reserves (share attributable to the Company)		**2C contingent resources (share attributable to the Company)**	
	Natural gas (BCF)	**Condensate (millions of barrels)**	**Natural gas (BCF)**	**Condensate (millions of barrels)**
Leviathan project	2,893.9	6.4	2,133.7 (1)	4.7[1)]
Tamar project(2)	977.9	1.3	-	-
Block 12, Cyprus (3)	-	-	570.2	1.2

The information refers to 2C contingent resources attributable to the reservoir from Phase 1 - First Stage and future developments together. For information about each one separately, see section 1.7.4(J) below.

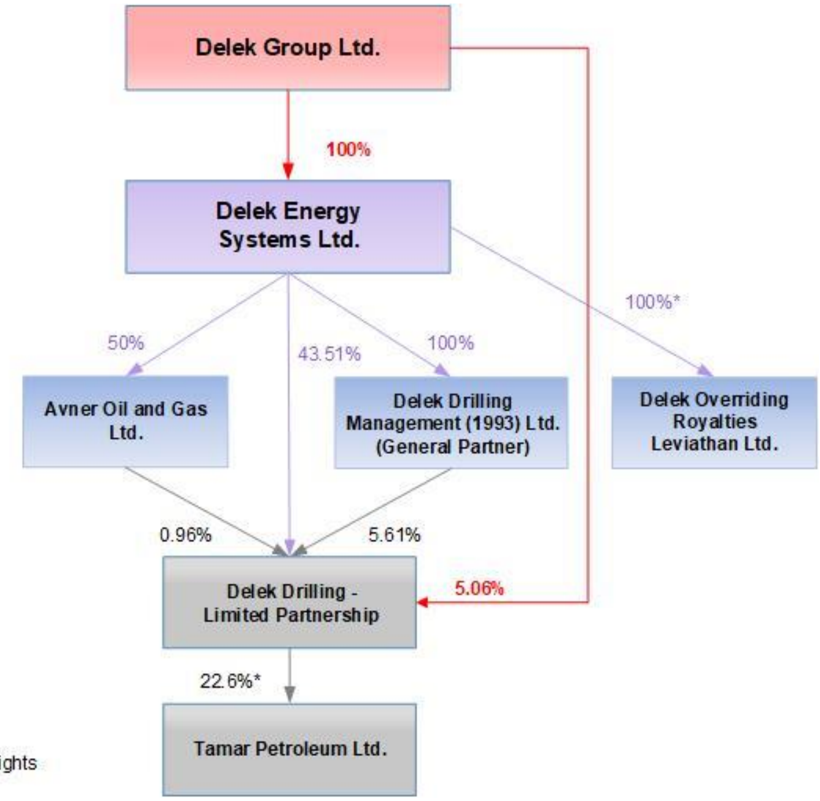
(1) The information refers to reserves attributable to the Tamar and Tamar SW reservoirs together. For information about the reserves attributable to each separately, see section 1.7.5(K)(1)(a) below.

(2) The information in the table refers to contingent resources attributable to the targets in Block 12 together. For information about the contingent resources attributable to each separately, see section 1.7.6(M) below.

(E) Map of all oil assets of the Company in the Mediterranean Sea area, as at the approval date of the report:



The chart below presents the Company's main holdings in the energy sector in Israel as at the approval date of the report:



** 13.42% of the voting rights

(F) The Gas Framework

(1) On August 16, 2015, Government Decision 476 (which was adopted with some adjustments on May 22, 2016) was approved, regarding the outline for regulation of the natural gas market in Israel, including in respect of the Partnership's rights in the Tamar, Leviathan, Karish, and Tanin natural gas reservoirs, which came into effect on December 17, 2015, with an exemption from a number of provisions of the Antitrust Law, 1988 ("the Economic Competition Law")[4] for the Partnership, Avner Oil Exploration Limited Partnership ("Avner"), Ratio Oil Exploration (1992) – Limited Partnership ("Ratio"), and to Noble by the Prime Minister, acting as Minister of Economy, in accordance with Section 52 of the Economic Competition Law (the government decision and provisions of the exemption are referred to collectively below as: "the Gas Framework"). For further information about the Gas Framework, see section 1.7.25(A) below.

(2) In accordance with the provisions of the Gas Framework, the Partnership is required to transfer, by December 17, 2021 ("the Effective Date for Tamar"), its entire holdings in the Tamar and Dalit Leases and to sell its holdings in Tamar Petroleum share. As at the approval date of the report, the Partnership is assessing various alternatives for the sale of its entire rights in the Tamar and Dalit Leases in accordance with the requirements set out in the Gas Framework. For further information, see section 1.7.31 below.

(G) Merger with Delek Energy and Delek Petroleum

On December 27, 2018, the Company's board of directors passed a resolution to approve the merger of Delek Energy and Delek Petroleum Ltd., without consideration, effective as from December 31, 2018. The proposed structure is intended for a business and economic purpose, and its objective is to allow the management of the merging companies within one legal entity. According to the merger agreement, its validity, performance, and completion are subject to the receipt of a number of approvals, including, a preruling from the Tax Authority, which will be accepted by each of the merging companies, according to which the merger plan under section 103C of the Income Tax Ordinance will be executed without a tax liability (tax deferral) in accordance with the provisions of Part E2 of the Income Tax Ordinance. The merger agreement, as amended, further stipulates that if, notwithstanding the efforts of the parties, the preconditions in the agreement have not been fulfilled in full by September 30, 2019, or a certificate of merger has not been issued by that date ("the Deadline"), the merger agreement and the transaction will be cancelled. On January 1, 2019, the Company submitted a merger proposal to the Registrar of Companies and an application was submitted to the Tax Authority for a preruling as set out in the agreement. Under the amendments to the merger agreement dated September 29, 2019 and March 29, 2020, the deadline was deferred and as at the approval date of the report, it will be September 30, 2020.

1.7.2. General environment and effect of external factors

(A) The Petroleum Law, 1952 regulates exploration, development, and production of oil and natural gas in Israel, and stipulates, among other things, that exploration in Israel may only be in geographical areas where the exploration company holds oil and gas rights under the Petroleum Law. The Natural Gas Sector Law, 2002 ("the Natural Gas Sector Law") regulates the transmission, distribution, marketing, and storage of natural gas and/or liquefied natural gas ("LNG") in Israel. In addition, the Taxation of Profits from Natural Resources Law regulates, among other things, tax issues, oil profits tax, and payment of royalties to the state. For further information about the Petroleum Law, the Natural Gas Sector Law, and the Taxation of Profits from Natural Resources Law, see sections 1.7.27(A) and 1.7.27(B) below, respectively.

(B) The economic viability of investments in exploration and development of natural gas reservoirs is heavily dependent on global oil and gas prices, including LNG prices, the demand for natural gas in local, regional, and international markets and on the export potential of natural gas (through pipelines, compressed or liquefied), which also requires significant gas reserves and a long-term agreements for the same of natural gas in significant quantities, which would justify the heavy investments required to establish suitable infrastructure and/or the payments for usage fees for existing infrastructure. In addition, the volume of payments to the state has a significant effect on the economic viability of investments in oil and gas projects.

(C) Development of the natural gas market in Israel began in 1999-2000 with the discovery of the Noa reservoir in the Noa Lease and the Mari B reservoir in the Ashkelon Lease. Total consumption of natural gas in Israel has increased alongside the progress of construction of the transmission

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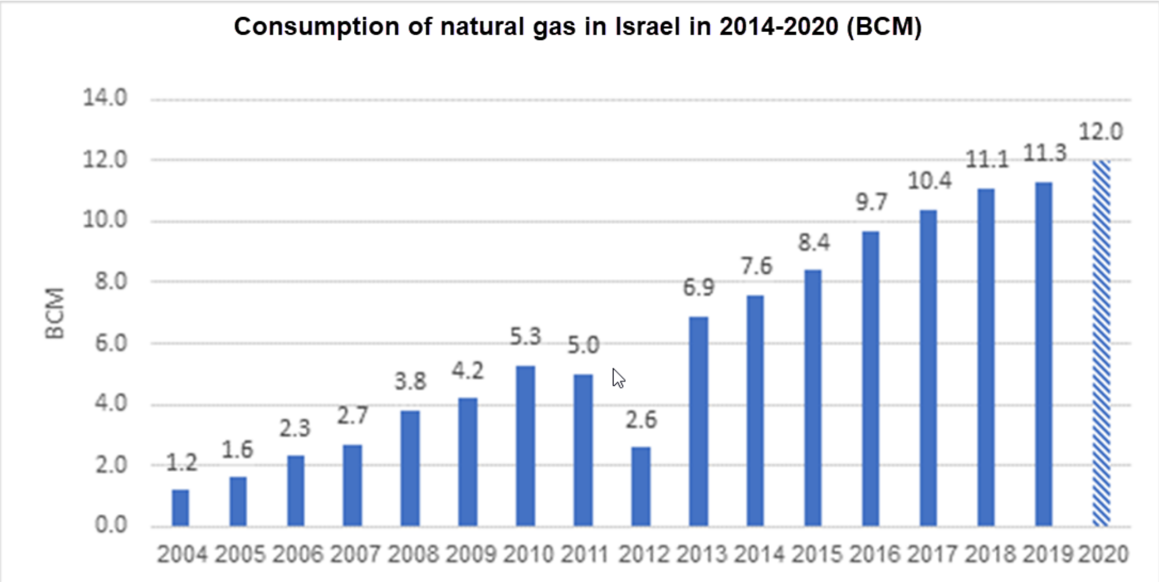
[4] On January 1, 2019, the amendment to the Competition Law was approved, including the change of the name of the law from the Restrictive Trade Practices Law to the Economic Competition Law.

infrastructure of Israel Natural Gas Lines Ltd. ("INGL") and the connection of consumers (including the Israel Electric Corporation's power stations and independent power producers) to the transmission system and the connection of smaller consumers to the distribution system.

(D) Over the last two decades, there have been significant changes in the natural gas sector in Israel (including regulatory, economic, commercial, and environmental changes). Within a few years, natural gas in the Israeli market has become the main component in fuel for electricity production and a material source of energy for indu stry. The natural gas reserves that were discovered in Israel are capable of supplying all the gas requirements of the Israeli market in the coming decades, and most of its energy requirements, thereby significantly reducing Israel's dependence on foreign energy sources and allowing the export of commercial quantities of natural gas in substantial amounts to neighboring countries, mainly Egypt and Jordan.

According to information from the Ministry of Energy,[5] the quantity of natural gas used in Israel has increased from 7.6 BCM in 2014 to 11.3 BCM in 2019, and in 2020, it is estimated at 12 BCM by the Partnership, all as presented in the graph below:



In 2017, natural gas was exported for the first time from the Tamar reservoir to Jordan, at a volume of 0.07 BCM, which increased in the following years to 0.14 BCM in 2018, 0.22 BCM in 2019, and 0.23 BCM in 2020. In addition, as from July 2020, natural gas exports from the Tamar reservoir to Egypt began, which amounted to 0.25 BCM in 2020.

(E) On December 31, 2019, natural gas began to flow from the Leviathan reservoir to the local market, and on January 1, 2020 and January 15, 2020, natural gas began to flow from the Leviathan reservoir to Jordan and Egypt, respectively. In 2020, natural gas amounting to 3.5 BCM was supplied from the Leviathan reservoir to the local market and 1.9 BCM and 1.9 BCM to Jordan and Egypt, respectively.

(F) The Company estimates that by 2040, natural gas consumption in Israel is expected to double itself, among other things, due to the connection of additional gas suppliers to the national transmission system; the government's policy to increase the use of natural gas to generate electricity and phase out electricity production using polluting coal-fired plants by the end of 2025, including by shutting down four production units at the coal-fired Orot Rabin plant by June 30, 2022 and conversion of the IEC's remaining coal-fired production units to natural gas use by the end of 2025; the assimilation of compressed natural gas in some of the transportation sectors (such as the migration of buses and heavy vehicles to natural gas); the accessibility of natural gas to other industrial plants in Israel, including through a government program to support to companies that have a government concession to install pipelines for the purpose of upgrading the distribution systems; the assimilation of the use of gas in other sectors, such as housing and services; external increase in demand for electricity (including in view of the accelerated introduction of electric vehicles, electrification of the railway, and the construction of additional desalination facilities), which accordingly increases the demand for natural gas; the development of natural-gas based industries (such as the development of petrochemical plants that consume natural gas); and the policy actions that will be taken in favor

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5 Source: Ministry of Energy - Natural Gas Authority, Review of Developments in the Natural Gas Sector, Summary for 2020, https://www.gov.il/BlobFolder/reports/ng_2019/he/ng_2019.pdf.

of this issue; all this, beyond the natural growth in demand for natural gas and electricity in Israel due to population growth and an increase in the standard of living. It should be noted that the increase in demand for natural gas is expected to slow down following the government's decision on "Promoting renewable energy in the electricity sector and amending government decisions" of October 25, 2020. For further information, see section 1.7.28(G) below. For information about the Minister of Energy’s decision to reduce the use of coal, and the reform in the IEC and the electricity sector, and the Minister of Energy's plan to save Israel from the consequences of the use of polluting energy, see sections 1.7.28(E) and 2.7.28(F) below, respectively. For information about orders in connection with the increase in the excise tax on coal and on compressed natural gas (“CNG”), see section 1.7.28(I) below.

(G) The Covid-19 crisis and its possible effect on the area of operations

At the end of 2019 and in the first quarter of 2020, the Covid-19 virus began to spread in China and then around the world and in March 2020, the World Health Organization announced a pandemic (“the Covid-19 Crisis”).

In the first half of 2020, global markets recorded extremely sharp declines in oil and natural gas prices, which the Partnership believes is attributable to the Covid-19 Crisis, as well as to other reasons and factors affecting the demand and supply of energy products. However, towards the end of 2020 and in the first months of 2021, global prices for energy products recovered, including prices of oil and LNG.

In addition, in the first half of 2020, and in particular in the second quarter, there was stagnation in local demand for natural gas compared with the corresponding period last year, mainly due to the effect of the Covid-19 Crisis on demand for electricity in this market, resulting from lockdowns and restrictions on economic activity. It should be noted that, notwithstanding the continuation of the Covid-19 Crisis, there was an increase in demand for natural gas in the second half of 2020 compared with the corresponding period last year.

As at the approval date of the report, it is difficult to estimate how the Covid-19 Crisis will continue and develop in the coming years, the extent of its effect on the global economy, and its effect on demand and sales from the Leviathan and Tamar reservoirs in the coming years. Under these circumstances, the Covid-19 Crisis is a global macroeconomic risk creating uncertainty regarding future global economic activity and its expected effect on financial markets, interest margins, exchange rates, and commodity prices in the energy sector and it may harm many industries, including the energy sector in which the Partnership operates.

For further information, see “Factors affecting the price of and demand for natural gas and other energy products" in section 1.7.3(D) below.

As part of the strategy for addressing the Covid-19 Crisis, the Tamar partners, Leviathan partners, and Block 12 partners in Cyprus took steps to streamline and reduce operating budgets for 2020 and to postpone planned investment budgets for later years, and accordingly, the partners in these projects approved revised budgets for 2020, such that the total reduction in practice amounted to USD 170 million (in terms of 100%, the Partnership’s share is USD 56 million). The Partnership continues to work, together with its other partners in these projects, to expand its streamlining plans in the coming years as well.

In addition, restrictions on entry into Israel and restrictions imposed on movement and gatherings in Israel, in an attempt to prevent the virus from spreading, may have a material adverse effect on the Partnership's work plans. These measures may result in delays in the entry of foreign experts and in the supply of special equipment in Israel, due to restrictions on the movement of citizens between sites and countries and restrictions on production or transportation in various countries, which may, among other things, disrupt routine production and the operator’s work plans, and even incur unforeseen additional costs. In this regard, it should be noted that Noble, which is the operator in the Tamar and Leviathan projects, in coordination with the Commissioner of Petroleum Affairs and the Ministry of Health, has prepared an action plan for addressing the Covid-19 crisis, among other things, with the aim of ensuring, to the extent possible, that the operator’s workforce will be able to reach the offshore and onshore facilities of the projects and continue essential operations in these facilities. As at the approval date of the report, the Covid-19 Crisis did not result in material damage to the operating system in the Tamar and Leviathan projects. However, since there is uncertainty about how the Covid-19 Crisis will develop, there is a risk that notwithstanding the preventative measures taken by the project partners, the operation of the reservoirs will be impaired.

Forward-looking information: The Company's assessments of the possible consequences of Covid-19 constitute forward-looking information, as defined in Section 32A of the Israel Securities Law, 1968 ("the Israel Securities Law"). This information is based, among other things, on the Partnership's assessments and estimates as at the reporting date and on reports published in Israel and around the world on this subject and on the directives of the relevant authorities, the materialization of which is uncertain, in full or in part, and is not under the Company's control.

Additional operations of the Partnership in Cyprus: For a description of the economic environment and competition in the Cypriot market, see section 1.7.16(D)(2)c below.

1.7.3. General information about the area of operations

(A) Operating segment structure and changes

Oil and natural gas exploration, development and production operations are complex, involving considerable costs and significant uncertainty as to costs, schedules, availability of oil or natural gas and the ability to produce it while maintaining economic viability. Consequently, notwithstanding the heavy investments, exploration, including the exploration and appraisal drilling, very often does not provide positive results and does not generate any revenues whatsoever and may result in the loss of most or all of the investment in a relatively short period. Exploration and production of oil and natural gas are usually performed as joint ventures between a number of partners who sign a joint operation agreement ("the Joint Operating Agreement" or "the JOA"). Under the JOA, one of the partners is appointed as the operator of the joint venture (see the operating agreement for the Tamar Project in section 1.7.29(L) below).

Oil and natural gas exploration, development and production in any area involves several stages, including the following:

(1) Preliminary analysis of geological and geophysical data for the selection of areas showing potential for oil and natural gas exploration

(2) Formulation of a preliminary geological model (play).

(3) Geophysical surveys, including seismic surveys, which assist in locating geological formations that may contain oil and/or natural gas ("Leads") and data processing and analysis.

(4) Examination of the Leads and preparation of viable prospects for exploration

(5) Decision to conduct exploration drilling and preparation for drilling

(6) Signing agreements with contractors for drilling and accompanying services

(7) Exploration drilling including logs and other tests

(8) Production tests if justified by the drilling finding

(9) Analysis of drilling results, and in the event of a discovery, based on a preliminary evaluation of reservoir properties and quantities of oil and/or natural gas reserves, economic and fiscal data (including a market valuation), and a preliminary evaluation of the development format and cost Additional seismic surveys and/or appraisal wells may be required to form a better estimate of the reservoir properties and oil and/or natural gas quantities in the reservoir

(10) Examination of alternatives for commercializing the oil and/or gas, identification and assessment of target markets, formulation of a development plan and an economic plan for the project

(11) Final analysis of the data and decision and final investment decision (FID).

(12) Projects for the development of natural gas findings, apart from engineering feasibility, also require the signing of long-term binding agreements for the sale of natural gas in appropriate quantities and at prices that are suitable, with customers that have the financial ability to raise project financing

(13) Development of the reservoir, including production wells, installation of pipelines, and construction of treatment facilities

(14) Production from the reservoir, including ongoing operation and maintenance, as well as additional development works to maintain and/or increase production capacity.

(15) After depletion of the reservoir, and after weighing various technical, economic and regulatory parameters, plugging of the wells, abandonment of the facilities and the lease area, according to accepted local regulations

Due to the different characteristics and data in each separate project, these stages do not necessarily exhaust all the stages of the exploration, development, production, and abandonment process for a specific project, which due to its quality and nature could include only some of these stages and/or additional stages and/or stages in a different order.

In addition, the timeframes for each stage vary according to the nature of the project.

It is noted that the commercial viability of an oil and/or gas finding is complex and depends on many different factors. In this context, there are significant differences between an offshore finding, the development of which requires financial inputs and the use of special technologies, such as deep-water drilling or laying underwater pipelines and facilities capable of operating with high levels of reliability in deep waters, and an onshore finding, where development costs may be significantly lower. In addition, the financial, logistical and technical inputs required to develop a natural gas reservoir, including for establishing the components used for the transmission and/or transportation of the natural gas that is intended for export to the regional or international market, are generally significantly higher compared with those required for the development and production from a natural gas reservoir intended exclusively for the local market. Another key parameter is demand and price in the target markets. It is extremely difficult to develop a project of a material scope when natural gas demand and prices do not allow raising of project financing. There are also material technological, marketing and economic differences between oil reservoirs and natural gas reservoirs. For example, the economic viability of a natural gas reservoir generally derives from its marketability to a guaranteed attractive destination over the years, since natural gas, unlike oil, is not a commodity sold at similar prices worldwide, and its transportation to target markets may be complicated and entail liquefaction or compression. Furthermore, the commercial viability of an oil reservoir is greatly affected by global oil prices. For example, a reservoir that is commercially unviable when the price of oil is USD X a barrel may become commercially viable when the price increases to USD X1.5 and vice versa. In view of the above, an oil and/or natural gas reservoir that is commercially unviable under certain market conditions may become commercial if significant changes occur in market conditions and regulation, and vice versa.

(B) Restrictions, legislation and special constraints that apply to this area of activity

For further information see section 1.7.25 below.

(C) Market developments or changes in the characteristics of customers

As at the approval date of the report, the Partnership sells natural gas from the Tamar and Leviathan projects to various customers in the local and regional market, mainly to Israel Electric Corporation Ltd. (“the IEC”), the National Electric Power Company of Jordan ("NEPCO"), industrial plants in Jordan, and Dolphinus Holdings Limited[6] ("Dolphinus"). For a description about the Partnership agreements with its customers, see sections 1.7.13(D) and 1.7.13(E) below. The Partnership also sells condensate, as set out in section 1.7.13(F) below.

At the same time, and in view of the significant quantity of resources discovered on Israel's coast, mainly the Tamar and Leviathan natural gas reservoirs, the Partnership is taking steps to identify markets and other customers in the local market and in neighboring countries and/or markets in Europe and Asia, subject to restrictions on gas exports, as described in section 1.7.25(A)(4)b below. The Partnership is also promoting use of infrastructure now in existence and/or that will exist in the foreseeable future and/or that will be built specifically for the purpose of exporting natural gas, including additional ways to export natural gas, including by way of liquefaction (LNG) and/or compression (CNG). For further information on this subject, see sections 1.7.13(D)(2)c, 1.7.13(E), and 1.7.14(B)(2) below.

(D) Factors affecting the price of and demand for natural gas and other energy products

The demand for energy in general and natural gas in particular depends on a number of key factors, including energy prices, the growth rate of the gross domestic product (GDP), the population growth rate, living standards, weather conditions, and the energy efficiency of electricity and gas consumers.

In addition, the Ministry of Energy's policy may affect the market share of natural gas in the mix of electricity production sources in Israel, among other things, encouraging the development of energy sources as an alternative to natural gas, such as renewable energy; efforts related to energy storage; the rate of introduction of electric transportation; the rate of connecting factories to the natural gas system; construction of new power stations using natural gas; and the rate of converting coal-fired power stations to natural gas.

Energy prices in international markets including the prices of natural gas and liquefied natural gas (“LNG”), renewable energies, oil, and coal, may also affect the volume of the Partnership’s natural

[6] To the best of the Partnership’s knowledge, Dolphinus is a special purpose company registered in the Cayman Islands. Dolphinus operates in natural gas trade and supplies gas to large consumers in Egypt, primarily to EGAS, a government-owned company.

gas sales and the selling prices of natural gas, both under existing agreements and under future agreements, such as agreements for the sale of natural gas to liquefaction facilities and/or agreements for the sale of LNG, thereby affecting the economic viability of the promotion of new projects that depend on the LNG market or the expansion of existing projects. In addition, low LNG prices in international markets may result in an increase of LNG imports to Israel and/or regional markets, a reduction in the demands for natural gas produced in Israel in the markets relevant to the Partnership, and impairment of the Partnership's revenues from the Tamar and Leviathan reservoirs. Thus, high LNG prices reduce LNG imports to Israel and/or regional markets, and increases the demand for natural gas produced in Israel.

In recent years, there has been a significant increase in the production capacity of LNG, partly due to the operation of new liquefaction facilities or the expansion of existing facilities, such as the liquefaction facilities in the United States, Qatar, Russia (the Arctic Circle), and Australia. However, on the demand side, there has been a significant slowdown, among other things, due to the Covid-19 Crisis and the accumulation of natural gas inventory in natural gas storage facilities. In these years, the excess supply over demand resulted in a decrease in LNG and natural gas prices on the spot markets in Europe and Asia, where natural gas prices developed independently of the oil price, and to where the excess LNG was directed.

In 2020, sharp fluctuations in oil and natural gas prices were recorded in international markets. The Partnership believes that the volatile prices are attributable to a combination of several factors, including: (A) an increase in supply and decrease in demand for natural gas (including LNG), among other things, due to the introduction of new liquefaction facilities and to weather conditions, as set out above; (B) a significant slump in demand for energy products due to the spread of the Covid-19 crisis, as set out in section 1.7.2(G) above; and (C) global macroeconomic factors, such as quantitative expansion plans and global currency fluctuations; and (D) the US-China trade war and the absence of an agreement between the oil producing countries to impose coordinated restrictions on global oil production with the aim of balancing and increasing the price of oil.

It should be noted that the decrease in prices and the excess global supply of LNG have led the IEC to purchase several LNG cargoes in 2020, at the expense of purchasing natural gas from the Tamar and Leviathan reservoirs. For further information, see section 1.7.16(B) below

As at the approval date of the report, energy prices in international markets have recovered and returned to price levels similar to those prior to the outbreak of Covid-19.

(E) Significant technological changes

In the past decades, there have been technological changes in oil and natural gas exploration, development and production, relating to data collection and analysis as well as drilling and production methods. These changes have improved the quality of data available to oil and natural gas exploration companies and allow more advanced identification of potential oil and natural gas reservoirs, and therefore might also reduce the risks involved in drilling. These technological improvements will also improve drilling and production works and allow operation under far more difficult conditions than in the past, including at significant water depths. Accordingly, oil and natural gas exploration companies are able to invest exploration efforts in areas where drilling used to be impossible, or was only possible at a very high cost and much higher risk. The Partnership and operators in the various projects in which the Partnership strive to use the best available technologies in all segments of operations. For example, up to 2020, considerable resources have been invested in the reprocessing of seismic surveys using innovative technologies, in order to improve the database, update the maps of the reservoirs and assess their characterizing parameters, and accordingly to update the volume of their resources. In addition, reprocessing was used to define new deep prospects. Furthermore, technologies defined as the best available technologies were used, to the extent possible, in both the Tamar project and the Leviathan project in order to increase the efficiency of the production system, enhance safety in the system, and reduce their effect on the environment.

Technological changes in production and marketing of natural gas, such as newer and more efficient technologies for converting natural gas into LNG through an onshore or offshore facility FLNG), or into CNG, and gas to liquids (GTL), may contribute to more efficient transportation and commercialization of natural gas.

(F) Critical success factors in the area of operations

(1) Identifying and obtaining exploration rights (purchase or farm-in) in areas where there is potential for a commercial finding

(2) Financial abilities and the ability to raise considerable financial resources

(3) Use of advanced technologies, for example, 3D seismic surveys and advanced data processing technologies for the identification and preparation of drilling prospect, for improvement of the evaluation of drilling results, and for the preparation of a development plan

(4) Partnering with highly knowledgeable and experienced entities which operate in the sector, to perform complex drilling and/or complex development plans, using their professional knowledge and their participation in the substantial financial investments

(5) Successful exploration operations

(6) If natural gas is found, signing agreements for the sale of the gas in satisfactory quantities and for appropriate prices

(7) Existence of engineering, geological, financial, and commercial knowledge, experience and ability to manage exploration, development, and production projects in considerable financial scopes, including the construction of production and export infrastructure

(G) Changes in raw materials and suppliers

For further information see section 1.7.20 below.

(H) Entry and exit barriers

The major entry barriers in the area of operations are the permits and licenses required for oil and natural gas exploration, development, and production, compliance with the provisions of the law and regulation, including the directives and criteria established by the Commissioner of Petroleum Affairs (in Cyprus - the directives and criteria established in legislation and arrangements under production sharing contract, as described in section 1.7.6(D) below), the ability to transfer and/or purchase rights in oil assets, including in respect of demonstration of the applicant's financial stability and the operator's technical capacity required to obtain them, as well as the existence of the technical and financial ability to make large-scale investments amounting to billions of USD, characterized by the relatively high risk level involved in exploration, development, and production.

The significant exit barriers in Israel are mainly the Partnership’s commitments under long-term agreements for gas supply. In addition, both in Israel and in Cyprus, there is a requirement to plug and abandon wells and dismantle production facilities before abandoning lease areas, as set out in the lease deeds, the PSC in Cyprus, and the provisions of the law regarding the abandonment of offshore oil and gas wells.

It is noted that for all matters relating to withdrawal from existing projects by way of a full or partial sale, there may be exit barriers arising from regulatory requirements, which will apply to the buyer and from the significant financial scope of this sale.

(I) Substitutes for products of the area of operations

Natural gas is used mainly to produce electricity and is sold in Israel and the region mainly to electricity producers and industrial customers. In general, natural gas alternatives include mainly: diesel fuel, fuel oil, coal, LPG, LNG, petcoke, and energy from renewable sources, such as solar and wind, energy, including renewable energy that may be produced beyond market demand and stored in energy storage facilities for use when the energy source is unavailable (for example, at night, when energy cannot be generated from solar sources). Each of these substitute fuels and alternative energy production methods have advantages and disadvantages, and they are subject to price fluctuations, availability, technical constraints, availability of land and more. The transition from use of one energy source to another usually requires considerable investment. The major advantages of natural gas over coal and liquid fossil fuels are that the energy efficiency of natural gas-fired power stations is significantly higher than that of coal- and diesel-fired power stations, and the emission of particles and sulfur oxides and nitrogen from combustion of natural gas is significantly lower than that of coal and fuel oil. For further information about the Minister of Energy's announcement that it was bringing forward the date for discontinuation of the use of coal in Israel to 2025 instead of 2030 and about the update of the intermediate target for renewable energy sources to 20% by the end of 2025, see sections 1.7.28(E) and 1.7.28(F) below, respectively.

(J) Structure of competition in the field of operations

For further information see section 1.7.16 below.

Oil assets in the Mediterranean Sea in which the Company holds rights:

1.7.4. Leviathan project

(A) General

As at the approval date of the report, the Company's rights in the Leviathan projects are due to its direct and indirect holdings in 54.7% of the unit capital of Delek Drilling, which holds 45.34% of the participating rights in the project, and due to the rights of the Company and Delek Energy to royalties from the Partnership's share in the project, as set out in section 1.7.1(B)(1) above and section 1.7.29(N) below. The information below is correct as at the approval date of the report, and refers to all the Company's direct and indirect rights in the project.

General information about the oil asset	
Name of oil asset	Leviathan North Leviathan South
Location	Offshore assets 130-140 kilometers west of Haifa
Area	The area covered by the two leases together is 500 square kilometers
Type of oil asset and description of permitted operations according to the type	Lease Operations permitted under the Petroleum Law - exploration and production
Original grant date of the oil asset	March 27, 2014
Original expiry date of the oil asset	February 13, 2044
Decision date for extension of the term of the oil asset	-
Current expiry date of the oil asset	February 13, 2044
Note whether there is an additional option of extending the period of the oil asset: if there is such an option, note the period of the possible extension	Subject to the Petroleum law, may be extended for an additional 20 years
Note name of the operator	Noble
Names of the direct partners in the oil asset and their direct share in the oil asset and, to the best of the Company's knowledge, the names of the controlling owners in the partners	• The Partnership (45.34%) • Noble[7] (39.66%) • Ratio Oil Exploration (1992) – Limited Partnership ("Ratio") (15%) To the best of the Company's knowledge, the General Partner in Ratio, Ratio Oil Exploration Ltd., is owned by D.L.I.N. Ltd. ("D.L.I.N") (34%); Hiram Landau Ltd. ("Hiram") (34%); Eitan Eisenberg Ltd. ("Eisenberg) (8.5%), Eyal Zafriri (4.3%), Ido Porat (1.4%), Asher Porat (1.4%), Daniel Soldin (1.4%) and Adv. Boaz Ben Tzur and Adv. Robi Behar in trust for Shlomi Shukrun (15%). D.L.I.N is a private company owned by Yair Rotlevy (1/3) and Ligad Rotlevy (2/3). Hiram is a private company and its shares are held by Yeshayahu Landau, the executor of the deceased's estate, (the late Mr. Landau bequeathed his shares in Hiram to his children, Yigal Landau, Yuval Landau, and Shlomit Landau, in equal parts). Eisenberg is a private company controlled by Eitan Eisenberg.[8]

7 Noble is a wholly-owned subsidiary of Noble Energy Inc. (in this section below: "Noble"), a public company traded on the NYSE. To the best of the Company's knowledge, no shareholder holds more than 12% of the issued share capital.

8 As at the approval date of the report, the interested parties in Ratio Yam held less than 22% (other than the holding in mutual funds and provident funds).

General information about the Company's share in the oil asset	
Acquisition date of the lease for the acquired oil asset	The Leviathan Leases were granted to the Partnership on March 27, 2014 to replace the 349/Rachel and 350/Amit licenses.
Description of the Company's holding in the oil asset	As set out in section (A) above.
Effective share of oil asset revenues attributable to equity holders of the Company:	In the right to participate in revenue: Before investment recovery – 20.57% After investment recovery – 19.33% In right to receive royalties: Before investment recovery – 0.68% After investment recovery – 2.95% In revenue: Before investment recovery – 21.25% After investment recovery – 22.28%
Total share of the Company's equity holders in the cumulative investment in the oil asset in the five years preceding the last day of the reporting year (whether recognized as an expense or as an asset in the financial statements):	USD 893,302 thousand [9]

(B) Main terms of the Leviathan Leases

(1) The terms that were established in the Leviathan North and Leviathan South Leases are the same in principal. The description below presents the major issues in the Leviathan South Lease (in this section below: "the Lease"), and where there is a material difference in relation to the Leviathan North Lease, this is stated.

(2) The operator's actions will be binding on the leaseholder and notices from the Commissioner of Petroleum Affairs or his representative to the operator will be binding on the leaseholder. The provisions in this section will not derogate from the obligations and responsibilities of any of the Leviathan partners to act in accordance with the provisions of the Lease and the provisions of the law, jointly and collectively.

(3) The leaseholder will only replace the operator with advance written approval by the Commissioner of Petroleum Affairs.

(4) Scope of the lease

A. The leaseholder will have the exclusive right for exploration and production of oil and natural gas in the lease area alone, for the entire term of the lease, subject to the other provisions of the lease deed and to any law.

B. The leaseholder, at its sole responsibility, will plan, finance, construct, and operate the production system and will maintain it for the purpose of its ongoing operation, through the operator, contractors, planners, and consultants who have a high level of expertise and extensive experience in their fields, in such manner so as to enable the reliable, regular, proper, and safe supply of oil and natural gas from the Leviathan field.

(5) Term of the lease

If the term of the lease ends or if the lease is revoked under the provisions of the Petroleum Law and its related regulations, or under the provisions of the lease deed, the right of the leaseholder to act by virtue of the lease deed will expire.

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9 The costs in the table reflect the Partnership's holding in the Leviathan lease after the merger, which is 45.34%, and do not include the costs for installing Israel's pipeline up to the Israeli-Jordan border as set out in section 1.7.14(B)(2)b.1 below **Error! Reference source not found.** and the costs for Leviathan participation fees (as defined in section 1.7.29(J)(3)c, and additional expansion costs of gas flow capacity to Egypt through the construction of the combined section (as set out in section 1.7.27(H)(9)b.2) and the EMG pipeline (as set out in section 1.7.29(J)(3).

(6) Sales to consumers in Israel and for export

A. The leaseholder will not unreasonably refuse to supply oil and natural gas to consumers in Israel.

The export of natural gas from the lease requires written approval from the Commissioner of Petroleum Affairs with the approval of the Minister of Energy (in this section: ("the Export Approval"), in accordance with the government decision set out in section 1.7.25(A)(4)b below. It is noted that actual exports will only be permitted after the implementation of a development plan that provides the local market with a quantity of 500 BCM, in accordance with the Government decision. In addition, exports will not be permitted in a manner that harms the leaseholder's ability to supply natural gas from the Leviathan field to the national transmission system, in an amount of at least 1.05 MCM of gas per hour (from the areas of both Leviathan Leases). In any event, actual export will not begin before the start of supply to the transmission system.

B. Notwithstanding the aforesaid, the Commissioner of Petroleum Affairs may consider decreasing the amount that the leaseholder is required to supply from the Leviathan field to the national transmission system as aforesaid, if there is, among other things, another leaseholder that will receive a lease after March 27, 2014, that supplies or is expected to supply, within a reasonable period, gas to the national transmission system.

C. If there is a shortage of natural gas in Israel, the leaseholder will give preference to the requirements of the local market, in relation to supply capacity that is not subject to the sales commitments under a contract that is valid at such time. The quantity supplied to the local market as aforesaid will be considered to be part of the quantity earmarked for the local market under the government decision, and will not diminish from the quantity permitted for export according to the Export Approval, if granted.

(7) Construction of facilities and adjustment of the capacity to requirements of the local economy

A. The planning and construction of the production system and the transmission system to the shore according to the development plan will be performed so as to allow the supply and flow of gas to the national transmission system in an amount of at least 1.4 MCM per hour (12 BCM per year) from the areas of the Leviathan Leases together.

B. The leaseholder may, subject to receiving written approval from the Commissioner of Petroleum Affairs and the Director General of the Natural Gas Authority, as applicable, increase the capacity of the production system and transmission system to the supplier, and add facilities and wells, in a manner that will allow the flow of gas to the national transmission system in quantities exceeding those stated in subsection (a) above.

C. The Commissioner of Petroleum Affairs may require the leaseholder, if he considers this necessary under special circumstances, to add facilities, wells, and another entry point to the production and transmission systems, in a manner that allows the safe, reliable, and effective flow of gas quantities, exceeding the quantities set out above, to consumers in Israel; this requirement will only be made under special circumstances, and while weighing and balancing all the relevant considerations, including considerations of economic feasibility, and if the Commissioner of Petroleum Affairs finds that the addition has no economic feasibility for the leaseholder, only if a solution is found. If the Commissioner of Petroleum Affairs makes such a demand, the leaseholder will prepare an addition to the development plan and submit it to the Commissioner of Petroleum Affairs for approval within the period determined by the Commissioner of Petroleum Affairs in his demand.

(8) Commercial production

A. Commercial production from the area of the lease will be in accordance with the following principles:

1. Production will be carried out with proper diligence, without waste, without creating risk, and in a way that does not harm the characteristics of the gas reservoirs in the Leviathan field.

2. Production from each well will be carried out in accordance with the maximum effective output; the Commissioner of Petroleum Affairs may instruct the leaseholder, from time to time, as to the maximum output, considering the data from the gas reservoirs in the Leviathan field and their characteristics.

3. The leaseholder will maintain the quality of the gas delivered to the national transmission system in accordance with the gas specification to be determined.

B. The leaseholder will carry out commercial production in accordance with the regulations issued by the competent authorities and with the law, and in accordance with the provisions of any license, permit, and other document required for such purpose under any law.

C. The leaseholder will not start commercial production or gas flow to the leaseholder's transmission system before applying to the Commissioner of Petroleum Affairs for approval to operate and before obtaining the approval of the Commissioner of Petroleum Affairs.

D. At the end of each year (at least 30 days before the end of the calendar year), the leaseholder will submit a detailed work plan to the Commissioner of Petroleum Affairs, describing the work planned for the lease in the following year for the purpose of production and compliance with the provisions of the lease deed, a projection of the costs for performing the operations in the work plan, and a forecast of the production rate in the following year.

E. The leaseholder will notify the Commissioner of Petroleum Affairs of the planned date for beginning construction of additional facilities in order to comply with the provisions in the lease deed.

(9) Supervision companies

The planning of the production system, production of its components, its construction and operation will be supervised by qualified supervision companies with experience in supervising planning, production, construction, or operation, as the case may be, of offshore production systems, subject to the approval of the Commissioner of Petroleum Affairs.

(10) The development plan

A. The leaseholder will prepare and submit the development plan that it proposes for the Leviathan field to the Commissioner of Petroleum Affairs for approval.

B. In the development plan, the leaseholders will include a detailed timetable for implementing the development plan for the production system for the local market, according to which commercial production and supply of natural gas to the transmission system will start 48 months from the date the lease deed was granted.

C. The leaseholder may submit a reasoned and detailed request to the Commissioner of Petroleum Affairs to postpone or update the timetable set out in the development plan. The Commissioner of Petroleum Affairs will postpone or update the timetable, as requested or otherwise, as he sees fit under the circumstances, if convinced that the leaseholder acted with appropriate diligence as required for meeting the timetable, and that the delay in the timetable is not due to an act or omission of the leaseholder, or due to an event the results of which the leaseholder could, with the appropriate diligence, have prevented or limited or minimized.

(11) Change of conditions in the lease deeds

If a layer is discovered in the area of the lease, from which crude oil can be produced in commercial quantities, the Commissioner of Petroleum Affairs will add sections to the lease deed that will include all the necessary provisions to adapt it to the production of crude oil, its processing and transmission; the leaseholder will not produce oil from the area of the lease unless these sections are added, and in accordance with their provisions.

(12) Cancellation or restriction of the lease

The lease will be terminated at the end of the lease term, upon its expiry under section 29 of the Petroleum Law or its cancellation under section 55 of the Petroleum Law, including if one of the conditions set out below occur:

A. The leaseholder materially deviated from a material provision of the lease deed or from the directives of the Commissioner of Petroleum Affairs by virtue of the lease deed.

B. The Guarantee (as set out in section 14 below) or a part of it has been foreclosed and the leaseholder did not complete the amount of the Guarantee as required under the provisions of the lease deed.

(13) The dismantling plan

A. No later than the date on which the balance of the reserves (2P) in the Leviathan field, according to the updated and latest resource assessment report, is depleted to less than 125 BCM, the leaseholder will submit a detailed plan to the Commissioner of Petroleum Affairs for the dismantling of the facilities, and an estimate of the dismantling costs (“the Dismantling Plan”) If the leaseholder does not submit the Dismantling Plan on time, or the Commissioner of Petroleum Affairs finds that the Dismantling Plan that was submitted is not suitable for approval, and the parties did not succeed in agreeing on a Dismantling Plan, the Commissioner of Petroleum Affairs will determine the Dismantling Plan in accordance with accepted international standards.

B. As at the approval date of the Dismantling Plan by the Commissioner of Petroleum Affairs, the Commissioner of Petroleum Affairs will determine a plan for the leaseholder according to which the leaseholder will provide collateral or a deposit in “an abandonment fund”, on the dates, in the format, and according to the accrual method, as instructed by the Commissioner of Petroleum Affairs, with the aim of ensuring that the leaseholder has the means required for implementing the Dismantling Plan.

C. The leaseholder will inform the Commissioner of Petroleum Affairs of the intention to abandon a well, at least three months before the date of the planned action, and the well will not be abandoned before receiving written approval from the Commissioner of Petroleum Affairs.

(14) Guarantees[10]

A. To ensure the fulfillment of the provisions of the lease deed and any approval of the Commissioner of Petroleum Affairs under the lease deed (in this section: "the Letters of Approval"), for ensuring the payments from the leaseholders to the State under any law, and as a condition for granting the lease deed, the leaseholder will provide an autonomous, unconditional and irrevocable bank guarantee in favor of the State of Israel in the amount of USD 50 million for each of the Leviathan Leases (a total of USD 100 million, the Partnership’s share is USD 45 million), in accordance with predefined timetables (in this section: "the Guarantee"). As at the approval date of the report, each of the leaseholders in the Leviathan project provided their share in the Guarantee.

B. The Guarantee will remain in effect throughout the Lease term and will remain in effect after the Lease expires, provided the Commissioner of Petroleum Affairs has not announced that it is no longer necessary and subject to the provisions of the Petroleum Law.

C. The Guarantee will secure the fulfillment of the provisions of the lease deed and Letters of Approval by the leaseholder, secure payments due to the State from the leaseholder by law for compensation and indemnity of the State and any State authority for any damage, payment, loss, or expense incurred by them, directly or indirectly, due to failure to fulfill any of the provisions of the lease deed or the Letters of Approval, at their due date and in full, or due to the cancellation, limitation or suspension of any of the lease terms, or due to any act or omission by the leaseholder in connection with the lease and the fulfillment of the lease terms, and to secure payment of any financial sanctions on the leaseholder under any law.

D. The Commissioner of Petroleum Affairs may foreclose all or part of the Guarantee, in any of the circumstances set out below:

1. The leaseholder did not carry out the development plan approved by the Commissioner of Petroleum Affairs and according to the conditions set out in the approval, or did not construct production system facilities, or did not begin commercial production or delivery to the transmission system on the dates set out in the lease deed or in the Letters of Approval.

2. A safety or environmental malfunction occurred as a result of the leaseholder’s operations, and the leaseholder did not repair the malfunction or its consequences according to the directives of the Commissioner of Petroleum Affairs and the law.

3. Regarding the Leviathan North Lease alone – the leaseholder violated a term set by the Commissioner of Petroleum Affairs regarding the abandonment of the Leviathan 2 well or did not implement the abandonment plan for the well in the optimal manner.

4. The leaseholder did not perform the abandonment in accordance with the Dismantling Plan.

5. A claim or demand is filed against the State for payment of compensation for damage caused due to a violation of any of the terms in the lease deed or the Letters of Approval, due to the deficient implementation of the provisions of the lease deed or the Letters of Approval or due to cancellation of the lease deed, and if the State incurs any expense due to the claim or demand; the Guarantee will only be foreclosed to cover the amount of the claim after a court judgment on the claim has been handed down (including an arbitrator’s judgment) and becomes final and conclusive, and in accordance with the amounts ruled against the State (and in the event of a settlement, subject to approval by the leaseholder, which will only be withheld for reasonable reasons) and subject the leaseholder having been given the opportunity to join as a party to the proceeding.

6. The State incurs expenses or damage as a result of the cancellation of the lease;

7. The leaseholder did not perform the tests required according to the lease deed, did not submit reports and documents as required according to the lease deed.

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[10] The guarantee will be provided for each of the Leviathan Leases separately, but each will apply to both leases, as aforesaid.

8. The leaseholder did not comply with any of the provisions relating to insurance as determined in the lease deed or as imposed according to any law.

9. The leaseholder violated the instructions of a representative of the IDF on any security matter related to the production system.

10. The leaseholder did not comply with the provisions in the lease deed relating to the Guarantee.

11. The leaseholder materially breached another condition in the lease deed or the Letters of Approval or the instructions of the Commissioner.

E. If the Commissioner of Petroleum Affairs finds that there are alleged grounds for the foreclosure, the Commissioner will notify the leaseholder of the grounds and will allow the leaseholder to respond to the alleged grounds and the possible foreclosure, within seven days from receipt of the warning letter, unless, under the circumstances, waiting is not possible. If the Commissioner of Petroleum Affairs decided, after considering the leaseholders response, if any, that there is room for foreclosure, a notice will be sent to the leaseholder describing the breach, the reasons for the foreclosure, and the amount of the foreclosure. The Commissioner of Petroleum Affairs may apply to the bank for foreclosure as from the end of the seven days from the day the notice was delivered, unless prior to that date, the leaseholder paid the amount set out in the notice.

F. Notwithstanding the provisions in subsection (E) above, if the alleged grounds for foreclosure are an act or omission that may be remedied, the Commissioner of Petroleum Affairs may notify the leaseholder that the request to the bank will be made if, within a defined period, the leaseholder does not remedy the act or omission, and the defined period passes without the leaseholder remedying the act or omission to the satisfaction of the Commissioner of Petroleum Affairs.

G. If the Guarantee or any part of it is foreclosed, the leaseholder will provide a new guarantee, or supplement the balance up to the amount of the Guarantee, as it is intended to be at such time, immediately upon receipt of the demand of the Commissioner of Petroleum Affairs.

H. Neither the authority to foreclose nor the foreclosure derogates from the right of the State to claim from the leaseholder payment for damages under the lease deed, or from the right of the State or the Director General of the Natural Gas Authority to claim any remedy or other relief according to any law or the lease deed.

(15) The lease deeds include additional provisions, including for the following matters: security arrangements; conditions for operation of the facilities and repair of malfunctions; tests; reporting and supervision; services to other leaseholders; provisions relating to environmental protection, safety; restrictions on the transfer of or pledge on the lease deed and assets of the production system; liability, indemnification and insurance.

(C) <u>Compliance with the terms of the work plan in the Leviathan project</u>

A binding work plan has not been established for the Leviathan project, other than the conditions in the terms of the Leviathan Leases described in section 1.7.5(B) above.

(D) Actual and planned work plan for the Leviathan project

The table below includes a summary of the main operations actually performed in the Leviathan project since January 1, 2018 through to the approval date of the report and a summary of the planned operations in the project:

Period	**Summary of actual operations in the period or of the planned work plan**	**Estimated total budget for operations on the level of the oil asset (USD thousands)**[11]	**Actual participation of the Company's equity holders in the budget (USD thousands)**[12]
2018[13]	• Completion of drilling the Leviathan 3 and Leviathan 7 wells, and completion of drilling the Leviathan 3, 4, 5, and 7 wells.[14] Continuation of Phase I - First Stage development of the Leviathan reservoir For further information, see section 1.7.4(E) below.	1,521,955	377,232
	Monitoring the area of the Leviathan 2 well, in coordination with the Ministry of Energy and Ministry of Environmental Protection, to ensure the continuation of environmental restoration	25	6
	• Continuation of the project for reprocessing seismic surveys, among other things, regarding exploration drilling to deep targets in the Leviathan Leases.	2,603	645
	• Continued update of the geological model and flow model, among other things, according to drilling data		
2019[15]	• Completion of the development of Phase I – First Stage for development of the Leviathan reservoir and the start of gas supply from the reservoir.	1,020,169	252,845
	• Completion of the project for reprocessing seismic surveys and the start of interpretation of the results, among other things, regarding exploration drilling to the deep targets in the Leviathan Leases.	2,093	519
	• Assessment of various alternatives for exporting natural gas through a subsea pipeline and/or liquefaction, including FLNG, through an agreement for engineering services for a FEED and engineering plan.	1,341	332
	• Monitoring activities in the area of the Leviathan 2 well, with the aim of ensuring the continuation of environmental restoration As at the approval date of the report, it appears that the plugging of the well in 2012 is effective, that there is no evidence of any effect from it, and that the environment is being restored gradually and continuously.	220	55
	• Continued update of the geological model and flow model, among other things, according to drilling data		

11 The amounts for 2018-2020 are amounts that have actually been expended and audited in the financial statements.

12 The costs in the table reflect the Company's holding in the Partnership (54.7%) as at the reporting date and the Partnership's holding (45.34%) in Leviathan after the merger of Delek Drilling and Avner.

13 Costs in 2018 do not include an adjusted budget (decrease) of USD 211 thousand (100%) (the Company's share is USD 52 thousand), abandonment costs of the reservoir, including their expenses, insurance, administrative and general costs, and costs for the construction of Israel's transmission system to the Israeli-Jordan border, as set out in section 1.7.14(B)(2)b.1 below.

14 The budget is included in the overall development budget of Phase I – First Stage as set out in section 1.7.4(E)(1)c below.

15 The costs listed in 2019 do not include the abandonment costs attributable to the asset in the financial statements, insurance and general and administrative costs, costs for construction of the Israel transmission system up to the Israel-Jordan border, as set out in section 1.7.14(B)(2)b.1 below, and costs for participation fees in Leviathan (as set out in section 1.7.29(J)(3) below), and costs associated with the EMG Transaction.

Period	Summary of actual operations in the period or of the planned work plan	Estimated total budget for operations on the level of the oil asset (USD thousands)[11]	Actual participation of the Company's equity holders in the budget (USD thousands)[12]
2020[16][17]	• Costs associated with the completion of Phase I – First Stage for development of the Leviathan reservoir, including advancing a trial run of all the systems on the platform (including the turbo expanders),[18] and completion of construction of the onshore condensate system, including completion of the Hagit site.	94,872	23,514
	• Start of production from the Leviathan reservoir, routine operation and maintenance[19]		
	• Assessment of various alternatives for exporting natural gas through a subsea pipeline and/or liquefaction, including FLNG, through an agreement for engineering services for a FEED and engineering plan.	2,052	509
	• Assessment of alternatives and performing FEED to further increase the flow capacity in the EMG system, including installing a second compressor		
	• Monitoring activities in the area of the Leviathan 2 well, with the aim of ensuring the continuation of environmental restoration	15	4
	• Continued update of the geological model and flow model, among other things, according to drilling and production data and plans for additional drilling, to the extent required	99	25
	• Advancing the formulation of a prospect to deep targets in the Leviathan Leases and assessment of the feasibility of conducting another seismic survey to enhance existing knowledge, in order to establish a decision on exploration drilling to the new targets.		
2021[20]	• Continuation of production from the Leviathan reservoir, routine operation and maintenance		
	• Completion of the trial run for all platform systems (including the turbo expanders) Improvement of the production system, addition of environmental systems in accordance with regulatory requirements, upgrade of the valve system, upgrade of the sanitary wastewater treatment system in accordance with regulatory requirements	48,900	12,120
	• Operation of the onshore condensate system, including completion of the Hagit site		

16 The costs listed in 2020 do not include costs incurred by the Company to expand gas flow capacity to Egypt through the EMG pipeline in the amount of USD 38.7 million (100%, the Company's share is USD 10 million).

17 The budgets set out for 2020 do not include costs that the Company may incur for the construction of the combined section (as defined in section 1.7.27(H)(1) below), the continued expansion of flow capacity to Egypt, and the abandonment costs of the reservoir, including expenses for insurance, administrative and general costs.

18 For information about the turbo expanders, which are intended to increase gas flow capacity from the Leviathan project to the INGL transmission system, see section 1.7.4(E)2 below.

19 In November 2020, maintenance was carried out on the Leviathan platform for five days, during which gas flow from the Leviathan platform was suspended.

20 The costs and activities described for 2021-2022 do not include the Company’s planned costs for additional expansion of gas flow capacity to Egypt through the construction of the combined section (as set out in section 1.7.29(J)(1) below) and the EMG pipeline (as set out in section 1.7.28(E) below) in the amount of USD 92.5 million and USD 27.5 million, respectively (100%, the Company's share is USD 23 million and USD 7 million, respectively).

Period	Summary of actual operations in the period or of the planned work plan	Estimated total budget for operations on the level of the oil asset (USD thousands)[11]	Actual participation of the Company's equity holders in the budget (USD thousands)[12]
	• Formulation of a prospect to the deep targets in the Leviathan leases. In this context, it should be noted that the Partnership is considering the possibility of adding a strategic partner with relevant knowledge and experience in the specification, drilling, and development of the exploration targets that were identified in the lease (specifically a carbonate buildup target).		
	• Continued update of the geological model and flow model, among other things, according to drilling and production data and plans for additional drilling, to the extent required		
	• Assessment of Phase I - Second Stage for development of the Leviathan reservoir and/or development alternatives, as required.	20,800	5,155
	• Formulation of an alternative for exporting natural gas through a subsea pipeline and/or liquefaction (including through a floating liquefied natural gas (FLNG) facility, among other things, through an agreement for engineering services for a detailed FEED and engineering plan.	3,750	929
	• Monitoring activities in the area of the Leviathan 2 well, with the aim of ensuring the continuation of environmental restoration		
	• Assessment of alternatives for exporting condensate, performing a FEED, detailed engineering planning, preparation for acquisition and execution	10,500	2,602
2022	• Continuation of production from the Leviathan reservoir, routine operation and maintenance		
	• Continuation of the improvement of the production system on the Leviathan platform and improvement of environmental systems, in accordance with regulatory requirements		
	• Formulation of a prospect to the deep targets in the Leviathan leases. In this context, it should be noted that as at the approval date of report, the Partnership is considering the possibility of adding a strategic partner with relevant knowledge and experience in the specification, drilling, and development of the exploration targets that were identified in the lease (specifically a carbonate buildup target).		
	• Continued update of the geological model and flow model, among other things, according to drilling and production data and plans for additional drilling, to the extent required		
	• Continuation of the assessment of Phase I - Second Stage for development of the Leviathan reservoir and/or development alternatives, as required		
	• Monitoring activities in the area of the Leviathan 2 well, with the aim of ensuring the continuation of environmental restoration		
	• Advancing an alternative for exporting natural gas through a subsea pipeline and/or liquefaction, including FLNG, among other things, by performing a		

Period	Summary of actual operations in the period or of the planned work plan	Estimated total budget for operations on the level of the oil asset (USD thousands)[11]	Actual participation of the Company's equity holders in the budget (USD thousands)[12]
	FEED, detailed engineering planning, and preparation for execution		
	• Formulation and development of the alternative selected for condensate exports Performing a FEED, detailed engineering planning, acquisition and preparation for execution	35,000	8,675
2023 onwards	• Continuation of production from the Leviathan reservoir, routine operation and maintenance		
	• Formulation of a prospect to the deep targets in the Leviathan leases. In this context, it should be noted that the Partnership is considering the possibility of adding a strategic partner with relevant knowledge and experience in the specification, drilling, and development of the exploration targets that were identified in the lease (specifically a carbonate buildup target).		
	• Continued update of the geological model and flow model, among other things, according to drilling and production data and plans for additional drilling, to the extent required		
	• Continuation of the assessment of Phase I - Second Stage for development of the Leviathan reservoir and/or development alternatives, as required		
	• Continuation of advancing an alternative for exporting natural gas through a subsea pipeline and/or liquefaction, including a FLNG facility, among other things, by continuing detailed engineering planning and construction of facilities		
	• Completion of the development and operation of the alternative for exporting condensate	24,500	6,072

(E) Plan for development of the Leviathan reservoir

On June 2, 2016, the development plan for the Leviathan field was approved by the Commissioner of Petroleum Affairs. In the approval letter, the Commissioner of Petroleum Affairs stated that based on the opinion of an international company that was submitted to his office, the estimated total recoverable quantity natural gas, based on the development plan that was submitted, is 17.6 TCF. The Commissioner of Petroleum Affairs also noted that after receiving additional data about the reservoir, and in particular, from the Leviathan-5 drilling, and after receiving data obtained during production from the field, the recoverable quantity will be updated, in order to calculate export permits, if required, among other things. It should be noted that the operator of the Leviathan project submitted and submits a full database to the Commissioner of Petroleum Affairs, which is updated from time to time, including data of the Leviathan 3, 4, 5, and 7 wells and completions, the results of seismic survey reprocessing, updated geological and flow models, and production data. It should be noted that the valuation of the resources in the opinion is materially different from the valuation of the resources submitted to the Leviathan partners by NSAI, as set out in section 1.7.4(J) below.

As at the approval date of the report, the Partnership, together with the other Leviathan partners, is continuing discussions with the Ministry of Energy regarding the possibility of updating the evaluation of the resources in the Leviathan reservoir. However, it should be emphasized that export licenses were granted for the entire quantity in the current agreements. In addition, the Partnership believes, given the Government's policy on natural gas exports, that the recoverable quantity, according to the Commissioner for Petroleum Affairs, is also sufficient for implementation of the Leviathan expansion plan as set out in this section below.

On February 23, 2017, the Leviathan partners made a final investment decision (FID) for the development of Phase I - First Stage in the development plan of the Leviathan reservoir, with an annual capacity of 12 BCM, at a budget of USD 3.75 billion (for 100% of the rights in the Leviathan reservoir). In the development period, there was a total decrease of USD 217 million (100%) in the Phase 1 – First Stage development budget as estimated when it was approved, therefore the total Phase 1 – First Stage development cost amounted to USD 3.5 billion (100%). Subsequent to the running-in period, on December 31, 2019, natural gas started to flow from the Leviathan reservoir; on January 1, 2020, the sale of natural gas to Jordan started under the NEPCO agreement (as set out in section 1.7.13(E)(2)a below); and on January 15, 2020, natural gas started to flow from the reservoir to Egypt under the Dolphinus agreement (as set out in section 1.7.13(E)(2)b below).

(1) The plan for the full development of the Leviathan reservoir (Phase I – First Stage and Phase I – Second Stage) includes the supply of natural gas to the local market and for export and the supply of condensate to the local market (below in this section: "the Development Plan" or "the Plan"), the main points of which are as follows:

A. Eight production wells in the first stage (four of which have already been drilled and completed for production under Phase I – First Stage) will be connected by a subsea pipeline to a fixed platform (below in this section: "the Platform"), located offshore in the territorial waters of Israel, in accordance with the provisions of National Outline Plan 37/H, on which the gas and condensate treatment systems were installed. Gas flows from the Platform to the northern entrance of the national transmission system of Israel National Gas Lines as defined in National Outline Plan 37/H ("the Connection Point to INGL"). The condensate flows to the shore through a separate pipeline adjacent to the gas pipeline, and is connected to the existing oil pipeline of Europe Asia Pipeline Co. ("EAPC") that leads to the tank farm of Petroleum & Energy Infrastructures Ltd. ("PEI") and from there to Bazan Ltd. ("Bazan"). In addition, a pipeline was installed to the Hagit site, where storage and offloading facilities for condensate have been constructed, providing backup if condensate cannot be delivered to Bazan.[21] Construction of the condensate storage system at the Hagit site was completed and the permits required for its operation have been obtained. For further information about approval of National Outline Plan 37/H and its provisions, see section 1.7.28(K) below.

B. The production system includes: the production wells, the subsea production system, the treatment and production platform, the system for transmission to the shore, and the related onshore facilities (in this section jointly: "the Production System") and it is designed to supply an annual quantity of 21 BCM after completion of Phase 1 – First Stage and Phase 1 – Second Stage of the development plans, as set out below. The gas to be supplied at the Connection Point to INGL is targeted for the local market and neighboring countries

C. The Development Plan is implemented in two stages, depending on the maturity of the relevant markets, as follows:

Phase I – First Stage: includes, in the first stage, four subsea production wells, a subsea production system connecting the production wells to the Platform, a system for transmission to the shore, and related onshore facilities. At this stage, annual gas production capacity from the reservoir is 12 BCM. As at December 31, 2019, the flow of natural gas and condensate has started as part of the development of Phase I – First Stage. As at December 31, 2020, the total cost invested in the development of Phase I – First Stage amounts to USD 3.6 billion (100%).

Phase I – Second Stage: will include, at the second stage, another four production wells, related subsea systems, and expansion of the Platform's processing facilities to increase the total production capacity of the system by an additional 9 BCM per year (a total of 21 BCM per year) at an estimated budget of USD 1.5-2 billion (for 100% of the rights in the Leviathan project). As at the approval date of the report, the Leviathan partners have not yet adopted an FID for the development of Phase I - Second Stage.

It should be noted that during the life of the project, additional production wells will be required to allow production in the required volume.

(2) As at the approval date of the report, and in accordance with the development plans, the daily gas supply capacity from the Leviathan project to the INGL transmission system is 1.2 BCF at maximum production. On completion of the trial run of all the systems on the Platform, and in particular, operation of the turbo expanders, the ability to increase the maximum daily supply capacity will be

[21] In the context of installing the pipeline to the Hagit site, the Partnership provided a guarantee in the amount of NIS 2.3 million in favor of the Israel Land Authority ("the ILA").

tested, subject to certain conditions, beyond 1.2 BCM. Availability (uptime) at the Leviathan project in 2020 was more than 98.5%.

(3) As at the approval date of the report, the Leviathan partners are assessing various alternatives for increasing production from the Leviathan reservoir beyond Phase I – First Stage, and concurrently with the assessment of Phase I – Second Stage, based on existing facilities, and are working to update the development plan accordingly, to allow expansion of annual production capacity up to 24 BCM, all in accordance with estimates that are updated from time to time regarding current and expected demand in the local market and in regional and global target markets, including the assessment of the following alternatives:

A. Increasing annual production capacity of Phase 1 – First Stage from 12 BCM to 16 BCM, by adding two wells and related subsea infrastructure and immaterial changes at the platform. This alternative will maximize utilization of the treatment infrastructure installed on the Leviathan platform as part of Phase 1 – First Stage, at an estimated cost of USD 875 million (for 100% of the rights in the Leviathan project).

B. Increasing annual production capacity from 16 BCM to 24 BCM (subject to implementation of the first alternative described above), including by adding, in the first stage, four production wells and related subsea infrastructure, beyond those described above in the first alternative), adding a fourth pipeline from the field to the Platform, and expansion of the treatment facilities at the platform at an estimated budget of USD 1.5-2 billion (for 100% of the rights in the Leviathan project). This alternative will allow the supply of additional quantities of gas for export, insofar as required, including to the liquefaction facilities in Egypt and/or for the supply of gas to the floating liquefied natural gas ("FLNG") facility. For further information, see section 1.7.14(B)(2)b.2 below. For information about the interim agreements of the Partnership and its partners in the Leviathan project with FLNG services and technology providers, see section 1.7.14(B)(3) below.

To assess various expansion alternatives, the Leviathan partners approved an engineering design FEED budget, as set out in section 1.7.4(D) above.

Forward-looking information: The above estimates regarding the expected production capacity from the Leviathan reservoir, the scope of the budget, and the timetables for the development stages of the Leviathan reservoir, as described above, are forward-looking information as defined in Section 32A of the Israel Securities Law. The information is based on the assessments of the Partnership and the operator of the Leviathan reservoir, based on diverse factors, including the development plan and the timetables for its implementation, receipt of regulatory approvals, estimated availability of equipment, services, and costs, as well as past experience. The estimates in this report may not materialize or may materialize in a very different manner if there are changes and/or delays in the diverse factors described above, and if there is a change in the estimates that were received, a change in the market conditions, and/or range of geopolitical changes and/or regulatory changes and/or operational and technical conditions in the Leviathan reservoir and/or from unforeseen factors related to the exploration, production, and marketing of oil and natural gas and/or as a result of progress in the development of the Leviathan reservoir until its completion.

(F) Actual participation rate in the expenses and revenues in the Leviathan Leases

Participation rate	% Before investment recovery	% After investment recovery	Rate grossed up to 100% before investment recovery	Rate grossed up to 100% after investment recovery	Explanations
Actual rate attributable to equity holders of the Company in the oil asset	24.78%	24.78%	100%	100%	See the description of the chain of holdings in section 1.7.4(A) above.
Actual rate attributable to equity holders of the Company in revenues from the oil asset	21.25%	22.28%	85.74%	89.89%	See the calculation in section 1.7.4(F) below.
Actual rate of participation of the Company's equity holders in expenses arising from exploration in the oil asset	25.03%-25.78%	25.03%-25.78%	101%-104%	101%-104%	See the calculation in section 1.7.4(H) below.

(G) Participation rates of the equity holders of the Company in revenues from the Leviathan Leases

Description	% Before investment recovery	% After investment recovery	Summary of the calculation method for royalties or payments
Projected annual revenues of the oil asset	100%	100%	
Royalties or payment (arising from revenues after the finding) related to the oil asset:			
The State	(12.50%)	(12.50%)	As stipulated in the Petroleum Law, the royalties are calculated at market value at the wellhead. The actual royalty rate may be lower due to deduction of expenses for the gas delivery and handling system up to the onshore gas receiving terminal.
Adjusted revenues on the level of the oil asset	87.5%	87.5%	
Share of the adjusted oil asset revenues attributable to the equity holders of the Company (linked)	24.78%	24.78%	
Share of the equity holders of the Company in the actual rate of revenues, at the level of the oil asset (before other payments at the level of the Company)	21.69%	21.69%	
Information about the royalties or payments (derived from the income after the finding) in respect of the oil asset at the level of the Company (the percentages below are calculated according to the rates of the equity holders of the Company in the oil asset):			
Share of the equity holders of the Company in payments to related parties and third parties	(1.12%)	(2.36%)	The Partnership pays royalties to the Company and Delek Energy for its share in the oil asset at a rate of 4.5% before investment recovery and 9.5% after investment recovery, calculated at the wellhead market value.[22] The calculation method for these rates is based on principles for calculating royalties to the State, therefore these rates may change if the calculation method of royalties to the State changes. For further information, including about the publication of draft directives for public comment regarding the calculation method of the royalty value at the wellhead for offshore oil rights, see sections 1.7.29(N)(5) and 1.7.1(A)(2)a below.
Total	20.57%	19.33%	
Rates of holders of the Company's equity in revenues due to additional royalties from the asset	0.68%	2.95%	Calculated on the basis of the right to royalties from the Partnership as set out in section 1.7.1(B)(1) above. The calculation method for these rates is based on principles for calculating royalties to the State, therefore these rates may change if the calculation method of royalties to the State changes. For further information about the calculation method of the royalty rates, see section 1.7.29(N)(1) below.
Actual rate attributable to equity holders of the Company in revenues from the oil asset	21.25%	22.28%	

22 The parties entitled to royalties are Delek Group, Delek Energy, and others that are not related parties.

(H) Share of the equity holders of the Company in exploration, development and production expenses in the Leviathan Leases

Description	%	Summary of the calculation method for royalties or payments
Theoretical expenses for the oil asset (without royalties)	100%	
Payments (derived from the expenses) at the level of the oil asset		
Operator	1%-4%	A rate of 1% for the operator's indirect expenses out of the total direct expenses for development and production, subject to certain exceptions, such as marketing activity. A rate of 1%-4% for exploration expenses, where the rate of payment to the operator decreases with the increase in exploration expenses. These amounts are for payment of indirect expenses to the operator and are in addition to reimbursement of direct expenses to the operator.
Total actual rate of expenses at the level of the oil asset	101%-104%	
Share of the equity holders of the Company in the oil asset's expenses (linked)	24.78%	
Total share of the equity holders of the Company in expenses, at the level of the oil asset (before other payments at the level of the Company)	25.03%-25.78%	
Payments (derived from the expenses) in respect of the oil asset and at the level of the Company (the following percentages will be calculated in accordance with the share of the equity holders of the Company in the oil asset)		
Actual share of expenses for exploration, development, and production in the oil asset, attributable to equity holders of the Company	25.03%-25.78%	The Partnership pays management fees to the General Partner, which consist of a fixed amount and a variable amount calculated as a rate of the exploration expenses on fulfillment of certain conditions. These amounts were not taken into account in this table.

(I) Royalties and payments paid during exploration operations in the oil asset (USD thousands)[23]

Description	Total share of equity holders of the Company in investment in the oil asset in this period (including costs for which payments are not made to the operator)	Of which, the share of equity holders of the Company in payments to the General Partner	Of which, the rates of equity holders of the Partnership in payments to the Operator (in addition to the return of direct expenses)
Actual budget invested in 2018	384,483	-	3,753
Actual budget invested in 2019	310,086	-	2,513
Actual budget invested in 2020	55,466	-	527

[23] The amounts in the table reflect the Company's holding in the Partnership (54.7%) as at the reporting date and the Partnership's holding (45.34%) in Leviathan after the merger of Delek Drilling and Avner.

(J) Reserves, contingent and prospective resources in the Leviathan Lease

For information about the probable resources and contingent resources in the area of the Leviathan leases and the discounted cash flow from the reserves and some of the contingent resources in the Leviathan leases, as at December 31, 2020, see the Company's immediate report dated March 10, 2021 (Ref. No.) 2021-01-031128). The information in this report is included as a reference. As at the approval date of the report, there has been no change to this information. The consent of NSAI to include the report in this report, including by way of a reference, and a letter from NSAI regarding the absence of material changes in the Leviathan leases is attached as Appendix A.

For information about the prospective resources in the area of the Leviathan lease, as at December 31, 2019, see section 1.7.4(J)(11) to the Company's Periodic Report for 2019. As at December 31, 2020, there has been no change to this information. The consent of NSAI to include the report in this report, including by way of a reference and a letter from NSAI regarding the absence of material changes in the Leviathan leases is attached as Appendix A.

1.7.5. Tamar and Dalit project

(A) General

As at the approval date of the report, the Company's rights in the Tamar and Dalit project are due to its direct and indirect holdings in 54.7% of the unit capital of Delek Drilling, which holds 22% of the participating rights in the project. In addition, Delek Energy holds 39.93% of the share capital of Delek Royalties, which holds the right to royalties from the share of the Partnership and Tamar Petroleum in the project. Unless otherwise stated, the information below is correct as at the approval date of the report, and refers to all the Company's direct and indirect rights in the Tamar and Dalit project, as described above.

In addition, the information below is calculated "after investment recovery" in the Tamar project (for further information about this matter, and about the legal proceedings regarding the investment recovery date for the Tamar project, see Note 24A3 to the financial statements).

Tamar Lease	
General information about the oil asset	
Name of oil asset	Tamar Lease
Location	An offshore property 90 km west of Haifa, at a water depth of 1,670 meters
Area	250 sq. km
Type of oil asset and description of permitted operations according to the type	Lease Operations permitted under the Petroleum Law - exploration and production
Original grant date of the oil asset	December 2, 2009
Original expiry date of the oil asset	December 1, 2038
Decision date for extension of the term of the oil asset	-
Current expiry date of the oil asset	December 1, 2038
Note whether there is an additional option of extending the period of the oil asset: if there is such an option, note the period of the possible extension	Subject to the Petroleum law for an additional 20 years
Note name of the operator	Noble

Tamar Lease	
General information about the oil asset	
Names of the direct partners in the oil asset and their direct share in the oil asset and, to the best of the Company's knowledge, the names of the controlling owners in the partners	• Isramco Negev 2 – Limited Partnership ("Isramco") (28.75%). To the best of the Company's knowledge, the general partner in Isramco, Isramco Oil and Gas Ltd., is a private company indirectly controlled by Naphtha Israel Petroleum Corp. Ltd., a public company, which to the best of the Company's knowledge is indirectly controlled by Haim Tsuff. • Noble (25%) • The Partnership (22%) • Tamar Petroleum Ltd. (16.75%) • Dor Gas Exploration Limited Partnership ("Dor") (4%) To the best of the Company's knowledge, the general partner in Dor Exploration is Alon Gas Exploration Management Ltd., a public company controlled by Alon Israel Oil Company Ltd., which is a private company. • Everest Infrastructures, Limited Partnership ("Everest") (3.5%) To the best of the Company's knowledge, Everest is a limited partnership in which Harel Insurance Company Ltd. and other institutional entities it owns are partners, as well as a partnership of the Israel Infrastructure Fund Group.

Tamar Lease	
General information about the Company's share in the oil asset	
Acquisition date of the lease for the acquired oil asset	The lease was granted on December 2, 2009 following the Tamar natural gas finding in 2009 in the area covered by the 309/Matan license.
Description of the Company's holding in the oil asset	As set out in section (A) above.
Effective share of oil asset revenues attributable to equity holders of the Company	Total revenue: 9.33%
Total share of the Company's equity holders in the cumulative investment in the oil asset in the five years preceding the last day of the reporting year (whether recognized as an expense or as an asset in the financial statements):	USD 132,894 thousand

Dalit Lease	
General information about the oil asset	
Name of oil asset	1/13 Dalit Lease
Location	Offshore asset 50 kilometers west of Haifa
Area	250 sq. km
Type of oil asset and description of permitted operations according to the type	Lease Operations permitted under the Petroleum Law - exploration and production
Original grant date of the oil asset	December 2, 2009
Original expiry date of the oil asset	December 1, 2038
Decision date for extension of the term of the oil asset	-
Current expiry date of the oil asset	December 1, 2038

Dalit Lease	
General information about the oil asset	
Note whether there is an additional option of extending the period of the oil asset: if there is such an option, note the period of the possible extension	Subject to the Petroleum Law for an additional 20 years
Note name of the operator	Noble
Names of the direct partners in the oil asset and their direct share in the oil asset and, to the best of the Company's knowledge, the names of the controlling owners in the partners	• Isramco (28.75%) • Noble (25%) • The Partnership (22%) • Tamar Petroleum (16.75%) • Dor (4%) • Everest (3.5%)

Dalit Lease	
General information about the Company's share in the oil asset	
Acquisition date of the lease for the acquired oil asset	The lease was granted on December 2, 2009 following the Dalit natural gas reservoir, which was discovered in 2009 in the area of the 308/Michal License.
Description of the Company's holding in the oil asset	As set out in section (A) above.
Effective share of oil asset revenues attributable to equity holders of the Company:	Total revenue: Before investment recovery – 9.93% After investment recovery – 9.33%
Total share of the Company's equity holders in the cumulative investment in the oil asset in the five years preceding the last day of the reporting year (whether recognized as an expense or as an asset in the financial statements):	USD 41 thousand

(B) Main terms of the Tamar and Dalit Leases

(1) The conditions set out in the Tamar and Dalit Leases (below in this section: "the Leases") are essentially the same. The description below addresses the major issues in Tamar and Dalit Leases.

(2) The production and transmission facilities (in this section: "the Facilities") will be constructed and operated through Noble (in this section below: "the Operator"), which will manage the required operations according to the lease deed and the Petroleum Law, on behalf of the leaseholder. The operator's actions will be binding on the leaseholder and notices from the Commissioner of Petroleum Affairs or his representative to the operator will be binding on the leaseholder. The provisions in this section will not derogate from the obligations and responsibilities of any of the Tamar partners to act in accordance with the provisions of the lease deed and the provisions of the law, jointly and collectively.

(3) The leaseholder will only replace the Operator with a company that has been approved in advance and in writing by the Commissioner of Petroleum Affairs.

(4) Scope of the lease

A. The leaseholder will have the exclusive right for exploration and production of oil and natural gas in the lease area alone, for the entire term of the lease, subject to the other provisions of the lease deed and to any law.

B. At the leaseholder's sole responsibility, the leaseholder will plan, finance, establish and operate the leaseholder's production and transmission systems and will maintain these systems for their ongoing operation, through the Operator, contractors, planners and consultants with knowledge and experience in their fields and in a manner that will allow the regular, orderly and safe supply of oil and natural gas from the field.

(5) Term of the lease

Under Section 29 of the Petroleum Law, the term of the lease is from December 2, 2009 to December 1, 2038 and it may be extended in accordance with the provisions in this Section (in this section below: "the Term of the Lease").

The Term of the Lease will be divided into two sub-periods:

A. Development period: the period in which the leaseholder performs all the operations required to reach the commercial production stage, including development drillings, and constructs the leaseholder's production and transmission systems, subject to the provisions in the lease deed.

B. Commercial production period: the period as from the end of the development period until the end of the lease term, during which the leaseholder performs commercial production from the lease area, subject to the provisions in the lease deed and any law.

If the Term of the Lease ends or if the lease is revoked under the provisions of the Petroleum Law, including under section 29 of the Petroleum Law, or under the provisions of the lease deed, the right of the leaseholder to act by virtue of the lease deed will expire.

(6) Sale to consumers in Israel

The leaseholder will supply the oil and natural gas reliably, efficiently, and properly, and will not unreasonably refuse to supply oil and natural gas to consumers in Israel.

(7) Construction of facilities

A. The leaseholder will only establish the production system after receiving the approval of the Commissioner of Petroleum Affairs and subject to the terms of the approval.

B. The leaseholder will establish the production and transmission systems in a manner that will allow commercial production capabilities for the Tamar and Dalit lease areas, which will be no less than 7 billion standard cubic meters of natural gas per year, beginning from the start of the commercial production period, subject to the approval the northern receiving point.[24]

C. If there is economic justification, the leaseholder will be entitled, subject to approval from the Commissioner of Petroleum Affairs and the Director General of the Natural Gas Authority under the Natural Gas Sector Law, to expand the capacity of the production and transmission systems and to add facilities and wells, including the installation of a pipeline to another receiving point, to allow reliable and efficient flow of larger quantities of natural gas to consumers in Israel.

(8) Supervision company

The planning and construction of the production system will be supervised by companies experienced in supervising the planning or construction of production systems, which the leaseholder will hire, subject to the approval of the Commissioner of Petroleum Affairs. In accordance with the above, supervision companies were selected to accompany the planning and construction of the production system, and these companies were approved by the Commissioner of Petroleum Affairs.

(9) Commercial production

A. Commercial production from the area of the lease will be in accordance with the following principles:

1. Production will be carried out with proper diligence, without waste, and in a way that does not harm the characteristics of the reservoir in the area of the lease.

2. Production will be according to minimum and maximum output approved by the Commissioner of Petroleum Affairs, from time to time, considering reservoir data and properties.

3. The leaseholder will be required to maintain the quality of the gas delivered to the national transmission system in accordance with the gas specification to be determined.

B. The leaseholder will execute commercial production as a prudent operator in accordance with the regulations issued by the competent authorities and the law, and according to the provisions of any license, permit, and other document required for that purpose in accordance with the law.

C. The leaseholder will not start commercial production or flow of natural gas to the leaseholder's transmission system before applying to the Commissioner of Petroleum Affairs for approval to operate and before obtaining the approval of the Commissioner of Petroleum Affairs.

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[24] Production is by means of a platform that was constructed off the Ashkelon coast and through the receiving terminal.

D. At the end of each year (at least 30 days before the end of the calendar year) the leaseholder will submit a detailed annual work plan to the Commissioner of Petroleum Affairs, with an estimate of the cost for the operations in the plan and a forecast of the production rate for the following year.

E. The leaseholder will notify the Commissioner of Petroleum Affairs of the planned date for beginning construction of additional facilities in order to comply with the provisions in the lease deed.

(10) Storage of natural gas

A. The Commissioner of Petroleum Affairs may instruct the leaseholder to act to transfer the natural gas for storage from the reservoir to approved reservoirs, if this does not impose any expense on the leaseholder for transmission, storage or recovery of the gas and compliance with those instructions does not damage the reservoir. The royalty for stored natural gas will apply when the gas is removed from the storage reservoir and not when it is produced from the reservoir.

B. If the leaseholder asks to store gas in approved storage reservoirs, at its own initiative, this will be at the leaseholder's expense and in accordance with the provisions to the law and any covenants.

(11) Cancellation or restriction of the lease

The lease will come to an end at the end of the lease period, upon expiry according to section 29 of the Petroleum Law, upon its cancellation according to section 55 of the Petroleum Law, if one of the conditions set out below occur:

A. The leaseholder materially deviated from a material provision of the lease deed or from the directives of the Commissioner of Petroleum Affairs by virtue of the lease deed.

B. The Guarantee or a part of it has been foreclosed and the leaseholder did not complete the amount of the Guarantee as required under the provisions of the lease deed.

(12) Abandonment plan

A. Within 30 months after commencement of production, the leaseholder will submit to the Commissioner of Petroleum Affairs a general plan for abandoning the production facilities and plugging the wells, when they are no longer to be used, during and after the lease period. ("the General Abandonment Plan"). In this context, it should be noted that on September 30, 2015, the General Abandonment Plan was submitted to the Commissioner of Petroleum Affairs for approval.

B. No later than the date on which the leaseholder has produced 170 BCM of gas from the lease area, the leaseholder will submit a detailed plan for dismantling the facilities to the Commissioner of Petroleum Affairs, in accordance with the General Abandonment Plan ("the Abandonment Plan"), which was approved by the Commissioner of Petroleum Affairs, as well as the estimated dismantling costs. If the leaseholder does not submit the Abandonment Plan on time or if the Commissioner of Petroleum Affairs believes that the Abandonment Plan is not suitable for approval and the Commissioner of Petroleum Affairs and the leaseholder fail to agree on the Abandonment Plan, the Commissioner of Petroleum Affairs will determine the Abandonment Plan.

C. As at the date the Abandonment Plan is approved by the Commissioner of Petroleum Affairs, the Commissioner of Petroleum Affairs will determine a plan for the leaseholder according to which the leaseholder will provide a guarantee or deposit in an abandonment fund, at the dates, format and accumulation method as instructed, to ensure that the leaseholder has the means required to implement the abandonment plan.

D. The leaseholder will notify the Commissioner of Petroleum Affairs of the intention to plug a well, at least three months before the operation. The notice will include an explanation of the need to plug the well and of the plugging plan. Plugging of the well requires the prior approval of the Commissioner of Petroleum Affairs.

(13) Guarantees

The lease deed sets out provisions for an irrevocable unconditional autonomous bank guarantee to be provided by the leaseholder to secure the conditions of the lease deed, its term, and grounds for foreclosure of the guarantee. For further information about the guarantee that was provided to secure compliance with the conditions of the lease deed, the provisions of the Petroleum Law, and the directives of the Commissioner of Petroleum Affairs, see section 1.7.1(A)(1) below.

(14) The lease deed also includes additional provisions, which refer, among other things, to the conditions for operating the facilities, safety, handling of malfunctions, tests, reporting and supervision, liability, insurance, and indemnification.

(15) In addition, in accordance with the approval for operating the production system in the Tamar Lease, increased duties were imposed on the leaseholder regarding the operation of the production system, due to the importance of gas production for Israel.

(C) Compliance with the terms of the work plan in the Tamar project[25]

A binding work plan has not been established for the Tamar project, other than the conditions in the Tamar Lease and Dalit Lease, as set out in section 1.7.5(B) above.

(D) Actual and planned work plan for the Tamar project[26]

(1) The table below includes a summary of the main operations actually performed in the Tamar project from January 1, 2018 through to the approval date of this report and a summary of the planned operations:

Tamar Lease			
Period	**Summary of actual operations in the period or of the planned work plan**	**Estimated total budget for operations on the level of the oil asset (USD thousands)**	**Actual participation of the Company's equity holders in the budget (USD thousands)[27]**
2018	• Continued production from the Tamar project, ongoing operation and maintenance.		
	• Continuation of the project for installation of systems to reduce emissions from the Tamar platform.	28,894	4,073
	• Upgrade and improvement of the production system at the Tamar platform and receiving terminal, including upgrade of the stainless steel plate to prevent corrosion.	24,845[28]	3,502
	• Continued update of the geological model and flow model, among other things, according to drilling and production data and plans for additional drilling.		
	• Mapping and definition of additional prospects, including a prospect to the deep targets in the lease area.		
	• Continuation of the reprocessing project for seismic surveys		
2019[29]	• Continued production from the Tamar project, ongoing operation and maintenance.		
	• Completion the project for installation of systems to reduce and monitor air emissions from the Tamar platform.	12,479	1,759
	• Completion of the reprocessing project for seismic surveys, and start of analysis of the processed surveys		

25 As at the approval date of the report, a detailed work plan for the Tamar Lease only has been submitted. .

26 The costs described in the work plan for 2017-2019 below do not include the ongoing operating and maintenance costs and the abandonment costs of the Tamar project, which are included in section 1.7.5(J) below.

27 The costs in the table reflect the Company's holdings in the Partnership (54.7%) as at the reporting date and the Partnership's direct and indirect holdings in the Tamar Lease at a rate of 25.7855% until December 31, 2018, and the Partnership's direct holdings in the Tamar Lease at a rate of 22% as from January 1, 2019.

28 The detailed costs do not include a decrease in investments in the amount of USD 33.6 million (100%) (the Company's share is USD 4.7 million. The decrease is partially due to the sale of drilling equipment, depreciation of the pipeline, and a decrease in investment in the Tamar SW drilling.

29 1.7.29(J)(3)The costs for 2019 do not include abandonment costs attributed to the asset in the financial statements, and costs for the Tamar participation fee amounting to NIS 50 million (as defined in section 1.7.29(J)(3) below).

Tamar Lease			
Period	**Summary of actual operations in the period or of the planned work plan**	**Estimated total budget for operations on the level of the oil asset (USD thousands)**	**Actual participation of the Company's equity holders in the budget (USD thousands)[27]**
	• Continued update of the geological model and flow model, among other things, according to drilling and production data and plans for additional drilling.		
	• Continued improvement of the production system at the Tamar platform and receiving terminal, including improvement of the operating systems, addition of structures, upgrade of the stainless steel plate to prevent corrosion, painting of equipment and pipelines, and continued upgrade of the valve system.	19,501[30]	2,749
	• Purchase of equipment and the pipeline for development of the Tamar SW reservoir.	53,463	7,536
2020[31][32]	• Continued production from the Tamar project, ongoing operation and maintenance.		
	• Installation of subsea infrastructure for the connection of the Tamar SW well to the subsea production system in the Tamar field. For further information, see section 1.7.5(D)(4) below.	31,833	3,828
	• Actions related to compliance with regulatory requirements and with emission, flow, and toxins permits, monitoring of the marine and air environment.	2,465	296
	• Continued upgrade and improvement of the production system at the Tamar platform and the receiving terminal, including the acquisition of land rights at the receiving terminal, improvement of the operating systems and upgrade of the stainless steel plate to prevent corrosion, painting of equipment and piping, and reviewing the upgrade of the MEG treatment systems.	8,941	1,075
	• Continued update of the geological and flow models, among other things, based on the Reprocessing Data of the seismic surveys that was completed in 2019, and according to drilling and production data, and planning and preparation for additional drilling and completion.		
	• Mapping and definition of additional prospects, including a prospect to the deep targets in the lease area.		
	• Assessment of alternatives and performance of a FEED for the MEG regeneration facility		

30 Costs in 2019 did not include an adjusted budget of USD 4.9 million (100%) (the Company's share is USD 0.7 million).

31 The costs and activities described for 2021 do not include the Company's planned costs for additional expansion of gas flow capacity to Egypt through the construction of the combined section (as set out in section 1.7.27(H)(9)a below) and the EMG pipeline (as set out in section 1.7.29(J)(1) below) in the amount of USD 41.5 million and USD 12.5 million, respectively (100%, the Company's share is USD 5.7 million and USD 1.6 million, respectively).

32 The amounts set out below are in nominal amounts. In addition, the table below does not include abandonment operations of the reservoir, including their expenses.

Tamar Lease			
Period	Summary of actual operations in the period or of the planned work plan	Estimated total budget for operations on the level of the oil asset (USD thousands)	Actual participation of the Company's equity holders in the budget (USD thousands)[27]
2021[33][34],	• Continued production from the Tamar project, ongoing operation and maintenance.[35]		
	• Continued upgrade and improvement of the production system at the Tamar platform and receiving terminal, including improvement of the operating systems, improvement of structures, addition of environmental systems for monitoring and reducing emissions, upgrade of the stainless steel plate to prevent corrosion, painting of equipment and piping, and continued upgrade of the valve system.	14,070	1,692
	• Mapping and definition of additional prospects, including a prospect to the deep targets in the lease area.		
	• Completion of the FEED for the MEG regeneration facility Continuation of details planning and preparation for execution	5,000	601
	• Covering a section of the subsea pipeline	6,000	722
	• Continuation of the assessment of additional development, including installation of a third pipeline from the Tamar field to the platform, to the extent required	750	90
2022 onwards	• In accordance with the provisions of the Gas Framework, the Partnership is required to sell its holdings in the project by December 2021, therefore the work plan from 2022 onwards was not included.		

Dalit Lease			
Period	Summary of actual operations in the period or of the planned work plan	Estimated total budget for operations on the level of the oil asset (USD thousands)	Actual participation of the Company's equity holders in the budget (USD thousands)
2018	• Review of development options with attention to the development plans of adjacent reservoirs and production data from the Tamar reservoir.	-	-
	• Update of the mapping and analysis of the Dalit reservoir based on the seismic survey and on data from adjacent fields, including production data from the Tamar reservoir.		

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33 The budgets for 2021 do not include costs that the Partnership may incur for the construction of the Combined Section (as defined in section 1.7.27(H) below) in the amount of USD 25 million and for other possible improvements and upgrades of the Tamar platform and the receiving terminal at an estimated amount of USD 70 million (100%).

34 The amounts set out below are in nominal amounts. In addition, the table below does not include abandonment operations of the reservoir, including their expenses.

35 For information about the operating costs in the Tamar project attributable to the Partnership, see information about the discounted cash flow attributable to the Partnership's share in the Tamar project reserves, as described in section 1.7.5(K)(1)e below.

Dalit Lease			
Period	**Summary of actual operations in the period or of the planned work plan**	**Estimated total budget for operations on the level of the oil asset (USD thousands)**	**Actual participation of the Company's equity holders in the budget (USD thousands)**
	• Mapping and definition of additional prospects in the lease area, including a prospect to the deep targets in the lease area.		
2019	• Review of development options with attention to the development plans of adjacent reservoirs and production data from the Tamar reservoir.	-	-
	• Update of the characterization of the Dalit reservoir based on the seismic survey and on data from adjacent fields, including production data from the Tamar reservoir.		
	• Characterization of deep prospects in the lease area.		
2020	• Review of development options with attention to the development plans of adjacent reservoirs and production data from the Tamar reservoir.	-	-
	• Update of the mapping and analysis of the Dalit reservoir based on the seismic survey and on data from adjacent fields, including production data from the Tamar reservoir.		
2021	• Review of development options with attention to the development plans of adjacent reservoirs and production data from the Tamar reservoir.	-	-
	• Update of the mapping and analysis of the Dalit reservoir based on the seismic survey and on data from adjacent fields, including production data from the Tamar reservoir.		
	• Mapping and definition of additional prospects in the lease area, including the deep prospects in the lease area.		
2022 onwards	• In accordance with the provisions of the Gas Framework, the Partnership is required to sell its holdings in the project by December 2021, therefore the work plan from 2022 onwards was not included.	-	-

(2) Development plan of the Tamar project

The production system of the Tamar project includes six subsea production wells, a subsea production system connecting the production wells to the treatment and production platform (in this section: "the Platform"), where most of the natural gas is treated, a system for transmission of natural gas and condensate from the Platform to the shore and the receiving terminal facility, where final treatment of natural gas is performed, and from there to the national transmission system of INGL, while condensate is delivered in a designated pipeline to the nearby Paz Ashdod Refinery.

On August 29, 2016, the Minister of Energy granted the Tamar partners a license to operate the 10-inch pipeline, which was originally intended for the transmission of condensate from the Platform, for the transfer of natural gas, with the aim of increasing the supply capacity of natural gas.

The daily gas supply capacity from the Tamar project to the INGL transmission system is 1.05 BCF. Since the start of commercial operation, the Tamar production system has very high operational availability with more than 99% up-time. For a detailed description of the production system of the Tamar Project, see section 1.7.18(B) below. As at December 31, 2020, the total cost invested in the Tamar project, as described above, amounts to USD 4.6 billion (100%) (including exploration costs in the Tamar and Dalit Leases, without disposal and abandonment costs, exploration costs in the Dalit Lease and Tamar participation fees (as defined in section 1.7.29(J)(3) below)).

(3) <u>Assessment of the option of expanding the supply capacity of the Tamar project</u>

The total supply capacity of the Tamar facilities is currently limited to the flow capacity of the double pipeline (as defined in section 1.7.18(B)(1)b below). The Tamar partners assess, from time to time, options for expanding the supply capacity from the Tamar project, if required, in accordance with the expected volume of demand in the local market and for exports.

Expansion of the supply capacity may include, among other things, completion of development of the Tamar SW reservoir and/or the drilling and/or completion of other production wells, which will be connected to the existing subsea production system, as well as the installation of a third supply pipeline from the Tamar field to the Tamar platform and/or the Mari B platform. In addition, the necessity and method of the required upgrade at the Tamar platforms and the receiving terminal are being assessed.

(4) <u>Tamar SW reservoir</u>

As described, the Tamar SW reservoir is divided between the area of the Tamar Lease (78%) and the area of the Eran license (22%).

According to the development plan of the Tamar SW reservoir, which was approved by the Commissioner of Petroleum Affairs in January 2019, and taking into consideration the provisions of the Gas Framework set out in section 1.7.25(A)(4)c) below, the Tamar SW reservoir will be developed by converting the exploration drilling to a production drilling and through its connection to the subsea facilities of the Tamar project. The development cost of the Tamar SW reservoir was partially approved by the Tamar partners, and accordingly, equipment was purchased and various operations were carried out for development of the reservoir, including the installation of a subsea pipeline between the Tamar SW reservoir and the subsea manifold of the Tamar project, which was completed in 2020.

For further information about the work plans and budget for completion and development of the Tamar SW reservoir, see the table in section 1.7.5(D) above.

For information about the mediation arrangement, in which it was agreed to divide the Tamar SW reservoir between the Tamar Lease (78%) and the Eran License (22%), see section 1.7.11(B) below. It should be noted that, as at the approval date of the report, the Tamar partners and the relevant state representatives are continuing to formulate the agreements required to implement the mediation arrangement, as set out above, but there is no certainty that they will be able to start reservoir development works in the near future.

<u>Consequences of the Covid-19 crisis</u>

As set out in section 1.7.2(G) above, due to the Covid-19 crisis, as at the approval date of the report, there is extreme and unusual uncertainty regarding the possible consequences of the crisis in and after 2021 on the global economy in general, and on energy prices in particular, and its possible effect on the availability of the professional human resources required to operate and rehaul the production facilities. Therefore, insofar as the Covid-19 crisis continues or intensifies, it is possible that there will be substantial changes in the work plans and/or the timetables set out above.

Forward-looking information: The above assessments of the Company regarding the planned operations, costs, timetables and execution of the planned operations, including options to expand supply capacity and production rates in the Tamar project are forward-looking information, as defined in Section 32A of the Israel Securities Law, based on the assessments of the operator and the General Partner in the Partnership regarding the planned operations, costs, timetables and execution of the planned operations, and production rates, which are all based on assessments that the General Partner in the Partnership obtained from the operator. Actual planned operations, costs, schedules, and production rates may be materially different from the above estimates, and are contingent, among other things, on appropriate decisions made by the Tamar partners, obtaining the approvals required by law, the completion of detailed planning of the project components, bids from contractors,

changes to suppliers and raw material markets, applicable regulation, technical ability and economic viability.

(E) Actual participation rates in expenses and revenues in the Tamar project (after the investment recovery date)

Participation rate	%	Percentage grossed up to 100%	Explanations
Actual rate attributable to equity holders of the Company in the oil asset	12.03%	100%	See section 1.7.5(A) above.
Actual rate attributable to equity holders of the Company in revenues from the oil asset	9.33%	77.58%	See the calculation in section 1.7.5(G) below.
Actual rate of participation of the Company's equity holders in expenses arising from exploration, development or production operations in the oil asset	12.15%	101%	See the calculation in section 1.7.5(I) below.

(F) Actual participation rate in the expenses and revenues in the Dalit Lease

Participation rate	% Before investment recovery	% After investment recovery	Rate grossed up to 100% before investment recovery	Rate grossed up to 100% after investment recovery	Explanations
Actual rate attributable to equity holders of the Company in the oil asset	12.03%	12.03%	100%	100%	See section 1.7.5(A) above.
Actual rate attributable to equity holders of the Company in revenues from the oil asset	9.93%	9.33%	82.58%	77.58%	See the calculation in section 1.7.5(H) below.
Actual rate of participation of the Company's equity holders in expenses arising from exploration, development or production operations in the oil asset	12.15%	12.15%	101%	101%	See the calculation in section 1.7.5(I) below.

(G) Participation rates of the equity holders of the Company in revenues from the Tamar project (after the investment recovery date)

Description	%	Summary of the calculation method for royalties or payments
Projected annual revenues of the oil asset	100%	
Royalties or payment (arising from revenues after the finding) related to the oil asset:		
The State	(12.5%)	In accordance with the Petroleum Law, State royalties are calculated at the market value of the royalty at the wellhead. The actual royalty rate is lower than one-eighth (12.5%) due to deduction of expenses for the gas delivery and handling system at the wellhead up to the onshore gas receiving terminal.
Adjusted revenues on the level of the oil asset	87.50%	

Description	%	Summary of the calculation method for royalties or payments
Share of the adjusted oil asset revenues attributable to the equity holders of the Company (linked)	12.03%	See the explanation in section 1.7.5(A) above.
Share of the equity holders of the Company in the actual rate of revenues, at the level of the oil asset (before other payments at the level of the Company)	10.52%	
Information about the royalties or payments (derived from the income after the finding) in respect of the oil asset at the level of the Company (the percentages below are calculated according to the rates of the equity holders of the Company in the oil asset):		
Rates of the equity holders of the Company in the Partnership's payments of royalties to Dor Chemicals Ltd.[36]	(0.05%)	The Partnership pays a royalty at the rate of 6% for 2.5% (of 100%) of its share in the oil asset, to the royalty holder, after the deduction of royalties to the State, according to the market value of the royalty at the wellhead. The calculation method for the rate is based on principles for calculating royalties to the State, therefore the rate may change if the calculation method of royalties to the State changes.
Rates of the equity holders of the Company in payments to related parties and third parties	(1.14%)	The Partnership pays overriding royalties for the Partnership's share in the oil asset at a rate of 9.5% after investment recovery, calculated at the wellhead market value. The calculation method for the rate is based on principles for calculating royalties to the State in the Tamar project, therefore the rate may change if the calculation method of royalties to the State changes.
Actual rate attributable to equity holders of the Company in revenues from the oil asset	9.33%	

(H) Participation rates of the equity holders of the Company in revenues from the Dalit Lease

Description	Before investment recovery	After investment recovery	Summary of the calculation method for royalties or payments
Projected annual revenues of the oil asset	100%	100%	
Royalties or payment (arising from revenues after the finding) related to the oil asset:			
The State	(12.5%)	(12.5%)	See the explanation in the table above, which presents the data for the Tamar Lease.
Adjusted revenues on the level of the oil asset	87.50%	87.50%	
Share of the adjusted oil asset revenues attributable to the equity holders of the Company (linked)	12.03%	12.03%	See the explanation in section 1.7.5(A) above.
Share of the equity holders of the Company in the actual rate of revenues, at the level of the oil asset	10.52%	10.52%	

[36] On January 21, 2007, the Partnership entered into an agreement with Dor Chemicals Ltd. to acquire 2.5% (of 100%) of the rights in the Michal and Matan Licenses (replaced by the Tamar Lease and Dalit Lease, respectively). In consideration for sale of the rights, Dor Chemicals Ltd. is entitled to overriding as set out in the table.

Description	Before investment recovery	After investment recovery	Summary of the calculation method for royalties or payments
(before other payments at the level of the Company)			
Information about the royalties or payments (derived from the income after the finding) in respect of the oil asset at the level of the Company (the percentages below are calculated according to the rates of the equity holders of the Company in the oil asset):			
Rates of the equity holders of the Company in the Partnership's payments to Dor Chemicals Ltd.	(0.05%)	(0.05%)	See the explanation in the table above, which presents the data for the Tamar Lease.
Rates of the equity holders of the Company in payments to related parties and third parties	(0.54%)	(1.14%)	The Partnership pays overriding royalties for the Partnership's share in the oil asset at a rate of 4.5% before investment recovery and 9.5% after investment recovery, according to the market value of the royalty at the wellhead. The calculation method for the rate is based on principles for calculating royalties to the State, therefore the rate may change if the calculation method of royalties to the State changes.
Actual rate attributable to equity holders of the Company in revenues from the oil asset	9.93%	9.33%	

(I) Participation rate of the Company's equity holders in exploration, development, and production expenses in the Tamar project and the Dalit Lease

Description	%	Summary of the calculation method for royalties or payment
Theoretical expenses for the oil asset (without royalties)	100%	
Payments (derived from the expenses) at the level of the oil asset		
Operator	1%	The Operator is entitled to reimbursement of direct and indirect expenses for its duties as Operator. On June 30, 2016, an amendment to the joint operating agreement in the Tamar project was signed, according to which it was agreed that as from January 1, 2016, the Operator will be entitled to reimbursement of indirect expenses at a rate of 1% of all the direct expenses, subject to certain exceptions, such as marketing activity.
Total actual rate of expenses at the level of the oil asset	101%	
Share of the equity holders of the Company in the oil asset's expenses (linked)	12.03%	See the explanation in section 1.7.5(A) above.
Total share of the equity holders of the Company in expenses, at the level of the oil asset (before other payments at the level of the Company)	12.15%	

Description	%	Summary of the calculation method for royalties or payment
Payments (derived from the expenses) in respect of the oil asset and at the level of the Company (the following percentages will be calculated in accordance with the share of the equity holders of the Company in the oil asset)		
Actual share of the Partnership's expenses for exploration, development, and production in the oil asset, attributable to equity holders of the Company	12.15%	The Partnership pays management fees to the General Partner, which consist of a fixed amount and a variable amount calculated as a rate of the exploration expenses on fulfillment of certain conditions. These amounts were not taken into account in this table.

(J) Royalties and payments paid during exploration, development and production operations for the oil asset (USD thousands)[37]

Tamar Lease			
Description	**Total share of equity holders of the Company in investment in the oil asset in this period (including costs for which payments are not made to the Operator)**	**Of which, the share of equity holders of the Company in payments to the General Partner**	**Of which, the share of equity holders of the Company in payments to the Operator (in addition to return of direct expenses)**
Actual budget invested in 2018	22,549	-	224
Actual budget invested in 2019	30,087	-	312
Actual budget invested in 2020	14,697	-	143

Dalit Lease			
Description	**Total share of equity holders of the Company in investment in the oil asset in this period (including costs for which payments are not made to the Operator)**	**Of which, the share of equity holders of the Company in payments to the General Partner**	**Of which, the rates of equity holders of the Partnership in payments to the Operator (in addition to the return of direct expenses)**
Actual budget invested in 2018	-	-	-
Actual budget invested in 2019	-	-	-
Actual budget invested in 2020	-	-	-

(K) Reserves, contingent, and prospective resources in the Tamar and Dalit Leases

(1) Reserves in the Tamar Lease

A. Quantitative data

According to a report received by the Partnership from NSAI, which was prepared in accordance with the principles of the Petroleum Resources Management System (SPE-PRMS), as at December 31, 2020 ("the Reserves Report"), the natural gas and condensate reserves attributable to the Tamar Lease (which include, as aforesaid, the Tamar and Tamar SW Reservoirs)[38] are as presented in the table below.

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37 The amounts in the table reflect the Company's holdings in the Partnership (54.7%) as at the reporting date and the Partnership's direct and indirect holdings in the Tamar Lease at a rate of 25.7855% until December 31, 2018, and the Partnership's direct holdings in the Tamar Lease at a rate of 22% as from January 1, 2019.

38 The reserves in the Tamar SW reservoir listed below do not include the reserves in the part of the reservoir that is migrating into the area of the Eran license. For further information about the Eran license and the mediation arrangement for the Eran license and the Tamar SW reservoir, see section 1.7.30(H)(1) below.

It is clarified that the information in the table below regarding the Company's share was calculated in accordance with the Company's direct and indirect rights in the Tamar project, assuming that the rate of royalty to the State is 12.5% (at the wellhead), and that the investment recovery date for the Tamar project is achieved. The Company's direct and indirect share in the Tamar project includes the Company's direct and indirect holding in 54.7% of the unit capital of Delek Drilling. In addition, the information in this section about the Company's share (including information about the discounted cash flow) also includes the rights attributed to the Partnership in the Tamar project, indirectly, through its holdings in Tamar Petroleum shares. For information about the dispute regarding the investment recovery date for the Tamar project, see section 1.7.29(N)(4) below.[39]

[39] The amounts in the table may not add up due to rounding-off differences.

Reserve category	Total (100%) in the oil asset (gross)						Total (Tamar and Tamar SW reservoirs) share attributable to equity holders of the Company (net)	
	Tamar Reservoir		Tamar SW reservoir		Total (Tamar and Tamar SW reservoir)			
	Natural gas BCF	Condensate (million barrels)	Natural gas BCF	Condensate (million barrels)	Natural gas BCF	Condensate (million barrels)	Natural gas BCF	Condensate (million barrels)
Proved reserves 1P	6,929.8	9.0	796.4	1.0	7,726.2	10.0	720.8	0.9
Probable reserves	2,595.9	3.4	159.1	0.2	2,755.0	3.6	257.1	0.4
Total 2P reserves Proved + probable reserves	9,525.7	12.4	955.6	1.2	10,481.2	13.6	977.9	1.3
Possible reserves	2,366.0	3.1	102.2	0.1	2,468.3	3.2	230.3	0.3
Total 3P reserves (proved + probable + possible reserves)	11,891.7	15.5	1,057.8	1.4	12,949.5	16.8	1,208.2	1.6

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

B. According to the NSAI reserves report, the maturity stage of the project to which the reserves are associated is on production. The NSAI reserves report also noted 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 are developed in accordance with the development plans, which will be operated reasonably, that no regulation will be set that will affect the ability of the holder of the oil rights to produce the reserves, and that 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 and condensate in the Tamar and Tamar SW reservoirs are forward-looking information as defined in Section 32 of the Israel Securities Law. These estimates are partially based on geological, geophysical, engineering and other information obtained from the drilling and from the operator of the Tamar project, 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 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 continued production from the Tamar project.

C. Discounted cash flow figures

The discounted cash flow data is based on various estimates and assumptions provided by the Partnership to NSAI, the main points of which are listed below:

1. Forecasted sales quantities: The cash flow assumptions for the natural gas quantities to be sold by the Partnership from the Tamar project are based on: i) the production capacity of the Tamar project.[40] It should be noted that the actual production rate for each of the reserve categories in the cash flow may be lower or higher than the production rate assumed in the cash flow. In addition, NSAI did not perform a sensitivity analysis for the production rate of the wells. (ii) The Partnership's assumptions regarding the quantities of natural gas to be sold to the Partnership's customers under the existing agreements entered into by the Partnership, including the agreement for the export of natural gas to Egypt signed with Dolphinus (for further information see section 7.11.5(B)(2) below), taking into consideration, among other things, the forecasts used by the Partnership for the Brent price and its possible effect on the quantities sold to Egypt, and the agreement for the supply of natural gas to the IEC (for further information see sections 7.11.4(A)4 and 7.11.4(A)6 (jointly below: "the Existing Agreements"). (iii) Additional quantities of natural gas that the Partnership estimates will be sold in the local market in Israel, based, among other things, on negotiations for the sale of natural gas from the Tamar project, the forecast for natural gas demand in the local market prepared for the Partnership by outside consultants (BDO Consulting Group, below: "BDO")[41] and with regard to the expected supply from other sources, particularly from the Leviathan project and from the Karish, and

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[40] As at the approval date of the report, the daily gas supply capacity from the Tamar project to the INGL transmission system is 1.1 BCF.

[41] The forecast for natural gas demand in the local market for the coming years used by the Partnership is as follows (BCM): 2021 – 13.1; 2022 – 15; 2023 – 15.6; 2024 – 16.6; 2025 – 17.9. The demand forecast is based mainly on the demand forecast for electricity, which is effected, among other things, by growth forecasts in Israel and the Covid-19 Crisis, as well as the mix of energy sources to be used in electricity production, which is effected by government policy on reducing the use of coal for electricity production. The demand forecast is forward-looking information, and there is no certainty that it will materialize, in whole or in part, and it may materialize in a fundamentally different way, due to various factors, including the continued spread of the Covid-19 pandemic and its effect on local and global economies, development in the strengthening of the Israeli economy; climatic conditions in Israel; the rate of discontinuation of coal as a source for electricity production, the rate of introduction of renewable energies as a source of electricity; the rate of introduction of electric vehicles into the Israeli market; and government policy in other areas that relate, directly or indirectly, to the increase in demand for natural gas.

Tanin reservoirs.[42] (iv) Additional quantities of natural gas, which the Partnership estimates will be sold in regional markets.[43]

2. Selling prices of natural gas and condensate: The cash flow assumptions for prices of natural gas to be sold from the Tamar project are based, among other things, on the weighted average of gas prices in existing agreements, according to the price formulas in the agreements; the Partnership assumptions for the prices to be set out in future agreements, based, among other things, the projected distribution of demand on the local market in the cash flow year as assessed by BDO; and on the Partnership's estimate of the expected supply. The price formulas set out in the existing agreements include linkage to the electricity generation tariff, the US-CPI, and the Brent price per barrel of oil ("the Brent Price"). The assumptions for the linkage components are based on information and forecasts received from BDO, as set out below:

a) The US-CPI , assuming an annual average increase of 2%

b) The Brent Price per barrel, based on average long-term forecasts of the following four entities:[44] the World Bank, the US Department of Energy, IHS Global Insights, and Wood Mackenzie. Accordingly, the price assumed for the cash flow was USD 52 per barrel of Brent in 2021, increasing to USD 68 per barrel in 2025, and a fixed price per barrel of USD 86 from 2030 through to the end of the cash flow period.

c) Price of electricity production tariff: a forecast based, among other things, on the NIS-USD exchange rate and on the forecast for the cost of fuel based on the price of gas to the IEC.

It should be noted that selling prices may change, due, among other things, to changes in the indexes on which the linkages are based in the gas supply agreements as set out above, commercial and competitive considerations, and price adjustment mechanisms, as set out in the agreement with the IEC[45] and in the agreement for export to Egypt.[46] In the cash flow, it was assumed that a price reduction of 25% will be made in the agreement with the IEC on the first adjustment date (on July 1, 2021), and 10% on the second adjustment date (on July 1, 2024). The price reduction was included in the forecast for the electricity production tariff. It should also be noted that no change in price has been taken into account as a result of the motion for certification of a class action filed by a consumer of the IEC against the Tamar project partners, as set out in Note 24A2(2) to the financial statements. In the opinion of the legal counsel of the Partnership, it is more likely than not that the motion for certification will be dismissed. At this stage, the parties are at the 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 (namely, after the motion for certification as a class action is accepted (if it is accepted) and an absolute ruling on the class action itself is received (if it is received) against the holders of rights in the Tamar project, this may have a material adverse effect on the Partnership's business, including on information about the discounted cash flow and on the prices at which the Partnership and the Company will sell natural gas to its customers, the scope of which will be derived from the results of the claim. The cash flow assumptions for condensate selling prices are based on the Brent Crude prices and adjusted to differences in quality, transportation costs, and the selling price of condensate in the region For further information about the agreement for condensate supply from the Tamar project, see section 1.7.13(F)(1) below.

3. Operating costs taken into account are costs provided by the Partnership to NSAI, based, among other things, on information provided by the operator. These costs include direct costs on the project level, insurance costs, and rehauling costs of production wells, transmission costs to the delivery point, as set out in the agreement for export to Egypt, and estimated overheads and general and administrative expenses of the operator, which together constitute the operating costs of the project.

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[42] For information about the forecast for natural gas sales from the Leviathan project, see the Company's immediate report dated March 10, 2021 (Ref. No. 2021-01-031128). The assumption in the discounted cash flows is that the sale of natural gas to the local market in Israel from the Karish and Tanin project will start in the first quarter of 2022.

[43] It was assumed that even after the termination of the gas supply in accordance with the forecasted quantities in the existing export agreements, additional gas quantities will be sold to customers in Egypt and Jordan, with a total aggregate volume of 37 BCM by 2040.

[44] To the best of the Partnership's knowledge, the Brent Price forecast is updated by these four entities at the following frequency: World Bank: twice a year; US Department of Energy: short-term forecast - every month, long-term forecast - twice a year; Wood Mackenzie: every six months; IHS Global Insights: once a month.

[45] The agreement with the IEC specifies two dates on which each party may request a price adjustment, according to the mechanism set out in the agreement. For further information, see section 1.7.13(D)(1)d.8 below.

[46] The agreement for export to Egypt includes a mechanism for an update of the price at a rate of up to 10% (addition or reduction) after the fifth year and after the tenth year of the agreement given certain conditions set out in the agreement. It should be noted that a price update on these dates was not assumed.

Operating costs in cash flow are not adjusted to inflation fluctuations. . NSAI has confirmed that the operating costs provided by the Partnership are reasonable, based, among other things, on NSAI's experience in similar projects.

4. The capital expenses included in the discounted cash flow are expenses approved by the Partnership and estimated future capital expenses not yet approved by the Partnership, which will be incurred during production for the purpose of retaining and expanding production capacity, including drilling and connecting new development wells, installing additional production infrastructure and equipment, expenses for engineering works, participation in construction costs of natural gas transmission infrastructure,[47] and indirect costs paid to the operator. The capital expenses in the cash flow are not adjusted for inflation changes. NSAI has confirmed that the capital expenses provided by the Partnership are reasonable, based, among other things, on the development plan in the Tamar project and on NSAI's experience in similar projects.

5. Abandonment costs are costs provided to NSAI by the Partnership according to its assessments, based, among other things, on the estimate of outside experts regarding the cost of abandoning the wells, the Platform, and the production facilities. These costs do not take into account the salvage value of the Tamar Lease and facilities in the Tamar project and are not adjusted to inflation changes.

6. The discounted cash flow takes into account the Partnership's estimate, according to which the effective rate of state royalties is 11.5% and the effective rate of royalties to be paid to third parties is 9.13% (for the Partnership's direct holdings in the Tamar project). The actual rate of royalties is not final and may change. For further information, see section 1.7.29(N)(5)b below.

7. The tax payments and rates included in the discounted cash flow were calculated from the aspect of a company that has held the Partnership's participation units from the beginning of the project. The tax calculations include corporate tax rates by law. Depreciation expenses for tax purposes were calculated in accordance with the statutory depreciation rates.

8. Calculation of the discounted cash flows takes into account the oil profits tax (in this section below: "the Levy") applicable to the holders of rights in the project and to parties entitled to royalties under the provisions of the law. It should be emphasized that calculation of the Levy was based, among other things, on the definitions, formulas and mechanisms set out in the law as understood and interpreted by the Company, and which were reflected in the Levy reports of the Tamar project to the Tax Authority. However, since the law is new and the calculation formulas and mechanisms set out in the law are complex, it is not certain whether this interpretation of the calculation method for the Levy will be the same as that adopted by the tax authorities and/or the same as the interpretations of the law by the court. It should be noted that as at the approval date of this report, a number of interpretative disputes regarding the implementation of the law in the Levy reports of the Tamar project are being discussed, as part of the objection and appeal proceedings set out in the law. The issues underlying the disputes have not yet been brought before the courts in Israel.[48] 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. In addition, the calculation was in USD, in accordance with the selection of the holder of rights in the project under section 13(B) of the Law, using the following assumptions: The Tax Authority will recognize all the payments attributable to the project (such as production costs, investments, and royalties) for the calculation of the Levy. The actual selling prices of natural gas will be taken into account for calculation of revenues attributable to the project.

9. Calculation of the discounted cash flow includes expenses and investments that were paid in practice and which are expected to be paid by the Partnership as from January 1, 2020, as well as revenue from sales of natural gas and condensate sales produced and which are expected to be produced as from January 1, 2021.

10. Revenue from natural gas and condensate sales to be made in a given year were taken into account in that year, regardless of the actual payment date.

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[47] To increase the possible flow capacity through the EMG pipeline, expansion of the supply capacity in the INGL system is required. For further information, see section 1.7.14(B)(2)b.2**Error! Reference source not found.** below.

[48] If the Tax Authority's position in the disputes is accepted, the Company believes that this is not expected to have a material effect on the discounted cash flow.

D. <u>It should be noted that the discounted cash flow presented below was adjusted compared to the discounted cash flow as at June 30, 2020, for the following main reasons:</u>

1. Adjusted projections of quantities to be sold mainly due to the Partnership's assumptions regarding the postponement of production from the Karish, Karish North, and Tanin reservoirs, and increase in annual sales quantities from these reservoirs.

2. Update of operating costs and investments made up to December 31, 2020, in accordance with actual investments made. Forecasts for operating cost forecasts and future investments were also updated according to the Partnership's assessment, based, among other things, on the production profile and updated estimates received from the operator, which were revised, among other things, due to expected streamlining and reduction in operating budgets.

3. The quantities of gas and condensate produced and sold in the second half of 2020 were updated, in accordance with actual data.

4. The discounted cash flow as at June 30, 2020 included data attributed directly and indirectly to the Partnership's share (through its holding of 22.6% in Tamar Petroleum) from the reserves in Tamar Petroleum (25.7855%), while the updated discounted cash flow included data attributed indirectly to the Partnership's share only (22%).

E. <u>Discounted cash flow from the reserves in the Tamar project</u>

Based on assumptions, which are described above, following is the estimated discounted cash flow as at December 31, 2020, in thousands of USD (after the levy and income tax) attributable to the Company, from the reserves in the Tamar project, for each of the reserve categories described above:[49]

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

Total discounted cash flow from 1P proved reserves as at December 31, 2019 (in USD thousands for the Company's share)																	
Cash flow items																	
										Taxes		Total discounted cash flow after tax					
Until	Qty. of condensate sales (thousands of barrels) (100% of the oil asset)	Sales qty. (BCM) (100% of the oil asset)	Revenue	Royalties payable	Royalties received	Operating costs	Development costs	Abandonment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Levy	Income tax	Discounted at 0%	Discounted at 5%	Discounted at 7.5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
December 31, 2021	395	8.60	163,852	33,804	-	17,556	7,965	-	104,527	25,042	16,193	63,293	61,767	61,045	60,347	59,021	57,778
December 31, 2022	421	9.16	184,667	38,098	-	15,892	3,374	-	127,303	38,828	17,317	71,158	66,136	63,842	61,678	57,700	54,131
December 31, 2023	419	9.13	188,387	38,866	-	15,815	25,933	-	107,774	38,606	19,309	49,858	44,133	41,612	39,288	35,155	31,607
December 31, 2024	436	9.49	195,400	40,313	-	15,788	37,505	-	101,794	40,689	19,240	41,865	35,293	32,503	29,990	25,669	22,117
December 31, 2025	475	10.35	214,369	44,226	-	15,865	-	-	154,278	69,568	15,199	69,512	55,809	50,202	45,268	37,061	30,602
December 31, 2026	488	10.62	225,553	46,533	-	15,892	-	-	163,128	76,344	16,178	70,606	53,988	47,435	41,801	32,734	25,903
December 31, 2027	501	10.91	234,840	48,449	-	15,913	-	-	170,477	79,783	17,839	72,855	53,055	45,530	39,211	29,371	22,273
December 31, 2028	505	11.00	241,050	49,731	-	16,187	19,145	-	155,987	73,002	20,713	62,272	43,189	36,202	30,468	21,830	15,865
December 31, 2029	526	11.46	253,973	52,397	-	16,237	4,291	-	181,049	84,731	20,116	76,202	50,333	41,209	33,894	23,229	16,178
December 31, 2030	535	11.65	260,527	53,749	-	16,262	-	-	190,516	89,161	20,264	81,091	51,012	40,794	32,790	21,495	14,347
December 31, 2031	535	11.65	260,667	53,778	-	16,263	-	-	190,626	89,213	20,409	81,004	48,531	37,907	29,777	18,672	11,943
December 31, 2032	535	11.65	259,637	53,565	-	16,259	-	-	189,814	88,833	20,365	80,616	45,999	35,093	26,940	16,158	9,905
December 31, 2033	535	11.65	259,621	53,562	-	16,259	12,238	-	177,563	83,099	21,732	72,731	39,523	29,452	22,096	12,676	7,447
December 31, 2034	535	11.65	259,730	53,584	-	16,259	23,435	-	166,451	77,899	23,844	64,708	33,489	24,375	17,871	9,807	5,521
December 31, 2035	535	11.65	254,300	52,464	-	16,238	-	-	185,598	86,860	21,334	77,404	38,152	27,123	19,434	10,201	5,503
December 31, 2036	494	10.77	235,182	48,520	-	16,165	-	-	170,497	79,793	19,487	71,218	33,431	23,214	16,256	8,162	4,220
December 31, 2037	366	7.98	173,752	35,847	-	15,928	-	-	121,978	57,086	13,550	51,342	22,954	15,568	10,654	5,116	2,535
December 31, 2038	286	6.24	135,939	28,045	-	15,783	-	-	92,111	43,108	9,895	39,108	16,651	11,031	7,377	3,389	1,609
December 31, 2039	236	5.13	111,811	23,067	-	15,690	-	-	73,053	34,189	8,020	30,845	12,508	8,093	5,290	2,324	1,058

Total discounted cash flow from 1P proved reserves as at December 31, 2019 (in USD thousands for the Company's share)																	
Cash flow items																	
										Taxes		Total discounted cash flow after tax					
Until	Qty. of condensate sales (thousands of barrels) (100% of the oil asset)	Sales qty. (BCM) (100% of the oil asset)	Revenue	Royalties payable	Royalties received	Operating costs	Development costs	Abandonment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Levy	Income tax	Discounted at 0%	Discounted at 5%	Discounted at 7.5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
December 31, 2040	200	4.35	94,865	19,571	-	15,625	-	-	59,668	27,925	6,481	25,263	9,757	6,166	3,938	1,655	722
December 31, 2041	174	3.78	82,406	17,001	-	15,577	-	-	49,828	23,320	5,277	21,232	7,809	4,821	3,009	1,210	506
December 31, 2042	153	3.33	72,572	14,972	-	15,539	-	-	42,060	19,684	4,326	18,050	6,323	3,812	2,326	894	358
December 31, 2043	135	2.93	63,833	13,169	-	15,505	-	-	35,158	16,454	3,481	15,223	5,078	2,991	1,783	656	252
December 31, 2044	118	2.58	56,189	11,592	-	15,476	-	-	29,121	13,628	3,024	12,468	3,961	2,279	1,328	467	172
December 31, 2045	104	2.27	49,421	10,196	-	15,450	-	-	23,775	11,127	2,909	9,739	2,947	1,656	943	317	112
December 31, 2046	91	1.99	43,310	8,935	-	15,427	-	-	18,948	8,868	2,319	7,762	2,237	1,228	683	220	74
December 31, 2047	81	1.76	38,292	7,900	-	15,407	-	-	14,985	7,013	1,673	6,299	1,729	927	504	155	50
December 31, 2048	71	1.54	33,494	6,910	-	15,389	-	-	11,195	5,239	1,209	4,746	1,241	650	345	102	32
December 31, 2049	62	1.36	29,569	6,100	-	15,374	-	9,811	(1,716)	-	1,701	(3,417)	(851)	(435)	(226)	(64)	(19)
December 31, 2050	55	1.20	26,082	5,381	-	15,360	-	9,811	(4,470)	-	1,068	(5,538)	(1,313)	(656)	(333)	(90)	(26)
December 31, 2051	44	0.95	20,671	4,265	-	15,339	-	9,811	(8,744)	-	85	(8,829)	(1,994)	(973)	(482)	(124)	(34)
December 31, 2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
December 31, 2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
December 31, 2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
December 31, 2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
December 31, 2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**10,044**	**219**	**4,723,959**	**974,591**	**-**	**491,716**	**133,886**	**29,433**	**3,094,332**	**1,389,090**	**374,558**	**1,330,684**	**842,879**	**694,695**	**584,248**	**435,170**	**342,738**

Total discounted cash flow from probable reserves as at December 31, 2020 (in USD thousands for the Company's share)																	
Cash flow items																	
Until	Qty. of condensate sales (thousands of barrels) (100% of the oil asset)	Qty. of gas sales (BCM) (100% of the oil asset)	Revenue	Royalties payable	Royalties received	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%	Discounted at 10%	Discounted at 15%	Discounted at 20%
December 31, 2021	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
December 31, 2022	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
December 31, 2023	-	-	-	-	-	-	(22,896)	-	22,896	9,090	(2,091)	15,897	14,072	13,268	12,527	11,209	10,078
December 31, 2024	-	-	-	-	-	-	(37,505)	-	37,505	17,878	(3,064)	22,691	19,129	17,617	16,255	13,913	11,987
December 31, 2025	-	-	-	-	-	-	37,505	-	(37,505)	(15,630)	5,508	(27,384)	(21,986)	(19,777)	(17,833)	(14,600)	(12,055)
December 31, 2026	-	-	-	-	-	-	22,896	-	(22,896)	(10,715)	3,513	(15,693)	(12,000)	(10,543)	(9,291)	(7,276)	(5,757)
December 31, 2027	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
December 31, 2028	-	-	-	-	-	-	(19,145)	-	19,145	8,960	(2,061)	12,246	8,493	7,119	5,992	4,293	3,120
December 31, 2029	-	-	-	-	-	-	(4,291)	-	4,291	2,008	(6)	2,288	1,512	1,238	1,018	698	486
December 31, 2030	-	-	-	-	-	-	-	-	-	-	555	(555)	(349)	(279)	(224)	(147)	(98)
December 31, 2031	-	-	-	-	-	-	-	-	-	-	555	(555)	(332)	(260)	(204)	(128)	(82)
December 31, 2032	-	-	-	-	-	-	-	-	-	-	555	(555)	(317)	(242)	(185)	(111)	(68)
December 31, 2033	-	-	-	-	-	-	(12,238)	-	12,238	5,727	(762)	7,273	3,952	2,945	2,210	1,268	745
December 31, 2034	-	-	-	-	-	-	(23,435)	-	23,435	10,968	(2,734)	15,202	7,868	5,726	4,199	2,304	1,297
December 31, 2035	-	-	-	-	-	-	4,291	-	(4,291)	(2,008)	(76)	(2,206)	(1,088)	(773)	(554)	(291)	(157)
December 31, 2036	40	0.88	19,215	3,964	-	74	19,145	-	(3,968)	(1,857)	4,146	(6,257)	(2,937)	(2,040)	(1,428)	(717)	(371)
December 31, 2037	168	3.67	79,900	16,484	-	307	12,238	-	50,871	23,807	9,860	17,203	7,691	5,216	3,570	1,714	849
December 31, 2038	248	5.41	117,848	24,313	-	453	23,435	-	69,646	32,594	14,451	22,601	9,623	6,375	4,263	1,958	930
December 31, 2039	299	6.52	142,097	29,316	-	547	-	-	112,235	52,526	13,277	46,432	18,828	12,183	7,963	3,499	1,592

Total discounted cash flow from probable reserves as at December 31, 2020 (in USD thousands for the Company's share)

Cash flow items

Until	Qty. of condensate sales (thousands of barrels) (100% of the oil asset)	Qty. of gas sales (BCM) (100% of the oil asset)	Revenue	Royalties payable	Royalties received	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%	Discounted at 10%	Discounted at 15%	Discounted at 20%
December 31, 2040	335	7.30	159,189	32,842	-	612	23,435	-	102,299	47,876	17,353	37,070	14,317	9,048	5,779	2,429	1,059
December 31, 2041	361	7.87	171,561	35,395	-	660	-	-	135,507	63,417	15,487	56,603	20,819	12,852	8,022	3,225	1,348
December 31, 2042	361	7.86	171,287	35,338	-	659	-	-	135,290	63,316	15,460	56,514	19,796	11,936	7,281	2,800	1,121
December 31, 2043	311	6.78	147,704	30,473	-	568	-	-	116,663	54,598	13,181	48,884	16,308	9,605	5,726	2,106	808
December 31, 2044	266	5.80	126,315	26,060	-	486	-	-	99,769	46,692	10,832	42,245	13,422	7,721	4,498	1,583	582
December 31, 2045	228	4.97	108,203	22,323	-	416	-	-	85,464	39,997	8,543	36,924	11,173	6,278	3,574	1,203	424
December 31, 2046	196	4.26	92,714	19,128	-	357	-	-	73,230	34,272	7,145	31,814	9,168	5,032	2,800	901	304
December 31, 2047	167	3.63	78,977	16,294	-	304	-	-	62,379	29,194	6,434	26,752	7,342	3,936	2,140	659	213
December 31, 2048	143	3.12	67,858	14,000	-	261	-	-	53,597	25,083	5,641	22,873	5,979	3,130	1,664	490	152
December 31, 2049	122	2.66	57,834	11,932	-	222	-	(9,811)	55,491	25,167	4,099	26,225	6,529	3,339	1,734	488	145
December 31, 2050	104	2.27	49,338	10,179	-	190	-	(9,811)	48,780	20,737	3,574	24,469	5,801	2,898	1,471	396	113
December 31, 2051	94	2.05	44,511	9,183	-	171	-	581	34,575	12,089	5,225	17,261	3,898	1,902	943	243	66
December 31, 2052	119	2.59	56,255	11,606	-	15,476	-	10,392	18,780	8,789	4,448	5,544	1,192	568	275	68	18
December 31, 2053	17	0.38	8,147	1,681	-	15,291	-	10,392	(19,218)	-	-	(19,218)	(3,936)	(1,832)	(868)	(205)	(51)
December 31, 2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
December 31, 2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
December 31, 2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	3,582	78	1,698,950	350,507	-	37,055	23,435	1,744	1,286,209	604,575	159,046	522,588	183,968	114,186	73,315	33,973	18,799

Total discounted cash flow from proved reserves + probable reserves (P2) as at December 31, 2020 (in USD thousands for the Company's share)																	
Cash flow items																	
										Taxes		Total discounted cash flow after tax					
Until	Qty. of condensate sales (thousands of barrels) (100% of the oil asset)	Qty. of gas sales (BCM) (100% of the oil asset)	Revenue	Royalties payable	Royalties received	Operating costs	Development costs	Abandonment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Levy	Income tax	Discounted at 0%	Discounted at 5%	Discounted at 7.5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
December 31, 2021	395	8.60	163,852	33,804	-	17,556	7,965	-	104,527	25,042	16,193	63,293	61,767	61,045	60,347	59,021	57,778
December 31, 2022	421	9.16	184,667	38,098	-	15,892	3,374	-	127,303	38,828	17,317	71,158	66,136	63,842	61,678	57,700	54,131
December 31, 2023	419	9.13	188,387	38,866	-	15,815	3,037	-	130,670	47,696	17,219	65,756	58,205	54,880	51,814	46,365	41,685
December 31, 2024	436	9.49	195,400	40,313	-	15,788	-	-	139,299	58,566	16,176	64,557	54,422	50,120	46,245	39,582	34,104
December 31, 2025	475	10.35	214,369	44,226	-	15,865	37,505	-	116,773	53,938	20,707	42,128	33,824	30,425	27,435	22,461	18,546
December 31, 2026	488	10.62	225,553	46,533	-	15,892	22,896	-	140,232	65,629	19,691	54,913	41,989	36,891	32,510	25,459	20,145
December 31, 2027	501	10.91	234,840	48,449	-	15,913	-	-	170,477	79,783	17,839	72,855	53,055	45,530	39,211	29,371	22,273
December 31, 2028	505	11.00	241,050	49,731	-	16,187	-	-	175,132	81,962	18,653	74,518	51,682	43,321	36,460	26,123	18,984
December 31, 2029	526	11.46	253,973	52,397	-	16,237	-	-	185,340	86,739	20,111	78,490	51,845	42,447	34,912	23,927	16,664
December 31, 2030	535	11.65	260,527	53,749	-	16,262	-	-	190,516	89,161	20,818	80,536	50,663	40,514	32,566	21,348	14,248
December 31, 2031	535	11.65	260,667	53,778	-	16,263	-	-	190,626	89,213	20,964	80,449	48,199	37,647	29,573	18,544	11,861
December 31, 2032	535	11.65	259,637	53,565	-	16,259	-	-	189,814	88,833	20,920	80,061	45,682	34,852	26,755	16,047	9,836
December 31, 2033	535	11.65	259,621	53,562	-	16,259	-	-	189,801	88,827	20,970	80,004	43,476	32,397	24,306	13,944	8,191
December 31, 2034	535	11.65	259,730	53,584	-	16,259	-	-	189,886	88,867	21,110	79,910	41,357	30,101	22,070	12,111	6,818
December 31, 2035	535	11.65	254,300	52,464	-	16,238	4,291	-	181,307	84,852	21,258	75,197	37,064	26,350	18,880	9,910	5,347
December 31, 2036	535	11.65	254,397	52,484	-	16,238	19,145	-	166,530	77,936	23,633	64,961	30,494	21,175	14,827	7,444	3,849
December 31, 2037	535	11.65	253,652	52,331	-	16,236	12,238	-	172,848	80,893	23,410	68,546	30,645	20,785	14,223	6,831	3,384
December 31, 2038	535	11.65	253,787	52,358	-	16,236	23,435	-	161,757	75,702	24,346	61,708	26,274	17,406	11,640	5,347	2,539
December 31, 2039	535	11.65	253,908	52,383	-	16,237	-	-	185,288	86,715	21,296	77,277	31,336	20,276	13,252	5,823	2,650

Total discounted cash flow from proved reserves + probable reserves (P2) as at December 31, 2020 (in USD thousands for the Company's share)

Cash flow items

Until	Qty. of condensate sales (thousands of barrels) (100% of the oil asset)	Qty. of gas sales (BCM) (100% of the oil asset)	Revenue	Royalties payable	Royalties received	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%	Discounted at 10%	Discounted at 15%	Discounted at 20%
December 31, 2040	535	11.65	254,053	52,413	-	16,237	23,435	-	161,967	75,801	23,833	62,334	24,073	15,214	9,718	4,084	1,781
December 31, 2041	535	11.65	253,968	52,396	-	16,237	-	-	185,335	86,737	20,763	77,835	28,628	17,673	11,031	4,435	1,853
December 31, 2042	514	11.19	243,858	50,310	-	16,198	-	-	177,351	83,000	19,786	74,564	26,119	15,749	9,607	3,694	1,480
December 31, 2043	446	9.71	211,537	43,642	-	16,074	-	-	151,821	71,052	16,663	64,107	21,387	12,595	7,509	2,762	1,060
December 31, 2044	385	8.38	182,503	37,652	-	15,962	-	-	128,890	60,320	13,857	54,713	17,384	10,000	5,826	2,050	754
December 31, 2045	332	7.24	157,624	32,519	-	15,866	-	-	109,239	51,124	11,452	46,663	14,120	7,933	4,517	1,520	536
December 31, 2046	287	6.25	136,025	28,063	-	15,783	-	-	92,179	43,140	9,463	39,576	11,405	6,259	3,483	1,121	379
December 31, 2047	247	5.39	117,268	24,193	-	15,711	-	-	77,364	36,206	8,107	33,051	9,071	4,862	2,644	814	264
December 31, 2048	214	4.66	101,352	20,910	-	15,650	-	-	64,792	30,323	6,850	27,620	7,220	3,780	2,009	592	184
December 31, 2049	185	4.02	87,403	18,032	-	15,596	-	-	53,775	25,167	5,800	22,808	5,678	2,904	1,508	425	126
December 31, 2050	159	3.47	75,419	15,560	-	15,550	-	-	44,310	20,737	4,642	18,931	4,488	2,242	1,138	307	87
December 31, 2051	138	3.00	65,182	13,448	-	15,511	-	10,392	25,832	12,089	5,310	8,432	1,904	929	461	119	32
December 31, 2052	119	2.59	56,255	11,606	-	15,476	-	10,392	18,780	8,789	4,448	5,544	1,192	568	275	68	18
December 31, 2053	17	0.38	8,147	1,681	-	15,291	-	10,392	(19,218)	-	-	(19,218)	(3,936)	(1,832)	(868)	(205)	(51)
December 31, 2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
December 31, 2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
December 31, 2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**13,626**	**297**	**6,422,911**	**1,325,100**	**-**	**528,774**	**157,321**	**31,176**	**4,380,543**	**1,993,667**	**533,605**	**1,853,277**	**1,026,848**	**808,880**	**657,562**	**469,144**	**361,536**

Total discounted cash flow from possible reserves (P2) as at December 31, 2020 (in USD thousands for the Company's share)																	
Cash flow items																	
										Taxes		Total discounted cash flow after tax					
Until	Qty. of condensate sales (thousands of barrels) (100% of the oil asset)	Qty. of gas sales (BCM) (100% of the oil asset)	Revenue	Royalties payable	Royalties received	Operating costs	Development costs	Abandonment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Levy	Income tax	Discounted at 0%	Discounted at 5%	Discounted at 7.5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
December 31, 2021	-	-	-	-	-	-	-	-	-	-	(5)	5	5	5	5	5	5
December 31, 2022	-	-	-	-	-	-	-	-	-	-	(5)	5	4	4	4	4	4
December 31, 2023	-	-	-	-	-	-	-	-	-	-	(5)	5	4	4	4	3	3
December 31, 2024	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
December 31, 2025	-	-	-	-	-	-	(37,505)	-	37,505	17,706	(4,072)	23,872	19,166	17,240	15,546	12,727	10,509
December 31, 2026	-	-	-	-	-	-	14,609	-	(14,609)	(6,837)	2,438	(10,210)	(7,807)	(6,859)	(6,045)	(4,734)	(3,746)
December 31, 2027	-	-	-	-	-	-	22,896	-	(22,896)	(10,715)	2,470	(14,651)	(10,669)	(9,156)	(7,885)	(5,906)	(4,479)
December 31, 2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
December 31, 2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
December 31, 2030	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
December 31, 2031	-	-	-	-	-	-	-	-	-	-	5	(5)	(3)	(2)	(2)	(1)	(1)
December 31, 2032	-	-	-	-	-	-	-	-	-	-	5	(5)	(3)	(2)	(2)	(1)	(1)
December 31, 2033	-	-	-	-	-	-	-	-	-	-	5	(5)	(3)	(2)	(1)	(1)	(0)
December 31, 2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
December 31, 2035	-	-	-	-	-	-	(4,291)	-	4,291	2,008	(462)	2,745	1,353	962	689	362	195
December 31, 2036	-	-	-	-	-	-	(19,145)	-	19,145	8,960	(2,827)	13,012	6,108	4,242	2,970	1,491	771
December 31, 2037	-	-	-	-	-	-	11,198	-	(11,198)	(5,240)	1,755	(7,712)	(3,448)	(2,338)	(1,600)	(769)	(381)
December 31, 2038	-	-	-	-	-	-	(11,198)	-	11,198	5,240	(924)	6,881	2,930	1,941	1,298	596	283
December 31, 2039	-	-	-	-	-	-	-	-	-	-	539	(539)	(219)	(141)	(92)	(41)	(18)

Total discounted cash flow from possible reserves (P2) as at December 31, 2020 (in USD thousands for the Company's share)

Cash flow items

Until	Qty. of condensate sales (thousands of barrels) (100% of the oil asset)	Qty. of gas sales (BCM) (100% of the oil asset)	Revenue	Royalties payable	Royalties received	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%	Discounted at 10%	Discounted at 15%	Discounted at 20%
December 31, 2040	-	-	-	-	-	-	-	-	-	-	539	(539)	(208)	(132)	(84)	(35)	(15)
December 31, 2041	-	-	-	-	-	-	-	-	-	-	539	(539)	(198)	(122)	(76)	(31)	(13)
December 31, 2042	21	0.46	10,024	2,068	-	39	23,435	-	(15,518)	(7,263)	4,030	(12,286)	(4,304)	(2,595)	(1,583)	(609)	(244)
December 31, 2043	89	1.94	42,251	8,717	-	163	-	-	33,372	15,618	4,083	13,670	4,561	2,686	1,601	589	226
December 31, 2044	150	3.27	71,199	14,689	-	274	-	-	56,236	26,319	6,881	23,037	7,319	4,210	2,453	863	317
December 31, 2045	202	4.41	95,993	19,804	-	369	-	-	75,820	35,484	9,277	31,059	9,398	5,281	3,007	1,012	357
December 31, 2046	248	5.40	117,507	24,243	-	452	-	-	92,813	43,436	11,258	38,118	10,985	6,029	3,354	1,080	365
December 31, 2047	287	6.26	136,178	28,095	-	524	-	-	107,560	50,338	12,606	44,616	12,245	6,564	3,569	1,099	356
December 31, 2048	321	6.99	152,009	31,361	-	585	-	-	120,064	56,190	14,410	49,464	12,930	6,770	3,597	1,060	329
December 31, 2049	295	6.43	139,897	28,862	-	538	-	-	110,497	51,712	13,222	45,562	11,343	5,800	3,012	849	252
December 31, 2050	289	6.30	137,015	28,267	-	527	-	-	108,221	50,647	12,944	44,630	10,581	5,285	2,683	723	206
December 31, 2051	263	5.72	124,254	25,635	-	478	-	(10,392)	108,534	50,794	10,592	47,148	10,646	5,194	2,576	664	181
December 31, 2052	220	4.80	104,232	21,504	-	401	-	(10,392)	92,720	43,393	8,416	40,911	8,798	4,192	2,032	501	131
December 31, 2053	288	6.28	136,419	28,144	-	525	-	(10,392)	118,142	46,297	11,864	59,982	12,285	5,718	2,709	639	160
December 31, 2054	247	5.38	116,780	24,093	-	15,709	-	10,392	66,586	31,162	10,297	25,127	4,901	2,228	1,032	233	56
December 31, 2055	195	4.25	92,163	19,014	-	15,614	-	10,392	47,142	22,063	7,918	17,162	3,188	1,416	640	138	32
December 31, 2056	92	2.00	43,371	8,948	-	15,427	-	10,392	8,604	4,027	3,202	1,375	243	106	47	10	2
Total	**3,209**	**70**	**1,519,293**	**313,442**	**-**	**51,624**	**-**	**-**	**1,154,227**	**531,338**	**140,994**	**481,895**	**122,133**	**64,526**	**35,458**	**12,520**	**5,842**

Total discounted cash flow from proved reserves + probable reserves + possible reserves (3P) as at December 31, 2020 (in USD thousands for the Company's share)																	
Cash flow items																	
										Taxes		Total discounted cash flow after tax					
Until	Qty. of condensate sales (thousands of barrels) (100% of the oil asset)	Qty. of gas sales (BCM) (100% of the oil asset)	Revenue	Royalties payable	Royalties received	Operating costs	Development costs	Abandonment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Levy	Income tax	Discounted at 0%	Discounted at 5%	Discounted at 7.5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
December 31, 2021	395	8.60	163,852	33,804	-	17,556	7,965	-	104,527	25,042	16,188	63,298	61,772	61,050	60,352	59,025	57,782
December 31, 2022	421	9.16	184,667	38,098	-	15,892	3,374	-	127,303	38,828	17,312	71,162	66,140	63,847	61,682	57,704	54,135
December 31, 2023	419	9.13	188,387	38,866	-	15,815	3,037	-	130,670	47,696	17,214	65,760	58,209	54,884	51,818	46,368	41,688
December 31, 2024	436	9.49	195,400	40,313	-	15,788	-	-	139,299	58,566	16,176	64,557	54,422	50,120	46,245	39,582	34,104
December 31, 2025	475	10.35	214,369	44,226	-	15,865	-	-	154,278	71,644	16,635	66,000	52,990	47,665	42,981	35,189	29,055
December 31, 2026	488	10.62	225,553	46,533	-	15,892	37,505	-	125,623	58,792	22,129	44,703	34,182	30,032	26,465	20,725	16,400
December 31, 2027	501	10.91	234,840	48,449	-	15,913	22,896	-	147,581	69,068	20,309	58,204	42,386	36,375	31,326	23,465	17,794
December 31, 2028	505	11.00	241,050	49,731	-	16,187	-	-	175,132	81,962	18,653	74,518	51,682	43,321	36,460	26,123	18,984
December 31, 2029	526	11.46	253,973	52,397	-	16,237	-	-	185,340	86,739	20,111	78,490	51,845	42,447	34,912	23,927	16,664
December 31, 2030	535	11.65	260,527	53,749	-	16,262	-	-	190,516	89,161	20,818	80,536	50,663	40,514	32,566	21,348	14,248
December 31, 2031	535	11.65	260,667	53,778	-	16,263	-	-	190,626	89,213	20,969	80,445	48,196	37,645	29,572	18,543	11,860
December 31, 2032	535	11.65	259,637	53,565	-	16,259	-	-	189,814	88,833	20,924	80,056	45,679	34,850	26,753	16,046	9,836
December 31, 2033	535	11.65	259,621	53,562	-	16,259	-	-	189,801	88,827	20,974	80,000	43,473	32,395	24,304	13,943	8,191
December 31, 2034	535	11.65	259,730	53,584	-	16,259	-	-	189,886	88,867	21,110	79,910	41,357	30,101	22,070	12,111	6,818
December 31, 2035	535	11.65	254,300	52,464	-	16,238	-	-	185,598	86,860	20,796	77,942	38,417	27,312	19,569	10,272	5,542
December 31, 2036	535	11.65	254,397	52,484	-	16,238	-	-	185,674	86,896	20,806	77,973	36,602	25,416	17,797	8,936	4,620
December 31, 2037	535	11.65	253,652	52,331	-	16,236	23,435	-	161,651	75,653	25,165	60,834	27,197	18,446	12,623	6,062	3,004
December 31, 2038	535	11.65	253,787	52,358	-	16,236	12,238	-	172,954	80,943	23,423	68,589	29,204	19,347	12,938	5,944	2,822
December 31, 2039	535	11.65	253,908	52,383	-	16,237	-	-	185,288	86,715	21,835	76,738	31,118	20,135	13,160	5,782	2,631

Total discounted cash flow from proved reserves + probable reserves + possible reserves (3P) as at December 31, 2020 (in USD thousands for the Company's share)																	
Cash flow items																	
										Taxes		Total discounted cash flow after tax					
Until	Qty. of condensate sales (thousands of barrels) (100% of the oil asset)	Qty. of gas sales (BCM) (100% of the oil asset)	Revenue	Royalties payable	Royalties received	Operating costs	Development costs	Abandonment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Levy	Income tax	Discounted at 0%	Discounted at 5%	Discounted at 7.5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
December 31, 2040	535	11.65	254,053	52,413	-	16,237	23,435	-	161,967	75,801	24,372	61,795	23,865	15,083	9,634	4,049	1,766
December 31, 2041	535	11.65	253,968	52,396	-	16,237	-	-	185,335	86,737	21,302	77,296	28,430	17,550	10,955	4,404	1,841
December 31, 2042	535	11.65	253,882	52,378	-	16,236	23,435	-	161,832	75,738	23,817	62,278	21,816	13,154	8,024	3,086	1,236
December 31, 2043	535	11.65	253,788	52,359	-	16,236	-	-	185,193	86,671	20,746	77,777	25,947	15,281	9,110	3,351	1,286
December 31, 2044	535	11.65	253,703	52,341	-	16,236	-	-	185,126	86,639	20,738	77,749	24,703	14,210	8,279	2,913	1,071
December 31, 2045	535	11.65	253,617	52,323	-	16,235	-	-	185,059	86,607	20,729	77,722	23,518	13,214	7,524	2,532	892
December 31, 2046	535	11.65	253,532	52,306	-	16,235	-	-	184,991	86,576	20,721	77,694	22,390	12,288	6,837	2,201	743
December 31, 2047	535	11.65	253,447	52,288	-	16,235	-	-	184,924	86,544	20,713	77,667	21,317	11,426	6,213	1,913	619
December 31, 2048	535	11.65	253,361	52,270	-	16,234	-	-	184,856	86,513	21,260	77,084	20,149	10,549	5,606	1,651	512
December 31, 2049	480	10.45	227,299	46,894	-	16,134	-	-	164,272	76,879	19,022	68,370	17,020	8,704	4,520	1,273	379
December 31, 2050	449	9.77	212,434	43,827	-	16,077	-	-	152,530	71,384	17,586	63,561	15,070	7,527	3,820	1,029	293
December 31, 2051	400	8.72	189,436	39,082	-	15,989	-	-	134,366	62,883	15,902	55,581	12,550	6,123	3,037	783	214
December 31, 2052	339	7.39	160,487	33,110	-	15,877	-	-	111,500	52,182	12,863	46,455	9,990	4,761	2,308	569	149
December 31, 2053	306	6.66	144,566	29,825	-	15,816	-	-	98,925	46,297	11,864	40,764	8,349	3,886	1,841	434	109
December 31, 2054	247	5.38	116,780	24,093	-	15,709	-	10,392	66,586	31,162	10,297	25,127	4,901	2,228	1,032	233	56
December 31, 2055	195	4.25	92,163	19,014	-	15,614	-	10,392	47,142	22,063	7,918	17,162	3,188	1,416	640	138	32
December 31, 2056	92	2.00	43,371	8,948	-	15,427	-	10,392	8,604	4,027	3,202	1,375	243	106	47	10	2
Total	**16,835**	**367**	**7,942,202**	**1,638,541**	**-**	**580,395**	**157,322**	**31,177**	**5,534,768**	**2,525,003**	**674,598**	**2,335,168**	**1,148,981**	**873,408**	**693,020**	**481,662**	**367,379**

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.

Forward-looking information: The discounted cash flows set out above are forward-looking information as defined in Section 32 of the Israel Securities Law. The information above is based on various assumptions, including the rate and duration of natural gas and condensate sales from the project, operational costs, capital expenditure, abandonment expenses, rates of royalties, and selling prices, including price adjustments according to the agreement with IEC, and there is no certainly whether these will materialize. It is noted that actual quantities of natural gas and/or condensate produced, the above expenses and revenues may be materially different from these estimates and assumptions, partly due to the market conditions and/or technical and operational conditions and/or regulatory changes and/or the supply and demand conditions in the local and/or export markets for natural gas and/or condensate and/or actual performance of the project and/or as a result of actual selling prices and/or due to geo-political changes. It should also be noted that price adjustment at the price adjustment dates 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 local market at the price adjustment dates, all in accordance with the adjustment mechanism set out in the IEC agreement.

F. Sensitivity analysis for the main parameters of the discounted cash flow (gas price and quantity of gas sold) as at December 31, 2020 (USD thousands), performed by the Company

Sensitivity/category	Present value discounted at 0%	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%	Sensitivity/category	Present value discounted at 0%	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%
10% increase in the price of gas					**10% decrease in the price of gas**				
Proved reserves 1P	1,484,904	647,398	481,670	379,157	Proved reserves 1P	1,175,799	520,781	388,343	305,980
Probable reserves	575,745	79,797	36,385	19,668	Probable reserves	470,322	67,111	31,772	18,102
Total 2P reserves (proved + probable reserves)	2,060,650	727,195	518,056	398,825	Total 2P reserves (proved + probable reserves)	1,646,121	587,892	420,115	324,082
Possible reserves	530,791	38,777	13,533	6,193	Possible reserves	432,817	32,032	11,424	5,425
Total 3P reserves (proved + probable + possible reserves)	2,591,441	765,971	531,588	405,018	Total 3P reserves (proved + probable + possible reserves)	2,078,938	619,924	431,539	329,507
15% increase in the price of gas					**15% decrease in the price of gas**				
Proved reserves 1P	1,561,644	678,847	504,799	397,243	Proved reserves 1P	1,098,353	488,967	364,822	287,475
Probable reserves (probable reserves)	602,762	83,160	37,687	20,184	Probable reserves (probable reserves)	444,170	63,975	30,645	17,732
Total 2P reserves (proved + probable reserves)	2,164,406	762,007	542,486	417,427	Total 2P reserves (proved + probable reserves)	1,542,524	552,942	395,466	305,207
Possible reserves	555,179	40,398	14,007	6,343	Possible reserves	408,361	30,398	10,949	5,284
Total 3P reserves (proved + probable + possible reserves)	2,719,585	802,404	556,494	423,770	Total 3P reserves (proved + probable + possible reserves)	1,950,885	583,340	406,415	310,491

Sensitivity/category	Present value discounted at 0%	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%	Sensitivity/category	Present value discounted at 0%	Present value discounted at 10%	Present value discounted at 15%	Present value discounte d at 20%
20% increase in the price of gas					**20% decrease in the price of gas**				
Proved reserves 1P	1,638,359	710,237	527,859	415,255	Proved reserves 1P	1,020,935	457,094	341,221	268,879
Probable reserves	629,808	86,563	39,031	20,741	Probable reserves	417,939	60,793	29,480	17,333
Total 2P reserves (proved + probable reserves)	2,268,167	796,800	566,890	435,997	Total 2P reserves (proved + probable reserves)	1,438,874	517,887	370,701	286,211
Possible reserves	579,568	42,018	14,482	6,493	Possible reserves (possible reserves)	384,135	28,903	10,584	5,230
Total 3P reserves (proved + probable + possible reserves)	2,847,735	838,818	581,373	442,489	Total 3P reserves (proved + probable + possible reserves)	1,823,009	546,790	381,285	291,441

Sensitivity/category	Present value discounted at 0%	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%	Sensitivity/category	Present value discounted at 0%	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%
10% increase in the quantity of gas sales					**10% decrease in the quantity of gas sales**				
Proved reserves 1P	1,377,048	634,353	476,805	377,263	Proved reserves 1P	1,175,809	520,786	388,347	305,983
Probable reserves	527,349	80,798	37,597	20,393	Probable reserves	470,327	67,112	31,772	18,102
Total 2P reserves (proved + probable reserves)	1,904,397	715,150	514,402	397,656	Total 2P reserves (proved + probable reserves)	1,646,136	587,898	420,120	324,086
Possible reserves	458,608	39,736	14,463	6,648	Possible reserves	432,821	32,032	11,424	5,425
Total 3P reserves (Proved + probable + possible reserves)	2,363,005	754,886	528,866	404,304	Total 3P reserves (proved + probable + possible reserves)	2,078,957	619,930	431,543	329,511
15% increase in the quantity of gas sales					15% decrease in the quantity of gas sales				
Proved reserves 1P	1,408,150	658,291	496,666	393,871	Proved reserves 1P	1,098,368	488,974	364,827	287,480
Probable reserves	507,755	82,848	39,201	21,340	Probable reserves	444,177	63,976	30,645	17,732
Total 2P reserves (proved + probable reserves)	1,915,905	741,140	535,867	415,212	Total 2P reserves (proved + probable reserves)	1,542,545	552,951	395,472	305,212
Possible reserves	460,857	43,113	15,968	7,282	Possible reserves)	408,368	30,399	10,949	5,284
Total 3P reserves (proved + probable + possible reserves)	2,376,762	784,253	551,835	422,494	Total 3P reserves (proved + probable + possible reserves)	1,950,913	583,349	406,421	310,496

Sensitivity/category	Present value discounted at 0%	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%	Sensitivity/category	Present value discounted at 0%	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%
20% increase in the quantity of gas sales [50]					**20% decrease in the quantity of gas sales**				
Proved reserves 1P	1,413,322	677,353	514,226	409,330	Proved reserves 1P	1,020,953	457,103	341,227	268,884
Probable reserves	507,817	88,026	42,294	23,053	Probable reserves	417,948	60,794	29,481	17,333
Total 2P reserves (proved + probable reserves)	1,921,139	765,379	556,520	432,384	Total 2P reserves (proved + probable reserves)	1,438,901	517,898	370,708	286,217
Possible reserves	461,037	46,976	17,811	8,106	Possible reserves	384,144	28,904	10,584	5,230
Total 3P reserves (proved + probable + possible reserves)	2,382,176	812,354	574,331	440,490	Total 3P reserves (proved + probable + possible reserves)	1,823,045	546,801	381,292	291,447

G. Sensitivity analysis of the main linkage components of gas price according to the agreements of the Tamar partners for gas sales (US-CPI and Electricity Generation Price as at December 31, 2020 (USD thousands), performed by the Company:

Sensitivity/category	Total	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%	Sensitivity/category	Total	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%
10% increase in the projected CPI					**10% decrease in the projected CPI**				
Proved reserves 1P	1,331,724	584,892	435,691	343,165	Proved reserves 1P	1,329,653	583,608	434,653	342,313
Probable reserves	522,582	73,310	33,969	18,796	Probable reserves	522,594	73,319	33,976	18,803
Total 2P reserves (proved + probable reserves)	1,854,306	658,203	469,660	361,961	Total 2P reserves (proved + probable reserves)	1,852,246	656,926	468,629	361,116
Possible reserves	481,896	35,461	12,522	5,844	Possible reserves	481,895	35,455	12,517	5,840
Total 3P reserves (proved + probable + possible reserves)	2,336,202	693,663	482,182	367,805	Total 3P reserves (proved + probable + possible reserves)	2,334,141	692,382	481,147	366,956

[50] It should be noted that due to infrastructure limitations, it is not possible to increase the gas quantities at this rate.

Sensitivity/category	Total	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%	Sensitivity/category	Total	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%
10% increase in the projected Cost of Electricity Generation					**10% decrease in the projected Cost of Electricity Generation**				
Proved reserves 1P	1,419,326	613,306	454,175	355,969	Proved reserves 1P	1,259,186	563,013	422,027	334,094
Probable reserves	561,492	78,184	35,867	19,561	Probable reserves	488,158	68,955	32,251	18,084
Total 2P reserves (proved + probable reserves)	1,980,818	691,490	490,042	375,530	Total 2P reserves (proved + probable reserves)	1,747,345	631,968	454,278	352,178
Possible reserves	517,524	37,856	13,239	6,082	Possible reserves	450,298	33,346	11,895	5,640
Total 3P reserves (proved + probable + possible reserves)	2,498,342	729,347	503,281	381,612	Total 3P reserves (proved + probable + possible reserves)	2,197,642	665,314	466,173	357,819

H. Below is a sensitivity analysis for sales of quantities beyond the minimum quantities (take or pay) in accordance with the Partnership's agreements for the sale of gas as at December 31, 2020 (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%**
An increase in the sales quantity of gas for quantities that are beyond the take of pay, at 10%					**A decrease in the sales quantity of gas for quantities that are beyond the take of pay, at 10%**				
Proved reserves 1P	1,403,739	616,129	457,339	358,816	Proved reserves 1P	1,217,857	548,115	411,511	326,107
Probable reserves	515,224	77,083	35,961	19,737	Probable reserves	469,865	66,730	31,425	17,786
Total 2P reserves (proved + probable reserves)	1,918,963	693,212	493,300	378,553	Total 2P reserves (proved + probable reserves)	1,687,722	614,845	442,936	343,893
Possible reserves	466,782	38,362	13,782	6,345	Possible reserves	433,043	32,165	11,528	5,508
Total 3P reserves (proved + probable + possible reserves)	2,385,745	731,574	507,082	384,898	Total 3P reserves (proved + probable + possible reserves)	2,120,766	647,010	454,464	349,401

I. <u>Reconciliation of the information in the report and information in previous reports relating to quantity of reserves attributed to the oil asset</u>

The main differences between the current reserves report and the previous contingent reserves and resources report are due to production of 172 BCF of natural gas and 225.5 thousand barrels of condensate in 2020.

J. <u>Production data</u>

Production data for the Tamar project, attributable to the Company in 2018-2020[51]

Natural gas[52][53]		**2018**	**2019**	**2020**
Total output (100%) in the period (MMcf)		363,950	368,712	291,339
Total output (attributable to equity holders of the Company) in the period (in MMcf)		52,925	48,529	35,034
Average price per production unit (attributable to equity holders of the Company) (USD per MCF) [54]		5.49	5.46	5.13
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	0.61	0.62	0.59
	Third parties	0.09	0.11	0.22
	Interested parties	0.35	0.39	0.24
Average intake for royalties (all compensation arising from the output of the producing asset, including from the gross income from the oil asset) received per production unit (attributable to the Company's share) (USD per MCF)		0.4[55]	0.27[56]	-
Average production costs per production unit (attributable to equity holders of the Company) (USD per MCF)[57]		0.39	0.46	0.38
Average net intake per production unit (attributable to equity holders of the Company) (USD per MCF)		4.45	4.15	3.70
Oil and gas profits levy		-	-	0.06
Average net intake per production unit after oil and gas profits tax (attributable to equity holders of the Company) (USD per MCF)		4.45	4.15	3.64
Depletion rate in the reporting period in relation to the overall quantity of gas in the project (%)[58]		3.29	3.31	2.70

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51 It should be noted that as from the start of flow of natural gas from the Tamar project (March 30, 2013) and up to December 31, 2020, a total quantity of 69 BCM of natural gas and 3.2 million barrels of condensate was supplied to customers. It is further noted that the average daily production of natural gas in the last two years (January 1, 2019-December 31, 2030) amounted to 0.9 BCF.

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

53 The production data for the 2019 and 2020 is based on the Partnership's direct holding of 22% in the Tamar project. The production data for 2018 includes, in addition to the Partnership's direct holding in the Tamar Project, the Partnership's share in the production data of Tamar Petroleum.

54 The average price per output unit weights the effective price of the Partnership, which includes the outline for the sale of natural gas from the Tamar project to the Yam Tethys project. In this matter, see also sections 1.7.9 and 1.7.30(C) below.

55 Receipts for royalties include the share of Delek Energy in overriding royalties from the project until June 7, 2018 (the date the royalty rights were transferred to Delek Royalties) at a rate of 6.5%, and the royalties paid to the Company and the Company's share of the royalties paid to Cohen Development in this period.

56 Proceeds for royalties include the Company's share in the overriding royalty from the project up to the date of the royalty from the project until the right to royalties was transferred to the up to the date of transfer of the right to the royalties 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), and the Company's share of the royalties paid to Cohen Development in this period.

57 The information includes current production costs only, and does not include exploration and development costs of the reservoir and the future tax payments by the Company.

58 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.

Condensate[59]				
		2018	2019	2020
Total output (100%) in the period (MMcf)		2,614	2,643	2,098
Total output (attributable to equity holders of the Company) in the period (thousands of barrels)		69.2	63.5	46
Average price per production unit (attributable to equity holders of the Company) (USD per barrel)		63.0	56.42	34.88
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	7.0	6.38	4.0
	Third parties	1.1	1.31	1.3
	Interested parties	4.1	3.73	1.7
Average intake for royalties (all compensation arising from the output of the producing asset, including from the gross income from the oil asset) received per production unit (attributable to the Company's share) (USD per barrel)		4.6	2.68	-
Average production costs per production unit (attributable to equity holders of the Company) (USD per barrel)		2.1	2.50	2.06
Average net intake per production unit (attributable to equity holders of the Company) (USD per barrel)		53.3	45.18	25.8
Oil and gas profits levy		-	-	0.3
Average net intake per production unit after oil and gas profits tax (attributable to equity holders of the Company) (USD per barrel)		53.3	45.18	25.5
Depletion rate in the reporting period in relation to the overall quantity of condensate in the project (%)		3.31	3.35	2.76

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

K. Opinion of the valuator

Attached to this report as a reference in Appendix B to Part A of the Partnership's Periodic Report as at December 31, 2020 (Ref. No. 2021-01-036588), is the reserves report of the Tamar Project (which includes the Tamar and Tamar SW reservoirs), prepared by NSAI as at December 31, 2020. NSAI's consent to include the reserves report in this report is attached to this report in Appendix A as a reference.

L. Management declaration

(1) Declaration date: March 29, 2021

(2) Name of the corporation: Delek Group Ltd.

(3) Name and position of the resource valuation officer in the Company: Gabriel Last, Chairman of the Board of Directors

(4) We confirm that the valuator received all the information required to perform the work.

(5) We confirm that no information has come to our attention that indicates any dependence between the valuator and the Company.

(6) We confirm that, to the best of our knowledge, the resources reported are the best and most current estimates available to us.

(7) We confirm that the information in this report was prepared in accordance with the professional terms listed in Chapter G of the Third Schedule to the Israel Securities Regulations (Prospectus Details and Draft Prospectus – Structure and Form), 1969,

59 All the comments referring to the above table presenting the production data of natural gas also apply to this table, with the required changes.

and within their meaning in the Petroleum Resources Management System (2018) as published by the Society of Petroleum Engineers (SPE), the American Association of Petroleum Geologists (AAPG), the World Petroleum Council (WPC), and the Society of Petroleum Evaluation Engineers (SPEE), as in effect at the approval date of the report.

(8) We confirm that no change has been made to the identity of the valuator who prepared the most recent disclosure of the reserves in the Tamar project published by the Company.

(9) We agree to include this statement in this report.

Gabriel Last
Chairman of the Board of Directors

(2) Contingent and prospective resources in the Dalit Lease

For information about the contingent and probable resources attributed to the Dalit Lease, as at December 31, 2017, see section 1.7.4(I)(5) to the Company's periodic report for 2017 published on March 28, 2018 (Ref. No. 2018-01-031177) ("the 2017 Periodic Report"), and the resources report prepared by NSAI ("the Dalit Lease Resources Report") attached in Appendix D to the Partnership's 2017 Periodic Report, which was published on March 21, 2018 (Ref. No. 2018-01-022209). The information in this report is included as a reference. As at December 31, 2020, there has been no change to this information, other than the change in the share attributable to the equity holders of the Company, following the change in the Company's holdings in the Partnership and the sale of the holdings to Cohen Development. NSAI's consent to include the Dalit Lease Resources Report in this report and information about the absence of significant changes in the Dalit Lease are attached in Appendix A.

Forward-looking information: There is no certainty that it will be commercially viable to produce any percentage of the contingent resources.

Prospective resources			
Prospective resources category	**Prospect**	**Total BCF in the oil asset (gross)**	**Total rate attributable to the equity holders of the Company (net) (BCF)**
Low estimate	West 1	134.2	14.8
	West 2	64.0	7.1
	West 3	2.9	0.3
	East 1	3.4	0.4
	East 2	1.8	0.2
	East 3	5.9	0.7
Best estimate	West 1	169.1	18.6
	West 2	80.8	8.9
	West 3	3.7	0.4
	East 1	4.3	0.5
	East 2	2.3	0.3
	East 3	7.4	0.8
High estimate	West 1	210.2	23.2
	West 2	101.8	11.2
	West 3	4.6	0.5
	East 1	5.5	0.6
	East 2	2.9	0.3
	East 3	9.3	1.0

Note – There is no certainty that any part of these potential resources will indeed be discovered; if discovered, there is no certainty that it will be commercially possible to produce any part of the resources. The prospective information is not an assessment of the reserves and contingent resources, which can only be assessed after exploration drilling, if at all.

Forward-looking information: The estimates of NSAI in respect of the contingent and prospective resources in the Dalit Lease is forward-looking information as defined in Section 32A of the Israel Securities Law and is partially based on geological, geophysical, and other information obtained from the wells and from the operator, and are the professional estimates and assumptions only of NSAI and there can be no certainty in their respect. Quantities of natural gas actually produces (if produced) may differ 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 market and/or actual performance of the reservoirs. The estimates and assumptions may be revised if additional information becomes available and/or as the result of a range of factors related to oil and natural gas exploration and production projects.

1.7.6. Rights in Cyprus - Block 12 Project

(A) General

As at the approval date of the report, the Company's rights in the Block 12 projects are due to its direct and indirect holdings of 54.7% of the unit capital of Delek Drilling, which holds 30% of the participating rights in the project, and due to the rights of the Company and Delek Energy to royalties from the Partnership's share in the project, as set out in section 1.7.1(B)(1) above and section 1.7.6(I) below. The information below is correct as at the approval date of the report, and refers to all the Company's direct and indirect rights in the project.

(B) Background

On February 11, 2013, the Cypriot authorities approved the transfer of 30% of Noble Cyprus' rights in the production sharing contract dated October 24, 2008 ("Production Sharing Contract" or "PSC"), which grants oil and/or gas exploration, appraisal, development and production rights in the exclusive economic zone of the Republic of Cyprus known as Block 12 ("Block 12") and in the exploration license under the PSC (in this section below: "the Exploration License").

On November 7, 2019, the holders of rights in the PSC and the Cyprus government signed an amendment to the PSC ("Amendment to the PSC") and in parallel, the rights holders were granted a production and exploitation license (in this Section 1.7.6: "the License" or "the Exploitation License" or "Block 12 License") and a development and production plan was approved for the reservoir (in this section 1.7.6: "the Development Plan"), as described in section 1.7.6(L) below. The Production Sharing Contract and the Amendment to the Production Sharing Contract will be referred to as: "the Production Sharing Agreement".

(C) General information about Block 12

General information about the oil asset	
Name of oil asset	Block 12
Location	An offshore area in the exclusive economic zone of Cyprus 35 km north west of Leviathan reservoir[60]
Area	386 sq. km
Type of oil asset and description of permitted operations according to the type	Exploitation license granted subject to the PSC.
Original grant date of the oil asset	November 7, 2019
Original expiry date of the oil asset:	November 7, 2044
Date of decision regarding extension of the term of the oil asset:	-
Current expiry date of the oil asset	November 7, 2044 (25 years from the license grant date).
Note whether there is an additional option of extending the period of the oil asset: if so, note the period of the possible extension	Extendable by 10 more years.
Name of Operator	Noble Cyprus
Names of the direct partners in the oil asset and their direct share in the oil asset and, to the best of the Company's knowledge, the names of the controlling owners in the partners	▪ Noble Cyprus (35%) ▪ BC Cyprus (35%) To the best of the Company's knowledge, BG Cyprus is a subsidiary (indirectly) of Royal Dutch Shell Plc. ("Shell"), an energy company that deals in all segments of the gas and oil industry and operates in over 70 countries worldwide61. ▪ The Partnership (30%)

60 It should be noted that most of the Aphrodite reservoir is located in the exclusive economic zone of Cyprus, and a small part in the license area of the 370/Ishai field ("the Ishai License") in the exclusive economic zone of Israel. It should be noted that the Aphrodite reservoir partners were contacted by the Ishai license partners and the Ministry of Energy regarding the need to regulate the rights of these parties prior to adoption of a resolution on the development of the Aphrodite reservoir. The position of the Aphrodite partners is that the matter is within the government's authority and that they will act according to the mechanism for regulation of the rights of the parties as shall be decided by the government and in accordance with international law. It is further noted that following negotiations between the Israeli and Cypriot governments to regulate the rights of the parties in the Aphrodite reservoir, on March 9, 2021 the governments signed a memorandum of understanding instructing the Aphrodite reservoir partners and the rights holders of the Ishai license to negotiate directly to regulate the issue of the spillover of the Aphrodite reservoir, including principles and timetables for the negotiations.

61 Further information about Shell is available on their website: https://www.shell.com/about-us/who-we-are.html.

General information about the Company's share in the oil asset	
Acquisition date of the lease for the purchased oil asset	January 22, 2009 On February 11, 2013, the Cypriot authorities approved the transfer of the rights in the PSC and the exploration license to the Partnership.
Description of the Company's holding in the oil asset	The Company holds the oil asset through its direct and indirect holdings in the Partnership's participating units and its right to receive direct and indirect royalties.
Effective share of oil asset revenues attributable to equity holders of the Company:	For details, see section 1.7.6(I) below.
Total share of equity holders of the Company in the cumulative investment in the oil asset in the five years preceding the last day of the reporting year (whether recognized as an expense or as an asset in the financial statements):	USD 5,821 thousand

(D) Additional information about the Block 12 and the PSC

(1) In the PSC, the Partners undertook, among other things, to comply with the main milestones for the development of the reservoir, as follows:

A. Drilling of an appraisal/development well in the license area in accordance with the development plan and completion within 24 months from the date of receipt of the Production License

B. Completion of a detailed front end engineering design ("the FEED"), delivery of the outputs in accordance with the Development Plan and adoption of a final investment decision ("FID") for development of the Reservoir, within 48 months after receiving the Production License (namely November 2021).

The PSC sets out certain conditions under which the Partners in the License will be entitled to an extension for the purpose of compliance with the milestones, with the deadline for adoption of an FID being six years after receiving the Production License. It should be noted that failure to comply with the milestones set out in the PSC will constitute grounds for cancellation of the PSC, other than for reasons of force majeure (as defined in the PSC).

(2) It is further noted that in the Amendment to the PSC, other changes and updates were made, including, with respect to the transfer of rights by the parties, approval of an annual budget and work plan, the manner of approving changes to plans and budgets, the manner of calculating the various expenses, changes in the grounds for termination of the PSC, arrangements for ensuring the plugging, dismantling, and removal of wells and facilities at the end of the term of the PSC, and more.

(3) Payments to the Republic of Cyprus

A. The Republic of Cyprus is entitled to one-time bonuses from the holders of rights in Block 12 when reaching the milestones for the average daily production rate for a continuous period of 30 days, which may amount to USD 9 million (for 100%).

B. The PSC sets mechanisms for distribution of oil and natural gas It should be noted that the Republic of Cyprus may receive its share in the oil or natural gas in kind.

1. Oil sharing

The Block 12 rights holders will share the oil produced (after offsetting the expenses set out below) with the Republic of Cyprus according to the average daily production rate of oil, if any[62], as follows:

[62] It should be noted that the oil sharing mechanism was not amended in the Amendment to the PSC.

Average daily production (in barrels)[63]	Price per barrel (USD)		
	Up to 50	50.01 to 100	Over 100
	The Republic of Cyprus' share (including Cypriot company tax)		
For the share of the average daily production of less than 50,000 barrels (inclusive)	60%	63%	65%
For the share of the average daily production of between 50,001 and 100,000 barrels	63%	67%	72%
For the share of the average daily production of between 100,001 and 150,000 barrels	70%	75%	80%
For the share of the average daily production of between 150,001 and 200,000 barrels	77%	80%	83%
For the share of the average daily production of over 200,000 barrels	83%	85%	85%

2. Sharing of natural gas

a) Prior to its amendment dated November 7, 2019, the PSC set out a mechanism for sharing of natural gas produced in the license area based on the average daily production rate, as set out in section 1.7.7(C)2.b of the Company's periodic report for 2018.

b) Following the Amendment to the PCS, a new mechanism for sharing the natural gas output was established based on an R-factor. According to this mechanism, the partners will be entitled to 55% of the annual revenues from the natural gas output, up to coverage of all of their recognized capital and current expenses ("Expense Coverage Output"), whereas the balance ("Distributable Output") will be divided between the partners and the Cypriot government according to the R-factor, the numerator of which consists of the total net accrued revenues and the denominator consists of the total accrued capital investments. According to the new mechanism, the Cypriot government's share of the Distributable Output increases linearly as a function of the factor and will reach a maximum rate when the R-factor equals 2.5. In this regard:

1) "Net Accrued Revenue" means: the partners' share of the revenue actually received from the gas output (including the Expense Coverage Output), less operating expenses borne by the partners in the lease area, as from the date of signing the PSC (October 28, 2008) to the end of the quarter preceding the calculation date ("the Calculation Period").

2) "Accrued Capital Investments" means: the development expenses, production expenses of a capital nature (excluding operating expenses) and all exploration expenses related to the area under the PCS actually incurred during the Calculation Period.

For information regarding to participation rate of the equity holders in the Partnership, according to four theoretical scenarios only, based on which the R-factor was calculated, see section 1.7.6(I) below.

(4) The Republic of Cyprus' share of the natural gas and/or oil will be calculated every year from the sales revenues of the natural gas and/or oil remaining after offsetting the Block 12 project rights holders' expenses for exploration, appraisal, development, production and operation ("Block 12 Expenses")[64] of up to 55% of the total revenues from the gas produced and up to 49% of the total oil revenues ("Production Intended to Cover Reimbursement of Expenses"). If the expenses are higher than the Production Intended to Reimbursement of Expenses, the entire surplus will be carried over to the next year until the expenses are fully covered or until the PSC ends. Expenses not covered by the termination date of the PSC will not be reimbursed.

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63 The calculation is made progressively based on the levels in the table.

64 Block 12 expenses are recognized every year according to reports submitted by the project operator and is limited to the budget submitted to the Republic of Cyprus for approval as part of the annual work plan approval process under the PSC.

(5) Expenses recognized in the Production Intended to Cover Reimbursement of Expenses under the PSC are subject to the approval of the Republic of Cyprus and include direct exploration and appraisal expenses; staff and subcontractor employment expenses; office rental; expenses for statutory environmental protection requirements, cost of materials, insurance expenses, legal fees, staff training expenses, the Operator's general and administrative expenses for the project, and any other reasonable expense required for reasonable and efficient exploration efforts. It is noted that the expenses to establish and operate an export facility are not recognized in the Production Intended to Cover Reimbursement of Expenses.

(6) The bonuses in section 1.7.6(D)(3)a above do not include the foregoing offsettable expenses.

(7) Payment of the Republic of Cyprus' share of the gas and/or oil produced also includes the corporate taxes that the rights holders will have to pay the Republic of Cyprus.

(8) The Republic of Cyprus may also require the Block 12 rights holders, by written notice, to sell gas to it from the production not intended to cover reimbursement of expenses, subject to compliance by the Block 12 rights holders with their obligations under natural gas supply agreements, if any.

(9) Under the PSC, any change in control of Delek Group or the Partnership, indirectly or indirectly, is subject to the advance approval of the Republic of Cyprus.

(10) Termination of the PSC

A. The Republic of Cyprus may cancel the PSC by three or six months' notice, as set out in the PSC, under one of the following conditions: (a) Breach of the provisions of Cypriot law and regulations; (b) arrears in payments to the Republic of Cyprus for three consecutive months; (c) breach of the development plan for six consecutive months, other than due to a force majeure event, as defined in the PSC; (d) regarding the production period, continuous suspension of production for two consecutive months or disruption of production for six consecutive months for reasons not approved by the Republic of Cyprus, other than a justified reason or force majeure event, as defined in the PSC; (e) financial or technical inability of a partners to meet their obligations under the PSC due to an event of bankruptcy, debt settlement, receivership of any of the partners or their parent company or any other event resulting in a material impairment of the financial or technical abilities of any of the partners compared to their state at the time of signing the PSC.

B. The holders of rights in the project may waive their rights to any oil and/or gas field in the license area after giving six-months' notice to the Republic of Cyprus.

(11) Performance guarantees to the Republic of Cyprus

For information about the unlimited performance guarantee provided by Delek Group in favor of the Republic of Cyprus to secure fulfillment of all of the Partnership's obligations under the PCS, see section 1.7.6(D)(11) of the Company's period report for 2019.

(E) Operations in the area of Block 12 before the Company held the oil asset

Operation carried out by:	Period in which the operation was carried out	Summary of the operation	Summary of the operating expenses
Noble Cyprus	2011-2012	Preparations for the Aphrodite A-1 appraisal drilling, drilling and initial analysis of the drilling results, and preparation for the appraisal drilling[65].	-

(F) Compliance with the terms of the binding work plan in Block 12

The binding work plan in the Block 12 was completed in full by the approval date of the report.

(G) Actual and planned work plan for Block 12

The table below includes a summary of the main operations actually performed in the oil asset from January 1, 2018 through to the approval date of the report and a brief description of the planned operations:

[65] The Aphrodite A-2 appraisal drilling began on June 7, 2013 and ended on October 2, 2013.

Period	Summary of actual operations in the period or of the planned work plan	Estimated total budget for operations on the level of the oil asset (USD thousands)[66]	Actual participation of the Company's equity holders in the budget (USD thousands)
2018	• Continued assessment of various alternatives for development of the Aphrodite reservoir.	1,898	311
	• Continued geological, geophysical, and engineering analysis of existing databases in the license, partially by integrating information from adjacent fields and updating the geological model and flow model.		
	• Assessment of a possible location for an appraisal well and the scope of the appraisal operation.		
	• Continued analysis of the prospects in the license area, partially due to the findings from adjacent fields, and particularly technical and economic analysis of the deep prospect.	386	63
	• Planning for additional drilling in the license area		
2019	• Continued assessment of various alternatives for development of the Aphrodite reservoir.	3,190	523
	• Submission of a revised development plan for the Aphrodite reservoir to the Cypriot government.	1,175	193
	• Continued geological, geophysical, and engineering analysis of existing databases in the license, partially by integrating information from adjacent fields and updating the geological model and flow model.		
	• Continued assessment of a possible location for an appraisal well, and its scope and cost.	296	49
	• Continued analysis of the prospects in the license area, partially due to the findings from adjacent fields, and particularly technical and economic analysis of the deep prospect.		
	• Planning for additional drilling in the license area		
2020	• Continued geological, geophysical, and engineering analysis of existing databases in the license, partially by integrating information from adjacent fields and updating the geological model and flow model.	2,056	337
	• Planning an appraisal well that will be converted, if necessary, into a production well.	3,372	553
	• Continued analysis of the prospects in the production license area, partially due to the findings from adjacent fields, and particularly technical and economic analysis of the deep prospect.		
	• Preparation of a front end engineering design prior to adoption of a final investment decision.	2,131	349
	• Continued examination of the options for commercialization of the natural gas from the Aphrodite reservoir.	885	145
2021[67]	• Continued geological, geophysical, and engineering analysis of existing databases in the license, partially by integrating information from	3,474	594

66 The amounts for 2017-2019 are those actually expended and audited in the financial statements.

67 As at the date of the report, of foregoing budgets, the Block 12 partners approved a budget of USD 28 million for 2021.

Period	Summary of actual operations in the period or of the planned work plan	Estimated total budget for operations on the level of the oil asset (USD thousands)[66]	Actual participation of the Company's equity holders in the budget (USD thousands)
	adjacent fields and updating the geological model and flow model.		
	• Planning and examining implementation of an appraisal well, if necessary, that will be converted into a production well.	27,071[68]	4,650[69]
	• Continued analysis of the prospects in the production license area, partially due to the findings from adjacent fields, and particularly technical and economic analysis of the deep prospect.		
	• Continued examination of the options for commercialization of natural gas from the Aphrodite reservoir by conducting Pre-FEED and ocean surveys.	18,637	3,087
2022 onwards	• Continued geological, geophysical, and engineering analysis of existing databases in the license, partially by integrating information from adjacent fields and updating the geological model and flow model.		
	• Examining implementation of an appraisal well, if necessary, that will be converted into a production well.	100,000	16,563[70]
	• Continued analysis of the prospects in the production license area, partially due to the findings from adjacent fields, and particularly technical and economic analysis of the deep prospect.		
	• Promoting an alternative to commercialization of natural gas from the Aphrodite reservoir. Conducting a FEED and planning for implementation.	35,000	5,797
	• Examining the possibility of adopting an FID for development of the Aphrodite reservoir in the format in Section 1.7.6(L) below.	2,500,000 to 3,000,000	414,080 to 496,896

Forward-looking information: The Company's estimate regarding the planned operations in Block 12 (including development of the Aphrodite reservoir), including costs, schedules, and actual performance, is forward-looking information, as defined in Section 32 of the Israel Securities Law, based on estimates of the Partnership's general partner regarding the work plan components, which are all based on estimates received by the general partners from the Operator. Implementation of the actual work plan, including schedules and costs, is subject to the Partners' approval and may differ materially from the above estimate, and is partially subject to applicable regulation, technical capacity, and economic viability.

68 This is a conditional budget by the Block 12 partners and depends on the timing of the drilling.

69 This amount includes management fees to the general partner for exploration efforts.

70 This amount includes management fees to the general partner for exploration efforts.

(H) Actual participation rate in Block 12 expenses and revenues

Participation rate	Percentage before investment recovery	Percentage after investment recovery	Rate grossed up to 100% before investment recovery	Rate grossed up to 100% after investment recovery	Explanations
Actual rate attributable to equity holders of the Company in the oil asset	16.40%	16.40%	100%	100%	For information, see section (a) above.
Actual rate attributable to equity holders of the Company in revenues from the oil field	For details, see section 1.7.6(I) below.				
Actual rate of participation of the Company's equity holders in expenses arising from exploration in the oil asset	16.56% - 17.06%	16.56% - 17.06%	101% - 104%	101% - 104%	See the calculation in section 1.7.6(I) below.

(I) Participation rates of the equity holders of the Company in revenues from Block 12

The table below presents details regarding the participation rate of the equity holders in the Company out of the revenues from natural gas produced from the oil asset, if any, according to the new distribution mechanism, based on four theoretical scenarios only, according to which the R-factor was set at 1, 1.5, 2 and 2.5. It should be emphasized that the data in the following table are based on calculations made under various work assumptions and assessments, among other things, regarding the production rate and sale of natural gas from the reservoir, the current production costs, etc., which may actually be materially different to the assessments and assumptions taken into account.

As at the approval date of the report, the Partnership and the Company (and the other parties entitled to royalties from the Block 12 oil asset) have not yet examined the question of whether to royalties to be paid to the Partnership for its rights in the Block 12 project, out of its gross share in the oil asset, meaning prior to distribution of the gas to be produced between the Republic of Cyprus and the Partnership according to the provisions of the PSC, or out of the Partnership's net share, meaning after deducting the Republic of Cyprus' share, and the method of calculating the royalty from this asset is uncertain. The table below presents data regarding both of the foregoing options.

	R-factor 1	R-factor 1.5	R-factor 2	R-factor 2.5	Remarks
Total revenues from natural gas output	100%	100%	100%	100%	
Cypriot Republic's share of the revenues from natural gas output	15.75%	21.75%	50.75%	67.5%	The figures in the table are based on calculations made on the basis various working assumptions, among other things, regarding the development and operating costs of the project, the rate of production and sale, gas prices, etc.
The partner's share of the revenues from natural gas output	84.25%	78.25%	49.25%	32.5%	
The Company's share in the oil asset	16.40%	16.40%	16.40%	16.40%	
The Company's share of the revenues from the natural gas output, before payment of overriding royalties	13.82%	12.83%	8.08%	5.33%	

	R-factor 1	R-factor 1.5	R-factor 2	R-factor 2.5	Remarks
Payment of overriding royalties to various parties	0.74%	1.56%	1.56%	1.56%	The parties entitled to royalties are the Company, Delek Energy and third parties. It should be noted that the figures in this table were calculated according to the Partnership's position, whereby the overriding royalties in Block 12 apply to the Partnership's share in the natural gas output, meaning after deducting the State's share of the output (as opposed to overriding royalties from oil assets in Israel, which apply to the Partnership's share in the output before payment of the State's royalties under the Petroleum Law).
Effective participation rate of the equity holders in the Company , in the revenues from the natural gas output, assuming that the royalties are calculated from the Partnership's gross revenues (before deduction of the Republic of Cyprus' share).	13.08%	11.27%	6.52%	3.77%	These revenues are from the Company's and Delek Energy's rights to royalties from the Partnership's share.
Effective participation rate of the equity holders in the Company , in the revenues from the natural gas output, assuming that the royalties are calculated from the Partnership's net revenues (after deduction of the Republic of Cyprus' share).	0.45%	1.95%	1.95%	1.95%	
Effective participation rate of the equity holders in the Company , in the revenues from the natural gas output, assuming that the royalties are calculated from the Partnership's gross revenues (before deduction of the Republic of Cyprus' share).	13.53%	13.22%	8.47%	5.72%	
Effective participation rate of the equity holders in the Company , in the revenues from the natural gas output, assuming that the royalties are calculated from the Partnership's gross revenues (before deduction of the Republic of Cyprus' share).	13.57%	13.14%	8.27%	5.46%	

Forward-looking information: The above figures regarding the participation rate of the equity holders in the Company from the revenues deriving from the oil asset, if any, is forward-looking information, as defined in section 32A of the Israel Securities Law. These figures are based to a large extent on various work assumptions and assessments, inter alia, regarding

the production rate of natural gas from the reservoir, the natural gas quantities and selling prices, the development costs of the reservoir and facilities, the current production costs, etc. It is emphasized that in practice, these figures may be materially different to the foregoing assessments and assumptions, and are affected and contingent, inter alia, to completion of the detailed design of the development plan, actual performance of the project and various other factors over which the Company does not have full control or which it is unable to estimate with sufficient certainty.

(J) Participation rates of the equity holders of the Company in exploration and development expenses in Block 12

Description	%	Summary of the calculation method for Royalties or payments
Theoretical expenses for the oil asset (without royalties)	100%	
Payments (derived from the expenses) at the oil asset level		
Operator	1%-4%	A rate of 1.5% for the Operator's indirect expenses out of the total direct expenses for development and production, subject to certain exceptions, such as marketing activity of 1%-4% attributed to exploration expenses.. These amounts are for payment of indirect expenses to the Operator and are in addition to reimbursement of direct expenses paid to the Operator. The rate of payment to the Operator decreases as exploration expenses increase.
Total actual rate of expense at the level of the oil asset	101%-104%	
Share of the equity holders of the Company in the oil asset's expenses (linked)	16.40%	
Total actual rate of the equity holders of the Company in expenses, at the oil asset level (before other payments at the level of the Company)	16.56% -17.06%	
Payments (derived from the expenses) in respect of the oil asset and at the level of the Company (the following percentages will be calculated in accordance with the share of the equity holders of the Company in the oil asset)		
Actual rate of participation of the Company's equity holders in expenses arising from exploration, development or production operations in the oil asset	16.56% -17.06%	The Partnership pays management fees to the general partner, consisting of a fixed amount and a variable amount calculated from the exploration expenses. These amounts were not taken into account in this table.

(K) Royalties and payments paid during exploration, and development operations in Block 12 (USD thousands)

Description	Total share of equity holders of the Company in investment in the oil asset in this period	Of which, the share of equity holders of the Company in payments to the general partner	Of which, the rates of equity holders of the Partnership in payments to the operator (beyond the direct return of expenses)
Actual budget invested in 2018	1,189	-	38
Actual budget invested in 2019	1,333	-	42
Actual budget invested in 2020	2,331	-	31

(L) Plan for the development of the Aphrodite reservoir

The development plan that was approved by the Cypriot government on November 7, 2019 is subject to updates in view of the results of the FEED, and the progress in the commercial and financial aspects of the project, and includes the construction of a floating treatment and production facility in the license area, with an estimated maximum production capacity of 800 MMcf/d, through five production wells in the initial stage, and a subsea transmission system to the Egyptian market. According to the updated appraisal of the Operator, which was submitted to the Partnership and to the Cyprus government, and prior to completion of the technical-economic feasibility tests, including the FEED, the estimated cost of the Development Plan, without the installation cost of the pipelines to the target markets, is between USD 2.5 billion and USD 3 billion (100%). The estimated budget for the work plan until the date of the FID is USD 150 million to USD 200 million (for 100%). Formulation of the development plan and the FID for development of the Aphrodite reservoir are subject, among other things, to an appraisal drilling/further development and to a FEED, commercial arrangements to develop the pipelines for export, signing of agreements for supply of natural gas, and compliance with the preconditions in the agreements, regulatory approvals, and financial arrangements. If the above preconditions are fulfilled, the date of commencement of natural gas supply from the Aphrodite reservoir might be in 2026. It should be noted that the above estimated costs do not include costs for the development and installation of a pipeline for the export of natural gas from the Aphrodite reservoir.

In the fourth quarter of 2020, the Aphrodite reservoir partners submitted an initial application to the Cypriot government for changes to the work plan approved under the development plan dated November 7, 2019. The main change is due to postponement by the partners of the A-3 appraisal well (Aphrodite 3) until November 2021 so as to be performed after adoption of an investment decision in the Aphrodite project and conversion thereof into a production well. According to the Aphrodite reservoir partners, it is unnecessary to drill the well prior to adoption of an investment decision in the project.

In several recent meetings held with the Cypriot government, a detailed request was presented to the Cypriot government, including supporting geological and other claims. Apparently, if the Cypriot government accepts the request, this change to the work plan and development plan will require revising the PSC and the development plan as well as the approval of the Cypriot Minister of Energy and the Cypriot government.

The Aphrodite reservoir partners submitted a work plan and budget for 2021 of USD 55.5 million to the government of Cyprus. Of this sum, the partners approved a work plan and budget for 2021 of USD 28 million (for 100% of the rights), when the balance will be submitted for approval by the partners with progress of the project, including a resolution regarding drilling of the A-3 appraisal well. It should be noted that as at the approval date of the report, the Cypriot government's approval for the 2021 work plan has not yet been received.

Forward-looking information: The foregoing information regarding the possible date of the FID, the estimated cost of the development plan and the possible date of commencement of natural gas supply is forward-looking information, as defined in section 32A of the Israel Securities Law, based largely on various estimates and work assumptions, inter alia, completion of the detailed design of the development plan, actual performance of the project and various other factors over which the Company does not have full control or which it is unable to estimate with sufficient certainty.

(M) Contingent and prospective resources in Block 12

According to a report received by the Partnership from NSAI, which was prepared in accordance with the principles of the Petroleum Resources Management System (SPE-PRMS) (below in section : ("the Resources Report"), as at December 31, 2020, some of the natural gas and condensate resources in the Aphrodite reservoir[71] in Block 12 have been proved by the Aphrodite A-1 and Aphrodite A-2 wells (and the Aphrodite A-2 well in the Ishai License area), and are therefore classified as contingent resources, while other natural gas and condensate resources in fault blocks adjacent to the fault block where drilling was performed have not been proven and therefore remain classified as prospective resources.

[71] It should be noted that most of the Aphrodite reservoir is located in the exclusive economic zone of Cyprus, and a small part in the Ishai License area in the exclusive economic zone of Israel.

(1) Contingent Resources

A. Quantitative data[72]

According to the Resources Report, as of December 31, 2020, the contingent resources in the Aphrodite reservoir, classified as development pending, are as described below:

Objective	Probability	Total (100%) gas in the oil asset (Gross)		Total rate attributable to the equity holders of the Company (gross)[73]	
		Natural gas BCF	Condensate Million barrels	Natural gas BCF	Condensate Million barrels
Sands A	Low estimate	18.7	0.0	3.1	0.0
	Best estimate	87.3	0.2	14.3	0.0
	High estimate	117.2	0.3	19.2	0.0
Sands C	Low estimate	1,539.4	3.1	252.4	0.5
	Best estimate	2,269.1	5.0	372.1	0.8
	High estimate	2,946.7	7.1	483.2	1.2
Sands D1U	Low estimate	55.9	0.1	9.2	0.0
	Best estimate	267.6	0.6	43.9	0.1
	High estimate	365.0	0.9	59.9	0.1
Sands D1M	Low estimate	12.1	0.0	2.0	0.0
	Best estimate	190.7	0.4	31.3	0.1
	High estimate	306.1	0.7	50.2	0.1
Sands D1L	Low estimate	64.9	0.1	10.6	0.0
	Best estimate	196.5	0.4	32.2	0.1
	High estimate	250.7	0.6	41.1	0.1
Sands D2U	Low estimate	236.6	0.5	38.8	0.1
	Best estimate	330.0	0.7	54.1	0.1
	High estimate	367.2	0.9	60.2	0.1
Sands D2M	Low estimate	61.3	0.1	10.1	0.0
	Best estimate	104.9	0.2	17.2	0.0
	High estimate	132.1	0.3	21.7	0.0
Sands D2L	Low estimate	17.9	0.0	2.9	0.0
	Best estimate	30.6	0.1	5.0	0.0
	High estimate	61.4	0.1	10.1	0.0

B. The resources report states that the contingent resources are subject, inter alia, to maturity of the development plan, an FID and signing agreements. For information about the development of the Aphrodite reservoir, see Section 1.7.6(L) above. It is noted that the report excludes an economic analysis of the oil asset, and based on the development of similar reservoirs, the contingent resources in the best estimate category have a reasonable chance of becoming commercial.

Forward-looking information: There is no certainty that it will be commercially viable to produce any percentage of the contingent resources.

72 The table does not include resources in the Ishai License area .

73 Considering the Company's holdings in the Partnership's participating units as at the approval date of the report and that Cyprus' share of the gas from Block 12 depends on the production rate, which is unknown and cannot be estimated as at the publication date of the report, it is impossible to determine, as at the publication date of the report, the rate of the resources of the Company's equity holders (net). Therefore, the rate of the Company's equity holders (gross) before deduction of the Republic of Cyprus' share under the provisions of the PSC and before royalties, was included in the above table.

(2) Prospective resources

A. Quantitative data[74]

According to the resources report, as at December 31, 2020, the prospective resources of natural gas and condensate in the Aphrodite Reservoir are as follows:

Objective	Probability	Total (100%) in the oil asset (Gross)		Total rate attributable to the equity holders of the Company (gross)[75]	
		Natural gas BCF	Condensate Million barrels	Natural gas BCF	Condensate Million barrels
Sands A	Low estimate	3.8	0.0	0.6	0.0
	Best estimate	9.8	0.0	1.6	0.0
	High estimate	18.5	0.0	3.0	0.0
Sands C	Low estimate	33.0	0.1	5.4	0.0
	Best estimate	52.3	0.1	8.6	0.0
	High estimate	81.0	0.2	13.3	0.0
Sands D1U	Low estimate	98.4	0.2	16.1	0.0
	Best estimate	166.1	0.4	27.2	0.1
	High estimate	296.0	0.7	48.5	0.1
Sands D1M	Low estimate	46.0	0.1	7.5	0.0
	Best estimate	105.4	0.2	17.3	0.0
	High estimate	263.9	0.6	43.3	0.1
Sands D1L	Low estimate	127.1	0.3	20.8	0.0
	Best estimate	194.7	0.4	31.9	0.1
	High estimate	291.5	0.7	47.8	0.1
Sands D2U	Low estimate	165.2	0.3	27.1	0.0
	Best estimate	356.2	0.8	58.4	0.1
	High estimate	883.0	2.1	144.8	0.3
Sands D2M	Low estimate	2.5	0.0	0.4	0.0
	Best estimate	23.6	0.0	3.9	0.0
	High estimate	271.1	0.7	44.5	0.1
Sands D2L	Low estimate	0.2	0.0	0.0	0.0
	Best estimate	4.5	0.0	0.7	0.0
	High estimate	206.5	0.5	33.9	0.1

B. The Resources Report was based on the results of a 3D seismic survey carried out by Petroleum Geo-Services in 2009 and 2013 and reprocessed in 2014 based on information collected from the Aphrodite A-1 and A-2 drilling in the Aphrodite reservoir area and the Aphrodite-2 drilling in the Ishai License area, and by comparison with adjacent reservoirs and similar wells around the world.

C. Basic parameters used to calculate the different scenarios:

Since the prospective resources in the reservoir are in two separate fault blocks, the following represent the basic parameters used to calculate the different scenarios in each of the fault blocks separately:

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[74] The table excludes resources in the Ishai License area.

[75] Before deduction of the Republic of Cyprus' share under the provisions of the PSC and before payment of royalties.

Central fault block

Target	Average gross thickness (feet)		Area (acres)		Gross rock volume (acre*feet)	
	High	Low	High	Low	High	Low
Sands D1U	17	68	5,878	3,473	416,701	235,317
Sands D1M	94	60	5,013	2,252	472,365	135,311
Sands D1L	79	77	5,005	3,889	396,826	298,899
Sands D2U	90	63	6,222	2,428	558,147	152,116
Sands D2M	98	16	5,152	332	504,043	5,372
Sands D2L	135	4	4,058	25	549,579	100

Target	Gas saturation (decimal)		Porosity (decimal)		Net-to-gross (decimal)	
	High	Low	High	Low	High	Low
Sands D1U	0.65	0.55	0.23	0.19	0.50	0.30
Sands D1M	0.55	0.45	0.26	0.21	0.45	0.25
Sands D1L	0.65	0.55	0.24	0.20	0.50	0.30
Sands D2U	0.75	0.65	0.23	0.19	0.90	0.70
Sands D2M	0.75	0.65	0.24	0.20	0.45	0.25
Sands D2L	0.65	0.55	0.23	0.19	0.70	0.40

Target	Gas Recovery Factor (decimal)		Gas formation volume factor (SCF/RCF)	
	High	Low	High	Low
Sands D1U	0.7	0.6	378	378
Sands D1M	0.7	0.6	378	378
Sands D1L	0.7	0.6	378	378
Sands D2U	0.7	0.6	379	379
Sands D2M	0.7	0.6	379	379
Sands D2L	0.7	0.6	379	379

South western fault block

Target	Average gross thickness (feet)		Area (acres)		Gross rock volume (acre*feet)	
	High	Low	High	Low	High	Low
Sands A	51	51	2,896	1,930	146,232	97,488
Sands C	103	103	736	490	75,972	50,648
Sands D1U	55	15	1,018	52	56,044	770
Sands D1L	84	4	732	25	61,355	100
Sands D2	39	32	395	115	15,383	3,649
Sands D1U	66	15	1,296	46	85,606	700
Sands D1L	74	4	909	25	66,966	100
Sands D2	83	4	487	25	40,415	100

Target	Gas saturation (decimal)		Porosity (decimal)		Net-to-gross (decimal)	
	High	Low	High	Low	High	Low
Sands A	0.60	0.50	0.20	0.16	0.13	0.03
Sands C	0.75	0.65	0.23	0.19	0.70	0.40
Sands D1U	0.65	0.55	0.23	0.19	0.50	0.30
Sands D1L	0.55	0.45	0.26	0.21	0.45	0.25
Sands D2	0.65	0.55	0.24	0.20	0.50	0.30
Sands D1U	0.75	0.65	0.23	0.19	0.90	0.70
Sands D1L	0.75	0.65	0.24	0.20	0.45	0.25
Sands D2	0.65	0.55	0.23	0.19	0.70	0.40

Target	Gas Recovery Factor (decimal)		Gas formation volume factor (SCF/RCF)	
	High	Low	High	Low
Sands A	0.7	0.6	375	375
Sands C	0.7	0.6	378	378
Sands D1U	0.7	0.6	378	378
Sands D1L	0.7	0.6	378	378
Sands D2	0.7	0.6	378	378
Sands D1U	0.7	0.6	379	379
Sands D1L	0.7	0.6	379	379
Sands D2L	0.7	0.6	379	379

D. The material risks involved on continuing the process are related to proving a commercial discovery and include, inter alia, appraisal and development costs for the reservoir. There are also risks in proving the probable resources in the undrilled fault blocks. For information about the risk factors involved in exploration activities, see section 1.7.33 below.

E. <u>The estimated probability of success of each of the risk factors in the drilling and statistical estimate of the geological probability of finding natural gas in the fault block of the prospective resources are as follows (in %)</u>:

Central fault block

Target	Trap integrity	Reservoir quality	Source quality	Timing and migration	Total
Sands D1U	100	95	100	100	95
Sands D1M	100	85	100	100	85
Sands D1L	100	95	100	100	95
Sands D2U	100	95	100	100	95
Sands D2M	100	75	100	100	75
Sands D2L	100	85	100	100	85

South western fault block

Target	Trap integrity	Reservoir quality	Source quality	Timing and migration	Total
Sands A	100	70	100	100	70
Sands C	100	95	100	100	95
Sands D1U	100	90	100	100	90
Sands D1M	100	80	100	100	80
Sands D1L	100	90	100	100	90
Sands D2U	100	95	100	100	95
Sands D2M	100	70	100	100	70
Sands D2L	100	80	100	100	80

F. Estimated probability of development for commercial production For information, see subsections (b) to (d) above.

G. The Company's explanation of the basic parameters used to calculate the various scenarios: The parameters used to calculate the estimates are based mainly on data collected the Aphrodite A-1 and A-2 drilling in the Aphrodite reservoir area and Aphrodite A-2 drilling in the Ishai License area, the results of the 3D seismic survey and general information concerning targets and similar reservoirs.

(3) The resources report prepared by NSAI includes a number of assumptions and qualifications:

A. The estimates with respect to the contingent resources were not adjusted to reflect development risk;

B. NSAI did not visit the oil field and did not check the mechanical operation of the facilities and wells or their state;

C. NSAI did not assess possible exposure from environmental issues. However, NSAI noted that at the date of the resources report, it is unaware of any possible liability for environmental events that could have a material effect on the estimated quantity of resources in the resources report or their commercial viability.

D. The resources described in the resource report are in an undeveloped location, therefore the appraisal is based on the estimated size of the reservoir and the recovery efficiencies, with an analogy to reservoirs with similar geological and reservoir characteristics.

(4) Reconciliation of the information in the resource report and information in previous reports relating to the oil asset

The differences between the current resources report and the previous one published in the Partnership's 2017 Periodic Report is due to an update of the reservoir mapping and the geological model to include the entire updated database and comparison with adjacent reservoirs.

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

There is no certainty that any part of these potential resources will indeed be discovered, If they are discovered, there is no certainty that it will be commercially viable to produce any part of the resources. The prospective information does not lie within the bounds of an evaluation in respect of the reserves and contingent resources, which can only be evaluated after appraisal drilling, if at all.

Forward-looking information: The estimates of NSAI in respect of the contingent resources and prospective resources in the Aphrodite reservoir are forward-looking information as defined in the Securities Law. These estimates are partially based on geological, geophysical, engineering and other information received from the operator, from wells drilled in the Aphrodite reservoir and from drilling in the adjacent reservoirs, and are the professional estimates and assumptions only of NSAI and there can be no certainty in respect of them. Actual quantities of natural gas and/or condensate actually produced (if any) 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 market and/or actual performance of the reservoir. The estimates and assumptions may be revised if

additional information becomes available and/or as the result of a range of factors related to oil and natural gas exploration and production projects.

(5) Expert Opinion of the Evaluator:

Attached to this report by way of reference to Appendix C of Chapter A of the periodic report of the Partnership as at December 31, 2020 (Ref. No. 2021-01-036588) is a contingent and prospective resources report in Block 12 prepared by NSAI as at December 31, 2020 and attached as Appendix A to this chapter is NSAI's consent to include the report in this report, including by way of reference.

(6) Management declaration

(1) Declaration date: March 29, 2021

(2) Name of the corporation: Delek Group Ltd.

(3) Name and position of the resource valuation officer in the Company: Gabriel Last, Chairman of the Board of Directors

(4) We confirm that the valuator received all the information required to perform the work.

(5) We hereby confirm that nothing came to our attention that indicates any dependence between the assessor and the Company.

(6) We confirm that, to the best of our knowledge, the resources reported are the best and most current estimates available to us.

(7) We hereby confirm that the data included in this Report were prepared in accordance with the professional terms under Chapter Seven of the Third Schedule to the Securities Regulations (Details of the Prospectus and Draft Prospectus - Structure and Form), 1969, and the meanings given to them in Petroleum Resources Management System (2018) published by the Petroleum Engineers Association (SPE), the American Association of Petroleum Geologists (AAPG), the World Petroleum Council (WPC) and the Association of Petroleum Assessment Engineers (SPEE), as in effect at the time of approval of the Report;

(8) We confirm that no change has been made to the identity of the valuator preparing the disclosure of the most recent reserves or contingent resources report issued by the Company.

(9) We agree to include this statement in this report.

Gabriel Last
Chairman of the Board of Directors

(7) Consequences of the Covid-19 Crisis:

As stated in section 1.7.2(G) above, due to the Covid-19 crisis, as at the approval date of the report, there is extreme and unusual uncertainty regarding the possible consequences of the crisis in and after 2021 on the global economy in general and energy prices in particular. Therefore, if the Covid-19 crisis continues or intensifies, this may prevent the possibility of adopting an investment decision in general, and in new projects in particular.

1.7.7. Ofek Hadash License

(A) On October 10, 2019, the transaction entered into by the Partnership with S.O.A. Energy Israel Ltd. ("SOA") for the purchase of 25% (out of 100%) of the rights in the 405/Ofek Hadash license ("the Ofek Hadash License"), located in the Shfela region (Judean Foothills) in central Israel (in this section: "The Purchase Transaction") was finalized. The Ofek Hadash License is a negligible oil asset compared to all of the Company's operations and assets and, therefore, a limited description thereof is presented below.

As at the approval date of the report, the Company's rights in this asset are due to its direct and indirect holdings in 54.7% of the unit capital of Delek Drilling, which holds 25.0% of the participating rights in the project, and due to the rights of the Company and Delek Energy to royalties from the

Partnership's share in the oil asset, as set out in section 1.7.1(B)(1) above and section 1.7.29(N) below. The information below is correct as at the approval date of the report, and refers to all the Company's direct and indirect rights in the project.

(B) General Details

General information about the oil asset	
Name of oil asset	405/Ofek Hadash
Location:	Onshore license in the Shfela region in central Israel
Area	344 sq. km
Type of oil asset	Oil exploration license
Original grant date of the oil asset	June 21, 2017
Original expiry date of the oil asset:	June 20, 2021
Date of decision regarding extension of the term of the oil asset:	April 5, 2020
Current expiry date of the oil asset	June 20, 2021
Note whether there is an additional option of extending the period of the oil asset: if so, note the period of the possible extension	Subject to the Petroleum Law, it may be extended for another 3 years with an extension option for further 2 years in the event of a discovery.
Name of Operator	SOA
Names of the direct partners in the oil asset and their direct share in the oil asset and, to the best of the Company's knowledge, the names of the controlling owners in the partners	• SOA - 45%, to the best of the Company's knowledge, the controlling shareholder of SOA is Saed Sarsur (a businessman, Israeli citizen and UK resident). • The Partnership - 25% • Globe Exploration (Y.C.D) Limited Partnership ("Globe") - 20%, to the best of the Company's knowledge, the controlling shareholder of Globe is Globe Exploration, which serves as Globe's general partner. • Capital Point Ltd. ("Capital") - 10%, to the best of the Company's knowledge, Capital has no controlling shareholder.

(C) The Company's share in the oil asset

General information about the Company's share in the oil asset	
Acquisition date of the lease for the purchased oil asset	March 19, 2019 (date of execution of the purchase transaction)
Description of the Company's holding in the oil asset	As set out in section (a) above.
Effective share of oil asset revenues attributable to equity holders of the Company:	In the right to participate in revenue: Before investment recovery - 11.20% After investment recovery - 10.52% In right to receive royalties: Before investment recovery - 0.63% After investment recovery - 1.88% Total revenue Before investment recovery - 11.83% After investment recovery - 12.40%
Total share of the Company's equity holders in the cumulative investment in the oil asset in the five years preceding the last day of the reporting year (whether recognized as an expense or as an asset in the financial statements):	USD 3,468 thousand

(D) Actual and planned work schedule

The main activity planned for the Ofek License is re-entry into the existing Ofek 2-ST well and performance of production tests in the well.

In September 2020, the license partners adopted a resolution to participate in the production tests to be conducted in 2021 at a budget of between USD 10 million and USD 13 million (100%). The Company's share of the budget is between USD 4.1 million and USD 4.6 million[76].

Below is a summary of the main activities actually carried out in the Ofek Hadash License from January 1, 2018 until the approval date of this report, and a summary of the planned operations in the License, based on the planned work plan approved by the Commissioner of Petroleum Affairs in December 24, 2020.

Ofek Hadash			
Period	**Summary of actual operations in the period or of the planned work plan**	**Estimated total budget for operations on the level of the oil asset (USD thousands)**	**Actual participation of the Company's equity holders in the budget (USD thousands)**
2018	Signing of an agreement with a drilling contractor and submission of a production test plan to the Commissioner of Petroleum Affairs for approval.		
2019	Submission of digitized seismic sections, log interpretation and petro-physical test plan to the Commissioner of Petroleum Affairs.	30	4
	Submission of a plan for re-entry into the well and performance of production tests to the Commissioner of Petroleum Affairs on May 15, 2019.	60	8
	Receipt of all permits and approvals required for breaking ground and performing the production tests, including approval from the land owners and the local council.	351	48
2020	Planning and preparation for production tests in Ofek-2 well.	5,845	799
	Submission of a signed agreement with the contractor for production tests in the License area, and an engineering plan to the Commissioner of Petroleum Affairs		
2021 onwards	Receipt of all approvals required for production tests in Ofek-2 well.		
	Production tests in Ofek-2 well.	5,914	1,077
	Submission of a summary report of the production tests to the Commissioner of Petroleum Affairs. Three months from completion of the production tests.		

Forward-looking information: The above information regarding the planned operations, costs, timetables and execution of the planned operations in the Ofek Hadash License is forward-looking information, as defined in section 32A of the Israel Securities Law, based the assessments of the general partner regarding the planned operations, costs, timetables and execution of the planned operations, and production rates, which are all based on assessments that the general partner in the Partnership received from the Operator (SOA).

76 It is noted that in the acquisition agreement, the Partnership undertook to bear the costs of production tests in the Ofek Hasash License up to a total amount not exceeding USD 6.5 million and if the cost of the production tests exceeds this amount, each of the Ofek Hadash License partners, including the Partnership, will pay its proportionate share of the additional cost, in accordance with the provisions of the joint operating agreements (JOA).

Actual planned operations, costs and timetables may be materially different from the above estimates, and are contingent, among other things, on appropriate decisions made by the Ofek Hadash partners, obtaining the approvals required by law, the completion of detailed planning of the project components, bids from contractors, changes to suppliers and raw material markets, applicable regulation, technical ability and economic viability.

Consequences of the Covid-19 crisis

As stated in section 1.7.2(G) above, due to the Covid-19 crisis, as at the approval date of the report, there is extreme and unusual uncertainty regarding the possible consequences of the crisis in and after 2021 on the global economy in general and energy prices in particular. Therefore, if the Covid-19 crisis continues or intensifies, this may delay the progress of existing projects or prevent the possibility of adopting an investment decision in general, and in new projects in particular.

1.7.8. Yahel Hadash License

(A) Under the purchase transaction of the Partnership with SOA as described above regarding the Ofek Hadash License, the Partnership also purchased 25% (out of 100%) of the participating rights in the 406/Yahel Hadash license ("the Yahel Hadash License"), which is located onshore in northern Israel.

As at the approval date of the report, the Company's rights in this asset are due to its direct and indirect holdings in 54.7% of the unit capital of Delek Drilling, which holds 25.0% of the participating rights in the project, and due to the rights of the Company and Delek Energy to royalties from the Partnership's share in the oil asset, as set out in section 1.7.1(B)(1) above and section 1.7.29(N) below. The information below is correct as at the approval date of the report, and refers to all the Company's direct and indirect rights in the project.

(B) General Details

General information about the oil asset	
Name of oil asset	406/Yahel Hadash
Location:	Onshore license in the Haifa Bay area, south of the Akko-Safed road and north of Yokneam
Area	397.5 sq. km
Type of oil asset	Oil exploration license
Original grant date of the oil asset	June 21, 2017
Original expiry date of the oil asset:	June 20, 2021
Date of decision regarding extension of the term of the oil asset:	April 5, 2020
Current expiry date of the oil asset	June 20, 2021
Note whether there is an additional option of extending the period of the oil asset: if so, note the period of the possible extension	Subject to the Petroleum Law, it may be extended for another 3 years with an extension option for further 2 years in the event of a discovery.
Name of Operator	SOA
Names of the direct partners in the oil asset and their direct share in the oil asset and, to the best of the Company's knowledge, the names of the controlling owners in the partners	• SOA - 45% • The Partnership - 25% • Globe - 20% • Capital - 10%

(C) The Company's share in the oil asset

General information about the Company's share in the oil asset	
Acquisition date of the lease for the purchased oil asset	March 19, 2019 (date of execution of the purchase transaction)
Description of the Company's holding in the oil asset	As set out in section (a) above.
Effective share of oil asset revenues attributable to equity holders of the Company:	In the right to participate in revenue: Before investment recovery - 11.20% After investment recovery - 10.52% In right to receive royalties: Before investment recovery - 0.63% After investment recovery - 1.88% Total revenue Before investment recovery - 11.83% After investment recovery - 12.40%
Total share of the Company's equity holders in the cumulative investment in the oil asset in the five years preceding the last day of the reporting year (whether recognized as an expense or as an asset in the financial statements):	USD 280 thousand

(D) Actual and planned work schedule

(1) Below is a summary of the main activities actually carried out in the Ofek Hadash License from January 1, 2018 (date of grant of the Yahel Hadash License) until the approval date of this report, and a summary of the planned operations in the License, based on the planned work plan approved by the Commissioner of Petroleum Affairs on January 11, 2021.

Yahel Hadash			
Period	**Summary of actual operations in the period or of the planned work plan**	**Estimated total budget for operations on the level of the oil asset (USD thousands)**	**Actual participation of the Company's equity holders in the budget (USD thousands)**
2019	Completion of an environmental documents according to the Petroleum Regulations (Authorization of Deviation from the Provisions of the Planning and Building Law), 2012.	27	4
	Submission of an application according to the uniform planning format together with an environmental document on June 11, 2019.		
	Hearing in the North District Planning and Building Committee on August 15, 2019, including addressing the Committee's terms.	12	1.6
2020	Planning and preparation prior to appraisal drilling in the License Area, including obtaining all required approvals.		
2021[77]	By September 1, 2021 - discussion and decision by the district committee to approve the drilling application.		
	By October 3, 2021 - submission of a drilling approval application and a signed agreement with a drilling contractor for approval by the Commissioner.	60	8

77 As at the approval date of the report, the budget for 2021 onwards has not yet been approved by the partners.

Yahel Hadash			
Period	**Summary of actual operations in the period or of the planned work plan**	**Estimated total budget for operations on the level of the oil asset (USD thousands)**	**Actual participation of the Company's equity holders in the budget (USD thousands)**
2022 onwards	By February 1, 2022 - commencement of the drilling.	20,000	2,733
	Three months from completion of the drilling - submission of a summary report.		

Forward-looking information: The above information regarding the planned operations, costs, timetables and execution of the planned operations in the Yahel Hadash License is forward-looking information, as defined in section 32A of the Israel Securities Law, based the assessments of the general partner regarding the planned operations, costs, timetables and execution of the planned operations, and production rates, which are all based on assessments that the general partner in the Partnership received from the Operator (SOA). Actual planned operations, costs and timetables may be materially different from the above estimates, and are contingent, among other things, on appropriate decisions made by the Yahel Hadash partners, obtaining the approvals required by law, the completion of detailed planning of the project components, bids from contractors, changes to suppliers and raw material markets, applicable regulation, technical ability and economic viability.

Consequences of the Covid-19 Crisis:

As stated in section 1.7.2(G) above, due to the Covid-19 crisis, as at the approval date of the report, there is extreme and unusual uncertainty regarding the possible consequences of the crisis in and after 2021 on the global economy in general and energy prices in particular. Therefore, if the Covid-19 crisis continues or intensifies, this may delay the progress of existing projects or prevent the possibility of adopting an investment decision in general, and in new projects in particular.

1.7.9. Yam Tethys project

(A) As at the approval date of the report, the Company’s rights in this asset are due to its direct and indirect holdings in 54.7% of the unit capital of Delek Drilling, which holds 48.5% of the participating rights in the project, and due to the rights of the Company and Delek Energy to royalties from the Partnership’s share in the oil asset, as set out in section 1.7.1(B)(1) above and section 1.7.29(N) below. The information below is correct as at the approval date of the report, and refers to all the Company’s direct and indirect rights in the project.

It should be noted that on May 3, 2020, an agreement was signed between Delek Group, the Partnership, Noble and Ratio regulating the method of supply of natural gas to customers with rights in the Yam Tethys reservoir (Noble, the Partnership and Delek Group) from the Leviathan reservoir.

The Company considers the Yam Tethys project, to be a negligible oil asset compared to all of the Company’s operations and assets and, therefore, a limited description thereof is presented below.

(B) <u>General Details</u>

General information about the oil asset	
Name of oil asset	Noa Lease Ashkelon Lease
Location:	Ashkelon Lease: 25 kilometers west of the Ashkelon Coast Noa Lease: 40 kilometers west of the Ashkelon Coast
Area	The total area of the leases is 500 square kilometers
Type of oil asset and description of permitted operations according to the type	Lease Operations permitted under the Petroleum Law - exploration and production
Original grant date of the oil asset	Ashkelon Lease - June 11, 2002 Noa Lease - February 10, 2000

General information about the oil asset	
Original expiry date of the oil asset	Ashkelon Lease - June 10, 2032 Noa Lease - January 31, 2030
Decision date for extension of the term of the oil asset	-
Current expiry date of the oil asset	Ashkelon Lease - June 10, 2032 Noa Lease - January 31, 2030
Note whether there is an additional option of extending the period of the oil asset: if there is such an option, note the period of the possible extension	Subject to the Petroleum law for an additional 20 years
Note name of Operator	Noble
Names of the direct partners in the oil asset and their direct share in the oil asset and, to the best of the Company's knowledge, the names of the controlling owners in the partners	• The Partnership (48.5%) • Noble (47.059%) • The Company (4.441%)

(C) <u>Actual and planned work plan for the Yam Tethys project</u>

The table below includes a summary of the main operations actually performed in the Ashkelon and Noa leases from January 1, 2018 through to the approval date of the report and a summary of the planned operations:

Yam Tethys project			
Period	**Summary of actual operations in the period or of the planned work plan**	**Estimated total budget for operations on the level of the oil asset (USD thousands)**	**Actual participation of the Company's equity holders in the budget (USD thousands)**
2018	• Production from the Mari B reservoir, ongoing operation and maintenance.		
	• Assessment of the uses of existing infrastructure and maintaining or increasing production capacity.		
	• Preparation for the future abandonment of wells and facilities in the Yam Tethys project	472.8	146
	• Continued update of the geological model and flow model, among other things, according to drilling and production data.		
	• Mapping and definition of additional prospects in the area of the oil asset, including a prospect to the deep targets in the area of the oil asset.		
2019	• Production from the Mari B reservoir, ongoing operation and maintenance.		
	• Assessment of the uses of existing infrastructure and maintaining or increasing production capacity.		
	• Preparation for the future abandonment of wells and facilities in the Yam Tethys project	1,497	463
	• Preparation of the platform for cold stacking, including air-gapping of gas pipes from the production wells to the	299.7	93

Yam Tethys project			
Period	**Summary of actual operations in the period or of the planned work plan**	**Estimated total budget for operations on the level of the oil asset (USD thousands)**	**Actual participation of the Company's equity holders in the budget (USD thousands)**
	treatment and production facilities on the platform. • Continued update of the geological model and flow model, among other things, according to drilling and production data.		
	• Mapping and definition of additional prospects in the area of the oil asset, including a prospect to the deep targets in the area of the oil asset.		
2020	• Ongoing operation and maintenance.		
	• Preparation of the platform for cold stacking, including air-gapping of gas pipes from the production wells to the treatment and production facilities on the platform.	2,342	724
	• Assessment of the uses of existing infrastructure and maintaining or increasing production capacity.		
	• Preparation for the future abandonment of wells and facilities in the Yam Tethys project	7,962	2,461
2021 onwards	• Assessment of the uses of existing infrastructure of the project.		
	• Cold stacking of the Mari B platform, among other things, by air-gapping the gas pipeline to the platform (including from the reservoir, the Tamar platform and the 30” pipe), and removal of unnecessary equipment and materials.		
	• Plugging and abandonment of the project’s production wells, according to the standards and guidelines of the Commissioner of Petroleum Affairs. Dismantling and abandonment of subsea facilities, according to the standards and guidelines of the Commissioner of Petroleum Affairs.	158,464	49,049

Forward-looking information: The Partnership's estimate regarding the planned operations in the Yam Tethys project, including costs, schedules, and actual performance, is forward-looking information, as defined in section 32A of the Israel Securities Law, based on estimates of the general partners regarding the components of the work plan, which are all based on estimates that the general partner received from the Operator. Implementation of the actual work plan, including schedules and costs, may differ materially from the above estimate and is subject, among other things, to applicable regulation, technical capacity, and economic viability.

1.7.10. Tanin and Karish Leases

(A) General

As at the approval date of the report, the Company’s rights in this asset are from its direct and indirect holdings of 54.7% of the unit capital of Delek Drilling, which holds the right to receive royalties from Energean, the holder of the rights in the Karish and Tanin Leases as set out in section (b) below, and from the Company's and Delek Energy's right to royalties from Energean for the Partnership's rights sold to Energean, as set out in section 1.7.1(B)(2) above/below. All information below is as at the approval date of the report and relates to all of the Company's direct and indirect rights in the oil asset.

As at the approval date of the report, the Company considers the benefit from the Tanin and Karish Leases a negligible oil asset for the results of its operations and for its assets, and therefore, a limited description of the rights in the Tanin and Karish Leases is presented below. It should be noted that the following description is based mainly on public information of Energean, a foreign public company whose shares are listed on the London Stock Exchange and the Tel Aviv Stock Exchange, which to the best of the Company's knowledge is the controlling shareholder of Energean Israel, and the Company is unable to independently verify the correctness of the details presented therein.

(B) Background

Following the Government's decision to ratify the Gas Framework, on August 16, 2016, an agreement was signed between Noble, Avner, Delek Drilling and Energean Israel for the sale of all of the rights of the Partnership, Avner and Noble in the Tanin and Karish Leases for a payment that constitutes reimbursement of the past expenses invested in the leases by the Partnership, Avner and Noble plus royalties for the natural gas and condensate to be produced from the leases. Under this agreement, the Partnership is entitled to receive royalties from Energean for all of its rights for the natural gas and condensate to be produced from the Karish and Tanin Leases, at the following rates: 5.12% before payment of oil profit tax under the Taxation of Profits from Natural Resources Law, 2011 ("the Levy") and before the investment recovery date; 2.47% before payment of the levy and after the investment recovery date; and 3.22% when payment of the levy starts and after the investment recovery date.

General information about the oil asset	
Name of oil asset	Tanin Lease Karish Lease
Location	Offshore assets, about 80-130 km west of the shores of Nahariya
Area	The area covered by the two leases together is 500 square kilometers
Type of oil asset and description of permitted operations according to the type	Lease Operations permitted under the Petroleum Law - exploration and production
Original grant date of the oil asset	December 24, 2015 effective as from August 11, 2014 (revised on April 25, 2017).
Original expiry date of the oil asset	August 10, 2044
Date of decision regarding extension of the term of the oil asset:	-
Current expiry date of the oil asset	August 10, 2044
Note whether there is an additional option of extending the period of the oil asset: if so, note the period of the possible extension	For a further 20 years, subject to the Petroleum Law.
Name of Operator	Energean Israel
Names of the direct partners in the oil asset and their direct share in the oil asset and, to the best of the Company's knowledge, the names of the controlling owners in the partners	• Energean Israel (100%)

General information about the Company's share in the oil asset	
Acquisition date of the lease for the purchased oil asset	-
Description of the Company's holding in the oil asset	As set out in section (a) above.
Effective share of oil asset revenues attributable to equity holders of the Company:	2.80% before payment of the levy and before the investment recovery date; 1.35% before payment of the levy and after the investment recovery date; and 1.76% when payment of the levy starts and after the investment recovery date.
Total share of equity holders of the Company in the cumulative investment in the oil asset in the five years preceding the last day of the reporting year (whether recognized as an expense or as an asset in the financial statements):	USD (3,015) thousand[78]

(C) Actual and planned work plan for the Tanin and Karish Leases

To the best of the Company's knowledge, the development plan of the Karish and Tanin reservoirs submitted by Energean to the Commissioner of Petroleum Affairs was approved by the Ministry of Energy in August 2017 (below in this section: "the Development Plan") whereby the Karish field will be developed in the first stage and the Tanin field will be developed later[79].

In 2018, Energean adopted an FID regarding development of the Karish reservoir. On November 17, 2020, Energean published an announcement indicating that the flow of gas from the Karish reservoir is expected to commence, in its estimation, in the fourth quarter of 2021. On February 11, 2021, Energean published a presentation and resources report prepared by a third party according to which the flow of gas from the Karish reservoir will commence, in its estimation, at the beginning of 2022.

On April 15, 2019, Energean released an announcement[80] about a natural gas discovery in the Karish North well. According to Energean's announcements, the Development Plan of the Karish North reservoir which it submitted was approved by the Ministry of Energy in August 2020 and an FID for development of the Karish North reservoir was subsequently adopted, on January 14, 2021[81]. According to Energean's estimation, the production from this reservoir is expected to commence in the second half of 2023. To the best of the Company's knowledge, the updated data regarding the resources attributable to the Karish, Tanin and Karish North reservoirs ("the Reservoirs") was recently published by Energean on February 11, 2021[82]. According to this report, the Reservoirs contain natural gas reserves (2P) in a volume of 98.2 BCM and liquid hydrocarbons in a volume of 99.6 million barrels (compared to natural gas resources (2P and 2C) in a volume of 98.6 BCM and liquid hydrocarbons in a volume of 82 million barrels, according to Energean's previous announcement in April 2020). In addition, Energean indicated that the FPSO will reach a production capacity of 8 BCM per hour in 2023. Energean also published the volume of prospective resources in the areas of the Karish and Tanin reservoirs and in the area of the licenses in the exclusive economic zone of Israel in its possession, including the Karish and Tanin reservoirs.

It should be emphasized that the Company does not bear the development plan expenses of the Karish, Tanin and Karish North reservoirs.

It should be noted that in April 2020, Energean and the Partnership exchanged letters about the Partnership's rights to royalties from the Leases. According to Energean, among other things, its obligation to pay royalties does not apply to hydrocarbons from the Karish North reservoir, and, in addition, not all the liquid hydrocarbons that will be produced from the Leviathan lease meet the

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78 This investment is for the pre-sale period to Energean, in which the oil asset was held directly by the Partnership; the cost presented is the joint cost of the Partnership after the merger of the partnerships, namely 52.941% The investment in this period includes an adjusted budget (decrease) of USD 3,015 thousands.

79 https://www.gov.il/he/Departments/news/spokesperson_development

80 https://maya.tase.co.il/reports/details/1224643

81 https://www.energean.com/media/4647/20210113-karish-north-fid.pdf

82 Link to Energean's announcement: https://www.energean.com/investors/reports-presentations/

definition of condensate under the agreement for the sale of the Partnership's rights in the Leases. The Partnership's position, based on the opinion of its advisors, is that under the agreement for the sale of the Partnership's rights in the leases, the royalty documents, and the registration in the Oil Register, Energean's obligation to pay royalties applies to natural gas and condensate produced from the leases, including the Karish North reservoir, and that all the liquid hydrocarbons that will be produced from the leases constitute condensate as defined in the agreement.

Consequences of the Covid-19 Crisis:

As stated in Section 1.7.2(G) above, due to the Covid-19 crisis, as at the approval date of the report, there is extreme and unusual uncertainty regarding the possible consequences of the crisis in and after 2021 on the global economy in general, and energy prices in particular. If the Covid-19 crisis continues or intensifies, this may delay the progress of the development and production works of the Karish and Tanin reservoirs, resulting in a decrease in the current value of the royalties that the Company is directly and indirectly entitled to from the Karish and Tanin reservoirs.

Forward-looking information: The above description of the planned activities in the Karish Lease, including timetables, and the date of gas flow from the Karish reservoir, is forward-looking information as defined in the Israel Securities Law, and is based solely on public announcements by Energean. Implementation of the actual work plan, including timetables, may differ materially from the above and is subject, among other things, to applicable regulation, technical capacity, and economic viability.

The following is a summary of the main operations actually carried out in the Tanin and Karish Leases as from January 1, 2018 through to the approval date of the report and a summary of the planned operations: Since the Company does not bear the development and production costs in the Karish and Tanin Leases, data regarding the budget of the activities and the actual participation of the Company's equity holders in the Company's budget are not taken into account in the following table:

Karish and Tanin Lease			
Period	**Summary of actual operations in the period or of the planned work plan**	**Estimated total budget for operations on the level of the oil asset (USD thousands)**	**Actual participation of the Company's equity holders in the budget (USD thousands)**
2018	• FID for development of the Karish and Tanin reservoirs.	-	-
	• Design and start of manufacture of an FPSO with a production capacity of 8 BCM per year and 0.8 million barrels of hydrocarbon liquids, to be connected by a 24-inch pipe to Dor beach.		
	• Planning of the subsea transmission system to connect the production wells of the Karish reservoir to the FPSO.		
2019	• Continued planning and manufacture of the FPSO.	-	-
	• Exploration drilling in the Karish North prospect. On April 15, 2019, Energean released an announcement[83] about a natural gas discovery in the Karish North well.		
	• Drilling of three production wells in the Karish reservoir, as from the second quarter of 2019 and start of completion thereof.		
	• Continued planning, manufacture and start of installation of the subsea transmission system to connected the production wells of the Karish reservoir to the FPSO.		
2020	• Completion of the three production wells in the Karish reservoir.	-	-

[83] Link to Energean's announcement: https://maya.tase.co.il/reports/details/1224643

Karish and Tanin Lease			
Period	**Summary of actual operations in the period or of the planned work plan**	**Estimated total budget for operations on the level of the oil asset (USD thousands)**	**Actual participation of the Company's equity holders in the budget (USD thousands)**
	• Continued manufacture and installation of the subsea transmission system to connect the production wells to the FPSO and to the shore.		
	• On April 4, 2020, the PFSO hull manufactured at a shipping yard in China sailed to Singapore for installation of the gas and condensate production and treatment systems (the topsides).		
	• Submission and receipt of approval for the Development Plan of the Karish North reservoir.		
2021	• On January 14, 2021, Energean announced an FID for development of the Karish North reservoir.	-	-
	• Completion of the installation of the gas and condensate production and treatment systems on the FPSO hull in Singapore.		
	• Sailing of the FPSO containing all relevant systems to Israel.		
	• Completing connection and a trial run of the production system.		
2022	• Commencement of commercial production from the Karish reservoir, routine operation and maintenance.	-	-
	• Installation of a second export riser, installation and trial run of a second liquid treatment system (oil train) and completion of the Karish North-1 well.		
2023 onwards	• Continued commercial production from the Karish reservoir, routine operation and maintenance.	-	-
	• Completing connection of the production well in Karish North to the FPSO and commencement of commercial production from the Karish North reservoir.		
	• Drilling of additional production wells in the Karish reservoir, and the Karish North reservoir if necessary.		
	• Development of the Tanin reservoir, including drilling production wells; production, installation and connection to the FPSO of a subsea system . Commencement of production from the Tanin North reservoir in 2027, according to Energean's announcements.		

1.7.11. Discontinued operations in the Mediterranean Sea

Following are details about the oil assets whose operations were recently discontinued:

1. 399/Roi license ("Roi License")

Under an agreement dated November 26, 2012, the Partnership was granted an option to acquire participating rights at a rate of 20% (out of 100%) in the Roi license. On March 19, 2019, the Partnership informed the partners that the option had been exercised, and the parties agreed to certain changes to the terms of the option, according to which the Partnership will acquire from Ratio rights at a rate of 24.99% of the license. One of the preconditions for completing the transaction is an exemption for a restrictive arrangement. On July 28, 2019, the Competition Commissioner handed down a decision not to grant an exemption for a restrictive arrangement. On March 22, 2020, Ratio reported that the partners in the license notified the Commissioner of Petroleum Affairs at the Ministry of Energy that they are forced to withdraw from the license and return their participating rights to the State and subsequently on July 13, 2020, Ratio reported that according to the Commission of Petroleum Affairs' announcement, the Roi license expired on June 14, 2020.

(A) Eran License

On June 14, 2013, the Eran license expired.

For information about the legal proceedings related to non-extension of the license that ended in a mediation arrangement, see section 1.7.30(H)(1) below.

(B) Alon D License

On June 21, 2020, the Alon D License expired.

In this context, it is noted that the Alon D License partners submitted an offer under a competitive process announced by the Ministry of Energy on June 23, 2020 for granting a natural gas and oil exploration license in Block 72, which is on an area covered by the license ("Block 72"), and that on October 21, 2020, the Partnership received at its offices a demand for information and documents in connection with Block 72 from the Competition Authority. It is noted that the winner of this competitive process has not yet been announced by the Ministry of Energy. On September 30, 2020, the Commissioner of Petroleum Affairs contacted the Concentrations Committee for a consultation regarding a decision on the winner in this competitive process. On January 10, 2021, the Concentrations Committee published its recommendation not to allow the Partnership to win the competitive process irrespective of its compliance with the process conditions. On January 14, 2021, the Partnership appealed to the Commissioner of Petroleum Affairs to disregard the Concentrations Committee's recommendation, because it is deficient, ignores material facts and is inaccurate. It should be noted that to the best of the Partnership's understanding, on the same day the Commissioner of Petroleum Affairs sent the Concentrations Committee a request for re-consultation on the matter. The Partnership believes that if its bid (together with Noble) is preferable to the other bids submitted in the process, with attention to the pre-defined conditions, it has the full right to obtain the license.

Further to the foregoing, on June 18, 2020 the Alon D License partners petitioned the Supreme Court in its capacity as High Court of Justice. Under the petition, the Court was requested to hand an order nisi instructing the Minister of Energy and Commissioner of Petroleum Affairs to provide reasons why the Minister's decision to dismiss the appeal should not be rescinded, why the license should not be extended or an alternative license granted to the license holders thereunder, and why the license holders should not be allowed to exercise their accruing economic rights from the natural gas in the Karish North reservoir, part of which is located in the license areas. They were also requested to issue an interim injunction preventing expiration of the license, or alternatively prohibiting opening of a competitive process to grant a new license in the license area (or part thereof) or granting such license to a third party pending a ruling, and a temporary injunction pending a ruling on the petition for an interim injunction. At the same time, a decision was handed ordering the Ministry of Energy and Commissioner of Petroleum Affairs to file their response to the petition for an interim injunction by June 28, 2020. In the decision, the Court dismissed the petition for a temporary injunction and therefore the license expired on June 21, 2020. On June 23, 2020, the Ministry of Energy announced a competitive process to grant a natural gas and oil exploration license in Block 72, which is on an area covered by the license. On June 24, 2020, the license partners informed the Court that the Ministry of Energy had opened a competitive process, claiming that this emphasizes the need for an interim injunction and requesting that the Court set a date for a hearing on the petition. On June 30, 2020, the Minister of Energy and Commissioner of Petroleum Affairs filed their response to the petition for an interim injunction, claiming that the petition should be dismissed, because in essence it is a petition for a mandatory injunction (extension of the license after expiration) and it was filed late (three days before the license expired and shortly before commencement of the competitive process). The Minister and Commissioner further alleged that the chances of the petition being accepted are low, because according to them, it is in fact directed against the Minister's decision of 2017, so filing thereof now is late. On July 6, 2020, the license partners filed their answer to the Minister and Commissioner's response to the petition for an interim injunction, setting out the reasons for dismissing the Minister and Commissioner's allegations. On July 7, 2020, the petition for an interim injunction was denied. A hearing on the petition has been scheduled for May 19, 2021.

1.7.12. Products in the Mediterranean discoveries

(A) **Natural gas**

The natural gas discovered in the reservoirs held by the Partnership is composed mostly of methane gas and is therefore defined as "dry", although small quantities of non-corrosive liquids are separated during production and treatment. Consequently, the treatment required for gas for the purpose of supply to customers in relatively minimal.

Generally, natural gas can be transported in three main ways: (a) by pipeline; (b) by liquefaction (i.e., turning it onto LNG) by cooling it to 161 degrees Celsius below zero, reducing its volume 600 times and allowing it to be transported and stored in large quantities; and (c) by compressing it (CNG), so that its volume is reduced 100-300 times, depending on the compression pressure.

Liquid and compressed gas can be transported in sizable quantities over large distances by special tankers.

For information about the local gas market, including developments and changes, see section 1.7.13(A) above and about the possibility of exporting natural gas and selling it on the international market, see section 1.7.13(B) below.

(B) **Condensate**

During natural gas production and treatment, condensate is also produced, which is a hydrocarbon byproduct of condensation of different natural gas components resulting from the differences between the pressure and temperature in the reservoir and those on the surface. Condensate requires minimum treatment, mainly stabilization, to be able to transport it to the Partnership's customers and it is used mainly as a raw material in the production of distillates. It should be noted that the percentage of condensate produced is smaller than the quantity of natural gas produced and is several barrels per MMcf of natural gas. For information about the condensate supply agreements of the Partnership together with its partners from the Tamar and Leviathan projects and assessment of condensate delivery and sale alternatives, see section 1.7.13(F) below.

1.7.13. Customers

(A) Local market: As at the approval date of the report, the Partnership together with its partners in the Tamar and Leviathan projects supply natural gas to the IEC, independent power producers, natural gas marketing companies and industrial customers, and condensate from the Tamar and Leviathan projects, as set out in Sections 1.7.13(D) and 1.7.13(F) below, respectively. In addition, the Tamar and Leviathan partners are continuing various stages of negotiations aimed at signing natural gas and condensate supply agreements to the local market from the Tamar and Leviathan projects.

(B) Export: As at the publication date of the report, the Partnership, together with its partners int he Leviathan and Tamar projects, export natural gas to Jordan and Egypt according to the agreements described in Sections 1.7.13(D) and 1.7.13(E) below. Negotiations are also underway to export natural gas to other consumers, as set out in section 1.7.13(E)(4) below.

(C) Main customers: IEC, NEPCO and Dolphinus are the Partnership's largest customers and, therefore, cancellation of the agreements signed between them and the Tamar and Leviathan partners or non-compliance with them will materially impact the Partnership's operations and future revenue. The Partnership's revenue from gas sales to IEC from the Tamar project in 2018 and 2019 constituted 50% and 46% of its total revenue, respectively. In 2020, the Partnership's revenue from gas sales to IEC from the Tamar and Leviathan projects was 32% of its total revenue; to Dolphinus from the Tamar and Leviathan projects, 17%, and to NEPCO from the Leviathan project, 19%. The remainder of the Partnership's revenue in 2020 was from independent power producers, industrial customers in Israel and Jordan, and natural gas marketing companies. For information about the agreements of the Tamar and Leviathan partners with IEC, NEPCO and Dolphinus, see Sections 1.7.13(E)(1) and 1.7.13(E)(2) below.

Forward-looking information: The Company's estimates regarding the scope of its revenue from IEC, NEPCO and Dolphinus in the coming years is forward-looking information, as defined in section 32A of the Israel Securities Law, and there is no certainty that it will materialize in the manner set out above or in any other manner, in whole or in part, and it might materialize in a substantially different manner, due to various factors, including changes in the volume, rate and timing of natural gas and condensate consumption by all Tamar and Leviathan project customers, including IEC, NEPCO and Dolphinus, the sale prices of natural gas and condensate from the Tamar and Leviathan reservoirs, and the decrease in rate of holdings of the Partnership in the Tamar reservoir.

(D) Natural gas supply agreements

(1) Agreements for the sale of natural gas by the Tamar Partners

A. Below is a summary of the natural gas supply agreements from the Tamar project signed by the Partnership together with the other Tamar partners that are valid as at the approval date of the report. It is noted that, except for IEC and Dalia Power Energies Ltd. ("Dalia Energies"), the Tamar Partners have no other customer from which the revenue in 2019-2017 constituted more than 10% of Delek Drilling's revenue. The other customers with which the Tamar Partners have signed gas supply agreements have been grouped in the following table by price linkage established in these agreements. For further information about these agreements see sections 1.7.13(D)(1)c, 1.7.13(D)(1)d below and 1.7.13(E)(1) below. For information about the engagement of the Partnership together with its partners in a condensate supply agreement with Paz Ashdod Refinery, see Section 1.7.13(F)(1) below.

	Year of start of supply	**Basic agreement period[84]**	**Is there an option for an extension?[85]**	**Total maximum contractual supply quantity (100%) (BCM)[86]**	**The quantity supplied up to December 31, 2020 (100%) (BCM)**	**Main linkage basis for the price of gas**
IEC[87]	2013	15 years	IEC has the option to extend the agreement period by a further two years, if the full contractual quantity of is not supplied in the basic period.	54.4	32.6	The linkage basis in the supply agreement is the US CPI.
Dalia Energies[88]	2015	17 years	Each party has the option to extend the agreement period by a further two years, if the full contractual quantity of is not supplied in the basic period.	17	6.3	The electricity production tariff, which includes a minimum price.[89]

84 In most of the agreements, the gas supply period, which started at the date of flow for the relevant agreement, will be as set out in the table above or until the buyer consumes the maximum contractual quantity set out in the agreement, whichever is earlier.

85 Some of the supply agreements that contain options for the customers to extend the agreement set out specific conditions for exercising them.

86 This quantity is the maximum gas supply quantity specified in the agreements throughout the entire agreement period. The quantity that the customers undertook to purchase is lower than this quantity. For information about the order backlog, see Section 1.7.15(A) below. The above quantity includes quantities that were actually reduced according to the reduction option, as described in Section 1.7.13(D)(1)c.3 below.

87 The Partnership estimates that as at December 31, 2020, the financial balance of the agreement with IEC is USD 3,400 million (100%), based on the terms of the supply agreement with IEC (including the settlement agreement dated January 30, 2021, as described in Section 1.7.13(D)(1)f.5 below) and the Partnership's estimates regarding the minimum quantities and the gas price that will be purchased by IEC.

88 The Partnership estimates that as at December 31, 2020, the financial balance of the agreement with Dalia Energies is USD 700 million (100%), based on the terms of the supply agreement and the Partnership's estimates regarding the minimum quantities and the gas price that will be purchased by IEC.

89 Linkage to the electricity production tariff in supply agreements to power producers is according to the terms of the alternative set in the Gas Framework, including a minimum price. For further information, see section 1.7.26(2) below.

	Year of start of supply	Basic agreement period[84]	Is there an option for an extension?[85]	Total maximum contractual supply quantity (100%) (BCM)[86]	The quantity supplied up to December 31, 2020 (100%) (BCM)	Main linkage basis for the price of gas
Other independent power producers	2013-2020	15-18 years, except one agreement for a period of eight years and two agreements for short periods.	Most of the agreements grant both parties an extension option for a further period of between one and three years, if the total contractual gas quantity was not consumed in the basic period.	20.2	19.2	Most agreements include a linkage formula based on the electricity production tariff, which includes a minimum price.
Industrial customers and natural gas marketing companies	2013-2020	2-7 years	Some of the agreements grant both parties an extension option for a further period, if the total contractual gas quantity was not consumed in the basic period.	1.6	6.9	Most agreement set a fixed, unlinked price.
APC and JBC export agreements (as described in section 1.7.13(E)(1)a below)	2017-2018	13-15 years	Both parties are granted an extension option for a further two-year period, if the contractual gas quantity was not consumed in the basic period.	2.3	0.65	The linkage formula is based on Brent prices and includes a maximum price.
Export agreement - Dolphinus (described in Section 1.7.13(E)(1)b below).	2020	15 years	If the buyer does not purchase the total contractual quantity in the basic period, the supply period will be extended by another two years.	25	0.25	The linkage formula is based on Brent prices and includes a maximum price.
Total				120.6	65.9	

B. The following table includes data about the Tamar project revenue (the Partnership's share) in 2018, 2019 and 2020, by price linkage established in them (USD millions)[90]:

	2018		2019		2020	
Customer	**Total revenue (USD millions)**	**% of the total revenue**	**Total revenue (USD millions)**	**% of the total revenue**	**Total revenue (USD millions)**	**% of the total revenue**
IEC (US CPI)	256.8	50	209.3	46	113.7	34
Independent power producers						
Dalia Energies	52.4	10	44.9	10	40.3	12
Others	157.8	30	143.9	32	121.2	37
Industrial customers and marketing companies						
	49.5	10	55.2	12	56.8	17

[90] The revenues in the table reflect the Partnership's holdings in the Tamar Project at a rate of 25.7% until December 31, 2018 and at a rate of 22% as from January 1, 2019.

C. Additional information about all agreements for sale of natural gas to the local market signed by the Tamar Partners

1. In most of the natural gas supply agreements, if the gas supply under the agreement is on a binding basis, the buyers have a take or pay agreement for a minimum annual volume of natural gas according to a mechanism set out in the supply agreement "the Minimum Quantity"). If those buyers do not purchase the minimum quantity in any given year, they will be required to pay to sellers for the difference between the minimum defined and the quantity actually purchased by them. It should be noted that in agreements that include an obligation for the Minimum Quantity, provisions and mechanisms were established that allow the buyers, after paying for gas not consumed due to application of the minimum chargeable quantity mechanism, to receive gas for no additional payment, to make up to the quantity of gas that was not consumed in the prior years, for which they paid the sellers under their Minimum Quantity undertaking, as aforesaid.

2. Most of the supply agreements also set out a mechanism for the accumulation of excess quantity consumed by the buyers in the course of any year, and its use to reduce the buyers' undertaking to purchase the Minimum Quantity, as set out above, in several subsequent years ("Carry Forward").

3. Following the decision of the Competition Commissioner set out in section 1.7.25(A) below regarding an exemption from a restrictive arrangement for agreements in which the basic supply period is more than seven years, apart from the agreement with IEC ("the Long-Term Agreements"), in some of the agreements signed with the customers, each of the buyers have an option to reduce the Minimum Quantity to 50% of the average annual quantity consumed in the three years prior to the notice of exercising the option, subject to adjustments as set out in the supply agreement (below in this section: ("the Reduction Option"). Upon reduction of the Minimum Quantity, the other quantities in the supply agreement will be reduced accordingly. For information about the Competition Commissioner's above decisions, see section 1.7.26(2)c below.

   In this context, it should be noted that in 2019-2020, the Tamar partners signed amendments to agreements with a number of independent power producers, including Dalia Power Energies, under which the producers undertook to purchase the full quantities of natural gas consumed in their facilities from the Tamar project, exclusively, commencing from the start of gas flow from the Leviathan reservoir until the date the producers exercise the Reduction Option (in this section below: "the Period"), if exercised. In addition, under the amendment, the parties agreed that to calculate the average quantity consumed by the producers under the agreements in the three years preceding the announcement of the exercise of the Option for the period, the calculation will be based on the Minimum Quantity (according to the mechanism set out in the amendments to the agreements) and not on the basis of the quantity actually consumed. All of the amendments to the agreements have come into effect, including the amendment to the agreement with Dalia Energies.

4. It is noted that in 2020, several customers notified that they are exercising the Reduction Option, including various independent power producers. These notices are expected to become effective on various dated in 2021 and 2022.

5. Pursuant to the Gas Framework, in natural gas supply agreements signed as from August 16, 2015 for a period exceeding eight years, the consumer has a unilateral right to shorten the term of the agreement. This right was also be granted in agreements signed up to December 13, 2020 for a period of more than eight years. For information, see section 1.7.25(A)(3)c below. It is noted that in 2020, several customers notified that they are exercising the early termination option, and such agreements ended on March 1, 2021.

6. Supply of the full quantities set out in the supply agreements signed prior to October 2012 uses the entire capacity of the production, treatment and transmission system (jointly below in this section: "the Production System") of the Tamar Project at peak consumption hours, therefore agreements for the sale of natural gas signed after October 2012 include an interim period that began in May 2015 and will end when the capacity of the Production System allows them to supply the quantities set out in the supply agreements (below in this section: ("the Interim Period"). In accordance with these agreements gas supply in the Interim Period was subject, among other things, to the gas quantities available at that time, after supplying gas to customers that signed the supply agreements prior to October 2012, based on the mechanisms established for each supply agreement. In all the agreements in the Interim Period, the undertaking to purchase the Minimum Quantity of gas will not apply. In November 2016, the Tamar partners notified most customers that have signed agreements for the sale of natural gas starting in October 2012 (according to the order of priority of signing the agreements), including independent power producers, among them Durad Energy Ltd., OPC Rotem Ltd. ("OPC"), natural gas marketing companies and industrial customers, that on September 30, 2020, the Interim Period will come to an end and accordingly, from this date, the Tamar partners will

supply natural gas to these customers under the agreements on a firm basis. Subsequently, on January 22, 2020, the Tamar Partners notified these customers that the end of the Interim Period (meaning September 30, 2020) was brought forward to March 1, 2020 and accordingly, as from this date, the Tamar Partners started supplying natural gas to these customers on a firm basis. It is also noted that in 2020, similar notices were sent to additional customers with respect to whom the Interim Period ended on various dates, between August 2020 and January 2021.

7. The supply agreements include further provisions, including the following: The right to end the agreement in the event of material breach of liability, the right of the Tamar Partners to supply gas to the buyers from other natural gas sources, compensation mechanisms in the event of delay in gas supply from the Tamar Project or failure to supply the quantities set out in the agreement, limitations for the parties' liabilities in the agreement, provisions regarding the right of the parties to assign their rights under the agreements, exemption from the liabilities of the parties in the event of a force majeure event (as defined in the agreements), mechanisms for settling disputes between the parties and regarding the relations between the Sellers and themselves in everything connected to gas supply for the buyers.

8. In 2020, due to the outbreak of the Covid-19 crisis, several customers sent notices of the occurrence of a force majeure event, but later when it became clear that the crisis will not have a material impact of their ability to meet the minimum purchase obligation, no further claims were raised in this regard.

9. The agreements are subject to the laws of the State of Israel and interpreted accordingly.

D. <u>Additional information about the gas supply agreement between the Tamar partners and IEC</u>

1. A gas supply agreement was signed between the Tamar Partners and IEC on March 14, 2012 and amended on July 22, 2012, May 7, 2015 and September 1, 2016, among other things, for the exercise of options to increase the gas quantities to be consumed by the IEC (“the IEC-Tamar Agreement” or in this section: “the Agreement”).

2. The period of the IEC-Tamar Agreement will continue until the total contractual quantity in the Agreement has been supplied or until July 1, 2028, whichever is earlier, unless the Agreement is terminated earlier by one of the parties or extended, according to the terms of the Agreement.

3. The total contractual quantity set in the IEC-Tamar Agreement (as amended) is 87 BCM, and the minimum quantity for billing, from January 1, 2019 until the end of the Agreement period will be 3 BCM per year. The agreement includes instructions for the calculation and adjustments of the minimum quantity for billing, including due to force majeure or failure to supply by the Sellers. A mechanism was also set out for the accumulation of excess quantity consumed by the buyers in the course of any year, and its use to reduce the buyers’ undertaking to purchase the Minimum Quantity, as set out above, in several subsequent years (“Carry Forward”). Accordingly, IEC may reduce the quantity purchased, using this mechanism, to a level of 1.75 BCM annually (so that the maximum quantity that can be used in a calendar year is 1.25 BCM).

   The quantity accrued for IEC under the Carry Forward mechanism as at December 31, 2020 is 1.85 BCM (for 100% from the reservoir).

4. The gas price under the formula includes a base price and a US CPI-based linkage mechanism for part of the quantities, subject to certain adjustments.

5. The agreement stipulates two dates on which each party may request an adjustment of the price (based on the mechanism set out in the agreement), if that party believes that the contractual price is no longer appropriate for a long-term contract with a significant buyer for consumption of natural gas in the Israeli market: After 8 years and 11 years from the date of commercial operation (as defined in the Agreement, as from July 1, 2013) from the Tamar Project (meaning July 1, 2021 and July 1, 2024), whichever is earlier. At the first adjustment date (July 1, 2021) (“the First Adjustment Date”), the adjustment to the price will be up to 25% (increase or reduction), and at the second adjustment date (July 1, 2024), the adjustment will be up to 10% (increase or reduction) of the price at that date[91]. If the Tamar Partners and IEC fail to reach an agreement on the price adjustment rate, each party is entitled to refer the matter to arbitration proceedings. For the discounted cash flow included in Tamar’s resources report, the Partnership assumed that the gas price would decrease by 25% on first adjustment date and 10% on the second adjustment date.

6. If one of the parties to the agreement defaults on a payment which it is required to pay under the agreement, the amount in arrears will accrue interest at an annual rate equivalent to LIBOR plus 5%

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[91] In this regard, see the Company’s assumptions in the discounted cash flow figures in the Tamar Lease in section 1.7.5(K)(1)b above.

from the due date under the agreement until actual payment. If the payment default continues for seven days or more, the party entitled to the payment may suspend deliver or receipt of the gas, as applicable, by 14 day's written notice. If the payment default continues for 120 days from the relevant due date, the party entitled to the payment may suspend deliver or receipt of the gas, as applicable, by 14 day's written notice. Exercising the right to terminate the agreement will not constitute a waiver of other remedies available to that party.

7. The IEC-Tamar Agreement includes provisions according to which IEC or the Tamar partners may terminate the agreement should the other party take any bankruptcy action (as defined in the agreement) which is likely to have a material adverse effect on the discharge of their obligations pursuant to the agreement, by giving at last 120 days' written notice. If due to a force majeure event the Tamar Partners or IEC are unable to implement any material undertaking required under the agreement and their inability to do so continues for a period of three consecutive years, the other party may terminate the agreement by prior written notice of at least 90 days. IEC and the Tamar partners agreed not to exercise any right they may have to lawfully terminate the agreement other than in connection with significant or continued breach of material provisions of the agreement, and only after granting a 120-day period to the party in breach to remedy such breach (unless a shorter period is stipulated in the agreement).

8. Under the agreement, should the Tamar partners fail to supply the gas volume ordered by IEC pursuant to the agreement, and should the non-supply exceed the deviation allowed by the agreement, the Tamar partners will compensate IEC in the subsequent month by supplying gas in the quantity not supplied at a reduced price. Furthermore, the agreement lists specific breaches for which damages are payable at higher rates. The agreement also sets limits for the liability of each party for breach of some of the agreement provisions at amounts specified in the agreement, both on an annual basis and throughout the agreement period. IEC is not liable to the Tamar Partners and the Tamar Partners are not liable to IEC any indirect, consequential or punitive damage or losses. The Tamar partners will be liable severally and not jointly for such breaches of the agreement.

9. The agreement stipulates that none of the provisions in the agreement will be considered as creating mutual liability among the Tamar partners, and each Tamar partner is individually liable to IEC for its share in the oil rights and in connection with any liability arising from the agreement. Although IEC may order gas volumes by a single notice to the Tamar partners' coordinator, the volume considered ordered from each of the Tamar partners will be the portion of each of them out of the total volume ordered.

10. According to the agreement, gas is supplied on an hourly basis with a maximum volume per hour, according to procedures and mechanisms set forth in the agreement.

11. Gas is delivered at the connection point to the INGL pipeline near the receiving terminal or any other connection point agreed between the parties.

12. The natural gas supplied at the delivery point under the agreement is required to comply with specifications of certain requirements prescribed in the agreement. IEC has the right to refuse to receive non-compliant gas until such non-compliance is remedied. All disputes between the parties with regard to gas quality may be submitted to an expert for resolution at the request of any of the parties.

13. The assignment of the rights and obligations of IEC under the agreement is contingent upon the transferee having the technical and financial ability to meet its obligations under the agreement and also for transferring the proportionate part of the power stations of IEC (meaning, if a proportionate part of the rights and obligations are transferred to a transferee, it will also assume the proportionate part of the power stations of IEC).

14. IEC or the Tamar Partners, as the case maybe, will be released from liability under the agreement if non-compliance with their obligations under the agreement (including the oblation to make reasonable efforts) stems from a force majeure event, provided that implementation of such obligation was prevented, thwarted or delayed in light of the force majeure event. The term "force majeure" is defined in the agreement and includes mainly any event or circumstance beyond the control of IEC or the Tamar partners (who acted and act reasonably and carefully) that caused non-compliance or inability of IEC or Tamar partners to comply one or more of their obligations (including the obligation to make reasonable efforts).

15. The agreement with IEC is subject to the laws of the State of Israel and interpreted accordingly. Any dispute or claim in respect of the agreement will be solved by the decision of an expert on specific issues set out in the agreement (mainly of a professional technical nature), or in arbitration proceedings according to the procedures set in the agreement.

16. Disputes regarding issues in which the amount in dispute is lower than the agreed threshold set in the agreement will be heard before a single arbitrator, according to the arbitration rules of the Israeli Institute of Commercial Arbitration and the arbitration will take place in Tel Aviv. Disputes regarding amounts exceeding this threshold, but within the range set in the agreement will be heard before a panel of three arbitrators and the arbitration will be conducted according to the rules of the London Court of International Arbitration (LCIA) and take place in Tel Aviv. Disputes regarding amounts exceeding the range set in the agreement will be heard before a panel of three arbitrators and the arbitration will be conducted according to the rules of the London Court of International Arbitration (LCIA) and take place in London.

E. Competitive process of IEC for the supply of natural gas in the short term

On December 2, 2018, IEC sent a request for a proposal to the Tamar and Leviathan partners for the supply of natural gas in an estimated annual quantity of up to 2 BCM, to be supplied from October 1, 2019 or the date of commencement of gas production from the Leviathan reservoir, whichever is later, until June 30, 2021 or the date of commencement of gas production from the Karish reservoir, whichever is earlier (in this section and Section F below: "the Supply Period" and "the Competitive Process", as applicable). On March 7, 2019, the Tamar and Leviathan partners submitted their proposals in the Competitive Process and on April 4, 2019, IEC notified the Leviathan partners that their proposal had been selected as the awardee of the Competitive Process. As a result, on June 12, 2019, IEC and the Leviathan partners signed a gas supply agreement, which is described in Section (2)c below ("IEC-Leviathan Agreement").

Following the Leviathan partners' win in the Competitive Process, the Tamar partners who do not hold the Leviathan reservoir (meaning Isramco, Tamar Petroleum, Dor and Everest, jointly: "the Other Tamar Partners") filed an administrative petition with the Tel Aviv District Court against IEC and the Leviathan partners, which was dismissed on July 7, 2019 and subsequently, the Other Tamar Partners appealed to the Supreme Court, which was also dismissed on August 24, 2020.

F. Nullification of the right to veto marketing decisions, balancing agreement of the gas produced from the Tamar reservoir and the settlement agreement between the Tamar partners and IEC

1. Against the background of the foregoing competitive process of IEC, in 2019, a dispute erupted between the Other Tamar Partners, the Partnership and Noble, among other things, regarding the right of the Other Tamar Partners to sign an amendment to the IEC-Tamar Agreement with IEC without the consent of the Partnership and Noble.

Subsequently, on November 20, 2019, the Other Tamar Partners contacted the Competition Commissioner, to clarify that the Partnership and Noble are not entitled to exercise a right of veto (severally or jointly), thereby preventing joint marketing of their share of the gas from the Tamar lease to a new customer or amendment of a gas agreement from the Tamar lease with an existing customer to which the Partnership and Noble are a party, including the amendment to the IEC-Tamar agreement proposed by them, under the conditions agreed on by the Other Tamar Partners, without the involvement of the Partnership and Noble.

On April 13, 2020, the representatives of the Ministry of Energy, the Economic Department of Legislation Advice at the Ministry of Justice, the Ministry of Finance, and the Competition Authority issued a notice, among other things, giving the Tamar partners a short time to modify the arrangements between them so as to ensure that the Partnership, Noble, and Isramco will not have any veto right over decisions on the marketing of natural gas from the Tamar reservoir.

Furthermore, on September 6, 2020, notice was received from the Competition Authority that holding by the Partnership of the right and power to prevent the other Tamar reservoir holders from adopting decisions or carrying out marketing activities of gas from the Tamar reservoir contradicts the terms of the exemption decision, violates the provisions of Section 4 of the Economic Competition Law, 1988 and therefore, the Partnership must act within a month to nullify its veto right. Until the veto right nullification date, the Partnership may hold its rights as they have been until now and conclude new contracts, but in the negotiations for new contracts in that period, the Partnership will not exercise its veto right on its own. To the best of the Partnership's knowledge, a similar notice was also received by Isramco. In addition, the Deputy Attorney General (Economics-Fiscal)[92] issued an opinion regarding Noble's veto right in the Tamar reservoir that each of the holders of the Tamar reservoir has a veto right, including Noble, which may hold such veto right until the date of sale of

[92] https://www.gov.il/BlobFolder/reports/opinion-vetorightnobel/he/publications_%D7%97%D7%95%D7%95%D7%AA%20%D7%93%D7%A2%D7%AA%20-%20%D7%96%D7%9B%D7%95%D7%AA%20%D7%94%D7%95%D7%95%D7%98%D7%95%20%D7%91%D7%9E%D7%90%D7%92%D7%A8%20%D7%AA%D7%9E%D7%A8%200920.pdf

the holdings in the Tamar reservoir to a third party unaffiliated with the Partnership or Noble or until December 17, 2021, whichever is earlier. On October 14, 2020, the Partnership notified the Competition Authority as follows: (1) The Partnership will not oppose decisions or marketing activities of natural gas produced from Tamar, on its own. The Partnership may, by an independent decision, join in the consent or refusal of one of the partners in respect of a decision or action in the Tamar project, ad hoc, provided that such joining is not in a framework agreement, under agreed collaboration or for a consideration. It is clarified that the Partnership will not be able to join a demand of its partner in Tamar to receive a higher price than the other partners for marketing its share in Tamar; (2) the Partnership will not be able to demand or receive compensation (in advance or retrospectively) for its consent to a gas marketing decision or action, whether the demand is made by it or by others. Even if there is a decision under which a partner receives compensation, the Partnership will not be able to demand the same compensation and will not stipulate conditions to its consent to an action or decision in such compensation demand.

Furthermore, according to reports of the Other Tamar Partners, on October 1, 2020 they signed a collaboration agreement with respect to marketing and sale of gas from the Tamar project, which nullifies Isramco's right to veto gas marketing and sales decisions in the Tamar reservoir.

2. On October 4, 2020, the Other Tamar Partners notified the Partnership and Noble that they have signed an agreement ("the Agreement in Dispute") which, in their opinion, constitutes an addendum to the IEC-Tamar Agreement, that the price of quantities of natural gas to be supplied to IEC, if any, above the minimum quantity for billing under the IEC-Tamar Agreement, will be updated. The Other Tamar Partners informed the Partnership and Noble that they have the option to join the Agreement in Dispute within 60 days from the signing date, and if the Partnership and/or Noble elect not to join, the Other Tamar Partners will supply to IEC the quantities that they undertook to supply thereunder from their share of the Tamar reservoir reserves. The Partnership joined Noble's position and together they informed the Other Tamar Partners that they would not join the Agreement in Dispute, which in the Partnership's opinion, based on the opinion of its legal counsel, does not constitute an addendum or part of the IEC-Tamar Agreement, as alleged by the Other Tamar Partners, but a new agreement that constitutes a breach of the IEC-Leviathan Agreement signed following the competitive process of IEC.

3. For further information, see the Company's immediate reports dated October 5, 2020 and October 14, 2020 (Ref. Nos. 2020-01-108027 and 2020-01-111951, respectively). As a result, the Other Tamar Partners and IEC raised claims with the Competition Commissioner regarding Noble's refusal to supply natural gas from the Tamar reservoir to IEC in accordance with the Agreement in Dispute, and requested her intervention.

4. In parallel, the Tamar partners conducted negotiations and on January 1, 2021, an understanding was reached between them and a Memorandum of Understanding was signed for the purpose of allowing each Tamar reservoir partner to market gas separately, and not jointly with the other Tamar reservoir partners, and allowing each partner to market gas beyond their proportionate share of the output, subject to available production capacity on a daily basis and if another partner does not market its share of the gas that day. In such case, balancing arrangements will apply with the aim of balancing the rights of the partners in respect of gas sold, according to their proportionate share in the reservoir, when necessary. Principles were also established regarding the tag along right of a partner to gas sale agreements signed by another partner in the reservoir, to allow Tamar partners to market their share of the gas in the Tamar reservoir if the marketing is not carried out by all partners in the reservoir, without diminishing the possibility of joint marketing of gas from the reservoir, subject to regulatory decisions (in this section: ("Memorandum of Understanding to Market Separately")

The Memorandum of Understanding to Market Separately stipulates, among other things, that the Tamar partners will negotiate to reach a detailed and binding agreement based on the Memorandum of Understanding by February 17, 2021 (in this section: ("the Detailed Agreement" and "the Effective Date", as applicable).

The Tamar partners have filed the Memorandum of Understanding for the Competition Authority's approval.

Further to the foregoing and the Company's immediate report of February 24, 2021 (Ref. No. 2021-01-021855), on February 23, 2021, the Tamar partners signed a detailed agreement based on the Memorandum of Understanding to Market Separately, as set out above, aimed at establishing detailed rules and mechanisms regarding participation of each of the Tamar partners in the gas output under the joint operating agreement[93], as well as the balancing arrangements that will apply among the partners in the event that the gas is not marketed according to their proportionate share of the output (in this section: “the Balancing Agreement” or “the Agreement”).

Below are the main points of the agreement:

Each of the partners has the right to join as a full party, a gas supply contract from the Tamar reservoir (“Supply Contract”) signed by another partner, according to its proportionate share of the reservoir and the mechanisms and conditions set out in the agreement (“Tag Along Right”). In respect of a Supply Contract for export, the Tag Along Right is subject to arrangements agreed upon by the partners specifically in respect of each export Supply Contract.

The Balancing Agreement includes various arrangements and mechanisms that enable a partner to market, subject to available capacity on a daily basis, quantities of natural gas that exceed its proportionate share in the Tamar Lease (“Oversupply Partner), after each of the other partners has first been given the possibility of ordering its full proportionate share in the output and a certain partner did not market its full share in the daily output (“Undersupply Partner”). In such a case, balancing arrangements will apply between the partners with the aim of balancing the partners’ rights in relation to the gas sold, according to their proportionate share in the reservoir: in money (meaning: by a payment to be made by the Oversupply Partner to the Undersupply Partner) or in gas (meaning: the Undersupply Partner will receive additional gas quantities in future, above its proportionate share in the output in order to reach a balance), according to the Undersupply Partner’s choice, all in accordance with and subject to the provisions of the Agreement. The Agreement also sets our mandatory balancing arrangements in money in each of the following cases: (1) When excess gas quantities have accrued in favor of the Undersupply Partner in a volume that exceeds the maximum set in the Agreement; (2) on the date at which the operator determines that 60 BCM of proven gas reserves remains in the reservoir; (3) on the date at which production in the reservoir ends or the date at which the lease deed expires or ends, according to the provisions of the Agreement.

The operator will be responsible, inter alia, for implementing the provisions of the Agreement, managing the pursuant orders and supplying the gas at the delivery points according to its provisions. The operator’s responsibility for a breach of its undertakings under the Agreement will be subject to restrictions and exclusions set out in the Joint Operating Agreement.

In the event of a discrepancy between the Agreement and the Joint Operating Agreement, the provisions of the Agreement will prevail.

Each party to the Agreement will bear the payment of taxes, statutory royalties, levies and statutory payments for the gas taken, and accounting arrangement were established between the Undersupply Partner and the Oversupply Partner in this regard in the event of balance in money. It was further held that the parties will file joint applications with the tax authorities and the Ministry of Energy to regulate the reporting method and payment of statutory royalties, levy and taxes in respect of the Agreement, and that until the decision of the authorities is received, the reports and payments will be made according to current practice.

Entry into force of the Balancing Agreement is subject to the Competition Authority’s approval[94]. If such approval is not received by May 31, 2021, the Balancing Agreement will be terminated by 30 days’ notice by any of the parties (unless the approval is received prior to termination of the Agreement). The Agreement will remain in effect until the termination of the Joint Operating Agreement.

If any of the partners seeks to transfer its rights in the Tamar Lease to others, the said rights will be transferred together with the partner’s rights and obligations under the Balancing Agreement.

The laws governing the Balancing Agreement are the laws of the UK and Wales. Any dispute between the parties that is not resolved according to the mechanism set out in the Agreement will be referred to arbitration in accordance with the arbitration rules of the International Chamber of Commerce, as stipulated in the Agreement. A party seeking to appeal the operator’s decisions regarding, among other things, the available output, allocation of orders and the above date or a decision of any party to the Agreement regarding the relevant prices for performance of money balancing, may refer the matter for a decision by an expert appointed according to the provisions of

[93] The Joint Operating Agreement dated November 16, 1999 (as amended from time to time). For further information, see section 1.7.29(L) below

[94] If required.

the Agreement, whose decision will be final and binding, except in the event of blatant fraud or error. If the expert fails to rule in the dispute, it will be referred to arbitration as set out above.

Implementation of the provisions of the Balancing Agreement requires establishment of various systems, adoption of procedures and obtaining approvals and clarifications from the tax authorities and various regulators. Therefore, the Agreement sets an interim period, from signing thereof until July 1, 2021. Only thereafter will it be possible to implement balancing arrangements (in money or gas).

5. In parallel, on January 30, 2021, the Tamar partners and IEC signed a settlement agreement concerning the disputes in respect of the Agreement in Dispute (in this section: "the Tamar Settlement Agreement"). The Tamar Settlement Agreement stipulates, inter alia, that: (1) The Agreement in Dispute will be canceled and be null and void; (2) until June 30, 2021, IEC may purchase a quantity of 1.25 BCM from the Tamar reservoir at a lower price than that in the IEC-Tamar Agreement, which varies according to the quantity purchased, of which 0.81 BCM was supplied in 2020, and under certain circumstances, additional quantities if such quantities are not supplied by the Leviathan partners under IEC-Leviathan Agreement; (3) the gas quantities supplied and to be supplied at a reduced price as aforesaid, will not be taken into account for the purpose of calculating the Take or Pay and Carry Forward in 2020 and 2021.

The Tamar Settlement Agreement also provides that the maximum daily contractual quantity that the Tamar partners will be required to supply to IEC under the Tamar-IEC Agreement in the first half of 2021 will be limited to 500,000 MMBtu (as opposed to 665,000 MMBtu).

Under the Settlement Agreement, the parties waived their claims in connection with the disputes.

The Tamar Settlement Agreement is subject to fulfillment of preconditions and regulatory approvals, including the approval of the Competition Commissioner and of the Competition Tribunal to the consensual decree pursuant to Section 50B of the Economic Competition Law, 1988, according to which the Competition Commissioner will not continue to deal with or take enforcement measures against Noble in respect of complaints filed against it in connection with the addendum. If the preconditions are not fulfilled within 30 days from signing of the Settlement Agreement, and 60 day in respect of the approval of Competition Tribunal, each party has the right to cancel the Agreement. For further information regarding the above consensual decree, see Section 1.7.26(2)d below. As at the report publication date, not all the preconditions set out in the Agreement have been fulfilled.

6. In parallel to signing of the Tamar Settlement Agreement, the Leviathan partners also signed a settlement agreement with IEC, as described in Section 1.7.13(D)(2)c below.

Forward-looking information: These estimates of the total financial value of the above supply agreements, the quantities of natural gas to be purchased by the above buyers, commencement of supply under the supply agreements, and the cumulative revenues from the natural gas sales to IEC under the above settlement agreements is forward-looking information, as defined in section 32A of the Israel Securities Law, and there is no certainty that it will materialize, in whole or in part, and it might materialize in a substantially different manner, due to various factors, including non-fulfillment of the preconditions in each of the supply agreements (to the extent they have not yet been fulfilled), failure to obtain regulatory approvals, changes in the volume, rate and timing of natural gas consumption by each of the buyers, the gas price based on the formulas in the supply agreements, the electricity production tariff, the USD-NIS exchange rate (if relevant to the supply agreement), Brent prices (if relevant to the supply agreement), the US-CPI (if relevant to the supply agreement), implementation and completion of the expansion project (if relevant to the supply agreement), construction and operation of the power station and/or other facilities of the buyers (if relevant to the supply agreement), exercise of the options granted to each party in the supply agreements, and the exercise date thereof, changes in the volume and timing of natural gas consumption by IEC as a result of the capacity and production limit of the Leviathan and Tamar reservoirs and/or changes in demand in the natural gas market, and/or due to non-fulfillment of preconditions or other factors that cannot be predicted at this time, and/or other factors beyond the Partnership's control, etc.

(2) Agreements for the sale of natural gas from the Leviathan project

A. Below is a summary of the natural gas supply agreements from the Leviathan project signed by the Partnership together the Leviathan partners, that are valid as at the approval date of the report. For information about the condensate supply agreements of the Partnership together with its partners, see Section (F) below.

	Year of start of supply	The Agreement[95]	Total maximum supply quantity (100%) (BCM)[96]	The quantity supplied up to December 31, 2020 (100%) (BCM)[97]	Main linkage basis for the price of gas
IEC[98]	2020	Until June 30, 2021	3.6[99]	2.4	Unlinked fixed gas price
Independent power producers	2020, or when commercial operation of the Buyers' power station starts (whichever is later).	Some of the agreements are a short period of up to 2.5 years and others are for a long term of 14 to 20 years. Half of the agreements do not grant parties an extension option. In most of the other agreements, each party is granted an option to extend the agreement if the total quantity is not purchased.	38.3	0.7	The natural gas linkage formula in most of the agreements, is based the electricity production tariff, and includes a minimum price. Several short-term agreements include an unlinked fixed price.
Industrial customers	2020	Some of the agreements are for a period of 5 to 15 years and the others are for a short period of up to two years. In most agreements, the parties are not given an option to extend the term of the agreement.	3.8	0.4	The linkage formula in most of the agreements s partially based on linkage to Brent prices and in part to the electricity production tariff, and includes a minimum price. There is also a partial linkage to the refining margin index and the general TOU index published by the Israel

95 This quantity is the maximum quantity that the Leviathan partners undertook to supply to customers during the term of the agreements. The quantity which the customers undertook to purchase is lower than this quantity (for information regarding the order backlog, see Section 1.7.15(A) It is noted that in some agreements, there is a mechanism whereby the Buyer may reduce/increase the quantities purchased (including the total contractual quantity) until the date set out in the agreement, based on its requirements and the provisions in the agreement. It should be noted that some agreements do not specify a maximum supply quantity.

96 The original supply agreement signed with IEC does not specify a maximum total contractual supply quantity. The figure above is equivalent to the volume of gas supplied under the contract until December 31, 2020 (2.4 BCM) plus an additional quantity of 1.2 BCM which IEC undertook to order from the Leviathan partners in the first half of 2021 (subject to certain adjustments) under the Leviathan settlement agreement described in Section 1.7.13(D)(2)c.

97 Due to the fact that it is the first year of operation of the Leviathan Project, the quantities in 2020 include accounting for the date of commencement of commercial supply.

98 For information about the agreement with IEC, see section 1.7.13(D)(2)c below.

99 The original supply agreement signed with IEC does not specify a maximum total contractual supply quantity. The figure above is equivalent to the volume of gas supplied under the contract until December 31, 2020 (2.4 BCM) plus an additional quantity of 1.2 BCM which IEC undertook to order from the Leviathan partners in the first half of 2021 (subject to certain adjustments) under the Leviathan settlement agreement described in Section 1.7.13(D)(2)c.

	Year of start of supply	The Agreement[95]	Total maximum supply quantity (100%) (BCM)[96]	The quantity supplied up to December 31, 2020 (100%) (BCM)[97]	Main linkage basis for the price of gas
					Electricity Authority.
Export agreement - NEPCO (as described in section 1.7.13(E)(2)a below)	2020	15 years The agreement stipulates that if the buyer does not purchase the total contractual quantity in the basic period, the supply period will be extended by another two years.	45	1.9	The linkage formula is based on linkage to Brent prices and includes a floor price.
Export agreement - Dolphinus (as described in Section 1.7.13(E)(2)b below).	2020	15 years The agreement prescribes that if the buyer does not purchase the total contractual quantity, the supply period will be extended by another two years.	60	1.9	The linkage formula is based on linkage to Brent prices and includes a floor price. The agreement includes a mechanism for updating the price at a rate of up to 10% (addition or reduction) after the fifth and tenth year of the agreement upon the fulfillment of certain conditions set out in the agreement.
Total			**151**	**7.25**	

2. <u>The following table includes a breakdown of Partnership's revenues from the Leviathan reservoir in 2020,based on the price linkage therein:</u>

Customer	Total revenue (USD millions)	% of the total revenue
IEC	183.3	31
Independent power producers		
Others	48.5	8
Industrial customers and marketing companies		
Others	32	5
Export of natural gas		
NEPCO	178.8	30
Dolphinus	144.5	25

B. <u>Additional information about the natural gas sales agreements to independent power producers and industrial customer on the local market signed by the Leviathan partners</u>

1. In most of the natural gas sales agreements of independent power producers and industrial customers (in this section: ("the Agreements"), the customers have a take or pay agreement for a minimum annual quantity of natural gas according to a mechanism in the supply agreement "the Minimum Quantity"). It should be noted that the agreements specify provisions and mechanisms allowing each of the buyers to receive gas at no additional charge up to the volume paid for, on account of gas not consumed under the agreement. The supply agreements also specify a mechanism for the accumulation of excess volume consumed by the buyer in the course of any year, and its use to reduce the buyer's undertaking to purchase the Minimum Quantity, as set out above, in several subsequent years ("Carry-Forward").

2. In accordance with the Gas Framework, each of the buyers in agreements signed until June 13, 2017 and for a term exceeding eight years has an option to reduce the Minimum Quantity to an amount equal to 50% of the average annual quantity actually consumed in the three years prior to the notice of exercising the option, subject to adjustments as set out in the supply agreement (in this section: "the Option"). Upon reduction of the Minimum Quantity, the other quantities in the supply agreement will be reduced accordingly. Each of the buyers may exercise the Option by notice to the Sellers, over a period of three years, starting from five years after gas starts to flow from the Leviathan project to the buyer or four years after the Commissioner approves the transfer of rights in the Karish and Tanin leases under the Natural Gas Framework (meaning December 13, 2020) (whichever is later). If the buyer gives notice of exercise of the Option, the quantity will be reduced 12 months after delivery of the notice.

3. Most of the supply agreements set out preconditions, including obtaining the required approvals from the buyers regarding the agreement. As at the approval date of the report, the preconditions in most of the agreements have been fulfilled.

4. The supply agreements include further provisions, including the following: The right to terminate the agreement in the event of material breach of liability, the right of the Leviathan partners to supply gas to the buyers from other natural gas sources, compensation mechanisms in the event of delay or failure to supply the quantities specified in the agreement, limitations for the parties' liabilities in the agreement, and regarding the relations between the sellers and themselves in everything connected to gas supply for the buyers.

C. <u>Additional information about the gas supply agreement between the Leviathan partners and the IEC:</u>

1. Following the competitive process of IEC, as described above, on June 12, 2019, the IEC-Leviathan Agreement was signed, regulating the natural gas supply from the Leviathan reservoir to IEC based on available capacity (in this section: "the Agreement").

   On October 29, 2019, all the preconditions for the entry of the supply Agreement into force were fulfilled.

2. Gas supply to IEC under the Agreement commenced on December 12, 2019, and according to the provisions of the Agreement, it will end on June 30, 2021 or on the date gas production starts from the Karish reservoir, whichever is earlier, unless it is terminated earlier according to the terms of the Agreement.

3. The Supply Agreement sets a fixed gas price that is not linked.

On January 30, 2021, in parallel to signing of the Tamar Settlement Agreement, the Leviathan partners and IEC signed a settlement agreement (“the Leviathan Settlement Agreement”) amending the IEC-Leviathan Agreement, in which without derogating from the obligations of the parties under the IEC-Leviathan Agreement, the IEC undertook to order from the Leviathan partners, in the first half of 2021, 1.2 BCM of natural gas from which certain gas quantities will be deducted, as agreed, mainly gas quantities ordered by the IEC from Leviathan and not supplied, as well as gas quantities that will not be consumed by the IEC due to force majeure events and/or malfunctions in significant production units of the IEC (“the Base Quantity”). If the IEC does not order the Base Quantity in the specified period, it will be required to pay the Leviathan partners for the difference between the Base Quantity and the actual quantity ordered. The IEC may use the remaining Base Quantity that it paid for but did not consume, according to the mechanism set out in the Leviathan Settlement Agreement.

In addition, the Leviathan partners will grant the IEC a price discount for ordering gas quantities exceeding 0.5 BCM as from January 1, 2021

Similar to the Tamar Settlement Agreement, the Leviathan Settlement is also subject to the fulfillment of preconditions and regulatory approvals, including the approval of the Competition Authority and of the Competition Tribunal to the consensual decree. As at the report publication date, not all the preconditions set out in the Agreement have been fulfilled.

4. The cumulative supply volume from the sale of natural gas to IEC from the Leviathan reservoir (in relation to 100% of the rights in the Leviathan project) up to December 31, 2020 amounts to 2.4 BCM, for a consideration of USD 404.8 million.

Forward-looking information: These estimates concerning the total financial value of the above supply agreements, the quantity of natural gas purchased by the above buyers, and commencement of supply under the supply agreements is forward-looking information, as defined in section 32A of the Israel Securities Law, and there is no certainty that it will materialize, in whole or in part, and it might materialize in a substantially different manner, due to various factors, including non-fulfillment of the preconditions in each of the supply agreements (to the extent they have not yet been fulfilled), failure to obtain regulatory permits, changes in the volume, rate and timing of natural gas consumption by each of the buyers, the gas price based on the formulas in the supply agreements, the Cost of Electricity Generation, the USD-NIS exchange rate (if relevant to the supply agreement), Brent prices (if relevant to the supply agreement), the US-CPI (if relevant to the supply agreement), exercise of the options granted to each party in the supply agreements, and the exercise date thereof, etc.

(E) Natural gas export agreements

(1) <u>Tamar project</u>

A. On February 19, 2014, a natural gas supply agreement was signed between the Tamar Partners and NBL Eastern Mediterranean Marketing Limited ("NBL") for the purpose of exporting natural gas for consumers in Jordan ("the First NBL-Tamar agreement"), which was revised on February 16, 2016 and September 30, 2017. NBL is a wholly owned subsidiary (linked) of Noble Energy, which is the controlling shareholder in Noble, the operator of the Tamar Project.

Simultaneously to signing the first NBL-Tamar Agreement, NBL also signed an agreement with two Jordanian companies, Arab Potash Company and Jordan Bromine Company (together in this section: "the Buyers"), whereby the Buyers will purchase natural gas from NBL for use of their plants on the eastern bank of the Dead Sea in Jordan (below in this section: “the First Supply Agreement”).

According to the first NBL-Tamar Agreement, the Tamar Partners undertook to supply NBL with natural gas to sell to the Buyers under the First Supply Agreement under back-to-back conditions (meaning: the Tamar Partners will be responsible for NBL's liabilities under the Supply Agreement and shall be entitled to all net revenues received by NBL thereunder).

In accordance with the First Supply Agreement (as amended), NBL undertook to supply the Buyers with a total quantity up to 2 BCM of natural gas. Under the First Supply Agreement, supply started in January 2017 and is expected to continue for 15 years.

On October 14, 2018, another gas supply agreement was signed between the Tamar Partners and NBL to export natural gas to consumers in Jordan and to supply it to buyers ("the Second NBL-Tamar Agreement"). Simultaneously to signing the Second NBL-Tamar Agreement, NBL signed another agreement with the buyers, whereby the buyers will purchase another quantity of natural gas for use by their plants on the eastern bank of the Dead Sea in Jordan (“the Second Supply Agreement”) on an interruptible supply basis of 0.1 BCM per year, when NBL has the right at the dates set in to the agreement to notify the buyers that the supply under the Second NBL-Tamar Agreement will be on a firm basis. The supply under the Second NBL-Tamar Agreement will commence in the first quarter of 2019 and is expected to continue until the date of completion of supply according to the First Supply Agreement.

On September 19, 2019, the Tamar Partners notified NBL that as from January 1, 2020 and up to December 31, 2020, supply under the First NBL-Tamar Agreement will be on a firm basis, instead of supply on an interruptible basis in peak demand months as was the case until that date.

On January 1, 2020, the Tamar partners notified NBL that as from August 12, 2020, the supply under the Second NBL-Tamar Agreement will be on a firm basis.

It should be noted that under the tax decision regarding the First Supply Agreement and Second Supply Agreement, given to the Tamar Partners by the Tax Authority, the Tamar Partners undertook to offer new potential consumers to sign agreements for the sale of natural gas at a price calculated according to the optimal formula based on the Brent price, as set out in the Gas Framework, when the offer undertaking will apply for three years from the government resolution (meaning, until August 16, 2018) and from the date of signature of the Second Supply Agreement (meaning until October 14, 2021). The offer will be made according to the provisions of the Gas Framework, including in respect of the supply date, which may be any date as from start of supply under the supply agreements (the first and second, as applicable) until six years from signing thereof, as set out above. For information, see sections 1.7.25(A)(4) and 1.7.25(A)(4)d below. For information about the NBL agreements, see section 1.7.1(A)(4) below.

B. On February 19, 2018, an agreement for the export of natural gas from the Tamar project to Egypt was signed between the Partnership, Noble and Dolphinus (jointly in this section below: "Original Tamar-Dolphinus Agreement" and "the Buyer", respectively), which superseded the previous agreement signed between these parties on March 17, 2015.

On September 26, 2019, the signing of the agreement for amendment of the Original Tamar-Dolphinus Agreement between the Tamar partners and Dolphinus was completed ("Amendment to the Tamar-Dolphinus Agreement"), and an agreement was signed between the Leviathan partners and Tamar Partners in connection with allocation of the available capacity in the transmission system from Israel to Egypt (for information, see section 1.7.29(J)(3) below).

It should be noted that in parallel to signing the Amendment to the Tamar-Dolphinus Agreement, an amendment to the agreement between the Leviathan partners and Dolphinus was signed ("Amendment to the Leviathan-Dolphinus Agreement"). For information, see section 1.7.13(E)(2)b below. Upon fulfillment of all preconditions for the Amendment of the Tamar-Dolphinus Agreement, on December 24, 2019 the Partnership reported that the Amendment to the Tamar-Dolphinus Agreement had taken effect.

In July 2020, after receiving a permit from the Natural Gas Authority for the flow of natural gas and completion of the running-in of the compressor installed at the EMG terminal in Ashkelon, gas started to flow from the Tamar reservoir to Egypt.

In July 2020, Dolphinus endorsed the agreements for export to Egypt to Blue Ocean Energy, related company of Dolphinus[100].

It should be noted that, in a tax decision regarding the amendment to the Tamar-Dolphinus Agreement issued to the Tamar partners by the Tax Authority on December 9, 2019, and according to the terms of the Gas Framework, the Tamar partners undertook to offer new customers (as defined in the Gas Framework) with which they engage or will engage from February 19, 2018 until three full years from the date the tax decision, i.e. December 9, 2022, agreements for the sale of natural gas at a price calculated according to the formula in the Amendment to the Tamar-Dolphinus Agreement, which is based on the Brent Price, while performing several adjustments as set out in the tax decision, including in view of the location of the delivery point in the Amendment to the Tamar-Dolphinus Agreement.

<u>Below is a summary of the details and terms of the Amendment to the Tamar-Dolphinus Agreement:</u>

1. The gas supply to the Buyer according to the Amendment to the Tamar-Dolphinus Agreement is on a firm basis (as opposed to supply under the Original Tamar-Dolphinus Agreement, which was on an interruptible basis with an option for the Tamar Partner to transition to a firm basis).

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[100] The reference to Dolphinus below in this chapter means Dolphinus or Blue Ocean Energy, based on the context.

2. The total contractual gas quantity that the Tamar Partners undertook to supply to the Buyer under the Amendment to the Tamar-Dolphinus Agreement is 25.3 BCM ("the Total (Firm) Contractual Quantity in the Tamar Agreement") (instead of 32 BCM under the Original Tamar-Dolphinus Agreement, which was, as aforesaid on an interruptible basis).

3. Supply under the Amendment to the Tamar-Dolphinus Agreement will start on June 30, 2020 and will continue until December 31, 2034 or until full supply of the Total Contractual Quantity, whichever is earlier ("the Termination Date of the Tamar-Dolphinus Agreement"). In the event that the Buyer does not purchase the total contractual quantity by December 31, 2034, each party may extend the supply period by up to an additional two years.

4. According to the Amendment to the Tamar-Dolphinus Agreement, the Tamar partners undertook to supply annual gas quantities to the Buyer as follows: (i) In the period beginning on June 30, 2020 and ending on June 30, 2022, 1 BCM per year; and (ii) in the period beginning on July 1, 2022 and ending on the termination date of the Amendment to the Tamar-Dolphinus Agreement, 2 BCM per year, by upgrading the systems at the EMG terminal in Ashkelon, including installation of an additional compressor, and the increase of transmission capacity in the INGL system, as set out in section 1.7.14(B)(2)b.2.a below.

5. The Buyer undertook to take or pay for quarterly and annual quantities, in accordance with the mechanisms set out in the Amendment to the Tamar-Dolphinus Agreement, which, among other things, allow the Buyer to reduce the TOP quantity in a year in which the average daily Brent price (as defined in the agreement) falls below USD 50 per barrel, such that it will be 50% of the annual contractual quantity. It should be noted that, insofar as the contractual quantity is reduced in event of a dispute regarding an adjustment to the gas price, as set out in section F below, the right of Dolphinus to reduce the take-or-pay quantity as aforesaid will be null and void. It should be noted that following the sharp drop in energy prices in the first half of 2020, the average daily Brent price (as defined in the agreement) fell below USD 50 per barrel[101].

6. The price of gas supplied to the Buyer will be calculated by a formula based on the price of a barrel of Brent oil. The Amendment to the Tamar-Dolphinus Agreement includes a mechanism for updating the price at a rate of up to 10% (addition or reduction) after the fifth and the tenth year of the Amendment to the Tamar-Dolphinus Agreement (in this section below: "the First Adjustment Date" and "the Second Adjustment Date", respectively), upon the fulfillment of certain conditions set out in the agreement. If the parties fail to reach an agreement on the price update as described above, the buyer will be entitled to reduce the contractual quantity by up to 50% on the First Adjustment Date and up to 30% on the Second Adjustment Date. It should be noted that the Agreement includes quantity-based incentives and it is subject to the price of a barrel of oil.

7. The Amendment to the Tamar-Dolphinus Agreement includes standard provisions for termination of the Agreement, as well as provisions in the event of termination of the Amendment to the Leviathan-Dolphinus Agreement due to its breach, and the refusal of the Tamar partners to supply the quantities set out in the Amendment to the Leviathan-Dolphinus Agreement, as set out in the agreement, including compensation mechanisms for such case. The Amendment to the Leviathan-Dolphinus Agreement also includes similar provision. For information, see section 1.7.13(E)(2)b below.

8. In 2020, the Tamar Partners supply 0.25 BCM to the Buyers, according to the terms of the Amendment to the Tamar-Dolphinus Agreement. As estimated by the Partnership on the of signing the Amendment to the Tamar-Dolphinus Agreement, the cumulative revenues for all Tamar partners from the sale of natural gas to the Buyers under the Tamar-Dolphinus Agreement may to amount to USD 5 billion. The Partnership's estimate was based on the assumption that the buyer will consume the total contract quantity including that set out in the Amendment to the Tamar-Dolphinus Agreement and on the Partnership's estimate regarding the natural gas price during the term of the Amendment to the Tamar-Dolphinus Agreement. It should be noted that the actual revenues from the Amendment to the Tamar-Dolphinus Agreement will derive from a range of factors, including the actual gas quantities purchased by the buyer and the Brent price at the time of the sale.

   Forward-looking information: The foregoing estimates regarding the total revenue expected under the Amendment to the Tamar-Dolphinus Agreement and the quantities of natural that may be sold to the buyer under the Amendment to the Tamar-Dolphinus Agreement is forward-looking information, as defined in section 32A of the Israel Securities Law, and there is no certainty that it will materialize, in whole or in part, and it might materialize in a substantially different manner, due to various factors, including changes in the volume, rate

[101] For information about a claim and motion to certify a class action filed against the Partnership in connection with the above condition, see Section 1.7.30(A) below.

and timing of natural gas consumption by the buyer, changes in the gas price under the Amendment to the Tamar-Dolphinus Agreement or other factors that cannot be predicted at this time and over which the Company has not control.

(2) Leviathan Project

A. On September 26, 2016, a detailed agreement for the supply of natural gas was signed between NBL Jordan Marketing Limited ("the Marketing Company") and the National Electric Power Company of Jordan (NEPCO) ("the Export Agreement"). The Marketing Company is a wholly owned subsidiary of the partners in the Leviathan project, including the Partnership, that hold it in proportion to their interests in the Leviathan project.

Under the Export Agreement, the Marketing Company undertook to supply natural gas to NEPCO for 15 years as from the date of commencement of commercial supply or when total supply reaches 45 BCM. Supply under the Export Agreement started on January 1, 2020.

According to the Export Agreement, the supply point is at the connection between the Israeli transmission system at the Israel-Jordan border and the Jordanian transmission system. In December 2019, INGL completed the construction of the Israeli transmission system to the Israel-Jordan border amounting at a cost of USD 120 million (100%).

NEPCO has a take or pay commitment for a minimum annual volume of gas according to a mechanism set out in the Export Agreement.

The gas price set out in the agreement is linked to Brent oil prices and includes a minimum price plus marketing fees, transmission fees, and NEPCO's bearing of the transmission payments to INGL. On signing date, the Leviathan partners estimated that the cumulative revenues from natural gas sales to NEPCO may amount to USD 10 billion, assuming that NEPCO consumes the total contract quantity and based on the Partnership's estimate regarding the natural gas price during the term of the Agreement.

On November 9, 2016, the Leviathan Partners and the Marketing Company signed a back-to-back GSPA ("the Back-to-Back GSPA"), whereby the amounts to be received, the liabilities, the risks and the costs relating to the Export Agreement will be endorsed to the Leviathan Partners under the same terms (back-to-back), as if the Leviathan Partners were a party to the Export Agreement instead of the Marketing Company.

On April 14, 2020, the Marketing Company, the Leviathan Partners and HSBC Corporate Trustee Company (UK) Limited ("HSBC") signed an Offtake Intercredifor and Security Trust Deed intended to secure the Marketing Company's undertakings to the Leviathan Partners under the Back-to- Back GSPA, according to which HSBC will act as trustee for the collateral and undertakings by virtue of the Export Agreement. In March 2020, against the background of the Covid-19 Crisis, the partners in the Tamar and Leviathan oil assets received several notices from their customers, including NEPCO, claiming that the Covid-19 Crisis and its consequences constitute a force majeure event, which may affect the ability of those customers to fulfill their future undertakings under the agreements in full and on time. It should be noted that, as at the approval date of the financial statements, the customers are continuing to fulfill their undertakings in accordance with the Agreements. The Partnership believes that the circumstances alleged in the notices received from the customers do not constitute a force majeure event, as required under the provisions of the agreements for the sale of gas.

Forward-looking information: The above estimates concerning the total financial value of the agreement and the quantity of natural gas purchased by the above buyers is forward-looking information, as defined in section 32A of the Israel Securities Law, and there is no certainty that it will materialize in the manner set out above or in any other manner, in whole or in part, and it might materialize in a substantially different manner to that described above, due to various factors, including changes in the volume, rate and timing of consumption of natural gas by NEPCO, changes in the gas price resulting from changes in the Brent oil price, etc.

B. On February19, 2018, the Partnership and Noble signed an agreement with Dolphinus, which endorsed its rights to Blue Ocean Energy (in this section below: "the Buyer") in July 2020 for the export of natural gas from the Leviathan project to Egypt (in this section: "the Original Leviathan-Dolphinus Agreement")

On September 26, 2019, the signing of an agreement for amendment of the Original Leviathan-Dolphinus Agreement between the Leviathan Partners and Dolphinus was completed ("Amendment to the Leviathan-Dolphinus Agreement"), and an agreement was signed between the Leviathan

Partners and the Tamar Partners in connection with the allocation of the available capacity in the transmission system from Israel to Egypt (for details, see Section 1.7.29(J)(3) below).

On January 15, 2020, natural gas started to flow from the reservoir to Egypt under the Amendment to the Leviathan-Dolphinus Agreement. In July 2020, after receiving a permit from the Natural Gas Authority for the flow of natural gas and completion of the running-in of the compressor installed at the EMG terminal in Ashkelon, gas started to flow from the Tamar reservoir to Egypt. Installation of the compressor made it possible to increase the gas flow to Egypt.

It should be noted that in a tax decision in connection with the Amendment to the Leviathan-Dolphinus Agreement issued to the Leviathan partners by the Tax Authority on December 9, 2019, and according to the terms of the Gas Framework, the Leviathan partners undertook to offer new customers (as defined in the Gas Framework) with which they engage or will engage from February 19, 2018 until three full years from the date the tax decision, i.e. December 9, 2022, to enter into agreements for the sale of natural gas at a price calculated according to the formula in the Amendment to the Leviathan-Dolphinus Agreement, which is based on the Brent Price, while performing several adjustments as set out in the tax decision, including in view of the location of the delivery point in the Amendment to the Leviathan-Dolphinus Agreement.

<u>Below is a summary of the details and terms of the Amendment to the Leviathan-Dolphinus Agreement:</u>

1. The total contractual gas quantity that the Leviathan Partners undertook to supply to the Buyer under the Leviathan Agreement Amendment is on a firm basis and it significantly increased to 60 BCM (compared with 32 BCM under the Original Leviathan-Dolphinus Agreement) ("the Total Contractual Quantity in the Leviathan Agreement").

2. The supply under the Amendment to the Leviathan-Dolphinus Agreement commenced on January 15, 2020 and will continue until December 31, 2034 or until full supply of the Total Contractual Quantity, whichever is earlier ("the Termination Date of the Leviathan Agreement Amendment"). The agreement prescribes that in the event that the buyer does not purchase the total contractual quantity, each party may extend the supply period by another two years.

3. According to the Amendment to the Leviathan-Dolphinus Agreement, the Leviathan Partners undertook to supply annual gas quantities to the Buyer as follows: (i) In the period beginning on January 15, 2020 and ending on June 30, 2020, 2.1 BCM per year; (ii) in the period beginning on July 1, 2020 and ending on June 30, 2022, 3.6 BCM per year; (iii) in the period beginning on July 1, 2022 and ending on the termination date of the agreement, 4.7 BCM per year, by upgrading the systems at the EMG terminal in Ashkelon, including installation of an additional compressor, and the increase of transmission capacity in the INGL system, as set out in section 1.7.14(B)(2)b.2.a below.

4. The Buyer undertook to take-or-pay for quarterly and annual quantities, in accordance with the mechanisms set out in the Amendment to the Leviathan-Dolphinus Agreement, which, among other things, allow the Buyer to reduce the take or pay quantity in a year in which the average daily Brent price (as defined in the agreement) falls below USD 50 per barrel, such that it will be 50% of the annual contractual quantity. It should be noted that, insofar as the contractual quantity is reduced in event of a dispute regarding an adjustment to the gas price, as set out in section E below, the right of Dolphinus to reduce the take-or-pay quantity as aforesaid will be null and void. It should be noted that following the sharp drop in energy prices in the first half of 2020, the average daily Brent price (as defined in the agreement) fell below USD 50 per barrel[102].

5. The price of gas supplied to the Buyer will be calculated by a formula based on the price of a barrel of Brent oil. The Amendment to the Leviathan-Dolphinus Agreement includes a mechanism for an update of the price at a rate of up to 10% (addition or reduction) after the fifth year and after the tenth year of the Amendment to the Leviathan-Dolphinus Agreement (in this section below: "the First Adjustment Date" and "the Second Adjustment Date", respectively), upon the fulfillment of certain conditions set out in the agreement. If the parties fail to reach an agreement on the price update as described above, the Buyer will be entitled to reduce the contractual quantity by up to 50% on the First Adjustment Date and up to 30% on the Second Adjustment Date. It should be noted that the Agreement includes quantity-based incentives and it is subject to the price of a barrel of oil.

6. The Amendment to the Leviathan-Dolphinus Agreement includes standard provisions for termination of the Agreement, as well as provisions in the event of termination of the Amendment to the Tamar-Dolphinus Agreement between the Buyer and all partners in the Tamar reservoir due to its breach,

[102] For information about a claim and motion to certify a class action filed against the Partnership in connection with the above condition, see Section 1.7.30(A) below.

and the refusal of the Leviathan partners to supply the quantities set out in the Amendment to the Tamar-Dolphinus Agreement, including compensation mechanisms for such case. The Amendment to the Tamar-Dolphinus Agreement also includes similar provision. For information, see section 1.7.13(E)(1)b above.

7. In 2020, the Leviathan Partners supply 1.9 BCM to the Buyers, according to the terms of the Amendment to the Leviathan-Dolphinus Agreement. As estimated by the Partnership upon signing of the Amendment to the Leviathan-Dolphinus Agreement, the cumulative revenues for all Leviathan partners from the sale of natural gas to the Buyers under the Leviathan-Dolphinus Agreement may to amount to USD 12.5 billion. The Partnership's estimate was based on the assumption that the buyer will consume the total contract quantity including that set out in the Amendment to the Leviathan-Dolphinus Agreement and on the Partnership's estimate regarding the natural gas price during the term of the Amendment to the Leviathan-Dolphinus Agreement It should be noted that the actual revenue will be derived from a range of factors, including the actual gas quantity purchased by the Buyer and the Brent price at the time of the sale.

Forward-looking information: The above estimates regarding the total revenue expected under the Amendment to the Leviathan-Dolphinus Agreement and the quantities of natural that may be sold to the buyer under the Amendment to the Leviathan-Dolphinus Agreement is forward-looking information, as defined in section 32A of the Israel Securities Law, and there is no certainty that it will materialize, in whole or in part, and it might materialize in a substantially different manner, due to various factors, including changes in the volume, rate and timing of natural gas consumption by the buyer, changes in the gas price under the Amendment to the Tamar-Dolphinus Agreement or other factors that cannot be predicted at this time and over which the Company has not control.

(3) The Partnership, together with its other partners in the Aphrodite reservoir, is assessing options for joint supply of natural gas with the Leviathan project to the liquefaction facility in Egypt, that will be performed, if at all, from the Aphrodite reservoir, in a volume of 6 BCM annually for a period of 10-15 years, according to the development plan of the Aphrodite reservoir, as set out in section 1.7.6(L) above, and from the Leviathan reservoir, as part of additional development stages of the Leviathan reservoir (beyond Phase 1 - First Stage of the development plan of the Leviathan reservoir), as set out in section 1.7.4(E) above. It is noted that, to the best of the Company's knowledge, the maximum annual feed gas capacity of the liquefaction facility is 12 BCM per year.

The Partnership, together with its partners in the Leviathan and Aphrodite reservoirs, is negotiating for a joint construction agreement for the pipeline and an agreed budget between them that includes the commercial, operating and regulatory principles. According to the agreement being formulated, the parties will agree to divide the costs in connection with feasibility studies and development of the project as aforesaid, but not in connection with implementation and construction of the project, and if the partners seek to progress to this stage, they will sign another agreement, such a shareholders agreement or JOA. It should be noted that the costs for development of the pipeline, both in the preliminary and construction stages, are not part of the upstream development costs and are not included in the cost recovery under the PSC.

(4) The Partnership is promoting negotiations at various stages with the owners of the liquefaction facilities to export LNG to Egypt, both with respect to the ELNG liquefaction facility operated by Shell and located near the city of Idku and in relation to the SEGAS liquefaction facility operated by SEGAS (joint venture) and located near the city of Damietta. The arrangements under review include options for purchasing liquefaction capacity, arrangements regarding receipt of liquefaction services to allow the Partnership to market natural gas in LNG form while paying for liquefaction services, and other options related to purchasing rights in these plants.

(F) <u>Agreements for the supply of condensate</u>

(1) <u>Agreement for the supply of condensate from the Tamar reservoir to Paz Ashdod Refinery</u>

Condensate has been supplied to Paz Ashdod Refinery since 2013 in a special pipeline in a negligible volume, under an agreement (as amended) that is expected to end in December 2020. The price of condensate is based on Brent prices, less a margin, as set out in the supply agreement. As a rule, the condensate sales by the Tamar partners are made under this Agreement.

(2) <u>Agreement for the supply of condensate from the Leviathan reservoir to Bazan</u>

On December 15, 2019, an agreement was signed under which condensate produced from the Leviathan reservoir will flow via the existing EAPC pipeline to PEI's tank farm in Kiryat Haim and from there to Bazan's facilities, in compliance with regulatory directives. ("the Bazan Agreement").

The Bazan Agreement is on an interruptible basis for 15 years, commencing from the start of condensate flow (in commercial quantities), with each party having the right to terminate the Bazan Agreement with at least 360 days' notice to the other party. In addition, each party may cancel the Bazan Agreement with shorter notice under certain circumstances, including in the event of a breach by the other party, and in the event of regulatory and other changes that will not allow the flow of condensate in accordance with the Bazan Agreement.

The flow of condensate to Bazan under the Bazan Agreement will be on an interruptible basis up to a maximum quantity agreed on by the parties ("the Maximum Quantity"). The parties may revise the Maximum Quantity from time to time, subject to compliance with the terms established by the authorities in this respect, including conditions laid down by the authorities in this regard, including the Ministry of Energy and the Ministry of Environmental Protection.

Under the Bazan Agreement, the delivery of the condensate to the Bazan will be for no consideration, and the Leviathan partners will bear all expenses, including the tax exposure, incurred for the flow of condensate.

The Bazan agreement sets out a number of preconditions, mainly referring to obtaining regulatory approvals for the flow of condensate to Bazan, including approvals regarding the sale of condensate for no consideration. The Bazan Agreement took effect on January 29, 2020.

The loss of revenue incurred by the Leviathan project due to the terms of the agreement is not material to the Partnership.

For further information about the assessment of delivery and sale alternatives of condensate that will be supplied from the Leviathan reservoir, see subsection (4) below.

Forward-looking information: The foregoing information regarding the scope of the loss of revenue from the Bazan Agreement is forward-looking information, as defined in section 32A of the Israel Securities Law, and there is no certainty that it will materialize, in whole or in part, and it might materialize in a substantially different manner, due to various factors that cannot be predicted at this time and over which the Company has no control.

(3) <u>Agreement for the supply of condensate from the Leviathan reservoir to an international fuel trading company (in this section: "the Buyer"):</u>

On December 15, 2019, the Leviathan partners signed an agreement whereby condensate produced from the Leviathan reservoir will be transported in road tankers and delivered to the Buyer in the PEI tanker farm ("the Supply Agreement").

The Supply Agreement came into effect upon the start of natural gas flow from the Leviathan reservoir and will be renewed annually for one additional year, unless one of the parties chooses not to renew it, by notice of at least 60 days. Each party may terminate the Supply Agreement in the event of its breach by the other party as well as in the event of regulatory and other changes that will prevent the supply of the condensate according to the provisions of the Supply Agreement.

The condensate will be supplied by the Leviathan partners to the Buyer under the Supply Agreement on an interruptible basis up to a daily maximum quantity that was agreed on between the parties.

According to the Supply Agreement, the Leviathan partners will bear all costs related to the condensate until its delivery to the Buyer at the gate of the PEI tank farm and the Buyer will bear all costs for the condensate from that point on.

The price of condensate set out in the Supply Agreement will be linked to the Brent barrel price and the Buyer will be entitled to a discount on the condensate it receives, and which will exceed the specification set out in the Supply Agreement.

The total revenue from the sale of condensate to the Buyer under the terms of the Agreement are not expected to be material for the Partnership.

It is clarified that the condensate will be sold under the Supply Agreement only in the event that the transport of condensate under the foregoing Bazan Agreement is not possible.

Forward-looking information: The foregoing information regarding the Supply Agreement and its financial value is forward-looking information, as defined in section 32A of the Israel Securities Law, and there is no certainty that it will materialize, in whole or in part, and it might materialize in a substantially different manner, due to various factors, including changes in the scope of supply of condensate to the Buyer, the Brent oil price, etc.

It should be noted that in parallel to delivery of condensate according to the above agreements, the Leviathan partners are continuing to explore additional delivery and sales alternatives of condensate produced from the Leviathan reservoir, and, among other things, alternatives to the installation of a pipeline carrying condensate to storage tanks in Hadera and/or Ashkelon and from there by designated vessel to consumers in and/or outside Israel as well as the possibility of collaborating with Energean regarding storage of the condensate produced from the Leviathan reservoir on the FPSO and delivery to potential consumer from there, are being examined.

1.7.14. Marketing and Distribution

(A) Supply to the local market:

The Partnership, together with its partners in the Tamar Project and Leviathan Project, are taking measures to market natural gas and condensate to potential consumers (see section 1.7.13 above) and are in various stages of negotiations with potential customers on the local market, including independent power producers and industrial consumers, with the aim of signing binding agreements for the sale of natural gas and/or condensate from these projects, subject to the gas prices and the term of the agreements set in the Gas Framework, as set out in sections 1.7.25(A)(4) and 1.7.25(A)(3)c below and subject to the supply capacity of these projects.

The supply of natural gas to some customers may also depend on further development of the national natural gas transmission system by INGL and completion of the regional distribution systems. As at the approval date of the report, natural gas produced from the Leviathan reservoir is marketed to customers jointly, in accordance with supply agreements signed between the customers and all Leviathan partners. Until recently, marketing from the Tamar reservoir was by joint marketing. For information about the Balancing Agreement signed between the Tamar partners for separate marketing of natural gas produced from the Tamar reservoir, see Section 1.7.13(D)(1)f.4 above.

(B) Export

(1) General

The Partnership, together with the partners of the different projects, are taking steps to find markets outside Israel and Cyprus to market natural gas. The Company believes that the potential markets include the countries near Israel (including the Palestinian market, which currently purchases electricity from Israel and there are plans to construct their own power station), mainly Egypt and Jordan, to which gas is exported by pipeline from the Tamar and Leviathan reservoirs, and more distant global markets to which natural gas may be exported though LNG (liquefied natural gas) and/or CNG (compressed natural gas). As aforesaid, as part of the Partnership's export marketing efforts, several agreements have been signed with customers in Jordan and Egypt and it is negotiating with other customers for the supply of natural gas in these and other countries. The Partnership is also reviewing the economic feasibility of several natural gas export projects through LNG (including liquefaction of natural gas in the FLNG facility) and CNG, as set out below.

(2) Export via a pipeline

A. In addition to the export agreements set out in section 1.7.13(E) above, the Partnership is working to promote the options of using of a pipeline (existing and/or new) and is in various stages of negotiation with respect to exporting natural gas by pipeline to regional markets.

The key parameters in the possible agreements for the sale of natural gas through pipelines are discussed in these negotiations, including the term of the contract, quantities, capacity, unit price, linkage formula, commitment for minimum purchase (take or pay), undertaking to construct the pipelines, etc. In this context, it is noted that on July 19, 2020, Government Decision No. 225 was adopted ratifying the agreement of January 2020 between Israel, Cyprus, Greece and Italy in respect of construction of a pipeline to transport natural gas from the natural gas reservoirs in Israel and Cyprus to European markets, under which the parties undertook to collaborate in connection with construction of the project[103].

Forward-looking information: The above information regarding the negotiations as aforesaid is forward-looking information, as defined in section 32A of the Israel Securities Law, and there is no certainty that it will materialize, in whole or in part, in the above or any other

[103] For information about the agreement for East-Med gas pipeline that lead from Israel, via Cyprus and Greece to Europe, see the Ministry of Energy's announcement of January 1, 2020: https://www.gov.il/he/departments/news/ng_021220

And of March 19, 2021: https://www.gov.il/he/departments/news/east_med_080321

For information about the Memorandum of Understanding for installation of the Eur Asia subsea power cable, see the Ministry of Energy's announcement of March 9, 2021:

https://www.gov.il/he/departments/topics/exploration_and_production_of_oil_and_natural_gas

manner, and it might materialize in a substantially different manner to the above description, and in particular there is no certainty that these negotiations will mature into binding gas sale agreements and that the conditions required under any law for such agreements to take effect, if signed, will be fulfilled.

B. The following is a description of the potential key marketing destinations for the export of natural gas through pipelines from the Tamar and Leviathan projects[104]

1. Jordan - In the Company's understanding, based on independent consulting companies, local use was 4 BCM in 2020, the same consumption as in 2019. Natural gas is the main energy source the production of electricity in Jordan. The estimate is that in 2020, 77% of the electricity in Jordan was produced using natural gas, when 16% of the balance is based on renewable energy and 7% on oil distillates. In the Partnership's estimation, based on independent external consulting companies and adjustments made by the Partnership to such data, in 2021, the natural gas consumption in Jordan is expected to be 4 BCM, and the estimate is that in the coming decade, it is expected to range between 3.8-4.2 BCM. The stability in the forecast of natural gas consumption in Jordan, despite the expected increase in demand for energy in general and electricity in particular, stems from the accelerated penetration of renewable energies in the electricity production sector in Jordan, following active government activity in this area as well as electricity production from the Jordanian power station (Attart power plant) whose source of fuel for electricity production is shale oil. The target set by the Jordanian government is for renewable energy to constitute 20% of the volume of electricity produced in the country in 2020 and for the actual electricity production from renewable energy to be 16% of the total electricity production that year. The current forecast is that this rate is expected to increase to 30% in 2025 and 45% in 2030. Jordan presently imports natural gas from the Leviathan project, which constitutes most of the gas consumed in Jordan, and it also imports natural gas from the Tamar project to industrial plants in the Jordanian Dead Sea area. Jordan also imports small quantities of natural gas from Egypt through the Pan-Arab Pipeline, which to the best of the Partnership's knowledge, amounted to less than 0.5 BCM in 2020, and produces negligible quantities of natural gas. Prior to signing the NEPCO agreement (set out in Section 1.7.13(E)(2)a below), LNG was Jordan's main source of natural gas, which was imported through a floating regasification facility in Aqaba. However, in 2020 Jordan imported LNG in an estimated quantity of 1.1 BCM through the facility in Aqaba under past agreements. It should be noted that this facility is still active and Jordan can continue importing LNG by taking advantage of opportunities in LNG spot markets. Regarding the export of gas from the Tamar project to the Jordanian Dead Sea plants, since early 2017, the Tamar partners export natural gas to two industrial plants located on the eastern bank of the Dead Sea in Jordan, as set out in section 1.7.13(E)(1)a above, through a connection in the Israeli transmission system to a dedicated pipeline to plants located on the eastern bank of the Dead Sea in Jordan ("the Southern Pipeline"). With regard to the export of gas from the Leviathan project to Jordan, it is noted that in January 2020, the installation a pipeline parallel to the existing one from the Tel Kashish region to Dovrat was completed, in addition to the construction of a new natural gas pipeline connecting the INGL transmission system (from the Dovrat region) to the border with Jordan and the follow-on pipeline on the Jordanian side, which connects the Israeli transmission system to the existing transmission pipeline in Jordan (the Pan-Arab pipeline operated by FAJR) ("the Northern Pipeline"). For information about the budget for construction of the Northern Pipeline, as approved by the Leviathan partners, see section 1.7.4(D) above. Based on the data known the Partnership, the capacity of the Northern Pipeline will allow the supply of natural gas in an annual quantity of up to 10 BCM to Jordan and via Jordan to Egypt.

   For information about the agreements signed for the supply of natural gas to Jordan, see sections 1.7.13(E)(1)a and 1.7.13(E)(2)a above.

2. Egypt - To the best of the Company's knowledge, based on independent consulting companies, natural gas plays a key role in the Egyptian energy market, while natural gas consumption in Egypt is used mainly to produce electricity, but also for industry and households. Natural gas is the main energy source the production of electricity in Egypt. In 2020, 84% of the electricity in Egypt was produced using natural gas. In the Partnership's understanding, the local production in Egypt in 2020 was 60 BCM, a decrease of 10% of 21% compared to 2019, with the decrease in production mainly due to initiated output cuts. The demand for natural gas in Egypt in 2020 was 61 BCM (stable compared to 2019). The gradual increase in local production in the last four years has transformed Egypt from a natural gas importer into an exporter. It should be noted that due to the seasonality of natural gas use in Egypt, it may export certain quantities of natural gas in winter and import natural

[104] The information was prepared by the Partnership, based, among other things, on data from reports published by independent consulting companies.

gas in summer. In addition, Egypt has two natural gas liquefaction facilities to manufacture LNG for export, with a total liquefaction capacity of 12.2 million tons of LNG annually for which 17-18 BCM of feed gas is required annually in addition to the local demand. As at the approval date of the report, the natural gas production capacity in Egypt is sufficient to meet the needs of the local market, and for export through LNG, but is insufficient to operate both liquefaction facilities at full capacity. In this situation, one of the facilities is operating at partial output. The other facility, which had been shut down since the end of 2012, resumed liquefaction activities in the first quarter of 2021. As of the approval date of the report, both facilities operate at partial output. Based on independent consulting companies, the demand forecasts for the local Egyptian market for 2021, 2022 and 2023 are 63 BCM, 64 BCM and 66 BCM, respectively, whereas the local production forecast for 2021, 2022 and 2023 from the producing fields, and fields under development or with a high chance of starting production is 65 BCM, 65 BCM and 67 BCM, respectively, excluding the demand for natural gas as feed gas for the LNG export facilities. The oversupply expected in the coming years is expected to lead to increased export of natural gas from Egypt in this period, mainly as LNG, depending on global market conditions and the world energy prices. However, oversupply in these years is insufficient to fulfill the entire existing liquefaction capacity in both LNG export facilities in Egypt. In addition, the forecast is that as from the middle of the decade, a shortage of gas for local consumption is expected to arise on the Egyptian local market, based on the local production forecast from producing fields, fields under construction or with a high chance for production. The demand forecast for 2025 to 2030 relates to local market consumption of 70-75 BCM annually, excluding the natural gas required as feed gas for the above liquefaction facilities. It should be noted that these forecasts will be updated periodically if new information is received and/or the independent consulting companies revise their forecasts. To the best of the Partnership's knowledge, the Egyptian government is taking measures to promote natural gas supply projects from discoveries in Israel and Cyprus, with the aim of making Egypt a natural gas hub, to satisfy the local market requirements and to use in the existing export facilities, and to promote investments in new export facilities, simultaneously to encouraging natural gas development and exploration projects in Egypt. Natural gas exploration operations promoted by the Egyptian government may increase and accelerate the natural gas exploration activities in Egypt, and therefore, more natural gas discoveries in Egypt are possible. For information regarding natural gas supply agreements to Egypt, see sections 1.7.135(E)(1)b and 1.7.13(E)(2)b above.

For information about the EMG Transaction, which allows the supply of natural gas to Egypt, see section 1.7.29(J)(2) below.

<u>Transmission agreements with INGL</u>

In July 2020, upon operation of the compressor at the entry to the EMG pipeline in Ashkelon, the flow capacity in the EMG pipeline, through the existing INGL transmission infrastructure, increased to 450,000 MMBtu/d (4.5 BCM per year).

On May 28, 2019, an agreement was signed between Noble and INGL for the supply of interruptible transmission services ("the INGL Agreement") for the delivery of natural gas from the Leviathan and Tamar reservoirs to the EMG terminal in Ashkelon for export to Egypt (in this section: "the 2019 Agreement"). On January 18, 2021, Noble and INGL signed an agreement for the supply of transmission services on a firm basis to deliver natural gas from the Tamar and Leviathan reservoirs to the EMG receiving terminal in Ashkelon for its transmission to Egypt, which came into effect on February 15, 2021 after fulfillments of its preconditions ("the Transmission Agreement" or in this section: "the Agreement"), the main points of which are as follows:

a) Under the Transmission Agreement, INGL undertook to provide transmission services for the natural gas to be supplied from the Tamar and Leviathan reservoirs, including maintaining a base capacity in the transmission system in the annual volume of 5.5 BCM ("the Base Capacity"). For the transmission services with respect to the Base Capacity, Noble will pay a capacity fee and will pay for the throughput gas quantity, according to the transmission tariffs that are customary in Israel, as updated from time to time[105]. INGL also undertook to provide interruptible transmission services for additional gas quantities over and above the Base Capacity, subject to the capacity that will be available in the transmission system. For the transmission of these additional quantities, Noble will pay a transmission tariff for interruptible transmission services for the throughput quantities. To the best of the Partnership's knowledge, the transmission system was designed to enable transmission of the full contractual quantity set out in the export agreements.

[105] As at the date of this report, the capacity and transmission fees collected by INGL from its customers is NIS 0.90 per MMBtu. It should be noted that on February 23, 2021, the Natural Gas Authority published a decision regarding reduction of the capacity and transmission fees by a rate of 5% as from March 1, 2021.

b) Under the Transmission Agreement, Noble undertook to pay for delivering a gas quantity of no less than 44 BCM throughout the entire term of the agreement. If the parties agree to increase the Base Capacity, the minimum quantity for delivery will be increased accordingly.

c) The flow of gas under the Transmission Agreement will commence on the date INGL completed the construction of the Ashdod-Ashkelon transmission section, in accordance with the resolution of the Natural Gas Authority Council regarding the financing of export projects through the Israeli transmission system and allocation of the construction costs of the Ashdod-Ashkelon combined section ("the Council's Decision"), in a manner that allows the flow of the full quantities under the Transmission Agreement ("the Gas Flow Commencement Date"). Under the Transmission Agreement, the Commencement Date of Gas Flow expected in the period between July 2022 and April 2023. For information about the annual gas quantities which the Tamar and Leviathan partners undertook to supply to Dolphinus, see sections 1.7.13(E)(1)b and 1.7.13(E)(2)b above. In addition, for information about the Council's Decision, see section 1.7.14(B)(2)b.2.c below.

d) It was also determined that the transmission period under the 2019 Agreement will be extended until January 1, 2024 or until gas starts to flow under the Transmission Agreement, whichever is earlier.

e) The Transmission Agreement will expire at the earlier of: (1) the date on which the total throughput quantity will reach 44 BCM; (2) eight years after the Commencement Date of Gas Flow; or (3) upon the expiry of INGL's transmission license. The Partnership believes that at the end of the term of the Agreement, no difficulty is expected in its extension at the standard capacity and transmission tariffs of the holder of the transmission license at such time.

f) In accordance with the principles set out in the Authority's Decision, Noble undertook to pay for the partners' share (56.5%) of the overall cost of construction of the Ashdod-Ashkelon combined section, which is estimated at NIS 738 million. Noble further undertook to pay NIS 27 million for the partners' share of the costs of acceleration of the doubling of the Dor-Hagit and Sorek-Nesher sections, which is estimated at this time at NIS 48 million.

g) In accordance with the Authority's Decision, the Leviathan partners and Tamar partners will provide a bank guarantee to secure INGL's share of the construction cost of the infrastructure, and to cover Noble's undertaking to pay the capacity and transmission fee. It should be noted that in February 2021, the Partnership provided such guarantees in the amount of NIS 172.9 million, against which the Partnership pledged a deposit of USD 13.3 million.

h) The Leviathan and Tamar partners will bear the costs set out in section 5 above and will provide the guarantees described in section 6 above at the rates of 69% and 31%, respectively.

i) Under the Transmission Agreement, in the event of discontinuation of the export of natural gas from the Tamar and Leviathan projects to Egypt, Noble will be entitled to terminate the Transmission Agreement, subject to payment of damages to INGL for the early termination, in the amount equal to 120% of the construction costs of the Ashdod-Ashkelon combined section, together with the costs of acceleration of the doubling of the Dor-Hagit and Sorek-Nesher sections, less the amounts paid by Noble until the termination date for such costs of construction and acceleration and for the flow of gas under the Transmission Agreement. If, subsequent to the termination of the Transmission Agreement, export to Egypt resumes, the Transmission Agreement will be renewed, subject to and in accordance with the capacity which will be available in the transmission system at such time.

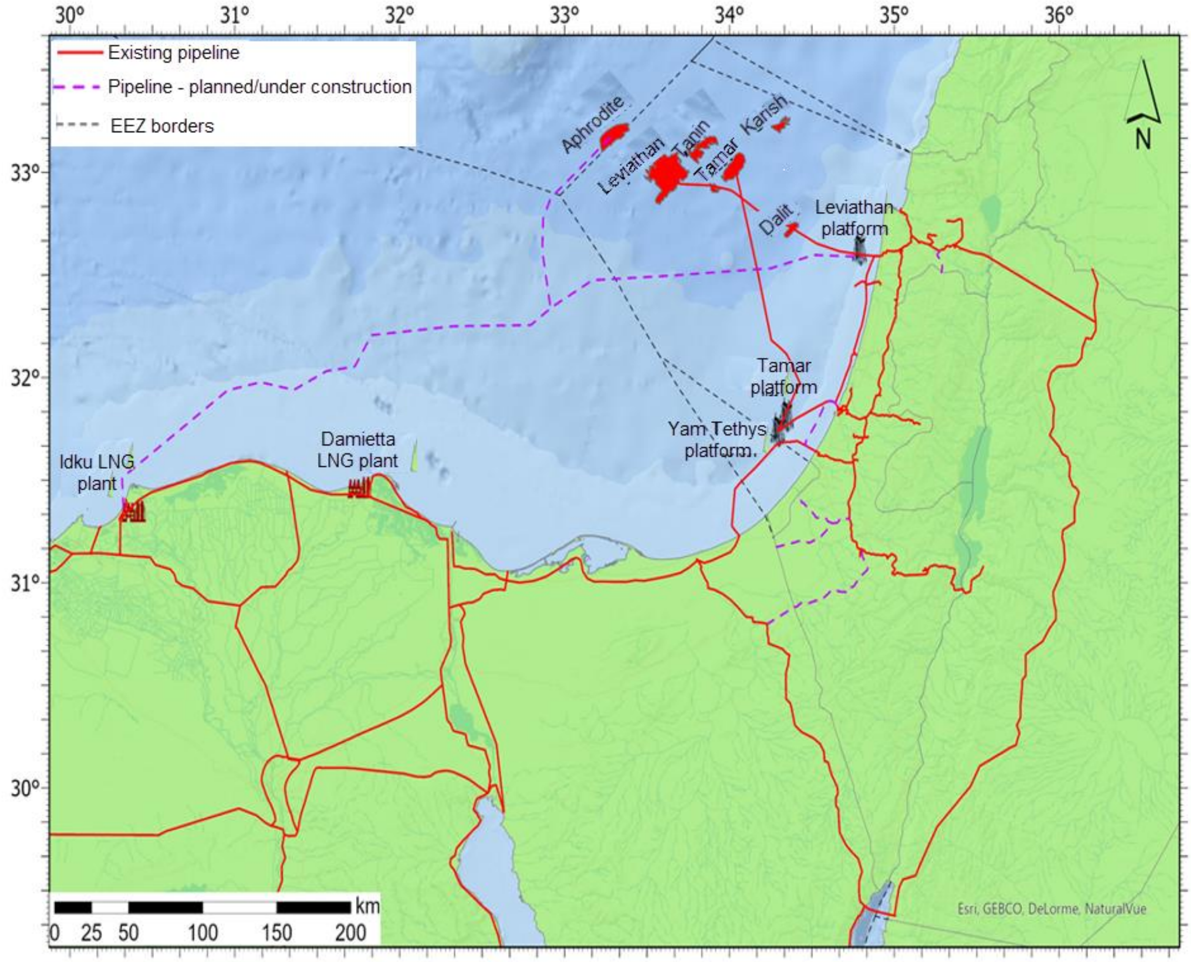
j) On February 14, 2021, all the preconditions for the entry of the Transmission Agreement into force were fulfilled.

k) Concurrently with the signing of the Transmission Agreement, Noble, the Partnership and the other Leviathan and Tamar partners signed a back-to-back services agreement (in this section: "the Service Agreement") determining that the Leviathan and the Tamar partners will be entitled to transport gas (through Noble) under the Transmission Agreement, and will also be responsible for fulfilling Noble's undertakings under the Transmission Agreement, such that the Leviathan and Tamar partners will be deemed to have been party to the Transmission Agreement in lieu of Noble, each according to its share as set out in the capacity allocation agreement between the Leviathan and Tamar partners, as set out in section 1.7.29(J)(3) below. The Service Agreement further stipulates that the Base Capacity retained in the transmission system for Noble, will be allocated between the Leviathan partners and the Tamar partners according to the rates set out in section H above and in accordance with the order set out in the capacity allocation agreement. Notwithstanding the aforesaid, the Leviathan and Tamar partners will bear a capacity fee in a fixed ratio of 69% (the Leviathan partners) and 31% (the Tamar partners), other than in the event that a party (the Leviathan partners or the Tamar partners, as the case may be) will have used the other party's share of available capacity.

Forward-looking information - The above estimates regarding construction of Ashdod-Ashkelon combined section, the costs of acceleration of the doubling of the Dor-Hagit and Sorek-Nesher sections, the costs of transmitting the gas, the date gas starts to flow, the quantities it will be possible to supply under the Transmission Agreement and the estimate regarding the possibility of extending the Transmission Agreement constitute forward-looking information, as defined in the Israel Securities Law, 1968,and there is no certainty that it will materialize, in whole or in part, and it might materialize in a substantially different manner, due to various factors, including delays and failures in construction of the transmission system sections, different actual construction costs to those estimated, failure to receive the required regulatory approvals, changes in transmission prices applicable in Israel and other factors beyond the Partnership's control.

<u>Transmission by construction of new infrastructure</u>

As at the approval date of the report, the Partnership, together with Noble, is examining additional options for supplying natural gas from Israel to Egypt, including the possibility of supplying natural gas from Israel via Jordan using the Northern Pipeline and Pan-Arab Pipeline) (for further information, see section 1.7.29(J)(5) below) and/or the possibility of constructing a new offshore pipeline to Egypt and/or building a new onshore connection, which will be implemented by INGL, between the Israeli transmission system and Egypt (in the Nitzana or Kerem Shalom area).



Forward-looking information: The above information regarding the negotiations with the parties and examination of the various possibilities concerning the construction and/or use of infrastructure, as set out above, is forward-looking information, as defined in section 32A of the Israel Securities Law, and there is no certainty that it will materialize, in whole or in part, in the above or any other manner, and it might materialize in a substantially different manner to the above description, due to various factors beyond the Company's control.

The forecasts and estimates regarding the Jordan and Egyptian markets are also forward-looking information, as defined in section 32A of the Israel Securities Law. This information is based, among others, on information received from independent consulting companies and is within the scope of estimated forecasts and assumptions that are naturally subject to

uncertainty. These forecasts and estimates may not materialize, in whole or in part, or may materialize in a substantially different manner to the above description, due to various factors beyond the control of the Partnership, including changes in demand for natural gas; changes in supply of natural gas, including local production, discovery and commencement of production of new reservoirs; changes in the energy mix, including accelerated introduction of additional energy source and renewable energies; changes due to macroeconomic effects that affect the economic activity in these markets, including acceleration or slowdown thereof, etc.

3. Palestinian Authority - Israel is the main source of electricity to the Palestinian Authority territories (Judea, Samaria and the Gaza Strip). The Palestinian Authority has recently started a process of creating the ability to produce electricity independently, inter alia, by promoting the construction of a new power plant in Jenin. As of the approval date of the report, the Partnership, together with its partners in the different projects, are in various negotiation stages with different entities in connection, among other things, with the option of supplying natural gas to existing power stations in Gaza and/or a future station to be constructed in the Jenin area and/or in other areas controlled by the Palestinian Authority.

   In the Partnership's estimation, the natural gas demand for operation of the power stations to be constructed in the Jenin area will be 0.7 BCM annually, whereas the demand for natural gas to operate the existing power station in Gaza will be up to 0.25 BCM annually.

4. Cyprus - As of the approval date of the report, Cyprus is almost completely dependent on imported oil products and electricity production in Cyprus is mainly based (90%) on burning oil-based products, such as diesel fuel. Cyprus also has difficulty in connecting to the European energy infrastructures due to its geographic location and being an island. In 2007, the Cypriot government set up the Natural Gas Public Company ("DEFA"), which is exclusively responsible for the import, storage, marketing, transportation, supply and trade of natural gas in Cyprus, including management of the Cypriot natural gas distribution system. According to the regulations in Cyprus enacted in 2007 concerning the Cypriot natural gas market, this gas company has exclusivity to import and distribute natural gas in Cyprus. As of the approval date of the report, Cyprus does not consume any natural gas. For further information about the Cypriot market, see section 1.7.16(D)(2) below. The Partnership, together with its partners in the Aphrodite reservoir, is continuing to promote various stages of negotiations connected with exporting natural gas from the Aphrodite reservoir to regional markets, including the Egyptian market, including negotiations for the supply of natural gas to the liquefaction facility in Idku, Egypt, in a quantity of 6 BCM per year for a period of 10-15 years.

   Forward-looking information: The above information regarding the negotiations as aforesaid is forward-looking information, as defined in section 32A of the Israel Securities Law, and there is no certainty that it will materialize, in whole or in part, in the above or any other manner, and it might materialize in a substantially different manner to the above description, and in particular there is no certainty that these negotiations will mature into binding gas sale agreements and that the conditions required under any law for such agreements to take effect, if signed, will be fulfilled.

(3) Liquefied natural gas (LNG)

The Partnership is exploring the option of liquefying the gas and transporting it as LNG in designated tankers to various countries where there is a demand for LNG. The construction of a natural gas liquefaction facility is a highly complex project, inter alia, due to the huge investment of liquefaction facilities with a liquefaction capacity of millions of tons of LNG annually, and due to the design, engineering, environmental and commercial challenges involved in this type of project.

In this context, the Partnership is reviewing the construction of an offshore floating liquefaction facility (FLNG) on a designated ship. In recent years, several FLNG facilities have started operating around the world, and there are additional floating liquefaction facilities in planning and construction phases, while the market trend is a switching standardization of the facilities, which will allow reduction of their cost, the shortening of production timetables, and mitigation of the construction risks. It should be noted that the Leviathan reservoir, which an operating reservoir, has sufficient treated gas and is located in a relatively comfortable climate with access to several main LNG markets, has many advantages over competing FLNG facilities. On July 29, 2019, the Leviathan partners entered onto two separate interim agreements with FLNG technology and service providers, as follows:

A. Agreement with Golar LNG Limited ("Golar") to examine the suitability of generic FEED (Front End Engineering and Design) carried out by them for a FLNG facility for the Leviathan project that will be located in the exclusive economic zone of Israel (in this section 1.7.14(B)(3) below: "the Facility") and for engineering planning of the Facility.

Golar is a public company listed on the NASDAQ, that specializes in the entire LNG value chain, including gas liquefaction, transportation and regasification. Golar is the operator and owner of an active FLNG facility in Cameroon, as well as of a fleet of LNG transportation and regasification vessels.

B. Agreement with Exmar NV ("Exmar") for performance of designated FEED for the Leviathan project and engineering planning for construction of the Facility.

Exmar is a public company listed on the Euronext in Belgium, that specializes in the entire LNG value chain, including gas liquefaction, transportation and regasification, and liquefied petroleum gas (LPG) transportation. Exmar is the operator and owner of an active FLNG facility in Argentina and acts, inter alia, as operator of the regasification vessel west of the coast of Hadera .

Under these two interim agreements, the Leviathan partners are negotiating with both of these suppliers regarding the commercial terms for the construction of the Facility with an estimated capacity of between 2.5 and 5 million tons of LNG annually (3.5-7 BCM) and operation thereof, including to promote receipt of the regulatory approvals required. If it is found that construction of the Facility is the preferred alternative for promotion of the future development stages for the Leviathan Project, the Leviathan partners will enter into long-term agreements with one of the suppliers for the lease of the Facility to be built, financed, operated and maintained by it.

In April 2020, initial offers for the provision of FLNG services were received from both suppliers. As at the approval date of the report, the Leviathan partners are reviewing these offers and holding discussions with these suppliers for clarifications and improvement of their offers.

In this context it is noted that in March 2020, the Ministry of Energy published a request for public comment regarding the Ministry's proposed alternatives for construction of an offshore export FLNG in Israel's exclusive economic zone[106]. On May 17, 2020, the Association of Oil and Gas Exploration Industries in Israel, in which the Partnership is a member, submitted its comments to the said document.

<u>Consequences of the Covid-19 Crisis:</u>

As stated in section 1.7.2(G) above, due to the Covid-19 crisis, as at the approval date of the report, there is extreme and unusual uncertainty regarding the possible consequences of the crisis in and after 2021 on the global economy in general and energy prices in particular. Therefore, if the Covid-19 crisis continues or intensifies, this may prevent the possibility of adopting an investment decision in general, and in new projects in particular.

Forward-looking information: The above information regarding the possibility of and forecast for signing of the agreement as aforesaid is forward-looking information, as defined in section 32A of the Israel Securities Law, and there is no certainty that it will materialize, in whole or in part, in the above or any other manner, and it might materialize in a substantially different manner to the above description, and in particular there is no certainty that the parties will reach an agreement regarding the terms of the agreement.

(4) <u>Compressed natural gas (CNG)</u>

The Partnership is exploring the possibility of exporting gas to countries in the Mediterranean Basin by compressing the natural gas (CNG) and transporting it by specialized ships or using designated portable tanks. Exporting natural gas in this way may allow access to new and more export markets, including Greece, Mediterranean islands, Italy and other countries. The Partnership held initial discussions with customers seeking to purchase Israeli natural gas in this way. It should be noted that, to the best of the Company's knowledge, there are currently no projects worldwide for supplying CNG in large quantities by sea.

1.7.15. Order backlog

(A) Following is the Company's order backlog as at the approval date of the report, calculated on the basis of the minimum gas quantities (according to the contract take or pay (TOP) quantity) set out in binding agreements (agreements on a firm basis in which all the preconditions were fulfilled) for the supply of natural gas and condensate from the Tamar and Leviathan projects, which the customers undertook to consume or pay for, subject to the following principal assumptions: (1) All the options granted to the customers of Tamar and Leviathan partners to decrease the contractual quantity, as set out in Section 1.7.13(D)(1)c will be exercised; (2) in 2020-2021, IEC's consumption under the

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[106] For further information, see the Ministry of Energy's notice at: https://www.gov.il/he/departments/publications/Call_for_bids/flng_public

Tamar Agreement will be less than the TOP, due to exercise of carry forward. In the first quarter of 2021, the Partnership's revenues from IEC were reduced according to the provisions of the foregoing Tamar and Leviathan Settlement Agreements; (3) IEC's consumption in 2021 above the minimum annual quantity under the Tamar Agreement will be according to the provisions of the foregoing Tamar and Leviathan Settlement Agreements; (4) the price forecasts are based on assumptions used for calculation of discounted cash flows in the Tamar project as set out in Section 1.7.5(K)(1)b and in relation to the Leviathan project, as set out in the Company's immediate report dated March 10, 2021 (Ref. No. 2021-01-031128), included in this report by way of reference; (5) there will be no change in the minimum annual quantities in the export agreements to Egypt, as set out in sections 1.7.13(E)(1)b.5 and 1.7.13(E)(2)b.4 above; (6) revenues from the Tamar project will be calculated according to the Partnership's direct holdings in the Tamar Project (22%):

Year	Total revenue (USD millions) as at December 31, 2020	
	Leviathan Project	Tamar Project
Q1 2021*	30	97
Q2 2021*	28	99
Q3 2021*	45	86
Q4 2021*	45	86
2023	121	290
2023	135	330
2024	132	344
2025	134	357
2026	137	359
2027	139	361
2028	101	375
2029	67	381
2030	64	384

* The quarters were divided on a linear basis and in accordance with the terms of the gas sale agreements (if determined) in relation to the gas quantities to be supplied and the Partnership's assumptions.

Forward-looking information: The Partnership's estimates concerning the date and total revenue expected from the order backlog is forward-looking information, as defined in section 32A of the Israel Securities Law, based on the minimum gas quantities set out in the binding natural gas supply agreements from the Yam Tethys, Tamar and Leviathan projects and the assumptions set out in this section, and there is no certainty that they will materialize, inter alia, due to the possible effect of any of the risk factors involved in the Partnership's operations, as set out in section 1.7.33 below.

(B) As at December 31, 2019, the Company's order backlog for 2020 amounted to USD 430 million. The Partnership's actual revenue from the above order backlog in 2020 amounted to USD 510 million. The difference between the expected revenue from the order backlog and the actual revenue in 2020 is due to the fact that the actual sales volume in most of the agreements was higher than the minimum gas quantities fixed in the natural gas supply agreements from these projects. For the purpose of the backlog order forecast, only agreements on a firm basis were taken into account, whereas the agreements on an interruptible were calculated based on actual consumption in January-February 2021 only.

1.7.16. Competition in the Mediterranean

(A) <u>Natural gas discoveries in Israel</u>

The Partnership's natural gas supply is currently carried out by pipeline and intended mainly for the local market as well as the markets in neighboring countries. The Partnership's main competition is with the holders of oil and natural gas assets operating in Israel and neighboring countries as well as LNG importers. It should be noted that if LNG facilities are constructed or the access to the existing facilities is expanded, and if the possibility of export by pipeline is expanded, so that the potential target markets expand, the motivation to carry our exploration, development and production activities in the zone will increase.

Upon the start of flow gas supply from the Leviathan reservoir in December 2019, the vast majority of the natural gas currently supplied to the Israeli market is from the Leviathan and Tamar reservoirs, which, as at the date of this report, are the only producing reservoirs within the territories of the State of Israel. In addition, small quantities of LNG are supplied to IEC by the regasification vessel through the offshore platform set up by INGL ("Offshore LNG Import Platform"). For further information, see Section 1.7.16(B) below.

In order to comply with the Gas Framework, which is intended to increase competition among the rights holders in the natural gas reservoirs discovered in Israel, as set out in section 1.7.25(A) below): (a) the rights of the Partnership and Noble in the Karish and Tanin reservoirs were sold to Energean Israel; (b) the Partnership sold 9.25% of its rights in the Tamar and Dalit Leases to Tamar Petroleum, as set out in section 1.7.29(R) above; and (c) Noble sold 3.5% of its rights in the Tamar and Dalit Leases to Everest and 7.5% to Tamar Petroleum. In addition, according to the provision of the Gas Framework, the Partnership is required to sell all its rights in the Tamar and Dalit Leases by December 17, 2021, in which case the Tamar reservoir will become the Partnership's competitor. For information about alternatives under review by the Partnership in this record, see Section 1.7.31 below.

On January 30, 2021, the Tamar partners signed a balancing agreement regarding separate marketing of natural gas, subject to fulfillment of certain conditions, which if fulfilled by the Tamar partners will increase competition. For further information, see section 1.7.13(D)(1)f. 1above .

In August 2020, Energean submitted a development plan for the Karish North reservoir to the Ministry of Energy as an appendix to the development plan of the Karish and Tanin reservoirs. According to the provisions of the Gas Framework, the Karish and Tanin reservoirs are designated for the supply of gas to the local market only. Once the development of the Karish, Karish North and Tanin reservoirs is completed, these reservoirs are expected to be another significant supply of natural gas to the local market along with the Leviathan and Tamar reservoirs. As stated in Section 1.7.10 above, to the best of the Company's knowledge and based on Energean's reports, the Karish reservoir is expected to start production in the first quarter of 2022. It should be noted that according to the provisions of the Gas Framework, the Karish and Tanin reservoirs are intended to supply gas to the domestic market only.

On November 15, 2016, the Minister of Energy announced opening of Israel's exclusive economic zone to oil and natural gas exploration in a competitive process ("the Competitive Process") in view of the findings of an independent study conducted for the Ministry of Energy, which determined that Israel's exclusive economic zone has the potential for new discoveries in a total volume of 6.6 billion barrels of oil and 2,137 BCM of natural gas. As part of the process, 24 exploration areas with a maximum size of 400 square kilometers each were offered at a distance of at least seven km from the shore, according to the provisions of the Ministry of Energy on the matter. According to the terms of the tender, to encourage competition in the Israeli gas market, an entity that holds more than 25% of the rights (directly or indirectly) in an offshore lease with more than 200 BCM in the 2C (contingent resources) category as at the publication date of the tender (including the Partnership) was precluded from bidding in the tender.

As part of the Competitive Process, on January 15, 2018, the Ministry of Energy granted the Greek company Energean five exploration licenses in the exclusive economic zone of Israel and on April 9, 2018, a license in one block to a consortium of Indian companies. To the best of the Company's knowledge, as at the approval date of the report, the consortium of Indian companies waived their right to continue exploration in the license area. Furthermore, on November 10, 2020, Energean announced it was waiving the rights to continue exploration in the Block 22 license area is therefore left with four exploration licenses granted in the Competitive Process.

On November 4, 2018, the Minister of Energy announced a second competitive process for natural gas and oil exploration in the exclusive economic zone of Israel (in this section: "the Second Competitive Process") in which 19 exploration licenses (blocks) were offered in five clusters of an area of 1,600 square kilometers each. The Ministry of Energy limited the number of licenses to be granted to each entity to 8 licenses only. Furthermore, it was determined that an entity that holds more than 25% in an oil interest that contains reserves of over 200 BCM in the 2P + 2C categories (including the Partnership) will not be able to participate in the Second Competitive Process and that preference will be given to a group that does not include an entity in existing leases[107]. As part of the Second Competitive Process, on October 28, 2019, the Minister of Energy granted eight oil licenses

107 It should be noted that in view of this announcement, the Partnership is precluded from participating in the Second Competitive Process.

in two clusters to a consortium that includes two UK companies, Pharos Cairn Energy Plc and Energy Plc (the operator), and Ratio, and four licenses in one cluster to Energean (the operator) and Israel Opportunity[108].

June 23, 2020, the Minister of Energy announced launching of a third competitive process for natural gas and oil exploration in the exclusive economic zone of Israel (in this section: "the Third Competitive Process) under which a single license called Block 72 covering extensive parts of the Alon D license was offered, in respect of which the Partnership, together with Noble as operator, submitted a bid. It should be noted that on October 21, 2020, the Partnership received a demand from the Competition Authority to provide information and documents concerning Block 72 (for further information, see Section 1.7.11(C) above). As at the date of this report, not response concerning the winner of the Third Competitive Process has been received from the Ministry of Energy. It is noted that Block 72 borders the unregulated EEZ border between Israel and Lebanon. To the best of the Partnership's knowledge, there have recently been talks between the countries, mediated by the US, in connection with regulating that border, but no final understanding have been reached on the matter.

On January 7, 2021, the Minister of Energy announced launching of a fourth competitive process for natural gas and oil exploration in the exclusive economic zone of Israel (in this section: "the Fourth Competitive Process") in which 25 exploration licenses (blocks) were offered in to six clusters of an area of 1,600 square kilometers each. If the drilling in the existing and/or new license areas leads to natural gas discoveries in significant quantities and if these discoveries (if any) are developed, these reservoirs will be competition in the Partnership's area of activity.

It is further noted that as far as the Company knows, over 15 years ago British Gas Group (now owned by Shell) discovered a natural gas reservoir known as Gaza Marine, off the coast of Gaza, with estimated reserves of 1 TCF, and this reservoir may be developed in future and marketed to the local market and the Palestinian Authority.

(B) LNG import

In January 2013, LNG started being imported to the local market through the Offshore LNG Import Platform and regasification vessel off the coast of Hadera The Offshore LNG Import Platform is designed to receive an LNG regasification tanker that converts LNG into gas through the regasification vessel in an amount of 0.5 BCM per day. In 2020, due to the decrease in LNG prices, IEC purchased several LNG shipments on account of the natural gas purchases from the Leviathan and Tamar reservoirs. According to the Leviathan partners' position, the LNG shipments were purchased by IEC in contradiction to the terms of the IEC-Leviathan Agreement. The dispute between the parties in this regard was settled in the Leviathan Settlement Agreement.

In this context, it is noted that on December 29,2020, the Ministry of Energy reported that the regasification vessel that has been operating since 2013 and used over the years as backup for the Israeli energy sector in the event of a natural gas shortage during peak hours or malfunctions, will discontinue its activity in two years' time[109]. As aforesaid, the decision will be implemented in 2022, when the three natural gas reservoirs, Leviathan, Karish and Tanin are connected to the short and operate regularly. Furthermore, the existing infrastructure to the regasification vessel will remain ready for operation and will be used by the sector when necessary.

(C) Coal and other alternative energy products

Coal and other alternative energy products are also competition for the natural gas suppliers. With respect to gas consumption by IEC, the natural gas suppliers compete with the use of coal for the production of electricity. Therefore, the level of consumption and price of natural gas may be affected by the price of coal worldwide and the tax policy thereof in Israel. For information about the Minister of Energy's decision to reduce the use of coal, see Section 1.7.28(E) below.

The natural gas supplied by the Partnership to industrial customers replaces the use of liquid fuels, such as diesel fuel and fuel oil. The price of liquid fuels is usually higher than the price of the natural gas supplied by the Partnership, but despite being pollutants, the downtrend of oil prices worldwide may make these fuels competitive compared to the natural gas supplied to these consumers. However, it should be noted that the Ministry of Environmental Protection institutes policy designed to ensure that plants with connection infrastructure that enables using natural gas refrain from using polluting liquid fuels. Moreover, the desire to increase the production of electricity from renewable

108 For the location of the licenses (blocks), see the publication on the Ministry of Energy website: http://www.energy-sea.gov.il/English-Site/Pages/Offshore%20Bid%20Rounds/2nd-Bid-Round.aspx.

109 Additional information is available on the Ministry of Energy's website at: https://www.gov.il/he/departments/news/press_291220

energy, such as wind or solar energy is also likely to compete with natural gas. For further information about alternatives to natural gas, see section.1.7.3(I) above.

(D) Renewable energy sources

Against the background of public discourse regarding climate changes and the human impact thereof, significant incentives are currently being provided to develop renewable energy sources, such as solar and wind, which compete with the natural gas sold by the Partnership for electricity production purposes.

In 2020, electricity production from renewable energy constituted 6% of the total electricity production in Israel, and according to the government's targets, as set out in section 1.7.28(G) below, it is expected to reach 30% of the total electricity production in 2030, among other things, by means of regulatory support and tax incentives to renewable energy electricity production facilities. It should be noted that electricity production from renewable energy has numerous advantages mainly from an environmental aspect. However, electricity production from renewable energy in Israel relates mainly to solar energy, which uses technology that is still relatively expensive and requires extensive areas. As such technology develops, together with the development of electricity storage technology that will allow inexpensive and stable electricity production from solar energy, the share of renewable energy in the electricity production mix in Israel is expected to grow.

Natural gas discoveries in neighboring countries

(1) Egypt

To the best of the Company’s knowledge, the volume of natural gas reserves and contingent resources discovered in Egypt is estimated at 50.6 TCF, of which 30.1 TCF are classified as reserves and the remainder as contingent resources. In addition, there is a potential for further significant discoveries due to numerous offshore and onshore exploration activities taking place in Egypt. In 2015, the Zohar natural gas reservoir was discovered in Egypt containing a volume of resources which, as at the approval date of the report, is estimated at 19 TCF (2P), based on various announcements. Production of gas from the Zohar reservoir commenced in December 2017 and to the best of the Company’s knowledge, is intended to be supplied to mainly the Egyptian domestic market. To the best of the Company's knowledge, production from the Zohr reservoir currently constitutes 40% of the local gas production in Egypt, which is expected to increase to 80% in 2030 if no other large reservoirs are discovered and/or additional producing fields start operating. Egypt recently granted the Zohar reservoir partners a license to export specific quantities of natural gas from the reservoir as LNG to international markets, after being liquefied in the SEGAS facility. The export license was granted as part of a separate agreement between the facility owners, which the sale of holdings of Naturgy Energy Group S.A in the facility, and restructuring of the ownership and operating agreements of the facility. It should be noted that in recent years, there are considerable exploration and production activities in onshore and offshore areas of Egypt, inter alia, with the entry and expansion of presence of significant players (such as Exxon Mobil, Shell, Chevron and Eni). In 2020, several dry or non-commercial wells were drilled in the Egyptian exclusive economic zone. Furthermore, in the second half of 2020, Eni reported two shallow water discoveries in the Nile Delta which according to unofficial reports amount to 1 TCF together. For information about the scope of the Egyptian local market demand in 2019 and 2020 and the local demand forecasts in Egypt for 2021, 2022 and 2023, see section 1.7.14(B)(2)b.2 above. For further information about the possible main target markets for the export of natural gas by the Partnership, see section 1.7.14.6(B)(2)b above. In 2020, Egypt granted 8 exploration licenses in its exclusive economic zone in the Mediterranean Sea. In February 2021, Egypt announced launching of another tender, which includes 9 exploration licenses in its exclusive economic zone in the Mediterranean Sea.

(2) Cyprus

A. For further information about the Cypriot market, see section 1.7.14(B)(2)b.4 above.

B. It should be noted that, as at the approval date of the report, Cyprus does not consume natural gas, despite the significant gas discoveries in its exclusive economic zone. The main reasons for this are the scope of the investment required to develop the discoveries on one hand, and the limited scope of the potential local market in Cyprus on the other hand. However, it appears that the Cypriot government is acting to import natural gas to Cyprus by other means, including construction of a floating regasification facility and purchasing LNG, as set out below.

C. As at the approval date of the report, in the absence of relevant regulation in Cyprus regarding natural gas export facilities, it is impossible to estimate how additional discoveries, if any, could affect the manner in which gas will be exported from Cyprus and the competition, if at all, and should it develop, with respect to the local market and access to export infrastructure.

D. To the best of the Company's knowledge, the Cypriot government and Cypriot electric company are taking steps to promote the replacement of fuel-based products with natural gas for the production of electricity. In October 2018, the Cypriot government published a tender for the construction of a regasification facility for LNG imported for the needs of the Cypriot local market, while in December 2019, it reported that the tender was awarded to a consortium led by China Petroleum Pipeline Engineering Co. Ltd. Simultaneously with the foregoing announcement, the Cypriot government indicated that the facility construction project is due to be completed in the first quarter of 2022. Accordingly, in June 2019, the Cypriot government announced a tender for the import of LNG. In December 2020, the Cypriot government reported that 25 different bids were received under the tender and that during 2021, it intends to sign agreements with the different companies for future import of LNG.

E. In February 2018, the consortium of Eni and Total made a new discovery of natural gas in Block 6 in the exclusive economic zone of Cyprus, known as Calypso. Estimated resources in this discovery have not yet been published, but it is estimated that there is 6.4 TCF in the reservoir, which has similar characteristics to those of the Zohar reservoir. It should be noted that a confirmation well was planned to be drilled in 2020, which was deferred to 2021 due to the Covid-19 crisis. This Calypso discovery may affect the Partnership’s operations in Cyprus and/or Egypt. In addition, the companies that own the reservoir will want to export the gas to the Egyptian local market and/or channel it to the Egyptian liquefaction facilities and sale on international markets. It should be noted that liquefaction of this gas will take up part of the liquefaction capacity of the Egyptian liquefaction facilities.

F. In September 2018, it was announced that a consortium headed by ExxonMobile had commenced the drilling two appraisal wells in Block 10 in the exclusive economic zone of Cyprus[110]. In February 2019, the consortium issued a press release that it had made a new natural gas discovery, known as Glaucus, with preliminary estimates of 5-8 TCF of gas in place, and that the consortium intends to continue the interpretation work and drilling appraisal wells to better estimate the scope of the resources. It should be noted that a confirmation well was planned to be drilled in 2020, which was deferred to 2021 due to the Covid-19 crisis. That discovery may affect the Partnership’s operations in Cyprus and/or Egypt.

G. In September 2019, it was reported that the Cypriot government had granted an exploration license in Block 7 to Total and ENI as part of a tender process held for companies that hold licenses adjacent to Block 7 only. In addition, the Cypriot government announced Total’s entry into Blocks 2, 3, 8 and 9, which are owned by Eni (together with other partners).

In addition, to the best of the Company’s knowledge, more appraisal drillings are expected in the coming years in the exclusive economic zone of Cyprus by a consortium headed by Eni in Blocks 3 and 8[111]. The verification and appraisal wells are planned this year in Glaucus (Block 10) and Calypso (Block 6). It should be noted that according to the press releases, the tension between Cyprus and Turkey may affect the timetables for the exploration activities in the exclusive economic zone of Cyprus. It was reported in the media that the drilling rigs of the Turkish national oil company tried to carry out exploration activities, including drillings in the exclusive economic zone of Cyprus. To the best of the Partnership’s knowledge, no activity of drilling rigs belonging to Turkey has taken place in Block 12 (in which the Aphrodite reservoir is situation), because it is not located in the exclusive economic zone which Turkey claims, on behalf of the Turkish Republic of Northern Cyprus, as its territory.

(3) <u>Lebanon</u>

At the end of February 2020, Total, which heads a consortium in Block 4 in the exclusive economic zone of Lebanon, announced the arrival of the Tungsten Explorer drilling vessel in the license area and a forecast for commencement of an exploration drilling, probably to a Miocene layer target. According to Total’s reports, the drilling ended on April 26, 2020 without any significant finding. This consortium plans to drill in Block 9, which partially overlaps the offshore area in dispute between Lebanon and Israel. It should be noted that since September 2020, indirect discussion are taking place between the countries, mediated by the US, in order to regulate the exclusive economic zone rights in this area. It is also noted that Block 9 borders the Alon D license as well as Block 72, which is offered for gas and oil exploration in Israel’s exclusive economic zone.

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110 Based on ExxonMobil’s public announcements.

111 Based on Eni’s public announcements.

1.7.17. Seasonality

In Israel and Jordan, the natural gas consumption for electricity production is affected, inter alia, by seasonal changes in demand for electricity and the maintenance plans of the power producers. The electricity consumption is usually the highest in the first and third quarters of the year (summer and winter). In Egypt, gas consumption is materially impacted by the demand for electricity and energy for cooling purposes and, therefore, summer months are the peak months in the demand for natural gas.

Following is a breakdown of natural gas sales (100%) from the Tamar and Leviathan projects in the last two years[112]:

Period	Q1 (BCM)	Q2 (BCM)	Q4 (BCM)	Q3 (BCM)
2020	3.6	2.9	4.4	4.6
2019	2.7	2.4	2.6	2.8

1.7.18. Facilities and production capacity of the Mediterranean reservoirs

(A) Leviathan Project

(1) Phase 1 - First Stage of the development plan of the Leviathan project

The Phase I - First Stage production system comprises five main segments, as follows:

A. Production wells: Four subsea production wells with a production capacity of up to 400 MMcf/d each. Natural gas from the Leviathan reservoir, which is at a depth of 3 km below the seabed, is transmitted from the production wells to the subsea production system.

B. Subsea production system: The subsea production system connects the production wells to the production platform, and is on the seabed The subsea system has 14-inch pipelines which deliver natural gas and condensate from the wells to the subsea manifold. The manifold has two 18-inch exit pipes of 120 km each, which deliver natural gas and condensate to the production platform. The subsea system also has two 6-inch pipes of 120 km each to deliver MEG from the production platform to the wells, and a 120-km umbilical cable that connects the production platform to the wells and allows command and control of the natural gas production from the wells.

C. Treatment and production platform: The Leviathan platform is located 10 km from the shore. The platform is anchored to the seabed at a water depth of 86 meters by a jacket. The platform topsides are assembled on the upper part of the jacket, above sea level, and are divided at this stage into two main modules: (1) the domestic supply module, which contains, inter alia, natural gas and condensate production and treatment facilities, including gas liquid separator facilities, MEG regeneration unit, emission reduction unit (FGRU), generators, tanks, pumps, air compressors, helipad, employee living quarters, firefighting facilities, life boats, security devices, gas dehydration units, and auxiliary facilities and services, etc.; (2) a liquids supply module which stores condensate and MEG. The platform is designed to treat 1,200 MMCF of gas daily and 5,400 barrels of condensate daily. It should be noted that under certain operating conditions, inter alia, using the turbo expanders, the production capacity of the platform is even expected to exceed this quantity. Unlike the Tamar project in which the final treatment of gas and condensate is performed in the onshore receiving terminal, in the Leviathan project, all treatment is performed offshore, on the platform.

D. Transmission system to the shore: The pipeline from the Leviathan platform to the shore comprises a 32-inch pipe to transmit natural gas[113] and a 6-inch pipe to transmit condensate. These pipes run below the shoreline, through a designated 52-inch pipe that is used as a sleeve, and reach the coastal valve station, and from there, to the Dor valve station, which is located near the INGL valve station, to which the natural gas is transferred. The condensate pipeline connects to EAPC's buried offshore oil line at the Nachsulim Valve Station.

E. Hagit site: The Hagit site includes a condensate storage tank and the pipeline, fittings, equipment, pumps, command, control and operation system, a tanker filling facility, auxiliary facilities and services, if required for safe and environment-friendly operation. The condensate reaches the Hagit

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112 The figures refer to total natural gas sales of all Leviathan and Tamar partners, rounded to the nearest tenth of a BCM. It should be noted that the figures do not include quantities supplied from the Offshore LNG Import Platform, which mainly operates during the months of peak demand for natural gas.

113 For information about the license for construction and operation of a pipeline, see section 1.7.28(M)(3) below.

site through a 6-inch buried pipe. Without the ability to transmit to Bazan, the condensate will be transmitted and stored at the Hagit site, and delivered to Bazan when possible or removed to the customers by tankers when necessary. It is noted that the construction work of the condensate storage system at the Hagit site ended in 2020 and in February 2021, all permits required for its operation were obtained.

As at the date of this report, and according to the development plan, the maximum daily production capacity of the Leviathan Project is 1,200 MMCF per day. As at the approval date of the report, the approval of the Ministry of Energy has been received to start operating the turbo expander system. Operating the system is likely to increase the production capacity to above 1,200 MMCF.

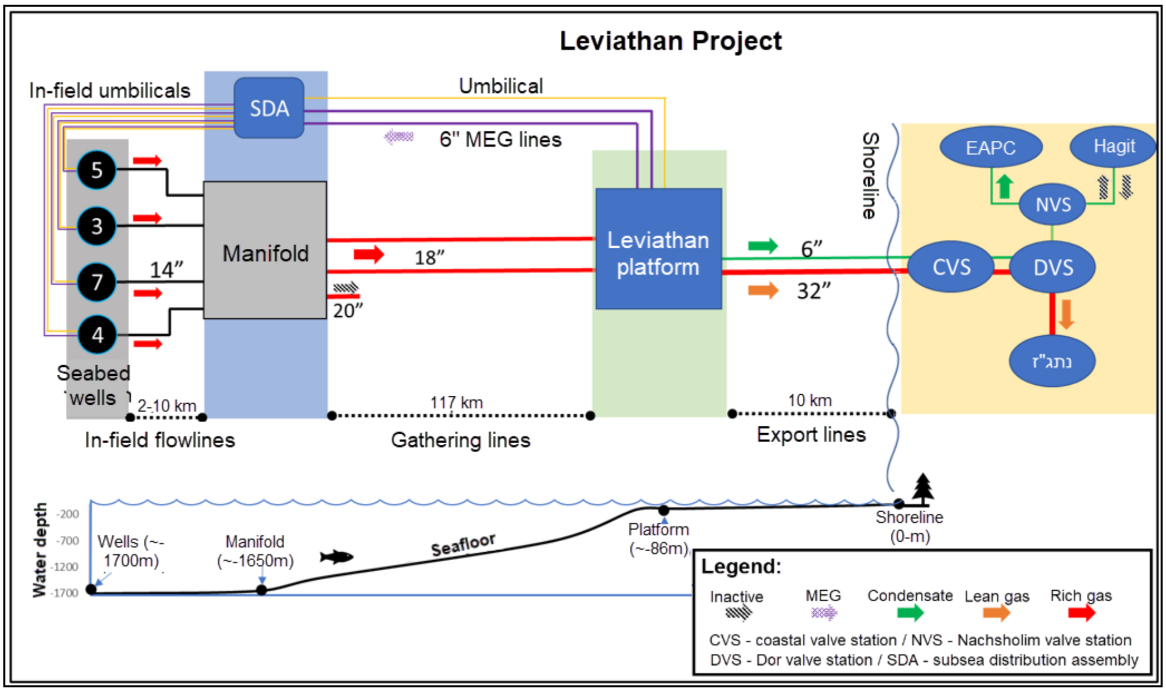
It is further noted that in the preliminary stages of activity of the Leviathan Project, operational events were recorded in the Leviathan platform which are being examined by the operator with the aim of improving the production regularity and continuity. As informed by the operator, these operational events had a negligible impact on the ability to meet demand and the environmental data, among other things, from the onshore monitoring systems, indicate that there was no harm to the environment. According to the operator's update, in 2020, the up-time of the Leviathan Project was 98.5%, which is equivalent to or exceeds the performance of similar facilities worldwide that are at a similar stage as the Leviathan Project.

(2) Phase 1 - Second Stage of the development plan of the Leviathan project

The planned facilities in the Leviathan Project based on Phase 1 - Second Stage of the development plan, if and when a resolution to approve it is adopted, might include: Four more production wells, each with a daily production capacity of up to 400 MMCF which will be connected by subsea pipeline to the existing subsea production system; another 20-inch subsea pipeline of 120 km to transmit gas from the manifold to the platform; a Regional Export Module with similar treatment facilities to the Phase 1 - First Stage facilities plus compressors, and a treatment capacity of 900 MMCF, intended mainly for regional export, so that together with the Phase 1 - First Stage treatment facilities, the total daily treatment capacity of the platform will be 2,100 MMCF. The gas from the platform to the export markets will be transported, inter alia, through a special pipeline, as set out in section 1.7.14(B)(2) above.

For information about the different alternatives for the additional phases in the Leviathan project development plan, see section 1.7.4(E)(2) above.

(3) Below is a diagram of the Phase 1 - Second Stage facilities of the Leviathan Project:



(B) Tamar project

(1) The production system of the Tamar Project comprises five main segments, as follows:

A. Production wells: Six subsea production wells with a production capacity of up to 250 MMcf/d each. Natural gas from the Tamar reservoir, which is at a depth of 3 km below the seabed, is transmitted from the production wells to the production system on the seabed.

B. Subsea production system: The subsea system connects the production wells to the production platform, and is on the seabed The subsea system has 10-inch pipelines which deliver natural gas and condensate from the wells to the subsea manifold. The manifold has two 16-inch exit pipes of 150 km each ("the Dual Pipeline") which deliver natural gas and condensate to the production platform. The subsea system also has two 6-inch pipes of 150 km each to deliver MEG (anti-freeze) from the production platform to the wells, and two umbilical cables of 150 km each that connect the production platform to the wells and allow command and control of the natural gas production from the wells. The Dual Pipeline include equipment that will enable the Dalit Reservoir to be connected the production of the Tamar Project in the future. The maximum supply of gas that can be transmitted through the Dual Pipeline under current conditions is 1.1 BCF daily and is, therefore, a bottleneck in the production system of the project.

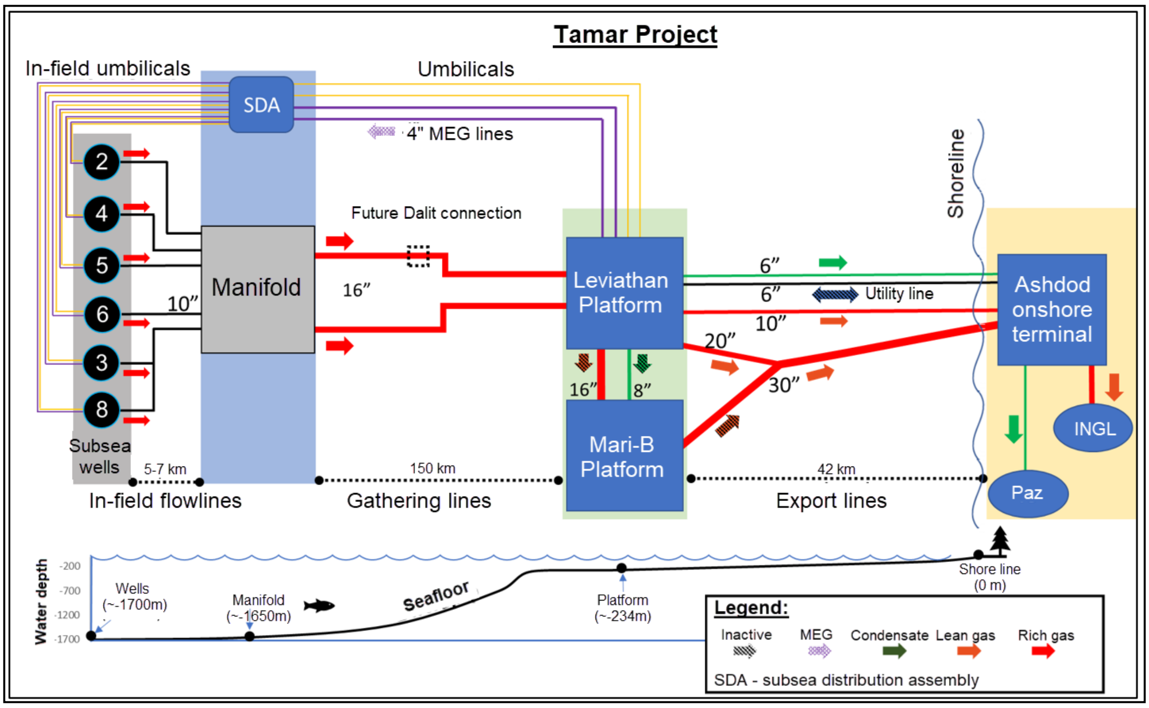
C. Treatment and production platform: The Tamar platform is located 25 km from the shore and two km north of the Mari B platform. The production platform is anchored to the seabed at a water depth of 236 meters by a jacket. The platform topsides are assembled on the upper part of the jacket, above sea level, and contain, inter alia, the natural gas production and treatment facilities, including gas liquid separator facilities, MEG storage, treatment and regeneration facilities, TEG gas dehydration units, emission reduction unit, generators, tanks, pumps, air compressors, helipad, employee living quarters, firefighting facilities, life boats, security devices, etc. The platform is designed to treat 1,200 MMCF of natural gas daily and 5,400 barrels of condensate daily. The treatment capacity of the platform can be increased by operating the four existing trains to a level of 1,600 MMCF of natural gas daily and 7,200 barrels of condensate daily, subject to making the required adjustments to the platform.

D. Transmission system to the shore and the Mari B platform: The transmission system from the Tamar platform comprises two parts: (1) a pipeline from the platform to the receiving terminal that includes a short 20-inch pipe segment connected to a 30-inch pipe for the transmission of natural gas, a 10-inch pipe for natural gas supply, and two 6-inch pipes for the supply of condensate and/or MEG form the Tamar platform to the receiving terminal; (2) a pipeline that connects the Tamar platform to the Mari B platform, which includes a 16-inch pipe for the supply of natural gas, an 8-inch pipe for the supply of condensate, and the equipment required to insert natural gas and condensate into the Mari B reservoir, when necessary.

E. Receiving terminal: Includes a system for supplementary treatment of the gas transmitted from the treatment and production platform so that it complies with the quality requirements for the purpose of transmitting it in the INGL national gas transmission system and a condensate stabilization, storage and transmission system.

For further information about the development plan for the Tamar project, including expansion of its supply capacity, see section 1.7.5(D) above.

(2) Below is a diagram of the Tamar Project facilities:



1.7.19. Human capital

(A) As at the date of the report, Delek Energy does not engage any employees. As at December 31, 2019 and December 31, 2020, the following employees were engaged in the Partnership:

Department	No. of employee at December 31, 2019	No. of employee at December 31, 2020
Management and headquarters	8 (4 of whom are officers)	9 (4 of whom are officers)
Professional	8 (3 of whom are officers)	7 (2 of whom are officers)
Total	16	16

(B) The Partnership and the Company also receive professional consulting services from various consultants, including geologists, geophysicists, lawyers, media consultants and financial advisors, as required. It is also noted that under the operating agreements in most of the projects to which the Partnership and/or the Company are partners, the project operator employs staff for management and operation of the projects.

(C) The Company provides Delek Energy with management services.

(D) Benefits and types of employment agreements

Generally, the staff of the general partner in the Partnership and the Partnership are employed under personal employment contracts. Officers and senior management staff are employed under terms agreed with each of these office holders, including monthly salary, company car, mobile phone, and provisions for executive insurance and study fund.

In accordance with the provisions of the Partnerships Ordinance, on July 10, 2019 the general meeting of holders of Delek Drilling units passed a revised compensation policy for the Partnership's officers and the general partner.

1.7.20. Raw material and suppliers of the Partnership

Generally, the Partnership does not contract directly with suppliers or professional contractors, and such contracting is left to the project operator. In general, there are currently no contractors in Israel that engage in drilling, offshore seismic surveys and some of the types of development and infrastructure works performed by the Partnership together with its partners in the various projects. Therefore, the operator signs agreements with foreign contractors for these services who are instructed to integrate local services and consultant in their activities, if possible. Offshore drilling equipment and other specialized equipment is chartered and transported from across the globe according to availability, type of work and the needs of each project. Another important parameter that affects this matter is the price of crude oil: an increase in the price of crude oil usually affects the volume of operations in the segment and as a result, also the availability of contractors and required equipment.

1.7.21. Working capital

(A) The Partnership's working capital is composed, with regard to the assets, primarily of cash balances, short term investments, various receivable balances and accounts and trade receivables resulting from joint transactions, and with regard to liabilities, primarily from debentures, loans from financial institutions and accounts payable resulting from joint transactions.

(B) Working capital deficit

Based on the figures in the Partnership's financial statements as at December 31, 2020, the Partnership has working capital deficit in the amount of USD 148 million, primarily due to current maturities of debentures (Series B1) that mature in December 2021. On March 14, 2021, the Board of Directors of the general partner of the Partnership determined that this deficit does not indicate a liquidity problem for the Partnership, and accordingly, there is no warning sign, as defined in Regulation 10(B)(14)(a) of the Israel Securities Regulations (Periodic and Immediate Reports), 1970.

	Amount included in the Partnership's financial statements as at December 31, 2020 (USD thousands)
Current assets	417,903
Current liabilities	566,047
Surplus current liabilities over current assets	148,144

1.7.22. Financing

(A) General

Below is information concerning the financing for the Partnership's operations and for Delek Leviathan Overriding Royalty Ltd. For information concerning Delek Energy loans and credit facilities, see section 1.16 in Part Four of this chapter.

As at the date of approval of this Report, the Partnership finances its operations mainly from the sale of natural gas and condensate to Tamar Project and Leviathan Project customers and issuing of debentures for the institutional market in Israel and abroad, and to the public in Israel.

(B) Debentures of Delek Leviathan Overriding Royalty Ltd.

On October 28, 2020, a wholly-owned SPC of Delek Energy, Delek Leviathan Overriding Royalty Ltd. ("the Issuer") completed the issuance of debentures to foreign and Israeli classified investors in the amount of USD 180 million par value, repayable in one installment on December 30, 2023 and bearing fixed USD-denominated interest at a rate of 7.494% payable twice a year, on June 30 and December 30 (in this section: "the Debentures: and "the Leviathan Debenture Issuance", respectively). The Debentures were rated with a B+ rating on the international Fitch rating scale and were also listed on the TACT-institutional trading system of the Tel Aviv Stock Exchange.

According to the transaction outline, the rights of the Company (25%) and Delek Energy (75%) in Leviathan Overriding Royalty and the rights attached to the royalty were transferred to the Issuer on the transaction closing date ("the Closing Date") and were pledged in favor of the trustee of the Debentures ("the Issuance Trustee") to secure repayment of the Debentures, under the terms of the deed of trust and the other documents under which the Debentures were issued (jointly: "the Issuance Documents"). In addition, the Issuer pledged in favor of the Issuance Trustee the rights attached to the royalty and rights in some of the bank accounts and insurance policies (jointly: "the Pledges").

The proceeds of the Issuance, less a security buffer and certain amounts were used for redemption of debentures of the Company under the amendment to the deed of trust described in section 1.7.22(E) below.

As is standard in financing transactions of this type, the Issuance Documents included covenants, restrictions, undertakings, and grounds to call for immediate repayment of the debentures and exercise the pledges.

It should be emphasized that the information set out below represents a partial and incomplete summary of the relevant provisions in the Issuance Documents and that the Issuance Documents include details of the various undertakings and grounds, restrictions subject to the occurrence of a material adverse effect ("MAE") on the Issuer (as defined in the Issuance Documents), as well as exceptions, additional terms, or cure periods that are not included in the description below.

A. The Issuer has undertaken, among other things, not to take any financial debt in addition to the Debentures.

B. The Issuer has undertaken that it will not carry out a merger or change its activities in a manner that is likely to cause a MAE, or that will result in liquidation proceedings or other defined structural changes, and will not sell, transfer, pledge or otherwise dispose of any of the pledged assets, other than transactions that are permitted under the Financing Documents, including full or partial sale of its rights in the Leviathan Overriding Royalty, subject to certain terms that are defined in the Financing Documents.

C. Provisions were set out regarding early redemption of the Debentures, including, (1) early redemption initiated by the Issuer, subject to payment of a make whole premium; (2) mandatory early redemption in certain defined cases, including at the time of sale of all or most of the rights in the Leviathan Overriding Royalty.

D. Events of default were defined, whose occurrence, subject to certain cure periods, qualifications, and terms that have been defined, will serve as grounds to call for immediate repayment of the unpaid balance of the debentures and the Issuance Trustee will be entitled to act to exercise the pledges, including in the following cases: (1) default on payment of principal, interest or other payments required under the Financing Documents; (2) material breach of representations; (3) breach of the covenants or negative covenants defined in the Issuance Documents; (4) an event or introduction of insolvency proceedings of a material party to a gas agreement (as defined in the Financing Documents), the operator in the Leviathan project or Delek Drilling, if it is likely to cause a MAE (as defined in the documents); (5) premature termination of the JOA, the terms of the Leviathan lease, or material gas agreements to which Delek Drilling is a party (as defined in the documents), if it is likely to cause a MAE, subject to certain conditions and qualifications; (6) if a party to a material gas agreement (as defined in the documents) to which Delek Drilling is a party breached the agreement, if it is likely to cause a MAE; (7) in the event of abandonment or suspension of operations at the Leviathan project for more than 15 consecutive days, if it is likely to cause a MAE; (8) if damage is caused to the Leviathan project (including physical damage, revocation of a license or transfer of Delek Drilling's rights in the project by a government entity), which is likely to cause a MAE, which has not been remedied; (9) in the event of denial or revocation of government approval related to the Leviathan project, which is likely to cause a MAE; (10) If any of the Financing Documents to which the Issuer is a party, or pledges provided under the Issuance Documents, with a cumulative value of more than USD 10 million, cease to be in effect; (11) if a non-appealable judgment is handed down against the Issuer for payment of an amount of more than USD 10 million, which was not paid; (12) the occurrence of an event that is likely to lead to the sale of the pledged assets or part of them subject to certain terms and restrictions; (13) if an undertaking to perform mandatory early redemption is breached; (14) if the provisions for expenses from the Issuer's account are breached.

E. The Issuer has undertaken that all the proceeds from the Leviathan Overriding Royalty will be deposited in revenue account pledged in favor of the Issuance Trustee, which is subject to a waterfall payment mechanism, while any surpluses remaining in the account may only be used for buyback of shares or early redemption of the Debentures and cannot be distributed.

F. Provisions have been stipulated for a safety buffer for the interest payments, and the Issuer has undertaken to comply with the covenant of an interest coverage ratio, as defined in the documents, such that this ratio will not be less than 1:1.2 (as at the date of the report, the ratio for 2021 is expected to be 2.2).

For further particulars, see Note 12L to the financial statements (Chapter C of this report).

(C) <u>Debentures of Leviathan Bond Ltd.</u>

On August 18, 2020, Leviathan Bond Ltd., a wholly-owned SPC of the Partnership, issued debentures to foreign and Israeli institutional investors, in accordance with Rule 144A and Regulation S, in a total amount of USD 2.25 billion, in 4 different debenture series, as follows (in this section: "the Debentures: and "the Leviathan Bond Issuance", respectively):

(1) Debentures in a total amount of USD 500 million par value, repayable on June 30, 2023 (in one installment), bearing fixed annual interest of 5.75%.

(2) Debentures in a total amount of USD 600 million par value, repayable on June 30, 2025 (in one installment), bearing fixed annual interest of 6.125%.

(3) Debentures in a total amount of USD 600 million par value, repayable on June 30, 2027 (in one installment), bearing fixed annual interest of 6.5%.

(4) Debentures in a total amount of USD 550 million par value, repayable on June 30, 2030 (in one installment), bearing fixed annual interest of 6.75%.

The principal and interest of the debentures are in USD. The interest on the debentures of each of the Series will be paid twice a year, on June 30 and December 30. The debentures were listed for trading on the TACT-institutional system of the TASE. For further information about the Leviathan Bond Issuance, see the Company's immediate report of August 5, 2020, presented in this report by way of reference (Ref. No. 2020-01-084072).

The foregoing subsidiary provided the issue proceeds as a loan to the Partnership, under back to back terms as the terms of the debentures. The loan balance as at December 31, 2020 (less capital raising costs) was USD 2,219.3 million. It is noted that upon completion of the Leviathan Bond Issuance on August 18, 2020, the loan provided to the Partnership to finance its share of the balance of the investment in the development of the Leviathan Project of USD 1.75 billion as well as loans provided to the Partnership in a total amount of USD 300 million were repaid in full. For further particulars, see Note 12K2 to the financial statements (Chapter C of this report).

(D) Debentures of Delek and Avner (Tamar Bond) Ltd.

On May 19, 2014, Delek and Avner (Tamar Bond) Ltd., a wholly-owned SPC of the Partnership, issued debentures to classified investors in the US, Israel and other countries, in an overall amount of USD 2 billion in five debenture series of USD 400 million each, repayable in December of each of the years 2016, 2018, 2020, 2023 and 2025 (in this section: “the Debentures”). The debentures were listed for trading on the TACT-institutional system of the TASE.

The foregoing subsidiary provided the issue proceeds as a loan to the Partnership, under back to back terms as the terms of the debentures. For further information concerning collateral and commitments relating to the debentures, see Note 12K1 to the Financial Statements. On October 6, 2016 the Partnership made early redemption of the first series in a total amount (original) of USD 400 million, instead of on the original redemption date on December 30, 2016. On July 27, 2017 the Partnership made partial early repayment of the four debenture series (Series 2018, 2020, 2023 and -2025), representing 20% of the outstanding balance of each debenture series (namely, USD 80 million for each series), with the addition of accrued interest of USD 1.1 million, all in accordance with the provisions of the deed of trust of the debentures. On August 31, 2018, the second series (2018) in a total amount of USD 320 million was repaid, instead of on the original repayment date of December 30, 2018. The amount of the early repayment of the foregoing second series included the principal, plus accrued interest in a total amount of USD 2.1 million, plus early repayment fee of USD 1.2 million (“the Early Repayment Fee”). On July 15, 2020, the Partnership repaid part of the third series (2020) in an amount of USD 240 million, of which USD 320 million instead of the original repayment date of December 30, 2020. The amount of the partial repayment of the foregoing third series included the principal, plus accrued interest in a total amount of USD 0.4 million, plus an early repayment fee of USD 4.2 million. For further information see the immediate report issued by the Company on June 14, 2020 (Ref. No: 2020-01-061302), where the information appearing in said report is noted here by way of reference. On December 30, 2020, the balance of the third series (2020) in the amount of USD 80 million was repaid. The loan balance as at December 31, 2020 (less capital raising costs) was USD 635 billion. For further particulars, see Note 12K1 to the financial statements (Chapter C of this report).

(E) Debentures (Series B1)

On December 26, 2016, the Partnership completed the public issue of debentures (Series B1) in an amount of NIS 767.8 million, and in a concurrent to the issue of debentures by Avner Partnership, a similar amount of NIS 760.7 million was raised. In total the Company and the Partnership jointly issued debentures (Series B1) at par value NIS 1,528,300, in return for their nominal value. The total proceeds received, less issue expenses, amounted to USD 392.6 million. Upon completion of the merger of the Partnerships, the Partnership’s Series B1 debentures were consolidated with Avner Partnership's Series B1 debentures, so that the two series became a single series of debentures (Series B1) in the amount of NIS 1.5 billion. Debentures (Series B1) of the Partnership are listed on the TASE. The proceeds from the issue were earmarked for the Partnership to use for investment and financing of operations in the Partnership’s oil fields and for financing its other ongoing needs and, among others, for distribution of profits. The loan balance as at December 31, 2020 (less capital raising costs) was USD 394 million.

The debentures bear fixed annual interest of 4.5%. The principal of the debentures is payable on December 31, 2021, together with the last interest payment. The principal and interest of the debentures are linked to the USD exchange rate.

The Partnership may redeem the debentures ahead of their due date, at its own initiative, in whole or in part at any time, in accordance with the terms set out in the deed of trust. The Deed of Trust stipulates provisions for forced early redemption of the debentures, if the holding of the Partnership in the Tamar lease falls below 10% (out of 100%) and/or if the holding of the Partnership in the Leviathan leases falls below 18% (out of 100% of the holdings of all the partners in the Tamar project), in accordance with the terms and definitions described in the Deed of Trust.

The Deed of Trust includes the undertaking of Partnership to repay the debentures, according to their terms, as well as additional standard undertakings in the Deeds of Trust, including the undertaking to ensure that until full repayment, the debentures will be rated by at least one rating agency, and the undertaking not to create a floating charge on all its assets in favor of any third party to secure any debt or liability, without the prior consent of the debenture holders. The foregoing does not restrict the Partnership in the creation of floating charge on all their assets, and the Partnership may create a fixed charge on all its assets and/or some of them, including the creation of fixed charges on one or more of its assets, and the Partnership may take non-recourse or limited-recourse loans without any restriction and without the prior consent of the holders of Debentures (Series B1) and/or the trustee, as the case may be.

The Deed of Trust includes grounds for calling for immediate repayment of the debentures in certain cases, as is standard in deeds of trust, including: (a) in the event that the economic capital of the Partnership (as defined in the Deed of Trust) is less than USD 400 million ("The Minimum Economic Capital") for two consecutive quarters; (b) the economic capital to debt ratio of the Partnership separately (as defined in the Deed of Trust) is less than 300% (x3) for two consecutive quarters; (c) in the event that the Partnership made a distribution as defined in the Deed or announced its intention to make a distribution, which will reduce the economic capital to debt ratio of the Partnership separately to less than 450% (x4.5); and (d) in the event that the auditors' opinion or review report of the quarterly or annual financial statements of the Partnership will contain a caveat concerning substantial reservations regarding the Partnership continuing its operations as a going concern. As at the date of the statement of financial position, the Partnership is in compliance with the financial covenants set out in the Deed of Trust.

In addition, the Deed of Trust contains a mechanism for adjusting the annual interest rate of the outstanding balance of the principal of the debentures in the event of a downgrade of the ratings Of the debentures so that it would be lower than their base rating of A1 (according to the Midroog scale), as set out in the Deed of Trust, and in the event that the Partnership's economic capital will fall below the Minimum Economic Capital, or in the event that the economic capital to debt ratio Of the Partnership separately will be less than 350% (x 3.5), as set out in the Deed of Trust.

For further information regarding the financial covenants that the Partnership undertook under the issue of debentures (Series B1), see section (L)(1) below.

(F) As stated in section 1.7.1(A)(6)e above, on July 20, 2017, the Partnership completed a transaction for the sale of 9.25% (out of 100%) of its rights in the Tamar and Dalit Leases to Tamar Petroleum against, among other things, a cash consideration of NIS 3 billion. Of the total cash consideration, the Partnership designated USD 321 million for partial early repayment of four series of debentures of Tamar Bond (Series 2018, 2020, 2023 and 2025), as set out in section 1.7.22(D) above.

(G) As part of implementing the provisions of the Gas Framework, the Partnership sold its holdings in the Karish and Tanin leases and are preparing to sell its holdings in the Tamar Project. The net proceeds (after tax, repayment of debentures/loans and other relevant liabilities, if any, inter alia, under the Partnership agreement) received from the sale of such holdings, will be used, among other things, to finance the Partnership's activities.

(H) Pursuant to a permit granted to the Partnership by the Income Tax Authority close to the date of incorporation, the Limited Partnership has undertaken to refrain from taking loans in excess of 3% of the amount raised from investors in the Partnership without prior consent of the Income Tax Authority.

(I) On May 17, 2018, the general meeting of holders of participating units of the Partnership approved the issue of participating units and/or securities convertible into participating units by way of an offering of rights to existing holders of participating units during the period from foregoing approval at the general meeting through May 6, 2021, in an amount and under the terms that will be fixed as may be decided by the general partner, for the purpose of raising the amounts required, in the opinion of the general partner, for financing the ongoing operations of the Partnership, including for investment in the Partnership's oil assets and repayment of its existing liabilities, and for empowering the general partner to decide on the structure, volume and timing of the issue, at its exclusive and absolute discretion, provided that a maximum amount will be set according to which the issue (or issues) will not exceed USD 300 million. As at the publication date of the report, these securities have not yet been issued. Such issue may be made at any time under one or more prospectus and/or shelf offering memorandum, as the general partner will decide.

(J) With regard to non-distribution of part of the Partnership's profits to finance drilling, exploration and development activities and the EMG transaction, see section 1.7.29(J) above.

(K) On July 26, 2020, the Board of Directors of the general partner of the Partnership approved a plan to purchase debentures (Series B1) and debentures of Delek and Avner (Tamar Bond) Ltd at a total estimated cost of USD 50 million (for the purchase of the debentures (Series B1) and the debentures of Delek and Avner (Tamar Bond) Ltd together). For further information see the immediate reports issued by the Partnership on July 27, 2020 (Ref. No: 2020-01-072868), the information appearing in said reports are noted herein by way of reference. The Partnership implemented a buy-back under the foregoing purchase plan of NIS 11,413,393 par value of debentures (Series B1) in return for USD 3 million.

(1) On November 17, 2020, the Board of Directors of the general partner approved another plan to purchase debentures (Series B1) at a total estimated cost of USD 30 million. The purchases were made from time to time in the period between November 19, 2020 and December 31, 2020 in TASE and off-floor transactions. It should be noted that this plan replaced the buy-back plan set out in section 1.7.22(K) above. For further information, see section A9b in Part Three of the update to Chapter A in the Company's quarterly report for the period ended June 30, 2020 published on August 31, 2020 (Ref. No. 2020-01-096111) ("the Q2 Report for 2020"), which includes information presented here by way of reference.

(2) Under the said purchase plan, the Partnership bought back NIS 7,450,000 par value of debentures (Series B1) in return for USD 2 million. For further information, see section A10c in Part Three of the update to Chapter A in the Company's Q3 Report for 2020, which includes information presented here by way of reference.

(L) <u>Financial criteria</u>

(1) Debentures (Series B1) - The Partnership has complied with the financial criteria that it undertook as part of the public issue of Debentures (Series B1), as aforesaid in section 1.7.22(E) above, and as set out below:

Financial covenant[114]	Method of calculation	Tested ratio as at December 31, 2020, and as at the approval date of the report[115]
The financial equity of the Partnership[116]	If the financial equity is less than USD 400 million (the "Minimum Financial Equity") for two consecutive quarters[117].	3,438
Capital to debt ratio	If the separate capital to debt ratio of the Partnership falls below 300% (3 times) for two consecutive quarters.	9
Distribution	If the Partnership distributes a dividend or announces its intention to distribute a dividend that is one of the following: (a) a distribution that is contrary to the provisions of the Partnerships Ordinance and Companies Law, 1999 ("the Companies Law"); (b) a distribution of revaluation gains; and (c) a distribution that results in the capital to debt ratio falling below 450% (4.5 times).	-

Failure to comply with the financial covenants described above will constitute grounds for calling the debentures for immediate repayment. Other than the grounds for calling for immediate repayment set out in the above table, another cause for the immediate repayment of debentures is the event that the auditors' opinion or review report of the quarterly or annual financial statements of the Partnership will contain a caveat concerning substantial reservations regarding the Partnership continuing its operations as a going concern..

1.7.23. Taxation

(A) For further information regarding taxation applicable to the Group's profits (below in this section: the "Companies") that were generated in Israel, see Note 31B1 to the Consolidated Financial Statements.

The special tax issues, including the permit under the Petroleum Profits Tax Law, related to the Partnership's operations, have yet to be litigated in Israeli courts and it is not possible to determine or to anticipate how the courts will rule on such issues, if and when they are brought before them. Furthermore, for some of the issues there is no way to anticipate the position of the Tax Authority. Since the operations of the Corporations are subject to special taxes that include tax benefits, changes that may result due to an amendment to the law, a ruling or a change in the position of the Tax Authority, as set out above, could have material implications on the tax applicable to the Corporations.

(B) On October 12, 2020, the draft Income Tax Regulations (Rules for Calculation of Tax on the Holding and Sale of Participating Units in an Oil Exploration Partnership) (Amendment), 2020, (below in this section: "the Draft Regulations"). Under the Draft Regulations, it is proposed to determine, among other things, that as from the 2021 fiscal year, an oil partnership whose participating units are listed

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114 As set out in the Deed of Trust, failure to comply with the financial covenants described above will constitute grounds for the Trustee and the debenture holders to call for immediate repayment.

115 The ratio is calculated, inter alia, based on the Tamar Project discounted cash flows as at December 31, 2020, included in this Report, and the Leviathan Project discounted cash flows as at December 31, 2020, also included in this Report.

116 The Partnership's equity, based on the last annual or quarterly financial statements issued by the Partnership, as the case may be, less the cost of the investment recorded in these financial statements in all the projects for which capitalized cash flows were included in the last annual periodic report issued by the Partnership, or for which capitalized cash flows were published subsequent to the last annual periodic report as part of the Partnership's reports pursuant to the provisions of the Securities Law (the "Projects" and the "Last Capitalized Cash Flows", respectively), with the addition of the amount of the Last Capitalized Cash Flows of the Projects and with the addition of the abandonment costs recorded in these reports for the Projects. In this regard: (a) "Discounted cash flows" - as defined in section 36 of the Third Schedule of the Securities Regulations (Particulars of Prospectus and Draft Prospectus – Structure and Format)1969, and (b) "Total discounted cash flows" - the total discounted cash flows of the expected reserves (2P) and/or of the expected contingent resources (2C) of the Projects, accordingly, after income tax at the applicable corporate rate, with discount rate of 10%.

117 If at any time the total outstanding par value of the outstanding debentures falls below NIS 400 million, then the minimum financial equity will be USD 250 million. Notwithstanding the foregoing, if at any time after the revision of the minimum financial equity, as aforesaid, the debenture series will be expanded so that the total outstanding par value of the outstanding debentures will be NIS 800 million and greater, then the minimum financial equity will again be USD 400 million.

on the TASE will be taxed as a company; in other words, based on the two-stage taxation method, and this as of the beginning of the fiscal year during which the oil partnership generated taxable income or distributed profits. On November 4, 2020, the Partnership submitted its comments on the Draft Regulations.

(C) <u>Interpretation of section 19 of the Taxation of Profits from Natural Resources Law</u>

(1) The Partnership is not a "transparent entity" for tax purposes under the provisions of the Income Tax Ordinance (New Version) 1961 and accordingly, taxation of the taxable income of the Partnership is imposed on the holders of the participating units. When filing a report on the Partnership's taxable income the General Partner is required to pay the taxes resulting from the report on account of the tax payable by the holders of participating units of the Partnership in the tax year.

(2) Pursuant to the provisions of section 19 of the Natural Resources Taxation Law, the tax is calculated according to the pro rata share in the Partnership of the holders of participating units that are corporations and the share of the holders of participating units of the Partnership who are individuals.

In a judgment handed by the District Court on November 1, 2017, in a petition filed by the comptroller of the Partnership, it ruled that the tax payment resulting from the provisions of the section should not be deemed as an equal distribution, in a uniform amount per unit, but rather as differential payment based on the various tax rates applicable to individuals and corporations, and that the Partnership and/or the General Partner must find the appropriate way to balance between the additional expense involved for the tax rate applicable to holders that are individuals and the expense involved for the tax rate applicable to holders that are corporations.

The General Partner appealed this judgment. On July 28, 2019 the Supreme Court dismissed the appeal and held that the arrangement under which the Partnership will bear the full tax rate for the holders, individuals and corporations, as required under section 19, and will make balancing payments to the holders that are corporations, which will not be considered a distribution as defined in the Law, rather as the required outcome of the fact that the payments were made from profits on account of the tax.

Shortly before the end of the 2017-2019 tax years, the Partnership paid, in addition to the payments on account of the tax applicable for holders who are individuals, balance payments to holders that are corporations. If there is a difference between the final assessment issued to the Partnership in the future and the estimate according to which the payments were made (the "Assessment Differences"), the Partnership will be required to pay (or receive) the required differences in the tax.

(D) As at date of approval of the Report, there is uncertainty regarding the proper balance arrangement with regard to the payment of the Assessment Differences (if any) and concerning the proper balance arrangement that the Partnership will be required to apply for the 2015-2016 tax years during which no balance payments were made.

In view of the existing ambiguity regarding the appropriate balancing arrangements that the Partnership is required to apply, for both the past periods and for the Assessment Differences that will only come to light in the future, the Partnership and the general partner in the Partnership filed an originating motion at the Tel Aviv District Court, petitioning the court, among other things, to determine the appropriate balancing arrangements between the individuals and corporations holding participating units of the Partnership, in view of tax payments that the Partnership is required to make under section 19, including: (a) tax payments insofar as they arise due to a discrepancy between the Partnership's estimate of the taxable income towards the end of the tax year and the independent assessment filed by the Partnership; and/or tax payments insofar as they arise from assessment discrepancies; (b) tax payments made for past periods; this given that the party holding the participating unit on the record date for a tax year in past periods may no longer hold it until it becomes clear (if at all) that the Partnership is required to pay additional tax for that tax year (or vice versa) and given the difference in tax rates applicable to individuals and corporations. As part of the originating motion, the court was presented with various possible alternatives to the arrangements in respect of the tax payments for the assessment differences and for the past periods, in order to decide on the appropriate arrangements as aforesaid. The respondents in the originating motion are the holders of the Partnership's participating units at the dates relevant to the originating motion, and the supervisor of the Partnership, who requested to join as a respondent in the originating motion so that he can present an independent position on his behalf. It is noted that, on October 18, 2020, the court approved the petition filed by the Partnership and the general partner for executing an alternative service of process for holders of the Partnership's participating units by way of a public notice, which also allowed each holder of the Partnership's participating units at the dates relevant to the originating motion (including all current holders of the Partnership's participating units) to join as a party to the proceeding. The court also ordered that the summary motion be heard jointly with the summary motion filed by Isramco on the same issue (SM 32178-03-20). On December 29, 2020, another pre-trial hearing was held, at which the court sought to accept the position of the Tax Authority with regard to proposals of various arrangements that arose according to the positions of the holders. At the end of the hearing, the court ordered that the parties may contact the Tax Authority to find out its detailed position regarding these proposals, and then to file with the court a conclusion in which the position of the Tax Authority will be presented. Due to a request from one of the groups of holders to the Tax Authority, on March 11, 2021 the position of the Tax Authority was filed to the court. The court permitted the parties to respond to this position by March 18, 2021.

The Partnership estimates that, based on the opinion of the legal counsels, there is more than a 50% chance that the Partnership will be required to pay a minimum amount of USD 13.1 million, but it is unable to assess the probability of the Partnership being required to pay an amount that exceeds this amount, due to past tax payments.

It is further noted that, based on the tax report for 2019 and the Partnership's results for 2020, the Partnership revised its taxable income estimate for both 2019 and 2020 tax year. Since, as at the date of approval of the Report, there is ambiguity as to the appropriate balancing arrangements that the Partnership is required to adopt for the Assessment Differences, considering the complexity of the issue and the inability to estimate the probability with respect to the amount that the Partnership will be required to pay as a balancing payment to corporate holders, and based on the opinion of its legal counsel, the Partnership made no provision for the foregoing in its financial statements.

(E) On December 2, 2020, the Ministry of Finance published the draft Taxation of Profits from Natural Resources Regulations (Advance Payments on the Petroleum Profit Levy), 2020 (in this section: "the Regulations")[118], under which the matter of advance payments to be made by holders of petroleum rights in a petroleum venture, including method of calculating such advances, payment dates and reporting thereof.

The Regulations are set up under Sections 10(B) and 51 of the Taxation of Profits from Natural Resources Law, 2011 (in this section: the "Law") for the purpose of regulating the issue of advance payments to be may by the petroleum rights holders of a petroleum venture. The Regulations provides method for calculation of advance payments, payment dates and reporting of payments, as defined in the Law. Breakdown of the main provisions included in the Regulations:

(1) The Regulations provide that a holder of petroleum rights in a petroleum venture (in this section: "Petroleum Interest Holder") will make advance payments on account of the levy for the current tax year, and that such payment will begin from the tax year following the tax year in which the levy coefficient was 1 or higher, with the addition of linkage differentials and interest from the date set for payment until the advance payment is made.

(2) Formulas were also set for calculating the amount of the advance payment, the rate, payment date and manner of reporting the amount paid. According to the Regulations, every entity that is a Petroleum Interest Holder will be required to make advance payments based on their pro rata share in the petroleum interest. It also provided, in the matter of the sale of oil in jointly owned enterprises, pursuant to Section 18 of the Taxation of Profits from Natural Resources Law, to separate the current intake for the effective month of the oil rights holder in the petroleum project. It further provided that in the first three tax years as of the tax year following the tax year in which the levy coefficient was 1 or higher, or as of the 2021 tax year, whichever is later, the rate of the advance payment will be: In the first tax year - 21%; in the second tax year - 30%; and in the third tax year 37%.

(3) Pursuant to section 9(B)(1) of the Law, a derivative payment is a payment calculated as a rate of the petroleum produced the petroleum venture field, the income from the venture or the petroleum profits of the venture. A recipient of a derivative payment is required to pay a levy called the "participation amount". The section provides that the participation amount will be deducted from the levy applicable to the Petroleum Interest Holder. Therefore, the Regulations provide that the participation amount deducted at source by a Petroleum Interest Holder be considered payment on account of advance payments that it is required to make. Such deduction is dependent on the existence of all of the following: (1) the holder of oil rights sent to the tax assessor the amount of the levy that was deducted no later than by the date of payment of the advance payment for the effective month; (2) the amount of the deduction sent was not deducted in the past; (3) the effective month for which the deduction is required is in the same tax year in which the derivative payment was received.

118 https://www.gov.il/BlobFolder/legalinfo/law8957/he/LegalInformation_kesher_8957.pdf

(4) The assessing officer may reduce or increase the rate of the advance payment for a certain tax year if it is proven, to his satisfaction, that the levy for the tax year in which the advance payment is made is higher or lower than the amount calculated for the advance advances for that tax year.

For further information, see Note 12R to the Consolidated Financial Statements.

(F) Memorandum of the Taxation of Profits from Natural Resources Law (Amendment), 2021

On January 7, 2021, a Memorandum was published for public comment concerning Taxation of Profits from Natural Resources (Amendment) Law 2021 (hereinafter in this section: the "Draft Memorandum"), under which a number of amendments to the Law were proposed, including: (1) to amend Section 11 of the Law in a manner that will enable the Tax Authority to collect a disputed levy following the Tax Authority decision to impose such levy under objection of the assessment of the levy and before such dispute has been heard in court; (2) amendment of Section 13 of the Law in a manner that will require the levy reports to be certified by an auditor, as the term is defined in the Accountants Law, 1956; (3) amendment of sections 14-15 of the Law in a manner that will enable the levy report assessment period for the year to be estimated from the date on which the levy reports are submitted for a period of 4 years from the end of the year in which the levy report was submitted;(4) the addition of Section 16(A) to the Law that relates to the application of Section 86 of the Regulation concerning the assessing officer's power to ignore certain transactions; and (5) the addition of Section 41(A) of the Law that relates to the powers vested in the assessing officer to impose a fine on a sum in arrears resulting from the date determined for payment until payment of the levy according to self-assessment. There is no certainty as to whether and when the draft Memorandum will be accepted and in what format (if it is accepted).

1.7.24. Environmental risks and means for their management

(A) Exploration, development, and production of oil or natural gas naturally involve risk of causing environmental damage, which could occur, inter alia, due to malfunction of equipment and/or work procedures and/or unexpected incidents. The severity of the risks varies for each incident and therefore the method for handling and treating them also varies.

(B) The laws and/or guidelines of the competent authorities on environmental issues applicable to the Partnerships

(1) The Petroleum Law and its regulations stipulate that, inter alia, drilling will be accomplished with due caution to prevent seepage of fluids or gas into the subsoil or uncontrollable gushing, as well as to prevent their penetration from one geological stratum to another. Furthermore, it is forbidden to abandon a well unless it is plugged in accordance with instructions of the Petroleum Commissioner.

(2) Furthermore, the Partnership's operations through the Operator may be subject to the provisions of various environmental laws, including the Prevention of Marine Pollution (Dumping of Waste) Law, 1983 and its Regulations; the Law for the Prevention of Marine Pollution from Land-based Sources, 1988 (Prevention of Marine Pollution from Terrestrial Sources Act) (the "Prevention of Marine Pollution from Land Sources Law") and its Regulations; Prevention of Marine Pollution by Oil (New Version) Ordinance, 1980; the Hazardous Substances Law, 1993 and its Regulations; the Maintenance of Sanitation Law, 1984 and its Regulations; the on Liability for Compensation for Oil Pollution Law, 2004 and its Regulations; the Protection of the Environment (Supervision and Enforcement Powers) Law, 2011 and its Regulations; the Prevention of Environmental Hazards (Civil Claims) Law, 1992; Clean Air Law, 2008 and its Regulations (below: (the "Clean Air Law"); the Environmental Protection Law (Environmental Emissions and Transfers - Reporting and Registers Requirements), 2012 and its Regulations; Prevention of Nuisances Law, 1961 and its Regulations; the Protection of the Coastal Environment Law, 2004; the Business Licensing Law 1968, and the regulations and orders issued thereunder.

(3) Furthermore, apart from the Israeli statutory regulation, additional provisions regarding environmental issues have also been added to the terms of the leases issued to the Partnership, and the permits granted for establishing and operating the production systems for the projects in which the Partnership is a partner. During exploration, drilling and/or oil and natural gas production operations, the Partnership purchases independently and/or through the Operator, in accordance with the directives for providing collateral with respect to oil rights (see section 1.7.27(L)(1) below), damage insurance coverage for expenses of environmental cleanup, removal of debris and bodily injury and/or property damage to third parties caused by sudden accidental, unexpected and uncontrolled eruption of oil and/or natural gas. The Partnership does not take out insurance for damages caused due to non-accidental pollution or resulting from gradual and ongoing progression. In this regard, the Petroleum Regulations (Principles for Offshore Petroleum Exploration and Production), 2016 (which revoked the Regulations of 2006) were published, which include various

provisions concerning offshore oil exploration and production, and among other things, conditions regarding the identity of the operator, including its experience in maintaining safety and environmental protection during its exploration and production operations.

(4) In September 2016, the Ministry of Energy, together with the Ministry of Environmental Protection and other ministries, published directives for regulating the environmental aspects of offshore oil and natural gas exploration, development and production activities. These directives are intended to instruct holders of offshore oil rights regarding the measures and documents they are required to prepare as part of their operations within their lease areas, for the purpose of preventing or minimizing as far as possible any environmental hazards that could develop during offshore oil and natural gas exploration, development and production activities. For further information concerning the foregoing environmental guidelines see section 1.7.28(J) below.

(5) In addition to the instructions of the Ministry of Energy and the Ministry of Environmental Protection, the Partnerships' operations may be directly or indirectly subject to environmental directives of other authorities, that may be given from time to time, on behalf of other governmental entities, including the Israel Lands Administration.

(6) In addition, the operating permits for the Leviathan and Tamar platforms stipulate the leaseholder’s duty to act, with regard to environmental protection issues, pursuant to the law and the provisions and permits that are given pursuant to any law, as well as provisions regarding waste discharge into the sea, and emissions into the air, etc. These platform operating permits further stipulate that on matters with regard to which there are no Israeli legislative provisions, US safety and environmental protection standards will apply, as well as the provisions specified in some of the annexes to the MARPOL Convention (International Convention for the Prevention of Marine Pollution), which are or will apply with regard to movable or permanent rigs.

(C) Environmental related events

Based on information given to the Partnership by the Operator, in 2018, there were no events or circumstances connected to the operations of the Partnership and Tamar Petroleum that caused environmental damage and that had a material effect on the Company and/or its operating sector. For further information on material legal or administrative proceedings relating to the environment, see section 1.7.24(F) below.

(D) Environmental risk management policies

The operator of the various projects adopts a strategic ecological policy for protecting the environment and for complying with the provisions of the law in general and the environmental laws in particular. These policies include the operator's strict compliance with internal procedures for dealing with the environmental hazards of its operations, and includes appropriate training of human resources, and includes a work program for minimizing environmental damage and preventing failures and accidents, and for consistent improvement of the organizational culture with regard to safety, the environment and hygiene. As part of this, the operator has a dedicated team for the development stage and the operating stage, responsible for implementing and supervising this policy and for carrying out the procedures to ensure implementation of and compliance with all requirements and standards, including various systems for the management of environmental risks, such as Safety & Environmental Management Systems (SEMS) In addition, the operator carries out due diligence, through a third party, in addition to the routine audits by the Ministry of Energy and the Ministry of Environmental Protection, of the production installations. The operator conducts routine activities with regard to environmental protection, safety and hygiene issues to increase awareness, knowledge and preparedness, including drills and training of the operating crews. The Partnership is working to obtain periodic and specific updates, as required, concerning the Operator's activities as aforesaid. It is further noted that, notwithstanding the Operator's different position with regard to the legal interpretation of the applicability of Israeli laws, and the environmental laws in particular, to its offshore operations outside of the territorial waters (including its operations in the EEZ fields) to that adopted in the expert opinion noted in section 1.7.28(D) below, in addition to the foregoing, the Operator acts to obtain all the permits required under the environmental regulatory provisions for each of the fields in which it operates, as the case may be, including business licenses under the Business Licensing Law, 1968, toxins permits under the Hazardous Substances Law, 1993, waste discharge permits under the Prevention of Sea Pollution from Land-Based Sources Law, and air emissions permits under the Clean Air Law.

In this regard it is noted that on November 6, 2019, the Operator received an air emissions permit for the Leviathan Rig, the validity of which is set out in the law, for a period of 7 years until 2026 (the “Leviathan Emissions Permit”). The emissions permit includes, among other things, maximum emission levels for emission sources on the Leviathan Rig, and provisions with regard to implementation of best available technology, monitoring, sampling, control and reporting to the Ministry of Environmental Protection.

Furthermore, in 2019, the Leviathan Project Operator received a preliminary business license, waste discharge permit and toxins permit for the Leviathan Rig, which are extended from time to time as required by law. A business license and toxins permit were received for the Hagit field, which are extended in a similar manner.

On August 31, 2020, the Ministry of Environmental Protection issued an emissions permit for the Tamar Rig, which is valid for a period of 7 years. However, the wording of the final permit issued includes substantial changes compared with a publicly published draft, according to the operator of the Tamar project, without an opportunity being given to comment on such changes. Following publication of the permit, the operator of the Tamar project contacted the Ministry of Environmental Protection regarding the flaws that it claimed occurred in the formulation of the permit and the technical problems that arise due to its final wording. The Tamar project operator informed the Partnership that on December 30, 2020, it had submitted a request to change the permit, in accordance with the provisions of the Clean Air Law, and other matters including the operator's position regarding reserving of its rights in this matter.

The Ashdod Oil Terminal operates under an emissions permit valid for 7 years as of December 10, 2014 (the “AOT Emissions Permit”). Based on information the Partnership received from the Operator, in view of the requirement of the Ministry of Environmental Protection, the operator submitted a request in May 2019 to amend the AOT Emissions Permit. On October 30, 2020, the Ministry of Environmental Protection published, for public comments, a draft revision of the AOT Emissions Permit, aimed at regulating all the operations executed at the reception facility, and subsequently on December 16, 2020 a revised AOT Emissions Permit was issued. It should be noted that, based on information the Partnership received from the Operator, the requirement for revising the AOT Emissions Permit was given following the Operator's hearing at the Ministry of Environmental Protection for alleged non-compliance with the AOT Emissions Permit provisions in breach of the Clean Air Law. To the best of the Partnership's knowledge, as at date of approval of the Report, once the Operator submitted its arguments in this matter before the Ministry of Environmental Protection, no further enforcement measures have been taken. At the same time, the Operator submitted an application for renewing the facility's emissions permit, which is expected to expire in December 2021.

(E) Environmental costs and investments

To the best of the Company's knowledge, the expected costs for environmental protection are included in the budgets for the various projects and are revised from time to time, in accordance with the approved work schedules. As at date of approval of the Report, no additional material costs are expected.

On March 31, 2019, the installation of a dedicated system for reducing air emissions from the Tamar platform was completed, at a budget of USD 40 million (100%), which reduces emissions of various pollutants by more than 98%, at levels that exceed the Operator's commitment to the Ministry of Environmental Protection.

(F) Material legal or administrative proceedings on environmental issues

As at date of approval of the Report and to the best of the Company's knowledge, no material legal and/or administrative proceedings are being conducted against the Company and/or Partnership and/or any of the Group companies operating in the energy sector in Israel and/or any of their officers, with regard to environmental protection, that could have a material effect on the Company and its operating segments.

(1) On August 28, 2019, the Homeland Guards Association (below in this section: “the Petitioner”) petitioned the Jerusalem District Court against the Ministry of Environmental Protection and its officials and against Noble and the Ministry of Energy, in which it sought to instruct the Ministry of Environmental Protection and its officials to require Noble or the Ministry of Energy to provide various items of information, which, the Petitioner claims, is required for the purpose of making a decision on the application for the Leviathan Emissions Permit; to release the full information to the public and to allocate a 45-day period for comments; and to refrain from issuing an Emissions Permit for the rig until the petition is heard. Concurrently with the petition, a motion was filed for an interim order and a temporary injunction, aimed at preventing the issue of the Leviathan Emissions Permit until the petition was heard. On September 5, 2019, the motion for an interim order and a temporary injunction was denied. On December 19, 2019, the court handed down its judgment, dismissing the petition and charging the Petitioner with the respondent’s costs in an amount of NIS 60 thousand. On

February 3, 2020, the Petitioner appealed the District Court's judgment with the Supreme Court. The Supreme Court scheduled a hearing on the appeal to be held on October 20, 2021. On October 26, 2020, the Petitioner filed its concluding arguments and on March 1, 2021, Noble filed its concluding arguments. As at date of approval of the Report, the Partnership believes that, based on the opinion of the Operator's legal counsel in the proceeding, the chances of the appeal being dismissed outweighs the chances of it being accepted.

(2) On November 21, 2019, a petition was served on Noble, which was filed by the Zichron Yaakov Local Council, Zalul Environmental Association, the Jisr az-Zarqa Local Council, the Megiddo Regional Council, the Pardes Hanna-Karkur Local Council and the Hefer Valley Regional Council (in this section: the "Petition" and the "Petitioners", respectively) against the Head of the Air Quality Division at the Ministry of Environmental Protection and against Noble (in this section: the "Respondents") with the Jerusalem District Court. In the petition, the court was moved to order the Leviathan Emissions Permit null and void, and to rule that there would be no activity on the Leviathan platform that entails the emission of gases. Alternatively, the court was moved to rule the approval of the running-in plan for the platform will be revoked. An interim injunction was also sought to prevent platform activity that requires an emissions permit. On December 17, 2019, the court handed a temporary injunction whereby, pending another decision, the Respondents will refrain from operations on the Leviathan rig that entail the emission of gases, and that the emissions permit will be frozen (below in this section: "the Temporary Injunction"). On December 19, 2019, the court handed a decision regarding cancellation of the Temporary Injunction and dismissal of the petition for an interim injunction. On January 5, 2020, a preliminary hearing was held on the Petition. On March 15, 2020, the court handed its judgment, dismissing the Petition. On June 22, 2020, an appeal was filed against the court judgment to the Supreme Court (below in this section: "the Appeal"). The Appeal seeks to amend the emission permit and to order that the pollutants emitted from the rig are not monitored by Noble or an entity with which it has contracted and that monitoring will be by the director of the Air Quality Division at the Ministry of Environmental Protection or someone that he appoints; and to amend the emission permit so that all the provisions relating to maintenance, environmental management, the environment, and the detection and treatment of leaks will be set out in the emission permit itself and not in an external plan. The hearing of the Appeal is scheduled for June 30, 2021. In November 2020 the Petitioners filed a motion to bring the hearing forward to April 5, 2021. As at date of approval of the Report, the Partnership believes that, based on the opinion of the Operator's legal counsel in the proceeding, at this stage the chances of the appeal being dismissed outweighs the chances of it being accepted.

(3) On January 19, 2020, the Homeland Guards Association (below in this section: the "Petitioner") filed a petition with the Jerusalem District Court against the Ministry of Environmental Protection and Noble Inc., seeking to order the Ministry of Environmental Protection to release to the public its reasoned decision on Noble Inc.'s request to view the information concerning the streaming in the Leviathan Reservoir wells as containing information classified as a trade secret. The Petitioner claims that failure to publish a reasoned decision constitutes a breach by the Ministry of Environmental Protection of the provisions of the Clean Air Law. It was further alleged that the Ministry of Environmental Protection had violated its internal procedures that deal with reviewing of requests to recognize a trade secret. On June 3, 2020, Noble responded to the petition and claimed that as the Petitioner has not requested relief of publication of any information or any relief from Noble, Noble leaves the decision on the petition to the discretion of the court. At the same time, it was alleged that the Ministry of Environmental Protection did not violate the Clean Air Law or its internal procedures. On June 17, 2020, the Ministry of Environmental Protection filed its response to the petition in which it claims that the court should dismiss the petition as it did not breach the Clean Air Law or its internal procedures. A preliminary hearing of the petition was scheduled for May 23, 2021. As at date of approval of the Report, the Partnership believes that, based on the opinion of the its legal counsel in the proceeding, at this stage the likelihood of the appeal being dismissed outweighs the likelihood of it being allowed.

(4) On April 27, 2020, Noble received notice from the Ministry of Environmental Protection of its intention to impose a monetary fine for the alleged breach of the Prevention of Marine Pollution Law and the waste discharge permit of the Leviathan Rig, where part of the alleged violations refer to the running in period. On July 26, 2020, Noble filed its written arguments in response to the foregoing notice and on November 12, 2020, it received the Ministry of Environmental Protection's decision under which it was decided to rescind two of the four sanctions that the Ministry planned to impose, and to partially diminish the amount of the remaining two fines. Payment for this fine was transferred to the Ministry of Environmental Protection on December 11, 2020.

(5) On May 20, 2020, Noble received notice from the Ministry of Environmental Protection of its intention to impose a monetary sanction, in an insignificant amount, for alleged violations of the emissions

permit granted to the Leviathan Rig and of the Clean Air Law, and the Commissioner's directive regarding continuous monitoring systems on the Leviathan Rig. Noble informed the Partnership that it had submitted a request to the Ministry of Environmental Protection for information under the Freedom of Information Law, 1998 (the "Freedom of Information Law"), that directly deals with the claims raised in the foregoing notice and that the Ministry of Environmental Protection approved a postponement of the date for submitting claims regarding this monetary sanction and fixed it for 30 days after receipt of the information. As at date of approval of the Report, it is unable to assess the likelihood of further reductions in the amount of the fine or Noble's ability to have some components of the sanction dismissed.

On July 1, 2020, Noble received another notice from the Ministry of Environmental Protection regarding its intention to impose a monetary sanction, in an insignificant amount, for alleged violations of the emissions permit granted to the Leviathan Rig and of the Clean Air Law, and the Commissioner's directive regarding the use of flare stacks on the production platform. On August 16, 2020, Noble submitted its arguments with regard to this sanction to the Ministry of Environmental Protection. On December 13, 2020, the Minister of Environmental Protection decision was received, according to which it was decided to consolidate part of the sanctions that the Ministry of Environmental Protection intended to impose and to cancel others, so that it will impose 4 sanctions on Noble and partially reduce the amount of one of the fines. Payment for these fines was transferred to the Ministry of Environmental Protection on January 12, 2021. On January 28, 2021, another decision of the Ministry of Environmental Protection was received canceling one of the fines that was imposed with regard to its foregoing decision, and at the same time it notified that it intends to impose such penalty, while giving Noble an opportunity to complete it arguments regarding it, by February 28, 2021 However, Noble informed the Partnership that it has submitted a request for information to the Ministry of Environmental Protection under the Freedom of Information Law, which directly addresses the claims raised in the foregoing notice, and, at the same time, a request for an extension for the submission of its arguments to within 30 days of the date of receipt of the requested information To date, a response to the freedom of information request and the extension has not yet been received, and therefore Noble filed its arguments on March 7, 2021

(6) On January 19, 2021, Noble received a warning and notice of a hearing from the Ministry of Environmental Protection, that was held on March 22, 2021, with regard to an alleged violation of the waste discharge permit that was given to the Leviathan platform, with respect to the open system waste standards set out in the permit. On March 24, 2021, the Ministry's summary of the hearing was received, in which it notes that the Ministry will not recommend punitive sanctions for the alleged violation, however in the event of further violations, it will consider exercising its full powers under the law. It further provided that Noble must prepare procedures and complete measures for locating sources of oil spill.

(7) On December 15, 2020, a motion for certification of a class action was filed with the Tel Aviv District Court by a resident of Dor Beach on behalf of "anyone who was exposed to the air, sea and coastal environmental pollution caused by prohibited emissions from the gas platform operated by the Respondents in the sea, which is located opposite Dor Beach, and that serves the Leviathan natural gas reservoir, during the period from commencement of the platform's activity in December 2019 through until a judgment is issued in the claim" (below in this section: the "Petitioner" and the "Class Members"). The motion for certification was filed against Noble and Chevron (in this section: "the Respondents"). In essence, the motion for certification argues that the Respondents exposed the Class Members to air, sea and environmental pollution, due to prohibited emissions deriving from the Leviathan reservoir platform. Such exposure, according to the Petitioner, created various health problems (which were not specified in the motion got certification) and damage of impairment of autonomy due to the health concerns as aforesaid. The main remedy sought in the motion for certification is compensation for the Class for the damage it allegedly incurred which is estimated at NIS 50 million. In addition, the Petitioner moved for a remedy of an order instructing the Respondents to immediately comply with the its obligations under the Clean Air Law and the Regulations promulgated thereunder. The pre-trial hearing was scheduled for January 19, 2022. As at date of approval of the Report, the Partnership estimates that, based on the opinion of the Operator's legal counsel in the proceedings, at this stage the likelihood of the proceeding being dismissed outweighs the likelihood of it being allowed.

(G) <u>Cyprus</u>

To the best of the Company's knowledge, under the Impact on the Environment from Certain Plans and/or Programs Law (2005), (which was adapted to the EU directive), strategic environmental assessment is required with regard to government decisions concerning activities or programs that may affect the environment. The Cypriot Ministry of Energy assigned the preparation of the strategic environmental assessment report to companies operating in the industry (following a tender) with regard to oil and natural gas exploration and production in Cyprus and in the Cypriot exclusive economic zone (EEZ) ("the Environmental Report"). The holder of an exploration and production permit is required to operate in accordance with the Environmental Report and to conduct preliminary environmental surveys for such operations in the permit area.

It is further noted that the EMG Pipeline and its operation, which connects the Israeli pipeline network in the Ashkelon area to the Egyptian pipeline network in the el-Arīsh are, are subject to both Israeli and Egyptian regulation.

In addition, as at the date of approval of this Report, and according to information the Partnership received from the Operator, the Company is not aware of any failure to comply or deviation from environmental requirements in any of the projects in which the Partnership holds rights, which could have material effect on the Partnership and on the Company.

1.7.25. Restrictions on and supervision of the Partnerships' operations

(A) The Gas Outline Plan

(1) On August 16, 2015, Government Decision No. 476 was issued (which was adopted in the government decision of May 22, 2016), regarding an outline plan for increasing the quantity of natural gas produced from the Tamar[119] natural gas field and swift development of the Leviathan, Karish, and Tanin gas fields and other gas fields (below in this section: the “Government Decision”), that came into force on December 17, 2015 with an exemption granted from certain provisions of the Economic Competition Law to the Partnership, Avner, Ratio and Noble (below in this section: the “Parties”) by the Prime Minister, in his capacity as Minister of the Economy, pursuant to the provisions of section 52 of the Economic Competition Law (below in this section: the “Exemption” or the “Exemption Pursuant to the Economic Competition Law”)[120]. The foregoing Exemption applies to certain restrictive arrangements which ostensibly may have been attributed to the Parties, as set out in the Government Decision (the “Restrictive Arrangements”). The Government Resolution and the Exemption will be referred to above and below as "the Gas Framework".

(2) The restrictive trade practices with respect to which the Exemption was granted are:

A. The restrictive arrangement that was allegedly created, according to the position of the Competitions Commissioner, as a result of the acquisition of the Ratio Yam license by the Partnerships and Noble; and the restrictive arrangement allegedly created, as a result of the parties joining together as co-holders of the Ratio Yam permit and Leviathan reservoir.

B. The restrictive arrangement that may allegedly be created if the parties or some of them will jointly market the gas produced from the Leviathan reserve to the domestic market until January 1, 2025. [121]

C. The restrictive arrangement that may allegedly be created if the parties or some of them will jointly market the gas jointly produced from the Leviathan Reservoir for export only.

D. The restrictive arrangement that may allegedly be created as a result of a specific natural gas purchase agreement from the Leviathan reserve, provided that such agreement is signed by January 1, 2025.

E. With regard to their operations in the Tamar and Leviathan reservoirs only, the Partnership and Noble hold a monopoly as declared by the Competitions Commissioner[122].

(3) The exemption from the restrictive arrangements set out in sections 1.7.25(A)(2)B and 1.7.25(A)(2)E above is conditional on the fulfillment of the following conditions:

A. Karish and Tanin

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[119] Tamar was defined in the exemption attached to the Gas Framework as "a natural gas reservoir located in the area of the Tamar I/12 and Dalit I/13 leases and the rights held by the holders of the Tamar in the gas pipeline infrastructure and all its components and parts, including the rights of the holders of Tamar to use the onshore reception and processing facility, from the Tamar Reservoir to the National Pipeline network".

[120] On January 1, 2019, the amendment to the Competition Law was approved, including the change of the name of the law from the Restrictive Trade Practices Law to the Economic Competition Law.

[121] The Minister of Energy has the authority, under certain conditions set out in the Exemption, to extend the exemption until January 1, 2030.

[122] The Minister of Energy has the authority, under certain conditions set out in the Exemption, to extend the exemption until January 1, 2030.

1. Under the Gas Outline Plan, the Partnerships and Noble are required to transfer all their interests in the Karish and Tanin Leases to a third party that is not affiliated with any of the Parties, subject to the approval of the Commissioner of Petroleum Affairs.[123]

2. The permitted export quota of 47 BCM from Karish and Tanin reservoirs was replaced, as of the date of approval by the Commissioner of Petroleum Affairs, by the duty to supply the domestic market imposed on the Leviathan leaseholders.

   In accordance with the provisions of the Outline Plan, the entire holdings in the Karish and Tanin Leases were transferred to a third party in December 2016. For further information see section 1.7.29(Q) of this Report.

B. <u>Tamar Project</u>[124]

1. The Partnership and Avner[125] will transfer, within 72 months from the date the exemption under the Economic Competition Law was granted ("the Tamar Effective Date") all their rights in the Tamar and Dalit Leases to a third party that is not related to the any of the parties or that holds a means of control in the Leviathan or Karish and Tanin reservoirs, subject to the approval of the Commissioner of Petroleum Affairs[126].

   On this matter it is noted that the Company and Delek Energy held discussions with the government on the question of whether the provisions of the foregoing Gas Framework regarding the exercise of the Partnership's rights in the Tamar reservoir also establish the obligation to dispose of the rights to royalties of the Company and companies under its control from the Tamar reservoir. In this regard, it is noted that Delek Energy sold its rights to royalties from the Tamar and Dalit leases to Delek Royalties, as set out in section 1.7.29(A) below, and the Company sold its rights to royalties from the Tamar and Dalit leases to a third party, as specified in Note 12C5.

   In order to obtain the approval of the Commissioner of Petroleum Affairs for the transfer of Delek Energy's royalty rights from the Tamar Project, the Company and Delek Energy undertook that the provisions of the Gas Framework will apply to the shares that they hold in Delek Royalties, and in the letter of the Competition Authority dated January 3, 2018, it states that it on December 17, 2021, the Company and/or Delek Energy will be a “related party” to Delek Royalties, as this term is defined in the Gas Framework, and if at this date the Company and/or Delek Energy will hold 5% or more of Delek Royalties shares, the provisions of the Gas Framework will apply, so that the sanctions for failure to comply with these provisions will apply only with respect to shares in Delek Royalties.[127] In this context, it should be noted that Delek Energy sold its royalty rights from its Tamar and Dalit holdings to Delek Royalties, as described in section 1.7.1(C) above. For further information, see Note 1C12(4) to the Consolidated Financial Statements.

2. By the Effective Date for Tamar, Noble will submit a binding sales contract to the Commissioner of Petroleum Affairs, such that subsequent to its realization, Noble's rights in the Tamar lease will be no higher than 25% and the excess rights will be transferred to a third party that is not related to the

[123] As aforesaid, on December 26, 2016, a transaction for the transaction was completed for the sale of all the interests of the Partnership, Avner and Noble, in the Tanin and Karish leases to Energian Israel.

[124] The Outline Plan provides that the periods during which a force majeure event occurred in Tamar will not be taken into account. If such events occur, the relative time count relating to Tamar will be halted, provided that the Partnerships and Noble act rapidly and diligently to correct the damage caused by the force majeure. A force majeure at Tamar was defined as being: "war, military operation, terror act, significant accident or natural disaster that result in significant malfunction or significant defect in any of the facilities or systems required for production gas, and that as a result supply of gas ceased or was significantly reduced for a significant period and prevented the Partnerships and Noble from selling the relevant oil asset in a regular course of business, and any rational person acting in place of the Partnerships and Noble would not have been able to prevent or overcome them".

[125] As stated above, on May 17, 2017, Avner was merged with and into the Partnership, so that all of Avner's assets and liabilities were transferred to the Partnership as is, and on May 17, 2017, Avner was liquidated without dissolution and was struck off from the records of the Registrar of Partnerships.

[126] To comply with the provisions of the Gas Outline Plan, on July 20, 2017 a transaction was engaged for the sale of 9.25% of the Partnership's interests in the Tamar and Dalit Leases to Tamar Petroleum. As at date of approval of this Report, the Partnership holds 13.42% of the voting rights and 22.6% of the equity rights in Tamar Petroleum. To comply with the provisions of the Gas Framework, the Partnership will be required to sell its foregoing holdings in Tamar Petroleum by the effective date.

[127] Namely, the Company and/or Delek Energy will retain holdings of less than 5% and if they have any additional holdings, these will be transferred to the trustee who will take necessary action to exercise them in accordance with the provisions of the Outline Plan.

parties or to any one of them, and does not hold the means of control in the Leviathan reservoir or the Karish and Tanin reservoirs, subject to the approval of the Commissioner of Petroleum Affairs[128].

3. If all the interests noted in subsections A and B above have not been transferred (the "Transferred Tamar Rights") by the Effective Date, the unsold Transferred Tamar Rights will be transferred to a trustee (as defined in the Gas Outline Plan), which will try to find buyers and obtain the highest bidder for the sale of Transferred Tamar Rights, and all in accordance with the Gas Outline Plan and the instructions received from the Competitions Commissioner. The trustee will sell the Transferred Tamar Rights while taking into account the market value and the highest price offered, and in any event no later than 12 months after the date of the transfer of the rights in Tamar (even if the price does not represent the real value of the Transferred Tamar Rights). From the Tamar Effective Date or the date of sale of Noble's interests in the Tamar Lease, as set out above, whichever is earlier, Noble will no longer hold any veto rights with respect to the Tamar reserve.

4. The consideration for the entire interests of the Partnership, Avner and Noble in Tamar may not be paid in royalties. The proceeds may be paid in future installments, provided that the installment milestones are not linked to the prices or volumes of gas to be sold from the Tamar reserve. Notwithstanding the foregoing, the Partnerships and Noble may retain the right to royalties from the sale of oil (other than condensate) from the Tamar reservoir, if any is discovered.

C. <u>New agreements for the supply of natural gas from the Leviathan and Tamar reservoirs</u>

1. Agreements for the supply of natural gas from the Leviathan and Tamar reserves signed after the date of the Government Decision will comply with the following provisions:

a) No limits will apply to consumers regarding the purchase of natural gas from any other natural gas supplier.

b) Consumers may resell the natural gas that they purchased pursuant to the terms and provisions set out in the Exemption.

c) The parties may not impose any limit on the selling price at which the consumer may resell the natural gas.

2. With regard to agreements for the sale of natural gas from the Tamar reserve that are singed from the date of the Government Decision through to the end of four years from the approval by the Commissioner of Petroleum Affairs for the transfer of the Karish and Tanin Interests ("Options Opening Date") the holders of rights in the Tamar reserve will be required to offer to every consumer the option for purchasing gas under contract for any term they will choose up to 8 years or longer term to be agreed between the parties and the consumer. With regard to an agreement that exceeds 8 years, the consumer will be given the unilateral right to cut the term of the agreement short within a time window of 3 years from the Options Opening Date.

3. With regard to agreements for the sale of gas from the Leviathan reserve that are signed from the date of the Government Decision through the Options Opening Date, the holders of rights in the Leviathan reserve will be required to offer every consumer the option of purchasing gas under contract for any term they will choose up to 8 years or longer, as agreed between the parties and the consumer.

4. On April 2, 2017, the Tamar partners clarified the following in a notice to the Minister of Energy, the Budget Director in the Ministry of Finance, and the Economic Competition Commissioner

a) that if there is a delay in the initial supply of gas by a new gas supplier, the Tamar partners will allow their customers, in accordance with gas supply agreements signed from the date of the Gas Framework until four years after the Commissioner's approval of the transfer of the rights in the Karish and Tanin gas reservoirs (the opening date of the options), which were supposed to start purchasing gas from the new supplier, fully or in part, to extend the contract with them until the new supplier is able to supply gas in commercial quantities (but no more than eight years after signing the agreement with them), without changing the terms of the agreement.

b) The Tamar partners also clarified that they will grant a consumer that is an electricity producer or other consumer wishing to construct new facilities and is forced by the financing requirements of the

[128] In December 2016, a transaction was closed for the sale of 3.5% of Noble's interest in the Tamar and Dalit Leases to Everest, in which Harel Insurance Company Ltd. and other institutional entities under its control, as well as Israel Infrastructures Fund Group. are partners; on March 14, 2018, the transaction between Tamar Petroleum and Noble was completed, under which Noble sold 7.5% (out of 100%) of its interests in the Tamar and Dalit leases to Tamar Petroleum. In this regard, it should be noted that Noble sold its shares in Tamar Petroleum and thus completed its obligation under the Gas Framework, regarding this matter. For further information, see footnote 149 below.

facilities to sign a long-term gas supply agreement, the option of signing an agreement that is longer than eight years, and according to the supply capacity of the Tamar project.

(4) Additional provisions in the Government Decision

A. Additional provisions regarding prices

1. So long as the holders in the rights in the Tamar and Leviathan leases comply with the terms and conditions of the Government Decision and Exemption under the Economic Competition Law, the provisions of the Commodity and Service Price Control Order (Application of the Law on Natural Gas and Level of Control) 2013 will remain in force, applying control on the gas sector with regard to reporting profit margins and gas prices, for a period commencing on the date of the Government Decision, i.e. August 16, 2015, through to the date on which the transfer of the Partnership, Avner and Noble's rights in the Karish and Tanin leases is completed, whichever is the earlier, ("the Transition Period").

2. During the Transition Period, the holders of the Tamar and Leviathan rights, including the Partnerships (below in this section: "Holders of Rights in the Leases") will offer potential consumers the natural gas price and linkage options, as set out below:

a) A base price that will be calculated according to the weighted average of the prices in the agreements between the leaseholders and their consumers and that is updated in each quarter (according to the formula set out in the Government Decision).[129]

b) The Brent price per barrel as calculated according to a formula that benefits the consumers that have, at the date of the Government Decision, agreements with the Tamar partners.

c) For private power producers (conventional or co-generation) that comply with the terms and conditions set out in the Government Decision, other than the alternatives provided in subsections (a) and (b) above, also the alternative that includes linkage to the power generation tariff, based on a simple average of the prices set in the supply agreements, as specified in the Decision.[130]

3. The provisions of subsection 2 do not derogate from the obligation of the holders of rights in the Tamar and Dalit Leases to offer Israeli consumers gas at the price fixed in an export agreement in order to meet the conditions for the taxation mechanism as set out in section 1.7.25(A)(4)D below.

With respect to tax decisions that were issued with regard to the amendment to the Tamar-Dolphinus Agreement and the amendment to the Leviathan-Dolphinus Agreement, see Sections 1.7.13(E)(1)b and 1.7.13(E)(2)b above

B. Provisions concerning the export of natural gas

1. The Gas Framework included several clarifications and amendments to Government Decision 442 of June 23, 2013, with regard to adoption of the main recommendations of the committee for examining government policy regarding Israel's natural gas sector and its future development (the Tzemach Commission Report). For further information, see section 1.7.28(A) below.

2. Furthermore, the decisions stipulated that the Tamar leaseholders will be permitted to use the Mari B rig for the entire term of the Tamar lease for natural gas production or supply to the local market from the Tamar reservoir, subject to the terms and conditions set out in the Government Decision.

C. Tamar SW Reservoir

Under the Government Decision, the Commissioner of Petroleum Affairs notice was issued, that the Tamar SW reservoir development plan will be approved on condition that the revenues from the natural gas produced from the Tamar SW reservoir will not exceed a volume higher than USD 575 million. This production limit will be canceled by the Commissioner of Petroleum Affairs once an agreement is reached between the State and the Tamar leaseholders regarding all the issues relating to the development of the Tamar SW reservoir. For further information regarding the Tamar SW reservoir, including the development plan that was approved, and regarding the mediation arrangement in which it was agreed to divide the Tamar SW reservoir between the area of the Tamar lease (78%) and the area of the Eran license (22%), see sections 1.7.30(H)(1) and 1.7.11(B) below.

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[129] The updated base price as calculated by the Natural Gas Authority in a release dated January 14, 2021 is USD 5.16 per MMBTU unit. For further information, see https://www.gov.il/BlobFolder/generalpage/decision476/he/ng_price_1_2021.pdf

[130] According to the foregoing notice of the Natural Gas Authority dated January 14, 2021, a simple average of the prices of conventional independent power producers is USD 4.7 per MMBTU and a simple average of the prices of cogeneration independent power producers is USD 4.7 per MMBTU.

D. Taxation

Under the Government Decision, the Tax Authority notice was issued regulating various tax issues regarding the operations in the Tamar and Leviathan reservoirs. The Government also decided to take measures to promote amendments to the Petroleum Profits Law aimed, among other things, at closing loopholes, providing various clarifications and assessment and collection procedures. In addition, it states that the price per unit of oil in the export agreement will be taxed according to the actual receipt from the export agreement and not according to the "local average price" for the same type of oil, as defined in the Natural Resources Profits Tax Law, and that there will be no need to annually review the receipts from the export agreement, subject to prior receipt of the Tax Authority approval that the price per unit of oil set in the export agreement is not lower than the "average local price" or alternatively that the holder of the export agreement undertakes to offer the price set in the foregoing export agreement to new customers in Israel, in the manner and at the terms as set out in the Gas Outline Plan. It is noted that the Tax Authority's approvals as aforesaid were received by the Partnership in relation to all of the export agreements in which the Partnership has engaged (both in the Tamar reservoir and in the Leviathan reservoir).

E. Local Content

The Government noted the Minister of the Economy announcement that the holders of rights in the Tamar and Leviathan reservoirs undertake to invest in local content in a cumulative amount of USD 500 million over eight years from the date of granting of the Exemption, i.e., as of December 17, 2015. Local content will be considered, inter alia, as expenses for the purchase of goods or services from entities registered in Israel (including foreign entities registered in Israel), purchase of goods, purchased from Israeli contractors, suppliers or manufacturers, investments in research and development in Israel (directly or indirectly), payroll expenditure (up to a maximum of 20% of such undertaking), professional training expenses, donations and social responsibility activities. It is noted that as at the date of approval of the Report, this undertaking with respect to investment in local content has been carried out in full.

F. Regulatory Environment Encouraging Investments

The Government of Israel undertook to maintain regulatory stability in the natural gas exploration and production segment on three issues: the maximum government take, export and the structural changes contained in the Government Decision, and this for a period of 10 years from date of the Government Decision.

Following the government decision and the granting of the Exemption, several petitions were filed with the High Court of Justice. On March 27, 2016, the High Court of Justice handed a ruling on these petitions stating, among other things, that the wording of the stability clause in the Gas Outline Plan (the government's undertaking to restrict future changes in the regulation of the natural gas sector) cannot remain and the State was given one year to regulate the issue of stability in the Gas Outline Plan.

On May 22, 2016, the government again adopted the decision of August 16, 2015, regarding the Outline, setting an alternative arrangement to section J of the Option for a "stable regulatory environment", to ensure a regulatory environment that encourages investments in natural gas exploration and production.

As at the date of approval of this Report, the Partnership is acting to implement the relevant provisions of the Gas Outline Plan. As part thereof, the Partnership has sold its holdings in the Karish and Tanin Leases, as set out in section 1.7.29(Q) above, and sold 9.25% of its holdings in the Tamar and Dalit Leases to Tamar Petroleum and commenced streaming of natural gas from the Leviathan Reservoir on December 31, 2019. It is continuing to act to sell its remaining holdings in the Tamar and Dalit reservoirs.

1.7.26. Antitrust and Economic Competition Law

(1) On October 12, 2000 the Competitions Commissioner approved a merger transaction under which Delek Investments and Properties Ltd.[131] ("Delek Investments") acquired the rights of RB Mediterranean Ltd. in the Yam Tethys project. This approval, as revised, is restricted by several conditions and includes, inter alia, a condition that any purchase of holdings by the Delek Group and/or Delek Investments and/or Delek Real Estate and/or Delek Israel, of 5% or more in a

[131] On April 16, 2012, and in force since December 31, 2011, Delek Investments was merged and assimilated into the Company under the provisions of the first part of the eighth section to the Companies Law and as a result was eliminated.

corporation that engages in exploration, production, transmission, marketing or selling of natural gas in Israel, requires prior approval of the Competition Commissioner, if the corporation possesses any natural gas discoveries; the provisions of this section do not apply to the joint venture in the Yam Tethys Project.

(2) Tamar Project

A. On August 28, 2006 the Competitions Commissioner granted an exemption from approval of a restrictive agreement pursuant to section 14 of the Economic Competition Law, an agreement that deals with the participation of the parties thereto in the rights of the Matan and Michal licenses, in the area where the Tamar and Dalit natural gas was discovered in 2009 and of which part of the rights therein were later transferred to Noble. The Competitions Commissioner's decision was contingent on the following principal conditions:

1. The "Local Corporations" (as defined in paragraph 3 below) would not hold jointly, whether individually or with additional holders, any gas rights other than the rights directly and exclusively arising from the Matan and/or Michal licenses, without the express prior written consent of the Competitions Commissioner. By December 31, 2006, the Local Corporations will terminate any joint holding in gas rights, other than those directly and exclusively arising from the Matan and/or Michal licenses, which they held jointly when the decision was made, whether individually or with other holders, unless such joint holding is expressly permitted in writing by the Competitions Commissioner.

2. In any arrangement, agreement or understanding, oral or in writing, with regard to setting a mechanism or system for decision making between holders of Matan and Michal licenses for marketing natural gas produced under the Matan and Michal licenses, none of the "local corporations" shall individually own, directly or indirectly, any right or power to prevent the other holders from taking any decision or action for marketing natural gas produced under the Matan and Michal licenses.

3. In this matter, "The Local Corporations" – means Delek Group and Isramco; "Delek Group" – Avner Partnership and/or Delek Drilling Limited Partnership and/or any person affiliated with any of them; "Isramco" – and any party affiliated to it.

B. On November 13, 2012, the Partnerships received notice from the Competitions Commissioner that it had declared them to be monopolies - together with the Tamar Project partners and separately - in the supply of natural gas in Israel from the commencement of commercial supply from the Tamar Project.

Subsequent to it being declared a monopoly, Chapter D of the Economic Competition Law applies to the Partnership, including prohibiting the Partnership from refusing, under unreasonable grounds, to supply natural gas and barring the exploitation of its market power in a manner that could reduce business competition or cause public harm.

C. In 2012 Tamar partners were granted an exemption on conditions (that were met) from approval for a cartel regarding the IEC agreement. In 2012 and 2015 the Competitions Commissioner issued several decisions concerning exemption from cartel regulations regarding fourteen natural gas supply contracts between the Tamar partners and private gas consumers in which the basic supply term exceeds 7 years ("the Commissioner's Decisions"). The highlights of the Commissioner's Decisions are as follows:

A power consumer will have the option of choosing, with regard to an agreement, one of the following two options:

1. shortening the term of the agreement to seven years, from the date of commencement of supply of natural gas; or alternatively:

2. reducing the volume of gas under the take or pay contingency to a volume equivalent to half of the average annual consumption of the power producer in the three years preceding the date of notice. The reduction of the purchase quantity will take effect one year from the date on which said notice was given through to the end of the agreement period, accordingly ("Reduced Purchase Quantity") Notice of Reduced Purchase Quantity may be given at any time during the longer of the terms: (1) from January 1, 2018 through December 31, 2020 (regarding five agreements for the sale of natural gas) or from January 1, 2020 through December 31, 2022 (with regard to nine agreements for the sale of natural gas); or (2) from the beginning of the fifth year following the natural gas supply date until the end of the seventh year, as aforesaid.

3. When the minimum quantity is fixed for which the gas consumer is committed to pay, as aforesaid, the annual gas quantity and the quantity included in the agreement, will be updated.

4. The gas consumer will be permitted to sell the natural gas earmarked for use of the gas distribution network consumers, up to a volume of 15% of the annual gas quantity in each year.

5. The gas consumer will not be restricted regarding the purchase of natural gas from other gas suppliers who are not among the Tamar partners.

6. The Tamar partners may not engage, directly or indirectly, in any agreement for the supply of natural gas from the Tamar Reservoir without obtaining a permit in advance from the Competition Authority.

With regard to this condition, it is noted that, on May 24, 2020, pursuant to Section 14 of the Economic Competition Law, the Competition Commissioner released her decision on canceling the demand to obtain a permit in advance from Supervision of Competition before each engagement in an agreement to supply gas from the Tamar reservoir, and determined that, instead, the agreements will be made part of a self-assessment regime i.e., the burden to review their legal validity will be imposed on the Tamar Partners and their customers, and the Competition Commissioner will be able to review the agreements in retrospect and not close to the time of signing, and to take enforcement measures if it transpires that arrangements which harm competition have been made.[132]

Further to the Competition Commissioner's decisions, these agreements were revised accordingly, and all new natural gas supply agreements signed by the Tamar partners were drawn up to comply with the Competition Commissioner's decisions.

D. For further information concerning disputes that arose between the other Tamar partners, that have no holdings in the Leviathan project, and Noble and the Partnership, with regard to, among other things, the ability of Noble and the Partnership to avoid amendments in the IEC-Tamar agreement, the exercise of vet rights over the marketing of the gas produced from the Tamar reservoir, and concerning the balancing arrangements signed between the Tamar partners with regard to separate marketing of gas, see section 1.7.13(D)(1)F.4 above.

The validity of the settlement agreements with Tamar and Leviathan are contingent upon, among others, approval of a consent decree signed by Noble and published for public comment by the Competition Commissioner on January 31, 2021 ("the Consent Decree").[133]

Pursuant to the Consent Decree, Noble undertook to enable each of the Tamar Partners to sell its share of Tamar reservoir separately from the other Partners, without requiring prior consent. Subject to compliance with Noble's undertakings, and in view of the settlement agreement signed between the Tamar Partners and the IEC, the Commissioner will not continue the matter and will not take enforcement measures against anyone in the Noble group for the acts specified in the complaints lodged by the other Tamar partners and the IEC concerning the agreement signed between them on October 4, 2020, as described in section 1.7.13(D)(1)F.2 above. The Consent Decree is subject to the approval of the Competition Court.

(3) For further information concerning a claim and motion for certification of a class action filed in February 2020 with the Tel Aviv District Court by an electricity consumer, claiming, inter alia, that the Partnership and Noble, which have cross ownership of the Tamar and Leviathan reservoirs, cannot prevent the other Tamar partners from engaging with the IEC in an agreement that reduces the cost of the natural gas it supplies to the IEC, see the immediate report issued by the Company on March 1, 2020 (Ref. No.: 2020-01-020439), the information appearing therein is noted here by way of reference.

1.7.27. Specific legislation applicable to the sector in Israel

Exploration, development and production of oil and/or natural gas (below in this section: "Petroleum") in Israel are regulated mainly under the Petroleum Law and its amendments and the regulations promulgated thereunder, the main points of which are as follows:

(A) <u>The Petroleum Law, 1952 (below in this section: "the Law").</u>

(1) The Law provides, inter alia, that a person may not explore for oil unless under a preliminary permit, license or lease (as defined in the Law) and a person may not produce oil unless under a license or lease.

(2) Preliminary testing (that does not include test drilling) in any area, to ascertain the prospects for discovering oil in such area, including conducting of seismic surveys, is subject to obtaining a preliminary license. The Law permits priority rights to be granted to the holder of the preliminary

132 https://www.gov.il/he/departments/legalInfo/decisions8856-0620

133 https://www.gov.il/he/departments/legalInfo/draftord-nobleenergy

rights for petroleum interests in the area for which the preliminary permit was granted, if such holder undertakes to conduct preliminary tests and invest in oil exploration as will be decided by the competent representatives of the State in this matter.

(3) A License grants the licensee, subject to the provisions of the Law and the terms and conditions of the license, mainly the right to explore for oil in the area of the license according to a plan submitted to the Commissioner of Petroleum Affairs in accordance with the Law, and the exclusive right to conduct appraisal and development drillings in the license area and to recover oil from it. In general, a license will be granted for an initial period of 3 years and may be extended, in accordance with the conditions provided under the Law, for an additional period that will not exceed 4 years.

(4) If a license holder discovers oil, it is entitled to an extension of the license period for a further sufficient period for defining the boundaries of the oil field, but no longer than two years, and the license holder is entitled to receive a lease on a certain area within the license area, which grants it exclusivity to explore and to produce oil in the area of the lease all the while it is valid. The lease is given for a period of up to 30 years from the date it is issued, but if a lease is given pursuant to a license that was extended after a discovery in the license area, the term of the license will commence from the date of termination of the original license, prior to extension. A lease may be extended, pursuant to the provisions of the Law, for an additional period of up to 20 years. A lease may expire following suitable prior notice given by the Minister of Energy, if the lease holder fails to produce or ceases to produce commercial volumes of oil.

(5) The Law requires, inter alia, a lease holder to pay royalties to the State at a rate of one eighth of the quantity of oil and/or natural gas produced from and used in the lease area (excluding the quantity of oil and/or natural gas used by the lease holder in operating the lease area), and in any case no less than the minimum royalty set in the Law.

(6) A lease may expire following suitable prior notice given by the Minister of Energy, if the lease holder fails to produce or ceases to produce commercial volumes of oil.

(7) Furthermore, the Law provides that the Commissioner may rescind the petroleum rights or drilling rights if the owner of the rights fails to comply with any of the provisions of the Law or the terms of the petroleum rights or the preliminary permit, or does not act according to the work plan that it submitted or was late in execution or did not invest the amounts it committed to invest in oil exploration, and this despite a written warning issued to the holder of the petroleum rights or preliminary permit 60 days earlier.

(8) The Commissioner will maintain a Petroleum Register that will be available for public review ("the Petroleum Register"). The Petroleum Register will contain records of every application, grant, extension, amendment or expiry and transfers of petroleum rights, or pledges on the petroleum rights or benefit therein or of granting of a deed of lease. Such transactions will not be valid unless so recorded.

(9) The Law provides that no single person may hold more than twelve licenses, and may not hold licenses for a total area exceeding four million dunam, other than with prior approval of the Petroleum Council.

(10) A preliminary permit, license and lease are personal and neither they nor any benefit therein may be pledged or transferred in any manner – other than through inheritance – other than with the Commissioner's permission, and the Commissioner will not permit such pledge or transfer of a license or of a lease other than after consulting with the Council.

(11) A holder of a lease may lay pipelines for the transport of oil and oil products. A holder of a lease will not lay an oil pipeline, other than collection pipelines which lead to tanks within the area of and surrounding the wells in the lease area, other than along lines approved by the Commissioner. An oil pipeline will be laid in accordance with detailed diagrams in accordance with the Law; the diagrams will first require the approval of the Commissioner, and will not be unreasonably withheld

(B) <u>The Petroleum Regulations, 1953 (below in this section: the "Petroleum Regulations").</u>

The Petroleum Regulations deal with, among other things, preliminary permits and priority rights in the licenses and in the leases (jointly below: the "Rights") and prescribe the manner for submitting application for receiving Rights, submitting reports, fees to be paid, terms and conditions concerning the shape of the area, provisions regarding rights granted by way of tender and provisions regarding the payment of royalties pursuant to the Petroleum Law.

(C) <u>The Petroleum Regulations (Principles for Offshore Petroleum Exploration and Production), 2017 ("the Offshore Regulations")</u>

(1) On November 15, 2016, the Offshore Regulations, which replaced the Petroleum Regulations (Principles for Offshore Petroleum Exploration and Production), 2006, came into effect. The Offshore Regulations prescribe, among other things, proof of the qualifications of an applicant seeking certification to act as operator.

(2) Breakdown of the principles of the Offshore Regulations:

A. The Petroleum Commissioner will not certify an applicant as an operator unless the following key conditions are met:

1. The operator will be a lease holder holding at least 25% of the Rights in the oil asset

2. The operator or its controlling shareholder (subject to the conditions in the Offshore Regulations) will have at least five years of experience, within the ten-years preceding the filing of the application, in performing the functions of an operator, including: (a) experience in offshore oil or natural gas exploration; (b) experience in offshore drilling; (c) experience in offshore development and production of oil and natural gas; (d) experience in maintaining health, safety, and environmental protection relating to operations in petroleum interests.

3. Furthermore, the Petroleum Commissioner will not certify a corporation as operator, unless it directly employs qualified employees with at least five years of experience in the offshore oil or natural gas exploration sector, and in the offshore oil or natural gas development and production sector, unless the Commissioner decides to certify a corporation as operator despite its noncompliance with the requirement of experience in offshore oil or natural gas development and production, as described below.

4. The Petroleum Commissioner may, based on the stage and nature of the Rights, and in accordance with the scope of demand for obtaining Rights in that area or according to the composition of the entire group, certify a corporation as operator even if it fails to comply with the foregoing requirement of experience in offshore oil or natural gas development and production.

5. The Petroleum Commissioner may require a certain corporation, for the purpose of certifying as operator, greater experience than that prescribed, if the Commissioner finds it necessary based on the stage and nature of the Rights, and taking under consideration the work plan, its complexity and environmental and safety aspects.

6. The Commissioner will not certify a corporation as an operator unless it has sufficient financial capacity and financial strength. For this purpose, an operator or its controlling shareholder (subject to the conditions set in the Offshore Regulations) is considered to be financially sound (as defined in the Offshore Regulations) and to have financial capacity that is deemed sufficient if the total assets in its balance sheet amount to at least USD 200 million and the total equity in its balance sheet amounts to USD 50 million.

B. The applicant for a petroleum interest must prove appropriate financial capacity by complying with both of the following:

1. The total assets in the balance sheet of the applicant (or of all joint holders of the petroleum interest, including a member of the group approved as the operator with respect to the petroleum interest) amounts to at least USD 400 million;

2. The total equity in the balance sheet of the applicant (or of all joint holders of the petroleum interest, including a member of the group approved as the operator with respect to the petroleum interest) amounts to at least USD 100 million;

An applicant for a petroleum interest may rely on its controlling shareholder in order to prove financial capacity, subject to the conditions prescribed by the Offshore Regulations.

The foregoing financial capacity, financial robustness[134], total assets and total equity will be reviewed according to the figures in the audited financial statements as of December 31 of the year preceding the application, or according to an average of the figures in the audited financial statements as of December 31 of the two years preceding the application, according to the discretion of the Petroleum Commissioner.

C. The Petroleum Commissioner may, with approval from the Minister of Energy, withhold approval of an application to receive a petroleum interest or an application to serve as an operator, even if all the foregoing conditions are met, if he is convinced that reasons of national security, foreign relations

[134] Financial robustness will be proven according to compliance with the conditions specified in the Regulations.

and international trade relations so justify, or if there are special circumstances due to which approval of the application is not in the best interests of the public or the energy sector in Israel.

D. Notwithstanding the foregoing provisions, an operator may be certified or a petroleum interest may be granted even if not all of the terms and conditions that appear above are fulfilled, provided that under the circumstances the failure to meet the conditions is immaterial and the Commissioner was convinced that there are special grounds which justify so doing.

E. The Offshore Regulations include additional provisions concerning the information to be included in the application for certification of an operator and reports that an operator and a holder of a petroleum interest are required to submit to the Petroleum Commissioner.

(D) <u>Natural Gas Sector Law, 2002</u>

The Natural Gas Sector Law and the regulations thereunder set out provisions with regard to the establishment of a system for the transmission, marketing and supply of natural gas. The Natural Gas Sector Law provides, inter alia, that:

(1) The following activities may not be undertaken without a license issued by the Minister of Energy (in this section: the "Minister") and in accordance with its terms and conditions:

A. the establishment and operation of a transmission pipeline or part thereof;

B. the establishment and operation of a distribution network or part thereof;

C. the establishment and operation of an LNG facility ("LNG License");

D. the establishment and operation of a storage facility;

E. the establishment and operation of a pipeline for export by anyone that is not a holder of a lease

(2) A transmission license will only be granted to a company established in Israel under the Companies Law.

(3) The holder of a transmission license or a power provider may not deal in the sale or marketing of natural gas, nor may a controlling shareholder or an affiliate of any of them.

(4) The sale and marketing of natural gas does not require a license, however the Minister has the discretion under certain conditions as set out in the Natural Gas Sector Law, to determine, with the agreement of the Minister of Finance and upon approval of the Knesset's Economic Affairs Committee, that for a certain determined term, the marketing of natural gas will be subject to a license.

(5) In the event that an individual applies for more than one license, the Minister may, after consulting with the Director General of the Natural Gas Authority, appointed by Law, (in this section: the "Director") make the licenses contingent on the conditions specified in the Natural Gas Sector Law.

(6) The Minister, in consultation with the Natural Gas Authority Council, which was appointed pursuant to Section 63 of the Natural Gas Sector Law (the "Natural Gas Authority Council"), may, among other things, in accordance with the Government's policy, grant, without a tender, to a corporation a license for an export pipeline of a non-lease holder, for a period which will be determined in the license and subject to the provisions of the Natural Gas Sector Law.

(7) A storage license and LNG license will be granted under a tender or according to another public proceeding; however, the Minister may, with the consent of the Minister of Finance and upon consultation with the Natural Gas Sector Council, decide that a storage license or LNG facility license may be granted without a tender or foregoing public proceeding, to the holder of the transmission license. Notwithstanding the foregoing, a holder of a lease may, for as long as its lease is valid, store gas produced by it in a reservoir in the area of the lease. Notwithstanding the foregoing in this section above, the Minister may grant the holder of a lease, without a tender or other public proceeding, and for as long as the lease is valid, a license to store gas which is not produced by the reservoir in the lease area; the term of the license will be set therein and will not exceed the remaining term of the lease. The Minister may instruct a holder of a lease, for as long as the lease is valid, to provide others with storage facilities in the reservoir that is in the area of the lease and to determine the terms and conditions for such services, after giving the holder of the lease an opportunity to state its arguments; if such instruction has been given, the holder of the lease will be deemed a holder of a storage license and the provisions of the Natural Gas Sector Law will applicable to it.

(8) Restrictions were placed on the other operations of a license holder, however the Minister, after consulting with the Natural Gas Sector Council, may grant the license holder a permit to engage in additional operations under conditions as prescribed in the Natural Gas Sector Law.

(9) The term of a license will not exceed 30 years, and will not be extended; however, this provision does not prevent the license holder from participating in a tender conducted for granting of a new license. Notwithstanding the foregoing, the Minister may decide not to limit the term of a distribution license, and if it is for a limited term, he may extend it or cancel the limited term and set terms and conditions in the license with regard to any such decision.

(10) The Minister, after consultation with the Director General of the Natural Gas Authority, may set out conditions in the license to ensure the aims of the Natural Gas Sector Law and compliance with its provisions, including terms and conditions that are to be met prior to commencing operations under the license. In addition, the Minister, with the consent of the Minister of Finance and in consultation with the Council, may modify, add or remove terms and conditions from a license if essentially necessary for realizing the objectives of the Natural Gas Sector Law or to comply with a relevant international treaty to which Israel is party, and taking into consideration technological, market-related and environmental changes that have occurred since the license was issued, and after the license holder has been given an opportunity to voice its arguments.

(11) The Minister, with the consent of the Minister of Finance, may set conditions for mandatory royalty payment in a license granted under a tender, or license fees to the State Treasury, and the manner of their calculation and payment, and if any of those are the subject for bidding in the tender – in accordance with the results of the tender; the Minister, with the consent of the Minister of Finance, and subject to approval by the Knesset's Economic Affairs Committee, may provide for mandatory royalty payments by a license holder whose license was not granted under a tender.

(12) The Director General of the Natural Gas Authority may, after consulting with the Natural Gas Sector Council and with the Minister's approval, and after granting the license holder an opportunity to state its arguments, rescind a license at any time, if one of the following conditions occurs: (a) the license holder failed to disclose to the tender committee or to the Minister material information that is required to be disclosed with regard to participation in the tender or the license application, or provided incorrect information; (b) the license holder fits one of the exceptions for receiving the license or ceases to meet any of the required eligibility conditions, and fails to remedy such exception within a period determined by the Director General in a notice that he sent to the license holder; (c) an order was issued for the dissolution of or a receiver was appointed for the license holder, and the order or the appointment are not annulled within the time frame set by the Director General in a notice that he sent to the license holder; (d) the license holder failed to comply with an instruction to correct deficiencies or breached a material regulation in the license, which was not remedied within the time frame set by the Director General or the Commissioner or is irremediable; (e) the license holder committed an ongoing breach of a provision under this Law or in the license or a condition in the license, which was not remedied as stated in section (d) above; (f) other grounds exist which are set out in the license as grounds for cancellation.

(13) A license or any part thereof may not be transferred, pledged or attached, in any manner. A license holder's gas facilities and assets that were set in the license as required for conducting the operations according to the provisions of the license, may not be transferred, pledged or attached, in any manner, other than with the prior written approval of the Director General, and under such conditions as he may determine. Any action taken contrary to the provisions of this section is null and void.

(14) Guaranties and undertakings provided by a license holder or its controlling shareholder, and money received from exercising it, may not be attached or pledged.

(15) No person may purchase or hold control or means of control of a license holder, and the holder of control or means of control of a license holder may not transfer them to another. As a rule, such transfer or purchase requires the Minister's approval, after consulting and with the consent of the Council.

(16) A license holder may not make the provision of a service conditional upon the purchase of another service or gas from it or from another or on not purchasing a service or gas from another. However, if it was proven to the Natural Gas Authority Council that there is a reasonable business connection between the requested service and the fulfillment of such condition, the Council may approve such condition.

(17) The tariffs that may be charged by a license holder, and any revision thereof, will be determined by the Natural Gas Sector Council, in accordance with the rules set out in the license; and with regard to operations for which the license was granted under a tender, the Natural Gas Sector Council will determine the tariffs based on the conditions of the tender; the Natural Gas Sector Council may set standards or provisions with regard to the level, nature and quality of the services that the license holder is required to provide to its consumers, and to ensure continuity throughout the term of the license

(18) Gas that is sold by a natural gas supplier to an independent power producer (as defined in the Electricity Sector Law, 1996) is a commodity that is subject to the Supervision of Prices of Commodities and Service Law 1996 (the "Price Control Law") and the level of supervision that will apply is in accordance with Section E of the Price Control Law.

(19) The Minister, in consultation with the Council, may grant a corporation, without a tender, a license for an export pipeline for anyone that is not a holder of a lease, for a period set by him in the license, once in compliance with all of the following:

A. The corporation that submitted the application (including the corporation controlling it or another corporation controlled by the controlling corporation) has engaged in a natural gas purchase agreement that complies with all of the following:

1. A long-term engagement of significant scope for export purposes;

2. The purchased natural gas will be produced from the area of a lease in accordance with the Petroleum Law, where the facilities used for such operation according to the lease will be connected to the pipeline for which the license is granted;

3. The Minister has approved the engagement in advance;

B. All of the following are duly incorporated in Israel or in a country which is not an enemy country:

1. The applicant for the license;

2. The controlling shareholder of the applicant for the license – if it is a corporation;

3. Another corporation controlled by the controlling corporation, which engaged in such an agreement, if it did;

C. If the controlling shareholder of the applicant for the license is not a corporation – he is not a citizen of an enemy country;

D. The holder of the lease to which the facilities used for operating the pipeline will be connected, holds the approvals required for the purpose of exporting via the pipeline.

(E) <u>Natural Gas Sector Regulations (Management of the Natural Gas Sector during an Emergency), 2017 (the "Emergency Regulations")</u>

(1) The Emergency Regulations are promulgated under section 91 of the Natural Gas Sector Law authorizing the Minister of Energy, with the government's approval, to announce a natural gas sector emergency and to legislate regulations applicable for the management of the natural gas sector during emergencies.

(2) The Emergency Regulations differentiate between a situation in which 90% of the total supply of natural gas in the market is supplied from one field and one pipeline (a "Significant Field"), and a situation in which the natural gas supply in the sector comes from at least two fields connected to the INGL via at least two separate pipelines, as is customary in Israel today:

A. <u>Provisions for when there is one Significant Field</u>

At any time that the aggregate hourly consumption of natural gas by consumers of a gas supplier that is unable to supply all or part of the natural gas from the field (the "Defaulting Supplier") exceeds the maximum volume that can be supplied, the Defaulting Supplier and the INGL will allocate the existing volume of gas according to the following guidelines:

1. The first allocation of natural gas will be to the distribution consumers (as defined in the Emergency Regulations). Such allocation will be carried out based on the maximum volume per hour of the natural gas consumed by the distribution consumers in the 12 months preceding the date of the declaration (as defined in the Emergency Regulations):

a) A volume of up to 3,600 MMBTU per hour will be earmarked for distribution consumers (the director general of the Gas Authority may determine how this volume will be divided among the distribution consumers);

b) A minimum volume of up to 3,600 MMBTU per hour will be allocated as follows:

1) First to household consumers;

2) The remainder of the allocation will be allocated to distribution consumers that not included in the subsection above.

2. The remaining volume will be divided between IPPs (consumers of a Defaulting Supplier that are IPPs that produce power capacity exceeding 45 megawatts using natural gas) and consumers who are not power producers, pro rata to the aggregate daily consumption of each category of consumers in the corresponding month of the previous calendar year;

3. The volume to be divided among the consumers that are not power producers (as specified above) will be determined based on their share of the per hour capacity ordered by each of them, under the transmission agreements they signed with the transmission license holder, and the total per hour capacity ordered by all these consumers under the transmission agreements they signed with the transmission license holder.

4. The IEC will offer to sell LNG to consumers that are not power producers, at the price at which it purchased the LNG, with the addition of 10%.

B. <u>Provisions with regard to supply from at least two fields</u>

Gas suppliers that are not Default Suppliers will be required to offer to sell their surplus gas (disposable daily volume after delivering the volumes commissioned by the supplier's consumers, provided that the volume ordered does not exceed the maximum volume that may be ordered under their agreement) to the Default Supplier. If the parties fail to reach an agreement on the price of surplus gas, the price will be based on the average market (to be set based on the total revenues from the sale of natural gas to consumers in Israel received from all fields in the quarter prior to the quarter preceding the announcement date, divided by the cumulative volume of natural gas in MMBTU units supplied to consumers in Israel in the quarter prior to the quarter preceding the announcement date, as published by the Natural Gas Authority from time to time on its website). At any time that the cumulative hourly consumption of natural gas consumers of a Default Supplier exceeds the maximum volume that can be supplied to them, the Default Supplier and the INGL will allocate the surplus volume of gas purchased to Israeli consumers only, as follows:

1. The first allocation of natural gas will be to the distribution consumers. The foregoing allocation will be based on the maximum hourly volume of natural gas consumed by the distribution consumers that received gas from the Default Supplier in the 12 months preceding the date of the declaration, as follows:

a) a volume that does not exceed the resulting volume by deducting from 3,600 MMBTU per hour the volume supplied to the distribution consumers by the gas suppliers that are not the Default Supplier, will be earmarked for the distribution consumers;

b) if the maximum volume exceeds the resulting volume by deducting from 3,600 MMBTU per hour the volume supplied by gas suppliers that are not the Default Supplier of the distribution consumers, a volume of MMBTU 3,600 per hour less the volume provided by the gas suppliers that are not the Default Supplier of the distribution consumers will be distributed as follows:

1) First to household consumers;

2) The remainder of the allocation will be allocated to distribution consumers that not included in subsection (a).

2. The remaining volume will be split between power producers and other consumers, based on the cumulative daily consumption of each of these consumer groups in the corresponding month in the previous year;

3. If excess gas supply remains, the Default Supplier may supply natural gas from the field (below: “Additional Volume”), so that the daily surplus volume of gas remaining for supply will be distributed among the power producers and consumers that are not power producers, pro rata to the average daily cumulative consumption of each of the consumer groups in the corresponding month of the year preceding the year in which such distribution is made.

4. The volume to be divided among the consumers that are not power producers (as specified above) will be determined based on their share of the per hour capacity ordered by each of them, under the transmission agreements they signed with the transmission license holder, and the total per hour capacity kept for these consumers under the all transmission agreements they signed with the transmission license holder, less the Additional Volume, if distributed, to each of the consumers that are not power producers.

C. <u>General</u>

If the Minister decides, after consulting with the director general of the Natural Gas Authority and director general of the Electricity Authority that the shortage of natural gas caused prolonged or extensive harm to the proper functioning of the economy or the regular supply of electricity to the

Israeli market, and that the shortage cannot be overcome through the use of other fuels, or if the Minister of Environmental Protection will inform the Minister of Energy that the ongoing shortage of natural gas is causing significant environmental damage that may harm public health, the Minister may disregard the provisions of the Regulations and order the volume of gas and LNG to be divided differently, and only if such disregard is not excessive.

The Regulations do not exempt the Default Supplier from its legal obligations or derogate from any remedies and relief provided in the agreement between the Default Supplier and the gas consumer.

(F) The Natural Gas Authority Council decision on the regulation of the use of the gas pipeline capacity from the Tamar Project production platform to the natural gas reception terminal at Ashdod ("Regulation of Use of the Pipeline Capacity")

On December 9, 2012 the Natural Gas Council at the Ministry of Energy (in this section "the Council") published a decision regarding the regulation of the use of the capacity of the natural gas pipeline, as well as with regard to retaining gas capacity for consumers and marketers on the distribution network and regulation of the issue of shortages in the Tamar Project supply capacity. It should be noted that it is the Council's opinion that Tamar partners will not refuse to sign natural gas sales or marketing agreements with consumers wishing to engage with them only because of the fact that such engagements mean that the total hourly volume of natural gas to flow in the pipeline exceeds the maximum capacity of 40,000 MMBTU per hour.

(G) The Natural Gas Authority Council decision on the regulation of criteria and rates for operating the transmission pipeline system according to a flow control regime

On January 3, 2021, the Natural Gas Authority Council released an amendment to the Council's decision regarding criteria and rates for operating the transmission system in a flow control regime, Decision No. 5/2020 (Amendment No. 2) [135] (in this section: the "Decision").[136] The Decision provides that the costs for the unaccounted for gas (UFG) in the gas transmission system due to reasons that cannot be attributed to malfunction of the gas transmission system, but to factors that cannot be prevented or controlled, such as timing of measurement, pressure differences and temperature differences, will be borne by the gas suppliers. The Decision further stipulates that a reasonable UFG is in the range of 0%-0.5% (plus or minus). Costs incurred for reasonable UFG will be divided equally between the gas suppliers and the gas consumers. The Decision will take effect as of April 1, 2021.

After the release of the Decision, INGL sent Noble a demand to apply the Decision retroactively from November 2019 with respect to the Tamar Project, and from the beginning of 2020 with respect to the Leviathan Project, and forwarded, for the review by Noble, a notice in this regard that it sent to its customers. Further to the foregoing notice, Noble wrote to the Gas Authority and expressed its objection to the retroactive application of the Decision, without derogating from its arguments against the Decision itself. As at the date of approval of the financial statements, Noble is considering its options with regard to the Decision.

The Partnership estimates that the aforesaid Decision entails costs in immaterial amounts. As at the date of approval of the financial statements, the Partnership is reviewing the implications of the Decision, before taking legal action.

(H) The Natural Gas Authority Council decision regarding funding of export projects via the national pipeline (below in this section: the "Decision").

On September 7, 2014, the Natural Gas Authority Council published a decision regarding arrangements for financing natural gas exports via the national pipeline (Decision No. 2/2014). The decision sets the conveyance prices that will apply for conveying Israeli natural gas via the national pipeline to neighboring countries or to the Palestinian Authority, as well as the financing of the sections of the pipeline designated for such export of natural gas. The decision provides the following criteria:

(1) The exporter (the entity selling or marketing the natural gas for export) will sign a conveyance agreement with the conveyance licensee, with the prior written consent of the Natural Gas Authority Administration. The exporter will pay the conveyance licensee a conveyance price, that will be the regular conveyance price applicable for Israeli consumers, as this may be from time to time.

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[135] Decision No. 5/2020 amends Decision No. 4/2020 of the Natural Gas Authority Council dated May 27, 2020, which amended the Council's Decision No. 8/2019.

[136] https://www.gov.il/BlobFolder/generalpage/ng_council_decisions/he/board_decision_5_20.pdf

(2) The exporter will bear all costs in establishing the sections of the national pipeline designated for export only ("the Export Section") and the costs of establishing an additional pipeline, adjacent to the existing pipeline ("the Duplicate Section"), with the addition of 2% management fees.

(3) So long as the conveyance agreement between the exporter and the conveyance licensee is valid and another consumer joins the Export Section in the future, the Natural Gas Authority Administration will fix the costs that will be attributed to the other consumer out of the total cost of establishing the Export Section, and this pro rata to the capacity of the other consumer out of the total conveyance capacity of the Export Section. The exporter will be credited with the amount of the costs attributed to the other consumer.

(4) If a certain section of the pipeline, leading to the Export Section, will in the future also be used for Israeli consumers, and that section leading to the Export Section was not duplicated when it was established, had it not been for the export of natural gas via the pipeline, the exporter will pay (in addition to the establishment costs of the Export Section as aforesaid) the pro rata cost for duplicating the Export Section. The Council will determine the division of costs among the exporter and the conveyance licensee.

(5) If, in the opinion of the Natural Gas Authority Administration, the existing capacity of the pipeline is sufficient at the signing of the agreement between the conveyance licensee and the exporter, but that it is probable that during the ten years following the commencement of piping of natural gas there may be capacity shortage for the Israeli consumers of the pipeline in the section leading to the Export Section, then at the signing of the conveyance agreement, the exporter may select one of the following alternatives: (1) to pay the conveyance licensee 50% of the budget for the future duplication of the relevant section of the pipeline, and this amount will not be refunded to the exporter even if at the end of the day the section is not duplicated as aforesaid; (2) not to pay this amount and in the event that the section is duplicated as aforesaid, the provisions of subsection 4 above will apply.

(6) The Natural Gas Authority Administration will decide with regard to each case, from which point along the pipeline will be considered the starting point of the section leading to the Export Section, and this point will be explicitly noted in the conveyance agreement.

(7) Despite the fact that the establishment costs are borne (in full or in part) by the exporter, the section will not be owned by the exporter and it will not have any connection of any kind to this section.

(8) This decision does not apply for export transmission agreements signed with the pipeline licensee before November 2, 2014 (including the transmission agreement signed with regard to the agreement dated February 19, 2014 for the export of natural gas from the Tamar Project to consumers in Jordan (as set out in section 1.7.13(E)(1) above).

(9) It should be noted that, under the Dolphinus agreements described in sections 1.7.13(E)(1)b and 1.7.13(E)(2)b, it was agreed that the Tamar partners and the Leviathan partners, as the case may be, will bear the costs of transporting gas flow in the INGL pipeline.

On March 26, 2020, the Natural Gas Authority Council issued an addendum to its Decision of September 7, 2014, regarding the financing of export projects through the national pipeline and division of the construction costs of the Ashdod-Ashkelon combined section (Decision No. 3/2020). The addendum to the Decision provides the following principles:

A. In addition to the categories that were defined in the decision of September 7, 2014, as described above, the Council may define a section which is designated for export and which allows for the closing of a loop in the system or creates surplus and backup for natural gas which is transmitted to the Israeli transmission consumers as a “combined section”.

B. If a section is defined as a “combined section”, the Council will define the ratio dividing the costs of construction of such section, and if necessary, the Council will provide additional conditions and obligations for any of the parties.

With respect to division of the costs of the Ashdod-Ashkelon combined section, the addendum to the Decision stipulates that:

1. The offshore section of the pipeline to be constructed in the future, which will begin at the reception terminal in Ashdod and end at the facility connecting to the export facilities of Prima Gas Ltd., will be defined as a combined section (the “Combined Section”).

2. The costs of the Combined Section and the method of allocating the costs between the exporter and the transmission license holder will be established in a transmission agreement between the transmission license holder and the exporter (the “Transmission Agreement”), according to the following principles:

a) The cost of the section will be determined according to the Council's Decision issued in September 2014. If the transmission license holder and the exporter fail to agree on the cost of the section by May 15, 2020, the Director General of the Natural Gas Authority will determine the cost of the section.

b) On June 23, 2020 the Director General of the Natural Gas Authority gave notice that he has determined that the costs of the Ashdod-Ashkelon Combined Section were estimated at a total of NIS 738 million (of which the Partnership's share is NIS 159 million) and will be revised based on an update and accounting mechanism between the parties, as set out in the transmission agreement with INGL.

c) 43.5% of the cost of the section, as will be fixed in accordance with section a. above, will be financed by the transmission license holder.

d) 56.5% of the cost of the section will be financed by the exporter, based on milestones that will be set in the Transmission Agreement.

e) In addition, the exporter will pay the transmission license holder an amount of NIS 27 million against its share in the costs incurred due to bringing forward the doubling of the Dor-Hagit and Sorek-Nesher sections (the "Doubling Cost"), which is estimated at NIS 48 million, and this because the doubling of the said Dor and Sorek sections will be included in Appendix A to the transmission license holder's permit for construction and operation of the pipeline, and before the construction begins.

f) The exporter will provide the transmission license holder with an independent financial guarantee on behalf of an Israeli bank, for 110% of the aggregate amount of the cost set out in section b. above (the transmission license holder's share of the of the cost of construction of the Combined Section plus ten percent), and of the amount of NIS 21 million, which will decrease in accordance with the provisions of the addendum to the Decision.

g) As long as the exporter exports to Egypt, the volume of natural gas as set in the Transmission Agreement will be transported via the transmission license holder's pipeline and not via a section outside of the Israeli transmission system.

h) If the exporter ceases to export to Egypt, it will be required to pay the transmission license holder the difference, if any, between 110% of the total aggregate cost provided in section b. and the total Doubling Cost (i.e. NIS 48 million), and the aggregate capacity and transmission fees that the exporter paid the transmission license holder from the date of completion of the Combined Section and of the payments that the exporter paid the license holder in accordance with sections c. and d. above.

As set out in section 1.7.14(B)(2)b.2 above, on January 18, 2021, Noble engaged in a binding transmission agreement with INGL for streaming of natural gas from the Tamar reservoir and the Leviathan reservoir to the EMG reception terminal in Ashkelon, to be transmitted to Egypt.

On February 23, 2021, the Natural Gas Authority issued a decision concerning the reduction of the transmission tariff, due to the expansion of the system by 5%. The reduction will take effect as of March 1, 2021.

(I) <u>Petroleum Law Legislative Memorandum (Amendment no. 7) (Regulation of Specific Export Pipelines and Liquefaction Facilities), 2020</u>

On August 9, 2020 the Ministry of Energy issued the Memorandum of the Petroleum Law (Amendment No. 7) (Regulation of Specific Export Pipelines and Liquefaction Facilities), 2020 (in this section below: ("the Bill"). The purpose of the Memorandum is to regulate the establishment of pipelines and facilities for the export of natural gas, including by entities that are not lease holders pursuant to the Petroleum Law. As at the date of approval of the Report, this matter is regulated under Section 10A of the Natural Gas Sector Law. The purpose of the Memorandum is, inter alia, to replace the regulation set out in the Natural Gas Sector Law. The Memorandum further proposes to regulate the establishment and operation of an offshore natural gas liquefaction facility, the purpose of which is to transform the state of the natural gas from gas to liquid, to allow the export of liquefied natural gas.

Furthermore, the proposed amendment to the Petroleum Law requires an indirect amendment to the Natural Gas Sector Law for adapting the Natural Gas Sector Law to the proposed amendments to the Petroleum Law

(J) <u>The Law to Promote Competition and Reduce Concentration, 2013</u>

For further information see section 1.19.1 below.

(K) <u>Regulation of Security in Public Entities Law, 1998 (below in this section: "the Law").</u>

(1) The Law applies to a "public entity", which, as defined under the Law, is a body listed in any Schedules to the Law.

(2) The Law imposes various duties on a public entity: (a) the appointment of a security officer, who will report directly to the general manager of the entity, to ensure the required level of security for the operations of the public entity; (b) appointment of an officer responsible for the security of essential computer systems; (c) appointment of a security guard in accordance with the requirements of an authorized officer.

(3) The Law confers broad powers for the security officer in a public entity, including: power to conduct a search and seize an object; power to require a person entering a public entity to provide identification; power to detain (under certain circumstances set in the Law); power to prohibit entry to a public entity with a weapon (and under certain circumstances prescribed in the Law, to also use reasonable force).

(4) Under the Sixth Schedule to the Law, a public entity listed in the Sixth Schedule will also be required to adopt offshore security measures. Offshore security measures are defined as actions necessary to safeguard the security of a person or to protect the property, structure or location of a public entity located offshore in the maritime zone, as well as actions required to prevent harm to any of these.

(5) Under the Sixth Schedule of the foregoing Law, a holder of a license under the Natural Gas Sector Law, 2002, that owns an offshore installation or operates an offshore facility, is considered a public entity for the purpose of imposing the duties set out in sub-section 2 above, and is required to adopt the offshore security measures.

(6) The IDF acts as the guiding authority in the matter of offshore security and its representative is considered by law to be a Certified Officer with regard to offshore security measures.

(7) According to the Law, an offshore installation is a facility located in the maritime zone, including a vessel as defined in the Shipping (Vessels) Law, 1960, that is used for the exploration and discovery of petroleum or for drilling of production wells, for transportation, liquefaction or gasification of petroleum or for the processing, storage or transport of petroleum (petroleum - as defined in the Petroleum Law). The maritime zone includes areas situated beyond the sovereign territory of the State of Israel and includes, apart from the Israel territorial waters, the Israeli continental shelf, as defined in the Shipping Law (Offenses against Security of International Sea Travel and Offshore Installations), 2008.

(8) In addition to the offshore installations included in the Sixth Schedule to the Law, section 21 of the Second Schedule includes "an operator of a land facility for processing of natural gas obtained via a pipeline from the sea or from a foreign country, under license or by law". Such operator is required to adopt physical security and information security measures (but not measures for the security of computer systems or offshore security measures).

(9) Under the Law, the owners of the Tamar and Leviathan reservoirs (below in this section: the “Reservoirs”), including the Partnership, are responsible, inter alia, for the security of the vital automated systems in the Reservoirs, in accordance with the instructions of the Israel National Cyber Directorate (the “INCD”). Because the operator is responsible for operating the production system of the Reservoirs, it is the operator that actually implements the instructions of the INCD on this matter. As the Partnership has been informed, and to the best of the Partnership’s knowledge, in February 2019, the operator received confirmation from the INCD regarding implementation of the information security requirements in the Tamar Reservoir, which included several issues for continued handling until 2021. In addition, in January 2020, the operator received confirmation from the INCD with respect to full compliance of the Leviathan Reservoir with the security requirements.

(10) As at Reporting Date, and as the Partnership was informed by the operator in December 2020, with respect to the operation of the Reservoirs, the operator is in compliance with the provisions of the Regulation of Security in Public Bodies Law and the sections concerning the security arrangements in the lease deeds, including the instructions on security matters issued by the professional officers in the navy pursuant to law.

(L) <u>Key Guidelines of the Commissioner of Petroleum Affairs</u>

(1) <u>Collateral provided with respect to petroleum rights</u>

A. On September 17, 2014 the Petroleum Commissioner issued, in accordance with section 57 of the Petroleum Law, directives for the provision of collateral with respect to petroleum rights, which were revised on July 18, 2019, the highlights of which are set out below. However, it should be noted that in addition to these directives, the Commissioner required verification of insurance as per the format prescribed by him, based on insurance plans that were submitted to him on the matter of insurance pertaining to the various leases. The main directives for providing collateral with respect to petroleum rights are:

1. Entities applying for new onshore licenses will deposit base guarantees in an amount equivalent to USD 500 thousand. Rules regarding the deposit of base guarantees for new offshore licenses will be set out as part of the procedures for the granting offshore licenses.

2. Prior to drilling, license holders will be required to provide an additional guarantee in an amount that the Petroleum Commissioner will determine based on the nature of the drilling and the drilling plan. The amount of the additional guarantee for offshore licenses will not be less than an amount equivalent to USD 5 million, and the amount of the additional guarantee for onshore licenses will be no less than an amount equivalent to USD 250 thousand. If the Petroleum Commissioner believes that the nature of the drilling so justifies, he may require guarantees in an amount that is lower than the foregoing amount.

3. The initial validity of the base guarantee for new onshore licenses will be for a period of one year, and the licensee will renew the guarantee each year until the Commissioner gives notice that it is not necessary. Furthermore, the base guarantee and the additional guarantee for existing onshore and offshore licenses will be valid for a period of one year until the Commissioner gives notice that it is not necessary. The Commissioner may increase the amount of the guarantee after allowing the licensee to present its arguments on the matter.

4. The Petroleum Commissioner will determine the amount of the guarantee for petroleum leases while taking into account, inter alia, the development plan, the details of the lease, the stage it is at, the size of the oil field, but in any event the guarantee will be no less than an amount equivalent to USD 7.5 million for an offshore lease, and from an amount equivalent to USD 1.5 million for an onshore lease. Guarantees for new leases will be deposited upon granting of the lease, for a period that will be decided by the Petroleum Commissioner. Furthermore, the Petroleum Commissioner reserves the right to revise the amount of the guarantee due to a change of circumstance.

5. The foregoing guarantees will remain valid also after the right for which they were given terminates, until the Commissioner advises otherwise, but no longer than 7 years after the right for which they had been provided expires.

6. If, in the opinion of the Petroleum Commissioner, a petroleum leaseholder failed to act with due caution with regard to the oil lease or caused damage by its actions due to the lease, or failed to expend such expenses or to comply with such obligations with respect to such expenses or obligations under the Petroleum Law, and during the term of the lease, the Petroleum Commissioner had instructed the leaseholder by way of written notice to act or expend such expenses or to comply with the obligations regarding the petroleum lease, and the leaseholder failed to comply with such instruction and failed to provide adequate explanation for such failure, the Petroleum Commissioner has the authority to order forfeiture of the guarantees or any part thereof, after hearing the arguments of the leaseholder with regard to forfeiture of the guarantee.

7. A petroleum leaseholder will purchase and maintain, at its expense and throughout the entire term of the petroleum lease, all insurances that are customary among international for oil or gas exploration or production companies.

8. If a petroleum leaseholder fails to comply with the directives, or if it comes to light that the guarantee or insurance that were provided had been revoked or terminated for any reason whatsoever, prior to their renewal, extension or replacement by another guarantee or insurance, the Petroleum Commissioner has the authority to forfeit the existing guarantee for the lease and may act to mitigate possible damage, at the expense of the leaseholder. Moreover, the Petroleum Commissioner may view the foregoing as non-compliance with the work plan and with the provisions of the lease and may act in accordance with the provisions of the Petroleum Law.

B. In addition, the directives include, among other things, provisions with regard to guarantees provided by applicants for new onshore licenses, existing onshore licenses, revision of the amounts of and extensions to the guarantee, as well as general provisions regarding guarantees.

C. Pursuant to these directives and the terms and conditions of the Partnership's oil assets, as at the date of approval of the Report, the Partnership, together with its partners in the various ventures, has deposited autonomous bank guarantees for the Ashkelon, Noa, Tamar, Dalit, Leviathan North and

Leviathan South, and for the Alon D and Ofek and Yahel licenses[137]. The Partnership's total share in the foregoing collateral amounts to USD 60.4 million.

(2) Directives for method of calculation of the royalty value at wellhead

A. In May, 2020, the Natural Resources Administration at the Ministry of Energy released the final version of the directives on the method of calculation of the royalty value at wellhead, pursuant to Section 32(B) of the Petroleum Law, 1952 (in this section: the "Directives").

1. The Directives state that the value of the royalty at wellhead will be equivalent to 12.5% of the sale price to customers at the point of sale, net of essential costs for treatment, processing and transportation of the petroleum, actually incurred by the lease holder between the wellhead and the point of sale.

The expenses to be recognized for the purpose of calculating the value of royalty at wellhead are expenses actually incurred by the lease holder, from the wellhead to the point of sale, as specified below, provided that the Commissioner deems them necessary for the oil to be marketable. (1) the following capital expenses (capex): (a) costs for the treatment and processing of the petroleum; and (b) costs of pipeline transportation of the petroleum up to the first point of connection to the national pipeline system; and (2) operating expenses (opex) arising directly from the types of capital expenses

2. The Commissioner will determine, from time to time, individually for each lease holder, specific directives for each lease, regarding the deductible expenses for calculating the royalty, based on the specific aspects of the lease.

3. Expenses incurred with regard to assets will be recognized in such a way where the depreciation rate for the fixed assets will be calculated based on the depletion method, from the date on which the fixed asset begins operating (i.e., only when the fixed asset reached the position and condition required for its operation, and started to operate). Total depreciation expenses to be recognized will not exceed the cost of the fixed asset. Depreciation expenses will be recognized for the fixed assets such that at the end of the life of the asset, the value of the asset will be zero. Depreciation expenses will be calculated by multiplying the depreciated cost at the beginning of the year of the recognized part of the fixed asset determined in the specific directives, by the depreciation rate determined in accordance with the depletion method.

If an agreement is signed granting third parties an ownership right in the fixed asset or a right of use in the fixed asset, with or without consideration, or if an agreement is signed involving the receipt of payment from third parties for the transportation or treatment of oil, the estimate of the fixed asset will be amended in the year in which the economic value was created for the asset over and above the depreciated cost of the relevant fixed asset as determined, taking into account the depreciation expenses that were deducted for the calculation of the value of the royalty at wellhead.

The estimate will be adjusted in the year in which the transaction in the relevant asset was made, based on the disposal principle, and the lease holder may be required to pay the State royalties for this value, even if it did not generate income in that year.

The financial value for the purpose of adjusting the assessment will be limited to the amount recognized and depreciated for royalty purposes, for the fixed asset sold or the rights of use were transferred

4. The Directives provide additional provisions, including a detail of the types of expenses that will not be recognized, the method for recognizing decommissioning costs and the method of treatment of transactions that are affected by the existence of special relations between the parties to the transaction.

B. On September 6, 2020, the Director General of Natural Resources at the Ministry of Energy released the Directives of the Petroleum Commissioner regarding the method of calculation of the value of the royalty at wellhead for the Tamar Lease.[138] It is noted that as of the date of approval of the Report, specific directives are yet to be received from the Petroleum Commissioner with respect to the method for calculation of the State's royalties from the Leviathan reservoir.

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137 For further information concerning additional guarantees provided by the Partnership together with its partners in the Tamar Project, see sections **Error! Reference source not found.** above and 1.7.27(L)(1) below, and with regard to additional guarantees provided by the Partnership together with its partners in the Leviathan Project, see section **Error! Reference source not found.** above. For information concerning the guarantees provided by the Partnership with regard to the Tamar and Leviathan projects, see Note 12O2 to the Financial Statements below.

138 https://www.gov.il/BlobFolder/policy/oil_search_publications/he/tamar_royalty.pdf

Below is a breakdown of the directives received regarding the method of calculation of the royalty value at wellhead in the Tamar Lease:

1. Capex that will be recognized for purposes of calculating the value of royalty at wellhead and the rate of recognition include: (a) Capital cost for the transmission pipeline from the main manifold to the Tamar platform and from the platform to the Terminal in Ashdod, will be recognized at a rate of 100%; (b) Capital costs in respect of the Tamar platform and the Terminal in Ashdod will be recognized at a rate of 82%; and (c) Capital cost in respect of the transmission pipeline from the Tamar platform to the entrance to the Terminal in Ashdod will be recognized at a rate of 100%.

2. Operating expenses arising directly from the types of services specified in subsection (a) above, will be recognized at a rate of 82%: payroll expenses of workers at the platform and the terminal; maintenance and repair expenses; expenses for travel and transportation to the platform; expenses for food for the workers at the platform and the terminal; expenses for guarding and security at the Tamar platform and the terminal; expenses for professional and engineering consultation; insurance expenses.

3. In the event that the contract sale price includes a transmission tariff component that is paid to INGL, all of the transmission expenses paid by the lease holder will be recognized.

4. Decommissioning costs will be recognized for calculating the royalty, in accordance with the provisions set out in the general directives, and provided that at least an aggregate of 170 BCM was produced from the Tamar Lease and the decommissioning plan was approved by the Commissioner.

C. Since commencement of production of natural gas from the Tamar reservoir, the Tamar Partners, including the Partnership, pay royalties at a rate that is set and revised from time to time by the Petroleum Commissioner. For further information, see section 1.7.29(N)(5)b below.

Over the years, the Tamar Partners informed the Petroleum Commissioner, shortly before commencing production from the Tamar reservoir, that they are paying the foregoing royalty under protest, and that they disagree with the manner in which the royalty calculation was determined by the Petroleum Commissioner, which they claim does not adequately weigh the expenses for transmission and processing of the gas from the wellhead to the pipeline network.

Following the issue of the Directives and setting out of specific guidelines regarding the calculation for the rate of the State's royalty in the Tamar project, the Partnership estimates that, based on the opinion of its legal counsel, there is a greater than 50% chance that the effective royalty rate that will ultimately be determined for the sale of natural gas from the Tamar reservoir will be around 11%, which is lower than the effective royalty paid to the State at its demand, since 2013. once the effective royalty rate in the Tamar project will be fixed, whether in agreement with the State or through legal proceedings, and if such will be lower than the rate of royalties actually paid, the Tamar Partners will be eligible for reimbursement of the surplus payments they made. Since more than seven years have passed since the Tamar Partners began paying royalties for the gas produced from the Tamar reservoir, and to reserve their rights against statute of limitations claims with respect to the royalties which they claim have been overpaid over the years (the "Surplus Payments"), the Tamar Partners queried this matter with the State, which confirmed that if the Tamar Partners take legal action concerning the Surplus Payments within a reasonable period (several months) from the date of the Directives regarding the calculation of the royalties to be paid by the holders of the rights, the State will not raise arguments regarding the time that has passed. For further information regarding agreements reached by the Partnership in this context with all the parties to which it paid royalties from the Tamar project over the years, see section 1.7.29(N)(5)B.6 below.

(3) <u>Transfer and pledge of oil asset rights and benefits in oil asset rights</u>

On December 28, 2020, the Commissioner of Petroleum Affairs issued new directives regarding Section 76 of the Petroleum Law, which replace the directives of December 31, 2015, for the purpose of regulating the procedure and conditions for transferring and pledging petroleum interests (preliminary permit, license and lease) and benefits (including rights to contract royalties) in a petroleum interest[139] (in this section below: the "Directives"). Breakdown of the principles of the Directives:

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[139] It is noted that directives for purposes of Section 76 were also applied to a transfer of a petroleum interest or a benefit between any entity that has a direct share in a petroleum interest in the framework of a group by virtue of the agreement between them, and will also apply to a transfer or allocation of means of control which confer a benefit in respect of a petroleum interest or control of the corporation or group that holds a petroleum interest or a benefit in respect of a petroleum interest.

In this section: “license-related benefit” and “lease-related benefit” – including a holding of each one of the following: (1) control of a license holder or a lease holder, or of a corporation that has holdings in a license or a lease, or a group, as the case may be; (2) more than 25% of a specific type of the means of control of a license holder or a lease holder, or of a corporation which has holdings in a license or a lease, or a group, as the case may be;(3) a right to contract royalties.

“Means of control” – means of control of a group or means of control of a corporation, as the case may be;

“Means of control of a group” – any one of the following: (1) voting rights in a meeting, at an operating committee or at another forum at which decisions are made that bind the group with respect to the operation of the petroleum interest; (2) a right to appoint members of a meeting, operating committee or another forum at which decisions are made that bind the group with respect to the operation of the petroleum interest, or to appoint a person whose role is to make such decisions; for this purpose, “operating committee” – a body in respect of which the group’s members have agreed that it will direct the group’s activity in the operation of the petroleum interest or will determine the manner of operation of the petroleum interest and performance of the duties imposed on the holder of the petroleum interest according to the terms and conditions of the right or its policy on such matters, or will supervise the same.

“Means of control of a corporation” – any one of the following: (1) voting rights in a general meeting of a company or in a corresponding entity of another corporation; (2) a right to appoint a director of a company or its CEO, or officers corresponding thereto in another corporation.

“Control” – control of a group or control of a corporation, as the case may be;

“Control of a group” – the ability, whether alone or together with others acting in cooperation on a regular basis, to direct the group’s business, with the exception of ability of an individual which derives merely from filling a position at the group or filling a position of a director or another officer at one of its members, and with the exception of ability which derives merely from filling the position of operator; without derogating from the generality of the aforesaid, a person is presumed to control a group (1) if the share that he holds in the petroleum interest that is held by the group is one half or more; (2) if he holds one half or more of the means of control of the group; (3) if he has the ability to make decisions for the group which pertain to actions regarding the petroleum interest and the activity for performance thereof, or to prevent the making of such decisions at the group.

“Control of a corporation” – the ability, whether alone or together with others acting in cooperation on a regular basis, to direct the corporation’s business, with the exception of ability which derives merely from filling a position of a director or another officer at the corporation; without derogating from the generality of the aforesaid, a person is presumed to control a corporation (1) if he holds one half or more of a certain type of the means of control of the corporation; (2) if he has the ability to make decisions for the corporation which pertain to the operation of the petroleum interest, or to prevent the making of such decisions at the corporation, by virtue of the corporation’s articles or by virtue of an agreement. In a corporation that is a limited partnership – each one of the said rights in the corporation that is the general partner.

1. The Petroleum Commissioner may approve the transfer of rights in a license and in a lease, if all of the following conditions are met:

a) The financial capacity of the license or lease holder after the transfer fulfills the requirements according to the law and the Directives of the Petroleum Commissioner.

b) If the transferor is the operator or employer of the professional staff and as a result of the transfer, it ceases to be the operator or employer of the professional staff, including due to its share in the right falling below the minimum rate required of the operator or employer of the professional staff, the transferee complies with the conditions required of an operator in accordance with the requirements of the law and the Directives of the Petroleum Commissioner, and if the transfer is to two transferors or more – one of the transferees complies with the aforesaid conditions.

2. The Petroleum Commissioner may approve a transfer of a preliminary permit for which a preemptive right was given to an entity which is controlled by the entity which controls the holder of the preliminary permit, provided that all of the conditions detailed in subsections a and b above and certain additional conditions are met.

3. The Petroleum Commissioner may approve a transfer of petroleum interests, as stated above, even if not all the above specified conditions are met, in the case of a small transfer of rights of no more than 10% of the license or lease; and not more than 25% of a certain type of means of control in the

license holder of lease holder, or if there are special grounds and additional circumstances as detailed in the Directives.

4. The Petroleum Commissioner will not approve a transfer of contractual royalties (per the meaning thereof in these Directives) whose value exceeds 5% of the value of the petroleum which will be produced and utilized in the framework of the right. In exceptional cases, the Petroleum Commissioner may approve the transfer of royalties of a value which exceeds 5% of the value of the petroleum which will be produced and utilized in the framework of the right, provided that it does not exceed 10% of the value of such petroleum.

5. The Petroleum Commissioner will not approve a transfer of a petroleum interest or of a benefit in a petroleum interest, if in his opinion one of the following is exists:

c) The transfer may delay or impair the performance of the duties of the holder of a petroleum interest to explore and produce oil in accordance with the license or lease or the Petroleum Law, accordingly.

d) The transfer may significantly impair the competition in the exploration and production sector.

e) The transfer may significantly harm the payment of the royalties which are due to the State Treasury under the Petroleum Law and the law.

f) The transferee or the holder of control in it breached the provisions of the Petroleum Law, or directives and requirements made by the Petroleum Commissioner thereunder, with respect to another petroleum interest which it has or had or a benefit related thereto, or the conditions of such petroleum asset, or acted with respect to such a petroleum interest inefficiently or irresponsibly, and as a result it is not fit to be a holder of a petroleum interest or a holder of part of a petroleum interest or a holder of a benefit in a petroleum interest, as the case may be.

g) The transferor or transferee have not yet paid any amount they are required to pay to the State Treasury with regards to a petroleum interest which they hold or held.

6. In addition, the Petroleum Commissioner may not approve a transfer, even if all the condition for providing the approval which are set in these Directives are met, if he is convinced that reasons of public security, national security, foreign relations or international trade relations so justify, and in this context, in the case the transferee is a corporation controlled by a foreign country or there are other special circumstance with respect to which the transfer is not in the best interests of the public or the energy sector in Israel.

7. The Petroleum Commissioner may approve a pledge of a petroleum interest or benefit in a petroleum interest prior to the commencement of commercial production, if the pledge is designated to serve as collateral for receiving a loan to finance activities which the petroleum interest holder must perform, or to ensure the receipt of contractual royalties or on special grounds which the Petroleum Commissioner deemed fit to approve. Additionally, similar conditions were determined to approve a pledge of petroleum interests after commercial production commence.

8. Authority to pledge does not constitute permission to transfer the pledged right, and if the conditions for exercising the pledge are met, the license or lease or any part thereof or benefit in the license or lease, as the case may be, will not be transferred to the pledge holder or any other body, unless the Petroleum Commissioner allows the transfer to the transferee in advance and in writing, pursuant to the Directives; the appointment of a receiver for the pledged rights will not be subject to the rules applicable to the transfer thereof, provided that the Petroleum Commissioner agreed in advance and in writing to the identity of the receiver and the powers provided to him

9. The Directives also include a list of types of transfers for which a fast-track application may be submitted. If the Petroleum Commissioner is of the opinion that the application is not suitable for approval in the fast-track, he will notify the applicants thereof and they will be entitled to submit an application in the regular track. If the Commissioner does not so notify within 45 days from the date of receipt of the application, the application shall be deemed as approved at the end of 45 days and the approval shall be recorded in the Petroleum Register.

10. The types of applications that may be approved in the fast track:

a) Transfer of a petroleum interest between group members up to a rate of 10%, other than the transfer of rights of an operator;

b) Transfer of a petroleum interest from a corporation to a corporation held thereby at a rate of 100%, or that is a holder thereof at a rate of 100%;

c) Transfer of benefit that is not a contractual royalty, other than the following cases:

c)1 The benefit pertains to a producing lease and may have a material effect on the activity under the lease;

c)2 A benefit in an operator or group member holding 40% or more of a petroleum interest;

d) Transfer of an existing right to a contractual royalty, other than royalties, the transfer of which is required by Government Resolution No. 476 of August 16, 2015;

e) Pledge of an existing right to a contractual royalty, other than royalties, the transfer of which is required by Government Resolution No. 476 of August 16, 2015;

f) Pledge of a benefit that is not a contractual royalty, unless the pledge of the benefit may have a material effect on the activity under a producing lease.

(4) Application for approval of export

On December 31, 2015 the Commissioner of Petroleum Affairs issued guidelines regarding application for natural gas export permit, that stipulates, among other things, the date and method for filing application for a permit to export natural gas from the lease field, the information to be included in the application and the documents to be attached thereto, as well as clarification with regard to such export permit. It is emphasized that export permits will be granted in accordance with the terms set out in the gas outline plan, as described in section 1.7.25(A) above, and subject to any law. It should be noted that as at the date of approval of this Report, approvals were received for export agreements signed by the Partnership and Tamar Petroleum, as set out in sections 1.7.13(E)(1)a and 1.7.13(E)(2)a above. On December 16, 2019, the Petroleum Commissioners approval for the export of natural gas from the Tamar and Leviathan leases to Egypt, was received. For further information see sections 1.7.13(E)(2)b and 1.7.13(E)(1)b above.

1.7.28. Additional regulatory restrictions

(A) Government decisions regarding adoption of the recommendations of the committees for studying government policy regarding the natural gas sector

(1) In October 2011 a committee was established to study government policy relating to the natural gas sector and its future development in Israel. The committee was headed by Mr. Shaul Zemach, former CEO of the Ministry of Energy (in this section: “Zemach Commission”). On September 12, 2012 the Zemach Commission published its final report. On June 23, 2013 the Government of Israel adopted the main recommendations of the Zemach Commission, with certain changes (below in this section: the “Government Decision regarding the Zemach Commission"). On December 17, 2015 the Gas Outline Plan was approved, as set out in section 1.7.25(A) above, which includes a number of clarifications and amendments to the foregoing Government Decision. On January 21, 2008, the Ministry of Energy announced the establishment of a professional inter-ministerial taskforce, headed by the Director General of the Ministry of Energy, Udi Adiri (“Adiri Committee”) to periodically examine the Zemach Commission recommendations. The Adiri Committee examined the developments in the natural gas industry in the five years since the Zemach Commission recommendations were adopted and has re-examined the issue of supply and demand for natural gas in 2018. On December 18, 2018, the Adiri Committee published its final conclusions, and on January 6, 2019, the Government of Israel adopted the main recommendations of the Adiri Committee (the “Government Decision regarding the Adiri Committee"). The main points of the Government Decision regarding the Adiri Committee that may impact the Partnership’s operations are as follows:

A. The volume of natural gas that must be guaranteed in favor of the domestic market will remain as approved under the Government's Decision regarding the Zemach Commission (540 BCM), and after updating due to the consumption of 40 BCM so far, will now be 500 BCM (below: ("the Minimum Volume for the Local Market"), which will allow supply of natural gas for local consumption for the next 25 years. In this section, the “volume of natural gas” - is the cumulative volume of natural gas as per the 2P and 2LC PRMS categories for discoveries recognized by the Commissioner of Petroleum Affairs, for which leases were granted and the connection of the leases to the shore was completed in accordance with the development plan, allowing supply to the Israeli market

B. The obligation to supply the Minimum Volume for the Local Market, with regard to the discoveries that were recognized prior to the Government Decision regarding the Adiri Commission, will remain as determined under the Government Decision regarding the Zemach Commission, according to the breakdown below:

Volume of Natural Gas in the Reservoir	Minimum rate of supply to the domestic market out of the volume of natural gas in the reservoir
More than 200 BCM (inclusive)	50%
Equivalent to or exceeding 100 BCM, but less than 200 BCM	40%
Equivalent to or exceeding 25 BCM, but less than 100 BCM	25%
Less than 25 BCM	To be fixed by the Commissioner of Petroleum Affairs

Obligation to supply the Minimum Volume to the Local Market, with regard to discoveries that will be recognized subsequent to the Government Decision regarding the Adiri Committee, will be as follows:

Volume of Natural Gas in the Reservoir	Minimum rate of supply to the domestic market out of the volume of natural gas in the reservoir
For each additional BCM and more exceeding 200 BCM	55%
For each additional BCM and more exceeding 50 BCM to 200 BCM	50%
Less than 50 BCM	There will be no obligation to supply to the local market.

It should be noted that, in the matter of reservoirs shared by Israel and other countries, the Commissioner of Petroleum Affairs will set the specific conditions and arrangements[140].

It was also determined that the export facilities will be located in an area under Israeli control located in its exclusive economic zone, unless otherwise provided in a bilateral agreement between Israel and another country.

C. Export of natural gas is subject to approval by the Commissioner of Petroleum Affairs[141], and the volume of gas that may be exported will be based on the pro rata share of the permitted export volumes in the reservoirs at the same time, subject to ensuring the Minimum Amount for the Local Market, as aforesaid.

D. Notwithstanding the aforesaid, a reservoir that was developed prior to the Government Decision regarding the Zemach Committee (i.e., Yam Tethys and Tamar Projects) may export 50% of the amount that the leaseholders have not yet committed to the local market as of the date of the Government Decision regarding the Zemach Committee, and no more, immediately, provided that an export permit is granted. It is hereby clarified that in the event that consumers exercise the option for reducing quantities granted to them under an agreement signed with the leaseholders prior to the said date, the volume of natural gas for which the option for reducing quantities is exercised will be seen as part of the volume of natural gas that the leaseholders have not yet committed to the local market.

E. Leaseholders in a developed reservoir may exchange their export quotas for the Requirement to Supply to the Local Market according to size and at the rates to be established, subject to the approval of the Petroleum Commissioner and the Competition Commissioner, and after weighing all relevant considerations, including the need to encourage the development of small reservoirs

F. It was decided that the duty to connect reservoirs to the local market will be imposed based on the size of the reservoir, as follows: (a) reservoirs with a volume exceeding 200 BCM will be required to be connected to the local market, as they are developed and before the date of commercial natural gas production; (b) reservoirs with a volume of 50 BCM to 200 BCM, which will begin commercial

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140 It should be noted that the permitted export quota from the Karish and Tanin reserves, in a volume of 47 BCM was replaced by the duty to supply the local market as applies to the holders of the Leviathan leases, commencing from the date of approval by the Commissioner of Petroleum Affairs for the transfer of the rights in the Karish and Tanin leases. For further details see section 1.7.25(A)(3)A.2 above.

141 For details regarding the directives of the Commissioner of Petroleum Affairs relating to submitting applications for approval for the export of natural gas, see section 1.7.27(L)(4).

production of natural gas by January 1, 2028, will be required to be connected to the local market by December 31, 2032, at the discretion of the Petroleum Commissioner; these reservoirs, which will commence commercial production after January 1, 2028, will be required to be connected to the local market as they are developed, and before the date of commercial natural gas production; (c) reservoirs with a volume of up to 50 BCM will not be obligated to be connected to the local market. In the case of fields producing through a single production system, where for at least two of the leases in which these fields are located the same entity is approved as the operator or holds more than 50% of the rights, the volume of gas in these fields for the purpose of the duty to connect to the local market, will be calculated cumulatively. Notwithstanding the foregoing, the Commissioner may decide, in a detailed decision, not to calculate the volume of natural gas in these fields cumulatively.

G. To encourage the connection of additional natural gas fields to the local market, Commissioner, the Director General of the Natural Gas Authority, and the Director General of Budget of the Ministry of Finance, are required to study the State's participation in the construction of an additional marine complex in the southern polygon as approved under NOP 37/H, including an offshore reception facility and connecting it to the shore, if the Commissioner believes that exploration operations have developed in Israel's southern maritime area. In addition to the foregoing, the Commissioner is required to examine additional means to encourage exploitation of the potential financial gains from the natural gas fields, including incentives for connecting fields to the local market that are not obligated to be connected or that were given a deferment of the obligation to connect, as set out above.

In view of the expected shortage of supply to satisfy the hourly demand during 2030-2040, it was suggested that combination of solutions be formulated, including requiring the Petroleum Commissioner to stipulate in the export permits the issue of hourly demand for the local market, to initiate incentives for the connection of additional fields to the local market (particularly before mid-decade (2030-2040)), and to examine cancellation of the agreement with the LNG tanker only in 2021 (the agreement is valid until 2022). In this regard, it is noted that, on December 29, 2020 the Ministry of Energy issued a notice according to which the Minister of Energy decided that the agreement with the LNG tanker would not be extended beyond 2022.

H. To require the Minister of Energy, in consultation with the Minister of Finance and the Minister of Economy and Industry, to draft criteria for the regulation required with regard to the sale of natural gas to domestic market consumers that is earmarked for the manufacture of downstream products intended mainly for export. Further to the foregoing, the subcommittee was established for purposes of formulating the principles of the regulation as aforesaid (in this subsection: the “Subcommittee”). On October 7, 2020,[142] the Subcommittee published a summary report of the principles of the regulation with respect to the export of natural gas downstream products, the key principles of which are:

1. Natural gas downstream products were defined as natural gas based products the production of which involves a chemical change of a natural gas methane molecule into a different compound or compounds, other than by oxidation (including methanol, ethylene, propylene, ammonia, GTL and DME).

2. The Subcommittee noted that the provision that the sale of natural gas to the downstream product industry will be considered as export has many repercussions, and primarily: repercussions due to the government’s policy on the natural gas sector, including the requirement for an export permit; including the gas in the total volume guaranteed for the domestic market; calculation of gas with regard to duty of minimal supply from a natural gas field to the domestic market; the natural gas price and financing of the pipeline network. It was further stipulated that the forgoing does not define the sale as export with regard to other aspects, such as for taxation purposes, including for purposes of the Encouragement of Capital Investments Law, 1959.

3. The Subcommittee recommended that a fixed volume of up to 5 BCM per year of natural gas sold to the downstream product industry be classified as sale in Israel and not for export, in order to allow the industry to continue existing without distorting the calculation of demand in the domestic market.

4. The allocation mechanism will be on a “first-come first served” basis, while the condition for receiving the allocation will be presentation of an agreement, or at the very least a signed MOU, regarding the

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142 The summary report of the Subcommittee is available at: https://www.gov.il/he/departments/publications/reports/ng_products?utm_source=InforuMail&utm_medium=email&utm_campaign=%D7%A2%D7%93%D7%9B%D7%95%D7%A0%D7%99%D7%9D+%D7%9E%D7%90%D7%AA%D7%A8+%D7%9E%D7%A9%D7%A8%D7%93+%D7%94%D7%90%D7%A0%D7%A8%D7%92%D7%99%D7%94+(182)

relevant plant. The allocated volume relates to all of the downstream products with no internal division or restrictions with respect to certain downstream products. The allocation will be carried out by the Director General of the Ministry of Energy, in consultation with the Director General of the Ministry of the Economy.

5. It was further stipulated that if applications are submitted during the two years following the date of adoption of the government resolution on this matter, for allocation of natural gas to the downstream product industry for a volume exceeding 5 BCM per year, both the volume allocated for this purpose and the policy will be reviewed.

6. The Subcommittee noted that the arrangement will be reexamined, together with the government's entire policy on the issue of the natural gas sector, 5 years after the date of adoption of the government resolution (as set out in subsection J below)

I. To require the Minister of Energy, in consultation with the Minister of Finance, to initiate regulatory amendments, including legislative amendments, if necessary, for the purpose of regulating secondary trade in natural gas, which may be directed to export. Including, to require the Minister of Energy, in consultation with the Minister of Finance, to ensure by means of such regulatory amendments, that secondary trade in natural gas that may be directed for export will be limited to a volume of 3% of the total natural gas sales to the Israeli market in the preceding year. Such volume will not be accounted for in the calculation of the total volume promised to the local market, but will be accounted for with regard to the minimum requirement for supply from a natural gas field to the local market; it is hereby clarified that for the purpose of exporting such limited volume, no export permit will be required.

J. The Government will review the Government Decision regarding the Adiri Committee, five years after it is approved, in order to revise, if necessary, the policy with regard to discoveries that may be recognized by the Petroleum Commissioner five years after the Government Decision regarding the Adiri Committee, based on the needs of the local market and taking into account the natural gas supply.

(B) In the Government Decision of October 25, 2020, that deals with the promotion of renewable energy, the second amendment to Government Decision of June 23, 2013 was approved, in which the Government decided to review, in 2021, the permitted limits on export quotas in order to increase them. The Subcommittee's interim recommendations are expected to be published in the near future. In view of the Government's policy regarding the export of natural gas and given the objective for increasing the use of renewable energy targets, the Partnership does not anticipate a restriction that will reduce the scope of permitted exports of natural gas to customers outside Israel.

(C) <u>Possibility of price controls on natural gas</u>

On May 25, 2011 the Ministry of Energy applied to the inter-ministerial price committee of the Ministry of Finance and Ministry of Energy ("the Price Committee") to examine the need to introduce price control on the natural gas sold in Israel.

Further to the Price Committee recommendations dated April 22, 2013, the Commodity and Service Price Control Order (Application of the Law on Natural Gas and Level of Control) 2013, was published, applying control on the gas sector with regard to reporting profit margins and prices. The foregoing duty of reporting applies separately regarding each project. Pursuant to the information that will be received, the need will be examined for price controls on natural gas in Israel, requiring fixed prices. According to the Gas Outline Plan, as long as the Partnerships and Noble comply with all the terms of the Gas Outline Plan, the duty of reporting will remain in force. The foregoing duty to report applies to the Partnerships and their partners in the Yam Tethys, Tamar and Leviathan Projects, and apply separately with respect to each project.

For further information concerning the risk factors regarding the possible impact of imposing price controls on natural gas products in Israel, see section 1.7.33(S) below.

(D) <u>Marine Zones Bill</u>

On November 6, 2017, the Marine Zones Bill, 2017 was placed before the Knesset ("Marine Zones Bill"). The proposed bill seeks to establish the judicial sovereignty over marine zones (including marine zones beyond the State's territorial waters), the sovereign rights of the State of Israel in these zones and the limits of the powers it may exercise concerning activities within these zones.

If the bill will be approved, it could have an effect on the Partnership's operations and costs, the scope of which as at date of publication of the Report, cannot be estimated. In this regard, it is noted, that in January 2013, the Deputy Attorney General (Economics-Fiscal) issued an opinion to the Government, in which he stated that under Israeli law and based on the provisions of international law, the laws regulating the oil and natural gas sector in Israel can be applied in marine zones beyond the territorial waters of the State, and this also with regard to the environmental protection laws and fiscal laws of the State of Israel. This opinion does not revoke applicability of additional laws.

(E) Minister of Energy decision to reduce the use of coal and Israel Electric Corp (IEC) and Electricity Sector reform

On June 3, 2018, Government Decision No. 3859 was issued, regarding the reform of the electricity sector and the IEC (the "Reform"). The reform includes, among other things, the following measures: The IEC will reduce its power generation operations by selling five generation sites with maximum capacity of 4,000 megawatt, which constitutes half of its power generation capacity, and in addition the IEC will build two modern natural gas powered generation units at Orot Rabin, as part of the trend to reduce the use of coal in the electricity production process

On November 13, 2019, the Minister of Energy announced that, the timetable for converting the coal-fired power plants in Hadera and Ashkelon to natural gas could be shortened to 2025, and in that year, in fact, the age of coal is expected to end in the State of Israel. Therefore, according to his new decision, he is shortening timetable that he previously determined, by 4 years. In addition, the decision stipulates that the production plant units at the Rotenberg Power Plant and units 5 and 6 at the Orot Rabin Power Plant in Hadera will be converted from coal to natural gas, by the end of 2025.

On June 8, 2020, a joint announcement was issued to the Ministry of Energy and the Ministry of Environmental Protection[143], concerning the decision by the ministers to order the IEC to expand its planned shutdowns of the polluting carbon units 1-4 at the Orot Rabin site in Hadera, from the second half of 2020 until their complete shutdown in 2022, thus, as published in the notice, bringing about a further significant reduction in pollutant emissions into the air.

On June 24, 2020, the Ministry of Energy issued a notice regarding the Minister of Energy's decision to reduce the use of coal at the IEC's power plants by a further 20% compared to 2019, and thereby use of coal in 2020 will not exceed 24.9% (compared with 30% in 2019). The Minister of Energy instructed the IEC to take the necessary measures to meet the new target, while maintaining the survivability of the power generation system.[144]

On February 8, 2021, a notice was issued that the Minister of Energy directed the IEC to reduce the use of coal so that it will not exceed 22.5% of the total electricity generation in 2021, as part of the policy to end the coal era in Israel by 2025.

(F) Plan to save Israel from polluting energy

On October 9, 2018, the Minister of Energy published its plan to save Israel from polluting energy, which primarily deals with the reduction of the use of polluting fuels by 2030, and subsequently, in March 2019, the Ministry of Energy issued a policy paper on the energy sector goals for 2030[145]. The plan set goals for 2030, stipulating concrete measures and timetables for three main sectors, as follows:

(1) The electricity generation sector – a gradual reduction of electricity generation using coal, until the use of coal in the production of electricity at all the coal-fired power plants will be cease completely, and the generation of power will be based on natural gas and renewable energies only. As aforesaid, on November 13, 2019 the Ministry of Energy announced further cutting of the timetable for ending the use of coal for power generation, as part of which it was decided to convert the coal-fired plants in Hadera and Ashkelon to natural gas by the end of 2025.

(2) The transportation sector - complete cessation of the use of polluting fuels for land transportation, to be replaced with the use of electric vehicles and vehicles powered by compressed natural gas (CNG). Accordingly, from 2030, a total ban will be imposed on the import of cars that run on polluting fuels. Further to this policy, the Ministry of Energy issued a tender[146] for establishing 2,500 electric car charging stations nation-wide, and in June 2019 it published the list of the winners of the tender. Prior to deployment of the new charging stations, the Ministry of Energy is working on promoting the

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143 Ministry of Energy website, Spokesperson announcement of June 8, 2020 https://www.gov.il/he/departments/news/press_080620

144 Ministry of Energy website, spokesperson announcement dated June 24, 2020 https://www.gov.il/he/departments/news/press_240620

145 https://www.gov.il/BlobFolder/rfp/target2030/he/energy_2030_final.pdf

146 https://www.gov.il/he/departments/general/electric_vehicle_ac_dc

creation of a map and an app that will include all such stations in Israel. Establishment of the system is expected to be completed by the end of 2021.[147]

(3) The industrial sector - to stop the use of fuel oil, liquefied petroleum gas (LPG) and diesel oil, and to replace them with cleaner and more efficient energy sources from 2030. Furthermore, additional advantages are being examined, such as using electricity to replace fuels and supplying compressed natural gas. Accordingly, in 2019 the Ministry of Energy allocated grants to the distributing companies to accelerate deployment of the distribution network.[148]

(4) Promotion of energy efficiency through the use of various mechanisms, including mechanisms to encourage reduction of power generation among electricity suppliers, producers and consumers and other license holders in the electricity sector; measures for requiring zero-energy construction; promotion of a model city for smart and efficient energy use; streamlining government agencies in order to reach the 20% target by 2025 and implementing energy rating targets according to actual consumption for existing buildings in Israel.

(5) Ensuring energy security in the market by ensuring surplus natural gas supply to the market, in the transportation, industry and electricity sectors

(G) Government Decision on "Promotion of renewable energy in the electricity sector and amendment of government decisions"

On October 25, 2020, a government decision was adopted which deals with the promotion of renewable energy in the electricity sector and amendment of government resolutions which, inter alia, adopted the Minister of Energy's policy according to which, by 2030, 30% of electricity production will be from renewable energy based mainly on solar power and partially on wind power. A revision was approved for the interim target, setting it at 20% electricity generation from renewable energies by December 31, 2025, and the policy for promoting conventional power generation facilities was modified. The government resolution included a series of decisions aimed at facilitating the advancement of renewable energy. Furthermore, the government's decisions regarding the adoption of the main principles of the Tzemach Committee were amended, so that during 2021 the government will review the restrictions on the natural gas export quotas. [149]

It was further decided, as part of the adoption of the Minister of Energy's policy and of his notice of August 11, 2020 as set out above, that Government Decision No. 2592 will be amended. Therefore, by July 31, 2023, approved plans require additional power generation capacity of 4,000 MW fired by natural gas and backed up by diesel fuel, in response to the needs of electricity consumers until 2030, including at least 4 plans that will enable cogeneration power production using available state-of-the-art technology.

On November 10, 2020, the Natural Gas Authority announced[150] that as part of the plan to save Israel from polluting energy, it is working on connecting 16 hospitals to the natural gas network, at a cost of NIS 40 million, thereby, a call for bids was published for the deployment companies offering them grants for connecting additional hospitals to the natural gas supply network. On January 12, 2021,[151] the Ministry of Energy announced that a grant was awarded for connecting five additional hospitals across Israel to the natural gas supply network within three years. The plan and the call for bids that were published are advancing a process that, at the end of which, as at the date of the revision, 18 governmental and non-governmental hospitals will be connected to the natural gas supply network

(H) Energy sector goals for 2050

On November 29, 2020, the Ministry of Energy announced, for public comment, the proposed goals for reducing emissions in the energy sector by 2050. According to the proposed plan, the energy sector will reduce greenhouse gas emissions by up to 80% by 2050. The plan presented by the Ministry of Energy also includes several secondary goals: commitment to shut down the coal-fired plants by 2025, reduce greenhouse gas emissions in the electricity sector by up to 85% by 2050, an

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147 https://www.gov.il/he/Departments/General/electric_vehicle_ac_dc

148 https://www.gov.il/he/departments/news/electric_car_110619

149 https://www.gov.il/he/departments/policies/dec465_2020

150 https://www.gov.il/he/departments/news/ng_101120?utm_source=InforuMail&utm_medium=email&utm_campaign=%D7%A2%D7%93%D7%9B%D7%95%D7%A0%D7%99%D7%9D+%D7%9E%D7%90%D7%AA%D7%A8+%D7%9E%D7%A9%D7%A8%D7%93+%D7%94%D7%90%D7%A0%D7%A8%D7%92%D7%99%D7%94+(184)

151 https://www.gov.il/he/departments/news/ng_120121

annual improvement of 1.3% in the energy intensity index, and further review of the natural gas sector export policy and full transition to natural gas in the industrial sector.[152]

(I) The Excise on Fuel (Exemption and Repayment) (Amendment and Temporary Provision) Order, 2018 (Green Taxation); the Excise on Fuel (Imposition of Excise) (Amendment No. 2 and Temporary Provision No. 3) Order, 2018 (Amendment), 2019; the Customs Tariff and Exemptions and Sales Tax on Goods (Amendment No. 8) Order, 2018 (Coal), (together: ("the Orders").

On March 14, 2018 and on February 21, 2019, the Knesset Finance Committee and the Knesset plenum approved the Orders, which provide, inter alia, that as of January 1, 2021, the excise tax on coal would increase by about 125%, in view of the Government's policy of the inclusion of external fuel costs and to encourage expansion of the use of natural gas.

It was further decided that as of January 1, 2024, the excise tax on compressed natural gas (CNG) will gradually increase, subject to the existence of no less than 25 CNG filling stations that will receive all the required approvals for operating. It was also determined that as of January 1, 2021, the excise tax on diesel fuel, which is used mainly for transportation purposes, will gradually be abolished.

On January 1, 2021 the increase in excise tax came into effect.

The Company believes that these Orders may lead to a significant drop in the use of coal for power generation and reduce the use of transportation diesel fuel, and accordingly, to an increase in the demand for natural gas in the country, beyond the natural growth in demand for natural gas and electricity in the Israeli economy.

(J) Environmental guidelines for offshore exploration and production of oil and natural gas

In September 2016, the Ministry of Energy, together with the Ministry of Environmental Protection and other ministries, published draft guidelines for receiving public observations for the purpose of regulating the environmental aspects of offshore oil and natural gas exploration, development and production activities. Furthermore, the Ministry of Energy and the Ministry of Environmental Protection, as well as other agencies on behalf of other governmental bodies, including the Israel Lands Authority, issued environmental directives to which the Partnership may be directly or indirectly subject. These directives are revised from time to time, and they are intended to instruct holders of offshore oil rights what measures and documents they are required to prepare as part of their activities within their leases, for the purpose of preventing or minimizing as far as possible any environmental hazards that could develop during offshore oil and natural gas exploration, development and production activities. These guidelines are an integral part of the oil right and the work plan, and digression could lead to revocation of the right. Therefore, the Ministry of Energy drafted, among others, the following guidelines:

(1) Environmental guidelines for conducting seismic surveys in view of the intensity of the noise generated when conducting seismic surveys and its impact, noise levels, path and dates of planned seismic surveys must be submitted for the Commissioner's approval for conducting the survey. When the survey is conducted in a nature reserve or near infrastructure installations, the survey must be coordinated with the authorities or competent entities. In addition, a survey plan must be drafted for conducting the survey, and for obtaining the Commissioner's approval as a precondition for its implementation.

(2) Environmental guidelines in a license: At the license stage, the right is granted to prospect for oil by drilling exploration wells and appraisal wells in the license area. As a condition of receiving approval to drill, the license holder must submit an application to the Commission together with the following documents: (1) an Environmental Statement (ES) that contains a baseline survey of the marine environment; (2) a contingency plan for treating oil spills (OSCP), approved by the Marine Environment Protection Division; and in addition, the license holder must obtain the following permits: Discharge and toxins permits.

(3) Environmental guidelines for a license after discovery and for a lease: As a condition for approval of the development plan and operating authorization the leaseholder is required to submit the following documents to the Commissioner: (1) an Environmental Impact Assessment (EIA) which includes a baseline survey of the marine environment, that addresses the planned development and production program; (2) Oil Spill Contingency Plan (OSCP). In addition, the leaseholder is required to obtain the following permits: discharge permit, toxins permit and emissions permit.

(K) National Outline Plan 37/H regarding reception and processing of natural gas

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152 https://www.gov.il/he/departments/publications/Call_for_bids/energy_2050_public

For preparing the planning infrastructure for connecting the natural gas reservoirs to the national pipelines network installing the necessary facilities, approval of the National Council for Planning and Construction (below in this section: "National Council") and the Israeli government is required for a detailed partial national outline plan that addresses the reception and treatment of natural gas from the discoveries to the national pipeline network (below in this section: "Outline Plan" or "NOP 37/H").

The Outline Plan designates areas (terrestrial and marine) for installing the facilities required for the production and conveying of natural gas, including, inter alia, natural gas reception and treatment stations, a gas pipeline etc. The Leviathan Reservoir development plan as set out in section 1.7.4(E) above, is compatible with NOP 37/H.

(L) Electricity Authority decision - principles for recognizing gas costs of IPPs and principles for recognizing costs of utility providers (the system management unit) in respect of agreements for the purchase of natural gas, (below in this section: the “Decision”).

(1) On March 6, 2019, the Decision was issued, setting out the method of calculating the recognized cost per MMBTU in NIS, for an IPP that signed a gas agreement under which the gas price is linked to the production component.

(2) The Electricity Authority’s decision will apply only to license holders that are eligible for recognition of the gas agreement costs according to the applicable Electricity Authority decisions (once the following two cumulative conditions have been met): [153]

The notes to the Decision state, among other things, that:

a) An IPP that signs a gas agreement that supersedes a previous gas agreement which was recognized by the Electricity Authority will benefit from 25% of the price difference between the agreements, provided that the price in the new agreement is lower.

b) An IPP that signs a gas agreement that does not supersede a gas agreement that was recognized by the Electricity Authority will benefit from 25% of the difference between the maximum gas price under the Gas Framework and the contract gas price.

This Decision sets up an incentive mechanism for IPPs to engage in agreements for the sale and purchase of gas, in which the gas price will be lower than the maximum price fixed in the Gas Outline Plan, by recognizing a price higher than the actual gas price. Furthermore, the Decision gives incentives for IPPs to engage in agreements with gas suppliers that are not related to the Tamar partners, if the gas price under such agreements is lower than the maximum gas price specified in the Gas Framework. It is hereby clarified that, with regard to IEC, the decision of the Electricity Authority of June 12, 2017[154] applies, which establishes the criteria that the IEC is required to comply with in order for the costs to be recognized, but does not define a similar mechanism.

(M) Yam Tethys Project and Tamar Project permits and licenses:

(1) As part of the development of the Yam Tethys project, the Yam Tethys Partners received a permit to construct a permanent rig for the production of natural gas and oil as well as a permit for operating a natural gas production system under the Petroleum Law, and the Minister of Energy also granted Yam Tethys Ltd. (a company owned by the Yam Tethys Partners) a license to establish and operate a pipeline system for transmitting the natural gas of the Yam Tethys Partners or of other natural gas suppliers, under certain conditions and subject to the terms of the license and the Natural Gas Sector Law, from the production platform to the reception terminal.

(2) In addition, as part of the Tamar Project development plan, the Tamar partners received permits for the construction of a permanent natural gas and/or oil production platform and a permit for operating a natural gas and condensate production system at the Tamar project under the Petroleum Law, under which the Tamar partners were required, inter alia, to submit guarantees in an amount of NIS 100 million (100%).[155]

Furthermore, on August 29, 2016 the Minister of Energy granted Tamar 10-inch Pipeline, Ltd. (a company owned by the Tamar partners proportionate to their interests in the lease) a national transmission license to operate the pipeline that will be used to convey natural gas from the Tamar Lease via the Tamar rig, to the reception point at the natural gas processing facility in Ashdod, subject to the terms of the license. The pipeline was established as part of the production system, as defined

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153 https://www.gov.il/BlobFolder/policy/55511/he/Files_Hachlatot_55511_1337.pdf

154 https://www.gov.il/BlobFolder/policy/51813d/he/Files_Hachlatot_13518.pdf

155 The Tamar partners provided guarantees in the amount of USD 35 million to secure the foregoing commitment and to secure the terms of the Tamar lease deed.

in the Tamar operating permit, primarily to be used for conveying condensate, and its use for conveying natural gas will be for a limited period, after which it will go back to be used for conveying condensate.

(3) As part of Phase 1A of the Leviathan Project development plan, the Leviathan Partners received a permit for the construction of a permanent natural gas and/or oil production reg and a permit for operating a natural gas and condensate production system at the Leviathan Project, under which the Leviathan Partners were required, inter alia, to provide guarantees as set out in section (B)(14) above.

On February 21, 2017 the Minister of Energy granted Leviathan Transmission Systems Ltd. (a company owned by the Leviathan Partners) a permit for the construction and operation of a pipeline network, which will be used to convey natural gas from the fields in the Leviathan Leases, or of other natural gas suppliers under certain conditions, all subject to the terms of the license.

(4) Furthermore, many additional permits and approvals were received under various laws, as required for the various projects (Yam Tethys, Tamar and Leviathan).

(N) <u>Specific legislation applicable in Cyprus</u>

Oil and gas exploration operations in Cyprus are subject to regulation that includes requirements for permits, licenses or rights to perform the operations, requirements regarding the scope of investment and schedules for exploration, payment of royalties to the state (under the concession agreement as set out in section 1.7.6(d) above, work safety and environmental quality.

Hydrocarbon exploration and production operations in the Republic of Cyprus, in the territorial waters and exclusive economic zone (EEZ) of the Republic of Cyprus are regulated mainly through local legislation and regulations issued under primary legislation ("the Cypriot Legislature"). Furthermore, the Republic of Cyprus is a full member of the EU and the EU directive concerning granting and use of hydrocarbon exploration and production permits (Directive 94/22/EC) and other relevant European legislature that also regulates hydrocarbon exploration and production operations in the Republic of Cyprus and the Cypriot EEZ are applicable.

The Republic of Cyprus adopted the UN Convention on the Laws of the Sea (UNCLOS 82) in 1988 and to the best of the Company's knowledge signed a number of agreements with its neighboring countries (Israel, Egypt and Lebanon) with regard to defining the Cypriot EEZ.

Under the Cypriot Legislature, a permit, valid for up to one year, is required for conducting 2D and 3D seismic surveys; a license, granted for an initial period of 3 years and which can be extended for two further periods of two years each, is required for hydrocarbon exploration; and an exploitation license is required, which is granted for an initial period of 25 years and can be extended for a further 10 years, subject to the terms of the license. An exploitation license relating to a commercial finding during exploration will be issued following approval of a development and production plan.

The relationship between the Republic of Cyprus and the license holder is prescribed under a Production Sharing Contract (in this section: ("the Concession Contract"). The Concession Contract prescribes the relationship, the liabilities and rights of the license holder and the fiscal terms applicable to the license holder. For further information regarding the Block 12 concession contract see section 1.7.6(D) above.

In 2014, the Republic of Cyprus decided to establish a special purpose government company, Cyprus Hydrocarbons Company Ltd., owned by the Government of Cyprus, which is its representative arm with regard to exploration activities in Cyprus' economic waters and the production and export of oil and natural gas from Cyprus.

1.7.29. Material Agreements

Below is a list of the material agreements to which Delek Energy and/or the Partnerships are a party, including agreements that were in force during the period from January 1, 2020 through to the date of approval of the Report or which affected the operations of Delek Energy and/or the Partnerships during this period:

(A) <u>Agreement for sale of royalty right from Tamar and Dalit Leases between Delek Energy and Delek Royalties</u>

For information concerning the agreement under which Delek Energy assigned to Delek Royalties, by way of a final and irrevocable assignment, its right to receive Tamar Royalties and all rights accompanying the royalty in return for a cash consideration and against the allotment of ordinary shares of Delek Royalties, see section 1.7.36(a) to the 2018 periodic report.

(B) Agreement for the sale of rights to overriding royalties from the Tanin I/16 and Karish I/17 leases

For further information, see immediate reports issued by the Company on May 25, 2020 (Ref. No. 2020-01-052266); and July 8, 2020 (Ref. No. 2020-01-073059), whereby the information appearing in said reports are noted here by way of reference.

(C) Agreement for the sale of Delek Energy interests in Delek Royalties

For further details see section 1.7.1(C) above.

(D) Agreement for the sale of Cohen Development shares held by the Company

For further information concerning the agreement under which the company sold its entire holdings of 51.7% of the share capital of Cohen Development for a set consideration in cash in the amount of NIS 207 million and of the Company's share of a dividend in the amount of USD 2.6 million, see the immediate report issued by the Company on April 19, 2020 (Ref. No.: 2020-01-039303), where the information appearing therein is noted here by way of reference.

(E) Balancing arrangements of gas produced from the Tamar Reservoir

For further details see section 1.7.13(D)(1))f above.

(F) Agreements for the sale of natural gas to the local market from the Tamar and Leviathan projects

For further details see section 1.7.13(D) above.

(G) Agreements for exporting natural gas from the Tamar and Leviathan projects

For further details see section 1.7.13(E) above.

(H) Financing agreements

For further details see section 1.7.22 above.

(I) Block 12 Concession Agreement

For further details see section 1.7.6(D) above.

(J) Agreements for the acquisition of EMG shares and rights in the EMG pipeline

For exercising the two agreements between the Partnership and Noble and Dolphinus for the export of natural gas to Egypt from the Tamar and Leviathan reservoirs, as set out in sections 1.7.13(E)(1)b and 1.7.13(E)(2)(b) (in this section: the "Dolphinus Agreements" of the "Egypt Export Agreement"), on September 26, 2018, EMED signed agreements for the acquisition of 39% of the shares of EMG (the "EMG Transaction").

On November 6, 2019 the EMG Transaction was closed and on January 15, 2020, transmission of natural gas from the Leviathan Reservoir to Egypt began and on June 30, 2020 transmission of gas from the Tamar Reservoir to Egypt began.

The closing of the EMG Transaction was subject, among other things, to the signing of a capacity, lease and operatorship agreement (CLOA), between EMED and EMG, in which EMG will grant EMED the exclusive right to lease and operate the EMG Pipeline for the transport of natural gas from Israel to Egypt ("the (CLOA"), which was signed on June 30, 2019, as set out below:

(1) General:

EMG is a private company registered in Egypt, which owns a 26-inch, 90-kilometer-long subsea pipeline connecting the Israeli transmission system near Ashkelon to the Egyptian transmission system near El-Arish, as well as related facilities ("the EMG Pipeline"). The EMG Pipeline was designed for an annual capacity of 7 BCM, with an option to increase the annual capacity to 9 BCM by installing additional systems. Transmission of gas via the EMG Pipeline from Egypt to Israel was discontinued in 2012, and to the best of the Partnership's knowledge, as at the date of signing of the agreement, EMG had no commercial activity, and it remains exposed to claims[156] and debts in

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[156] Furthermore, to the best of the Company's knowledge, on December 30, 2018, Bazan filed a request for arbitration against EMG with the International Chamber of Commerce in accordance with the agreement for the sale of natural gas signed between them on December 12, 2010 ("the EMG-Bazan Agreement"). Bazan's main claim is that due to the failure to supply natural gas in the period of the EMG-Bazan Agreement and the termination of the Agreement, it incurred damage estimated at USD 350 million. Moreover, Bazan's second claim is that contractual limitations on liability, at USD 45 million plus interest, apply. EMG claims that Bazan is not entitled to compensation at all since the EMG-Bazan Agreement was suspended due to force majeure, and that the statute of limitations applies to Bazan's claims. EMG further claims that even if Bazan is found to be entitled to damages, the amount of the damages is limited to USD 20 million, under the terms of the EMG-Bazan Agreement. The arbitration hearings were held from

significant amounts vis-à-vis the authorities, creditors, suppliers and customers[157]. It should be noted that under the Transaction, the Partnership is not required to provide any collateral or guarantees for the existing debts of EMG.

As at the date of signing of the agreement, the EMG's shareholders are:

(a) EGI-EMG LP - 12%;

(b) The Merhav MNP Ltd. – 8.2%;

(c) Merhav Ampal Energy Holdings, Limited Partnership - 8.6%;

(d) Merhav - Ampal Group Ltd. - 8.2% ("Merhav Ampal Group");

(e) PTT Energy Resources Company Limited ("PTT")[158] – 25%;

(f) Mediterranean Gas Pipeline Ltd. ("MGPC")[159] – 28%;

(g) Egyptian General Petroleum Corporation ("EGPC")[160] – 10%

(Shareholders (a) - (d) will be jointly referred to in this section 1.7.29(J) below as: (the "Sellers").

(2) Agreements for the acquisition of 39% of the share capital of EMG

On September 26, 2018, EMED signed four separate, mostly similar, agreements with the Sellers to acquire EMG shares held by the Sellers, constituting 37% of the shares of EMG (collectively, in this sub-section (J): the "Share Acquisition Agreements "), as well as an additional agreement for the purchase of shares constituting 2% from MGPC ("the MGPC Agreement").

A. Highlights of the Share Acquisition Agreements:

1. Once the preconditions, the main ones which are described in section 5 below, and the terms for closing of the EMG Transaction were met, the Sellers sold the shares they held in EMG and transferred them to EMED, amounting to 37% of the share capital of EMG (below in this section (J): "the Acquired Shares"), including all the rights attached to the Acquired Shares.

2. The Sellers, the shareholders of the Sellers and the companies related to the Sellers will waive any claim, action, award, ruling, order or remedy they may have against the government of Egypt and companies owned by the government of Egypt, with regard to the Arbitration Proceedings.[161]

3. In return for the Acquired Shares, waiver of their rights under the Arbitration Proceedings, and other rights in accordance with the Share Acquisition Agreements, as set out above, EMED paid the Sellers on date of closing of EMG Transaction, a total amount of USD 527 million US dollars (below in this section (J): the "Consideration") of which the Partnership and Noble each paid an amount of USD 188.5 million, and the balance was paid by the Egyptian partner.

4. The jurisdiction applicable to Share Acquisition Agreements is UK law. Disputes between the parties will be adjudicated in arbitration in London (according to the rules of the London Court of International Arbitration).

October 12, 2020 through October 16, 2020 and included the submission of written documents that continued through to December 18, 2020. The Arbitrator's award was handed to the parties on March 5, 2021, under which all the claims against EMG and Bazar were required to pay expenses.

157 According to EMG financial statements as at December 31, 2019 and December 31, 2018, EMG 's assets amounted to USD 402 million and USD 105 million, respectively; its total liabilities amounted to USD 390 million and USD 520 million, respectively; and shareholders' equity of USD 12 million and deficit in equity of USD 415 million, respectively. Furthermore, in 2019 and 2018, EMG did not recognize operating income, but in 2019, the company recorded income from the disposal of assets and debt settlement with an Egyptian bank, which generated profits in the amount of USD 427 million, and in 2019 it accumulated losses in the amount of about USD 25 million. The EMG financial statements are presented in US dollars and are prepared in accordance with generally accepted accounting principles in Egypt. It should be noted that the foregoing financial statements do not include a provision for possible claims by customers.

158 A public energy company partially owned by the Government of Thailand.

159 A private company which, to the best of the Company's knowledge, is controlled by Evsen Group, a company headed by Dr. Ali Evson.

160 An Egyptian government company.

161 It should be noted that some of the Sellers, shareholders of the Sellers, and companies related to the Sellers, were involved in several arbitration proceedings in international arbitration institutions against the government of Egypt and companies held by it, in connection with the suspension of the flow of gas from Egypt to Israel (jointly in this section 1.7.29(J): "the Arbitration Proceedings"). EMG is also a party to arbitration against companies owned by the government of Egypt.

5. Closing of the EMG Transaction underlying the Share Acquisition Agreements was subject to standard preconditions, including: receipt of all the approvals and consents required for the transfer of the Purchased Shares from the Sellers and their registration in the name of EMED; receipt of the approvals and consents required by any law in Egypt and in Israel for performance of the transactions underlying the Share Acquisition Agreements and for the delivery of gas through the EMG Pipeline from Israel to Egypt (including the approval of the Transportation Authority); signing of the CLOA and the removal of any material obstacle to its performance; completion of engineering due diligence for the EMG Pipeline, testing the continuous flow of gas from Israel to Egypt through the EMG Pipeline, in the quantities and for the period determined; restructuring and rescheduling of EMG's debt to an Egyptian bank, to the satisfaction of EMED; receipt of all the formal approvals required by the Sellers, including with respect to the controlling shareholder in Merhav-Ampal Group which is in the process of liquidation, court approvals[162], and the closing of all the Share Acquisition Agreements.

6. On July 31, 2019, the decision of the Competition Commissioner[163] was issued in accordance with section 20(b) of the Competition Law, allowing purchase of the interests in the EMG pipeline under the following main conditions

a) The Partnership (and any affiliate, as defined in the decision: (an "Affiliate"), Noble (and any Affiliate), EMG and EMED (EMG and EMED hereinafter referred to, jointly and severally, the "Parties") may not refuse a gas swap application and will supply natural gas to a customer in Israel that has signed a natural gas supply agreement with a natural gas supplier in Egypt, of such volume and quality that will be no less than the quality that the natural gas supplier in Egypt committed vis-à-vis the customer in Israel (a "Gas Swap Arrangement"), and in this context, they will make every reasonable effort, including by exercising their rights in the Tamar and Leviathan projects to accept such application, All provided that the Egyptian supplier will supply natural gas to the customer of the Israeli supplier (i.e. the Tamar partners and the Leviathan partners) (The "Israeli Supplier") in a volume and of a quality that will be no less than the quality that the Israeli Supplier undertook to sell to the customer in Egypt.

b) The obligation of the Partnership, Noble and the Parties as set out in subsection 1 above is for up to the gas volumes set out in the take-or-pay conditions signed by the Leviathan partners or any one of them and the Tamar partners or any one of them, in respect of which there are transmission agreements via the EMG pipeline (i.e., any agreement for using capacity of the transmission infrastructure of the pipeline in the direction from Ashkelon to el-Arīsh).

c) EMG will not charge an Egyptian supplier for natural gas that will be swapped under the Gas Swap Arrangement (i.e., a supplier that meets the requirements of the Egyptian law for the export of natural gas to Israel, if any), an amount that exceeds half of the transmission fees via the EMG pipeline.

d) The Partnership, Noble and the Parties may not refuse to provide transmission services via the EMG pipeline to an entity seeking to transport natural gas that does not originate from an Israeli Supplier via the EMG pipeline from Ashkelon to el-'Arīsh (an "Other Entity") that wishes to receive transmission services via the EMG pipeline up to the scope of available capacity (i.e., capacity via the EMG pipeline that is not reasonably required by the Tamar partners or the Leviathan partners).

e) Notwithstanding the foregoing, the duty to provide transmission services will not apply in any of the following cases: (a) the Other Entity refused to sign a transmission agreement with the Parties, despite the verification of the Director General of the Natural Gas Authority that the transmission agreement contains no conditions that are unnecessarily burdensome on the Other Entity; (b) the Other Entity refused to meet conditions required by the Director General of the Natural Gas Authority with respect to such transmission agreement.

f) EMED will not exercise the option to extend the Capacity, Lease & Operatorship Agreement by a further ten years without receiving a permit in advance from the Competition Commissioner.

For information concerning the petition filed with the Competition Tribunal at the Jerusalem District Court regarding such approval by the Competition Commissioner, see section 1.7.30(I) below. For information concerning the signing of an agreement between Noble and INGL with regard to the possibility of transmitting the natural gas to the EMG pipeline via the INGL system, see section 1.7.14(B)(2)b.2 above.

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162 On November 16, 2018, the required approval was obtained from the bankruptcy court in New York.

163 https://www.gov.il/BlobFolder/legalinfo/decisions037056/he/decisions_037056.pdf

B. Highlights of the MGPC Agreement

Concurrently with the signing of the Share Purchase Agreements, an agreement was signed between EMED and MPGC, according to which MPGC transferred to EMED, for no financial consideration, once the Share Purchase Agreements are completed, 2% of the shares it holds of EMG, against ending of disputes between some of the Sellers and MPGC.

Subsequent to closing of the EMG Transaction, and as at the date of approval of this Report, EMG's shareholders are:

1. EMED – 39%;
2. PTT – 25%;
3. MGPC - 17% (controlled by Dr. Eli Evson);
4. Egyptian partner - 9%;[164]
5. EGPC – 10%

(3) Capacity, Lease and Operatorship Agreement

As aforesaid, the closing of the EMG Transaction was contingent, among other things, upon the signing of the capacity, lease and operatorship agreement between EMED and EMG, in which EMG will grant EMED the exclusive right to lease and operate the EMG Pipeline for the entire term of the Dolphinus Agreements, with an option to extend the agreement. According to this agreement, which was signed on June 30, 2019, the costs required for refurbishment of the EMG Pipeline, and the current operation costs of the pipeline, will be borne by EMED (collectively in this section: "the Operating Costs"), and EMG will be entitled to receive the current transport fees to be paid by Dolphinus for use of the pipeline (below in this section: "the Transmission Fee"), net of the Operating Costs. As at December 31, 2020, Noble and the Partnership have invested in the refurbishment of the EMG Pipeline, through EMED, an amount of USD 124 million[165], most of which will be recovered from the cash flow generated by payments for the transmission of gas to EMED.

Concurrently with the signing of the agreements for export to Egypt, the Partnership and Noble signed an agreement with the Tamar partners and the Leviathan partners for allocation of capacity (below in this section: "the Capacity Allocation Agreement") in the pipeline from Israel to Egypt. The division of capacity in the transmission system from Israel to Egypt (the EMG Pipeline and the transmission pipeline in Israel) will be on a daily basis, according to the following order of priority:

A. First layer - up to 350,000 MMbtu per day will be allocated to the Leviathan Partners.

B. Second layer - the capacity exceeding the first layer, up to 150,000 MMbtu per day up to June 30, 2022 (the "Capacity Increase Date"), and 200,000 Mmbtu per day after the Capacity Increase Date, will be allocated to the Tamar Partners.

C. Third layer - any additional capacity exceeding the second layer will be allocated to the Leviathan Partners.

At closing of the EMG Transaction, the Leviathan Partners paid an amount of USD 200 million[166] (the "Leviathan Participation Fee") and the Tamar Partners paid an amount of USD 50 million[167] (the "Tamar Participation Fee"), in consideration of the undertaking to enable transmission of natural gas from the Leviathan and Tamar reservoirs and guaranteed capacity in the EMG Pipeline, all for the execution of the Egypt Export Agreements. It should be noted that the final Leviathan Participation Fee and Tamar Participation Fee will be determined by June 30, 2022, according to the ratio of the gas volumes actually supplied by the Leviathan Partners and Tamar Partners via the EMG Pipeline until that date (including gas volumes not yet supplied and that were paid for under the take or pay undertaking).

In addition, the Capacity Allocation Agreement includes arrangements for participation in the costs of the EMG Transaction, additional costs related to gas flow, and investments which will be required to maximize utilization of the capacity of the EMG Pipeline, the payment of which will be divided

164 To the best of the Company's knowledge, MGPC transferred the foregoing shares to the Egyptian partner.

165 Of this, USD 72 million was invested in financing the joint transactions of Michal, Matan and Ratio Yam under the capacity allocation agreement.

166 The Company's share is USD 90.7 million.

167 The Company's share is USD 11 million.

between the Leviathan partners and the Tamar partners. For information concerning the rights of Ithaca and the operators in these assets, see section 1.7.13(D)(1)f below.

The Capacity Allocation Agreement further stipulates principles for a backup arrangement between the Tamar partners and the Leviathan partners according to which, as from June 30, 2020, and until the Capacity Increase Date, if the Tamar Partners are unable to supply the quantities which they undertook to supply to Dolphinus, the Leviathan partners will supply the required quantities to the Tamar Partners.

The term of the Capacity Allocation Agreement is until the termination of the Egypt export agreements, unless it had been terminated earlier in one of the following cases: a breach of a payment undertaking that was not remedied by the party in breach; in a case where the Competition Authority does not approve extension of the Capacity Lease and Operatorship Agreement according to the decision of the Competition Commissioner, as set out in section 1.7.29(J)(2)A.5 above. Furthermore, each party will have the right to terminate its part in the Capacity Allocation Agreement if its export agreement is cancelled.

To the best of the Company's knowledge, on August 26, 2019, PTT, which holds 25% of EMG shares, filed a claim with the Economic Court in Port Said, Egypt, against EMG and other parties. In the statement of claim, PTT seeks the revocation of the resolutions of EMG's general meeting on June 10, 2019, including revocation of the resolution to approve the signing of the CLOA. PTT claims that these resolutions constitute discrimination of the minority shareholders and are contrary to the Company's best interests, in violation of the Egyptian company's law, which applies to EMG. As at the date of approval of the Report, the hearing of the claim is scheduled for April 2021.

(4) EMED shareholders agreement

Shortly before signing the Share Purchase Agreements, the shareholders of EMED signed a shareholders agreement governing the relationship between them as shareholders of EMED, including provisions regarding material decisions, which will be made unanimously. In addition, arrangements were established for the right of first refusal for the transfer of shares in EMED.

(5) MOU for the use of additional infrastructures

Concurrently with the signing of the Share Purchase Agreements, as described above, an MOU was signed between the Partnership and Noble and between the Egyptian Partner (which holds the Pan-Arab Gas Pipeline) in the section from El Arish to Aqaba, and a related company of Dolphinus, in which the parties agreed that the Partnership and Noble would receive access to additional capacity in the Egyptian transmission system, through the Pan-Arab Gas Pipeline, at the entry point to the Egyptian transmission system in the Aqaba area, allowing the delivery of additional quantities of gas over and above the quantities of gas that will flow through the EMG Pipeline ("the Additional Infrastructure"), for implementation of the Dolphinus agreement and additional agreements for the sale of natural gas to Egypt. The parties further agreed to assess additional projects for the delivery of natural gas from Israel to potential customers and facilities in Egypt.

(6) Agreement between EMG and EAPC and Eilat-Ashkelon Infrastructure Services Ltd

On July 1, 2019, an agreement was signed between EMG and EAPC and Eilat-Ashkelon Infrastructure Services Ltd. (in this section: the "EAPC Companies" and the "EAPC Agreement" or "Agreement", respectively) for regulating a sublease of areas within the EAPC complex at the Ashkelon port, rights of way at the port and EMG and EMED use of the natural gas facility located in this complex, for the purpose of transporting natural gas via the EMG Pipeline.

In return for these rights, the EAPC Companies are eligible for payments as set out in the Agreement.

The EAPC Agreement took effect on November 6, 2019, together with the closing of the EMG Transaction, and will be in effect (unless terminated prior thereto, inter alia, by EMG in the event that the Egypt Export Agreements are revoked due to a breach by the buyer or due to force majeure, all in accordance with the provisions of the Agreement) until June 10, 2030. According to the Agreement, and subject to its provisions (including the extension of the lease agreement between Eilat-Ashkelon Infrastructure Services Ltd. and the Israel Land Authority), EMG may extend the term of the Agreement until October 6, 2043.

For the purpose of securing the payments to the EAPC Companies, EMG is required to provide a bank guarantee (renewable over the term of the Agreement) in the amount of USD 4 million (in this section: the "Guarantee Amount"). As at date of approval of the Report, EMG has not provided such bank guarantee, and instead EMED provided a company guarantee for up to the Guaranty Amount, which is backed by two bank guarantees in the amount of USD 2 million each, which were provided by the Partnership and Noble (in this section: the "Bank Guarantees"). The guarantee provided by

EMED will expire and rendered null and void in the event that: (a) all of EMG's undertakings vis-à-vis the EAPC Companies are canceled; (b) the EAPC Companies will have received payment in the amount of the Guarantee Amount due to exercise of the Bank Guarantees; (c) the Bank Guarantees are replaced by a bank guarantee provided by EMG; or (d) the Bank Guarantees have expired or been canceled. It is further noted that, under the terms and conditions of the guarantee provided by EMED, the EAPC Companies will be required to first exercise the Bank Guarantees and only in the event of that they are not paid, will they be entitled to exercise the EMED guarantee.

Concurrent to the signing of the Agreement, the Tamar and Leviathan Partners provided a letter of release, according to which each of the partners releases the EAPC Companies from any future lawsuit in respect of damage that may be caused to it (if any) due to an act or omission of the EAPC Companies or anyone on their behalf as parties to the EAPC Agreement or as the operators of the Ashkelon port (with the exclusion of damage caused by malicious intent).

The EAPC Companies provided a similar letter to the Tamar and Leviathan Partners.

(K) Joint operating agreement for the Leviathan Leases[168]

Exploration and production activities in the Leviathan Leases (in this section: "the Oil Asset") were carried out through a joint operating agreement ("JOA" or "Joint Operating Agreement") dated August 3, 2008 (as amended from time to time). The parties to the JOA are the Partnership and the other partners in the Leviathan leases as described in section 1.7.4(A) below (in this section: ("the JOA"). The provisions of the JOA refer, inter alia, to the following issues:

(1) All the rights and interests, and all the liabilities of the parties, in respect of the JOA, will be according to the percentage of the parties' participation in the oil assets

(2) Noble was appointed as operator and will be solely responsible for the Partnership's operations in the Oil Asset - which includes, among other things, drafting of work plans, budgets and payment orders, the execution of the work plan in accordance with the approval of the joint operating committee, the planning and obtaining of all approvals and materials required for executing them, and providing consultation and technical services as required for the effective running of the joint operation, this in accordance with the terms and conditions for the Oil Assets and the applicable regulations, laws and the JOA. Inter alia, the Operator will determine the number and identity of the workers, their work hours and the salary that will be paid to them regarding the joint operations in the oil asset.

(3) Provisions were determined for indemnification and limit of liability for the Operator (including its directors and officers, and related parties and their directors and officers), whereby the Operator is entitled to indemnity for any damage, loss, cost, expense or liability incurred by virtue of fulfillment (or non-fulfillment) of its duties and functions as an operator (except in exceptional cases of gross negligence by the Operator's senior officers, whereby the indemnification will apply for any damage, loss, cost, expense or liability exceeding USD 5 million). The aforesaid does not exempt the Operator from liability for its share according to the rate of participation in any damage, loss, cost, expense or liability.

(4) The Operator is entitled to reimbursement for all direct expenses arising from fulfillment of its duties as an operator and reimbursement for indirect expenses arising from the share of the joint venture expenses, according to the Operator's accounting principles and practices. On June 30, 2016, an amendment to the JOA was signed, according to which the Operator will be entitled to receive indirect expenses at a rate of 1% of the total direct expenses for development and production activities, subject to certain exceptions, such as marketing activity.

(5) The parties to the JOA established an operations committee with the authority to approve and supervise the joint operations required to fulfill the terms of the Oil Asset and the JOA. The operations committee is comprised of representatives of the parties, with each representative having voting rights in accordance with the rights of the party that they represent. Resolutions of the operations committee will be passed by a vote in favor by two or more of the parties, (which are not related or associated parties), holding together at the time of the vote at least 60% of the total participating rights in the area of the Oil Asset relevant to the resolution.

It is further noted that, to pass a resolution to terminate the lease or waive any part of the lease area, a vote in favor by all the parties is required. A positive decision by one party to JOA is sufficient for approving any application for a license or renewal of a license or a lease.

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[168] It is noted that at January 1, 2012, operations in the Leviathan Leases were carried out under a single JOA.

(6) Procedures for submission and approval of a work plan, budgets and authorizations for expenditure for operations in areas covered by the JOA.

(7) Operations in which not all the parties participate (defined in the JOA as exclusive operations, and which are commonly known in the oil exploration sector as sole risk operations) will not be carried out if they contradict the joint operations of all the partners to the JOA. The JOA provides a general framework for these operations.

(8) Subject to the provisions of the JOA, the Operator may at any time, with prior notice of at least 120 days, resign from its position as Operator. In addition, subject to the provisions of the JOA, the Operator will be removed from its position if it becomes insolvent or bankrupt, or makes an arrangement in favor of its creditors; if a party to the agreement gives notice of a court order or a valid ruling for restructuring according to bankruptcy laws; or if a receiver is appointed for a significant portion of its assets; or it the Operator is dissolved or ceases to exist.

(9) Sanctions applicable to the partners and conditions for imposing the sanctions if one of the parties fails to pay its proportionate share in the joint expenses ("the Party in Breach"), including revoking the right of the Party in Breach to participate and vote in operating committee meetings, to receive data and information about joint operations and to receive the share of output to which it is entitled, and the option of allowing the partners to demand removal of the Party in Breach from the JOA and from the Oil Asset if the breach is not remedied within 90 days from the date of the breach announcement.

(10) Provisions for full or partial withdrawal of a party from any oil asset (and from the applicable JOA), and determines the cases in which withdrawal is possible, and the rights and obligations of the withdrawing party towards the other partners in the Oil Asset and the JOA.

(11) It also states that if a party to the JOA wants to transfer its rights (excluding transfer to a corporation under its control), the other parties to the JOA have the right of first refusal to acquire these rights in accordance with the provisions of the JOA.

(12) It also provides that in the event of a change of control in one of the partners, and if the value of the Oil Asset exceeds 50% of the market value of the entire holding of such partner in which such change of control occurred, the partner must notify the other partners of such change of control (the “Notice”). The Notice will contain, among other things, the market value of the partner’s interests under the JOA, based on the amount that the buyer of the control is willing to pay in an arm’s length transaction. Once such Notice has been given, each of the other partners will have the right to purchase the full interests of the partner in which the change of control occurred, within 30 days from receipt of the Notice, and such purchase will be under the same terms and at the price given. It is further noted that, under the terms and conditions set out in the JOA, the other partners may dispute the value given in the Notice of the change of control.

In the event that more than one partner gives notice of its willingness to exercise its right to purchase the interest as aforesaid, the interest will be divided pro rata to the holdings of the partners.

(13) The JOA is subject to the laws of England and Wales. Any dispute will be decided in an arbitration proceeding in accordance with the arbitration rules of the London Court of International Arbitration (LCIA).

(L) <u>Joint operating agreement for the Tamar and Dalit lease</u>

Exploration and production operations in the Tamar project leases are carried out under a joint operating agreement (in this section: "the JOA" or "the Agreement") of November 16, 1999 (as amended from time to time). The parties to the JOA are the Partnership and the other Tamar project partners, which includes the following provisions:

(1) All the rights and interests, and all the liabilities of the parties, in respect of the JOA, will be according to the percentage of the parties' participation in the oil assets

(2) Noble will be the Operator in accordance with the JOA and will be solely responsible for management of the joint operations in the oil asset, including the agreement with third parties, insurances, access authorization for the parties to the JOA to supervise the joint operations, determining the number of workers and their wages, in accordance with the terms of the oil asset and rules applicable to it, the JOA, and the guidelines of the operating committee (as defined below).

(3) The role of the Operator cannot be assigned without the prior written consent of the parties to the JOA (which are not the Operator), as well as any consent required by the Commissioner of Petroleum Affairs, with the exception of assignment to a third party of the Operator as defined in the agreement.

(4) The Operator is entitled to reimbursement for all direct expenses arising from fulfillment of its duties as an operator and reimbursement for indirect expenses arising from the share of the joint venture expenses, according to the Operator's accounting principles and practices. In the amended JOA of June 30, 2016, an accounting method was also set for Noble’s indirect expenses and it was determined that, as of January 1, 2016, Noble will be eligible for indirect expenses of 1% of the total direct expenses, other than with regard to marketing and fees, as specified in the amendment to the agreement, as aforesaid.

(5) The Operator is not liable to any of the other parties to the JOA (except for its proportionate share) for any claim, liability, loss or damage arising from or in respect of joint operations, unless these are a result of the Operator's willful misconduct or failure to obtain the required insurance and in any case shall not be responsible for consequential damages. The aforesaid does not exempt the Operator from liability for its share according to the rate of participation in any damage, loss or liability.

(6) Operations committee: The parties have set up an operations committee as part of the JOA, which has the authority to make decisions regarding operating policy, approval of plans and requests for budgets, determining schedules, making decisions regarding applications for licenses and leases, and replacement of the Operator. The operations committee is comprised of representatives of the parties, with each representative having voting rights according to the rights of the party that they represent. The Committee's resolutions will be passed by a vote in favor of two or more of the partners, holding together at least 68% of the rights in the lease (related parties as defined in the agreement will be considered as one party). To pass a resolution regarding termination of the lease or waiver of any part of the lease area, a vote in favor is required by all the parties. A positive decision by one party to JOA is sufficient to approve any application for a license or renewal of a license or a lease.

(7) Procedures for submission and approval of a work plan, budgets and authorizations for expenditure for operations in areas covered by the JOA.

(8) Operations in which not all the parties participate (which are commonly known as sole risk operations in the oil exploration industry) will not be carried out if they contradict the joint operations of all parties to the JOA. The JOA provides a general framework for these operations.

(9) Subject to the provisions of the JOA, the Operator may at any time, with written notice of at least 180 days, or shorter notice with the consent of the operating committee, resign from its position as Operator. In addition, subject to the provisions of the JOA, the operating committee may dismiss the Operator if one of the events stipulated in the JOA occurs, including if the Operator ceases to hold at least 10% of the participating rights in the leases or insolvency or liquidation of the Operator.

(10) Sanctions that apply to the partners and conditions for imposing the sanctions if one of the parties fails to pay its proportionate share in the joint expenses ("the Party in Breach"), including revoking the right of the Party in Breach to participate and vote in operating committee meetings, to receive data and information about joint operations and if the breach continues for more than six days, denial of the proportional share of the Party in Breach in production. If the breach continues for more than 90 days, the other partners may demand the removal of the Party in Breach from the JOA and the oil asset.

(11) Each party to the JOA may transfer its rights to a third party subject to the approval of the other parties to the JOA, and the parties may oppose the transfer on reasonable grounds only.

(12) The JOA includes provisions for withdrawal of a party from any license, and determines the cases in which withdrawal is possible, including the rights and obligations of the withdrawing party towards the other partners in the license.

(13) The JOA is subject to the laws of England and Wales. In addition, any dispute will be resolved in arbitration in accordance with the Arbitration Rules of the International Chamber of Commerce. In the arbitration process, a single arbitrator will be appointed, who will not be a resident or an Israeli or UK citizen.

(M) Joint operating agreement for Block 12

The foregoing JOA covers the same issues and is in a similar format as the JOA applicable for the Leviathan Project (as described in section (K) above), whereby resolutions are adopted by a decisive majority vote which is a positive vote in favor of a decision by at least two participants that are not affiliated parties and that jointly hold at least 65% of the license rights. Noble Cyprus serves as the Operator.

(N) Royalties to the State and to Related and Third Parties

(1) General

Under the Petroleum Law, the Partnership is required to pay the royalties to the State at the rate of one-eighth (12.5%) of the volume of oil and natural gas produced from the area of each lease and utilized, at the market value of the royalty at wellhead (the "State Royalties").

In addition to State Royalties, the Partnership pays royalties, according to the market value of the royalties at wellhead, to related and third parties (the "Royalty Holders") under their obligations in two agreements: (a) the undertaking to pay royalties to the Company and to Delek Energy under the Rights Transfer Agreement of 1993, as described in subsection (2) below; and (b) the undertaking to pay royalties under the Avner Partnership Limited Partnership Agreement ("Avner Partnership Agreement"), as described in subsection (3) below, which the Partnership assumed as part of the merger of Partnerships that was completed in May 2017.

The Partnership undertook to pay royalties to Royalty Holders at certain rates from the Partnership's share of the oil, gas and other substance of value produced and utilized from the oil assets in which the Partnership has an interest, at the market value of the royalty at wellhead.

As aforesaid, pursuant to the Petroleum Law, the leaseholder is required to pay the State the "market value of the royalty at wellhead". A method must be set for calculating the market value of the royalty at wellhead is required because natural gas sales are priced at the onshore gas delivery point, and therefore, the contractual price stipulated in the gas sale agreements is higher than the price that would have been set had the gas been delivered at wellhead. Consequently, the effective rate of the State Royalties is actually lower than one-eighth (the "Effective Rate"). For information concerning the draft directives issued by the Ministry of Energy for public comment regarding the method for calculating the market value of the State Royalties at wellhead, see section 1.7.29(N)(5) above. For further information concerning the method of calculation of the Effective Rate of the State Royalties in the Partnership's projects and regarding the discussions with the State on this matter, see subsection (5) below. It is noted that in practice, the calculation of royalties paid by the Partnership to the Royalty Holders is based on the calculation of the value of the State Royalties at wellhead.

(2) Royalties under the 1993 Agreement

Under the 1993 Agreement signed between Delek Energy and Delek Israel (the "Transferors") of the one part, and the general partner in the Partnership, of the second part, the Transferors transferred to the Partnership rights in several licenses and the Partnership undertook in return to pay royalties to the Transferors from the Partnership's share of the oil, gas and other substance of value produced and utilized from the oil assets in which the Partnership has an interest. The Royalties will be paid from the Partnership's total share, as aforesaid, at the value of the Royalty at wellhead, before deduction of royalties of any kind but after deduction of the oil used for its production needs.

The royalty paid by the Partnership under the 1993 Agreement is divided between Delek Energy (75%) and Delek Israel (25%). Following reorganization, the Company currently holds Delek Israel's right to such royalties.

The rate of royalties set in the 1993 Agreement, and as revised on the date of the merger of the partnerships, are as follows: (a) until date or return on investment of the Partnership, royalties will be paid at a rate of 2.5% for onshore oil assets and 1.5% for offshore oil assets; and (b) after ROI date, royalties will be paid at a rate of 7.5% for onshore oil assets and 6.5% for offshore oil assets.

Pursuant to the 1993 Agreement, the Partnership and the Transferors signed deeds of royalties under which the royalty rights were recorded in the Petroleum Register.

In July 2017, the Partnership sold participating rights of 9.25% in the Tamar Project to Tamar Petroleum, which assumed the Partnership's undertakings to pay royalties to the Royalty Holders with respect to these rights.

On June 7, 2018, Delek Energy completed a transaction under which it sold its right to receive royalties from Tamar and Dalit leases to Delek Royalty, retroactively from January 1, 2018. On December 26, 2019, the Company completed a transaction under which it sold its right to receive royalties from Tamar and Dalit leases to the Study Funds for Teachers and Kindergarten Teachers and to Study Funds for High School Teachers, Seminary Teachers and Supervisors, retroactively from April 1, 2019. Subsequent to these transactions, the Company and Delek Energy no longer hold rights to receive royalties from the Tamar Project under the 1993 Agreement.

On October 28, 2020, the Company and Delek Energy notified the Partnership that the issue in the amount of USD 180 million was completed and thereby their right to receive royalties from the Partnership's share (45.34%) in the oil and/or gas and/or other valuable substances to be produced and utilized from the Leviathan North and Leviathan South leases were transferred to Delek

Overriding Royalty Leviathan Ltd (“Delek Overriding Royalty”), and that the record in the Petroleum Register had been amended accordingly. In view of the foregoing, as of October 28, 2020 the Partnership pays all of the proceeds of these royalties directly to Delek Overriding Royalties.

(3) Royalties under the Avner Partnership Agreement

Under the Avner Partnership Agreement, Avner Partnership undertook to pay to Cohen Development and other third parties, royalties of 6% of its entire share in the oil, gas and other substances of value that are produced from the oil assets in which it has or had an interest. The Royalties are calculated at the value of the Royalty at wellhead, before deduction of royalties of any kind but after deduction of the oil used for production needs. According to this undertaking, deeds of royalties were signed between Avner Partnership and the Royalty Holders, under which the royalty rights were recorded in the Petroleum Register.

Under the merger of the Partnerships, the Partnership assumed the undertakings of Avner Partnership to pay royalties and accordingly, the rate of royalties paid by the Partnership to the Royalty Holders under the Avner Partnership Agreement was adjusted to 3%. In the amendment to the Delek Drilling Partnership Agreement drawn up at the time of the merger, the Partnerships clarified that the Avner Partnership Agreement and deeds of royalties signed under them would retain full validity with respect to the parties therein.

(4) Dispute regarding the ROI Date for the Tamar Project

In December 2017 the Partnership began paying royalties with respect to the Tamar Project at a rate of 6.5%, the rate after the ROI date of the Project (the “Increased Rate”), based on a draft calculation prepared by the Partnership at that time. Consequently, Tamar Petroleum also began paying royalties from the Tamar Project at the Increased Rate since May 2018, retroactively from January 1, 2018.

In September 2018, the Partnership’s audit committee and board of directors, approved the calculation date of the ROI date for the Tamar Project, according to which the ROI date fell in January 2018 (due to an error in the calculation, and this instead of December 2017, when the ROI Date falls according to the draft calculation). The calculation was approved after completion of the special audit by the Partnership’s auditors, based on the advice of an independent legal advisor that the Partnership’s audit committee received. Consequently, to the error, the Company and Delek Energy returned an amount of USD 2.8 million for overpaid royalties, as the Partnership claims.

Furthermore, the Supervisor of the Partnership requested an assessment by an external economic consultant regarding the calculation of the ROI Date prepared by the Partnership. To the best of the Company’s knowledge the main issue noted in the consultant's assessment report is the treatment of the taxes on gas and oil profits under the Income Tax from Natural Resources Law (the “Sheshinski Levy”), with regard to which the consultant noted, among other things, that his conclusions do not necessarily represent deficiencies in the draft calculation and are subject to legal and economic interpretation of the royalty’s agreement.

In January 2019, the Supervisor of the Partnership filed a claim of discrimination with the Tel Aviv District Court against the Partnership, the general partner, the Company, Delek Energy and Delek Royalties. The claim was defined as a declaratory claim and a claim for relief of ceasing discrimination, in which the court was requested to declare, inter alia, that the calculation of the "return on investment date" should include the payments that the Partnership is required to pay to the State in accordance with the Sheshinski Levy; to declare that the ROI date in the Tamar lease has not yet passed and to determine when this date will fall; to declare that the royalty rights holder must reimburse the Partnership for the excess payments allegedly received. For further information concerning these proceedings, see Note 24A3(3) to the Financial Statements.

In February 2019 Tamar Petroleum demanded that the Company and Delek Energy refund an amount of USD 852,255 thousand with respect to royalties that it claims were overpaid, this based on a calculation that it made according to which the ROI Date of the Tamar Project fell at the end of February 2018, subject to adjustments and reservations. Tamar Petroleum attached to its demand a special report of its auditors. According to Tamar Petroleum, as the calculation does not include the effect of the Sheshinski Levy on the ROI Date, it was an interim calculation. Tamar Petroleum further stated that considering that it has worthy arguments in favor of including the Sheshinski Levy in the final calculation, it seeks to determine, together with the Company and Delek Energy, an agreed mechanism for assessing the Sheshinski Levy and its inclusion in the calculation of the date of ROI.

As its demand was not accepted, on February 27, 2019, Tamar Petroleum offset the above amount from the royalty payments it made at the end of February 2019. As under the sale agreement of royalty rights from Delek Energy to Delek Royalties provides an indemnification arrangement between the parties, Delek Energy will indemnify the buyer if it is decided that the ROI Date fall on a later date, Delek Energy transferred to Delek Royalties the amount that was deducted from its share, as aforesaid.

The Company and Delek Energy strongly objected to the contents of Tamar Petroleum's foregoing demand, including the attached calculation, and denied its right to the offset (which they claim was made in contravention of the law). Furthermore, Delek Energy and the Company further noted that they have serious claims regarding pushing back of the ROI date that applies long before February 2018. In August 2019, the Company and the other the holders of royalty rights engaged with Tamar Petroleum in an agreement according to which they will resort to mediation proceedings and if the mediation proceedings fail, the parties agreed to appoint a retired judge as sole arbitrator. Simultaneous to signing of the agreement, Delek Energy signed a letter of undertaking according to which, if under the arbitration ruling Delek Royalties or anyone representing it is required to return excess royalties paid as a result of omitting the Sheshinski Levy from the ROI date calculation, Delek Energy will bear this payment. The mediation is ongoing and at this stage, the parties are meeting separately and together with the mediator.

For further information regarding the legal proceedings underway with regard to setting the ROI Date of the Tamar Project, see Note 24A3 to the Financial Statements.

(5) Method of calculation of the market value of royalties at wellhead

A. Under the terms of the royalties, the Partnership is required to pay the State and royalty holders (including the Company) the market value of the royalties "at the wellhead".[169]

B. Rate of royalties in the Tamar Project

1. The Partnership, to date, calculated the market value of royalties at wellhead according to the method for calculating the market value of the State Royalties and therefore the State Royalties market value calculation also affects the effective rate of royalty of the Company's royalty rights as well as of the other royalties paid by the Partnership.

2. According to the Ministry of Energy, the agreement regarding the method for calculating the value of the State Royalties at wellhead in the Yam Tethys project does not apply with regard to the State Royalties in the Tamar Project. Following discussions held by the partners in the Tamar Project, including the Partnership, with the Ministry of Energy, regarding the method of calculation of the market value of the royalty at wellhead in the Tamar Project, the Tamar Partners paid the State advance payments, pursuant to the Ministry of Energy's demand and under protest, on account of the royalties, at a rate of 11.65%, 11.3% and 11.3% for 2018, 2019 and 2020, respectively, with regard to income from the Tamar Project. The Operator and the Other Tamar Partners are of the opinion that the calculation of the effective rate of the State Royalties in the Tamar Project ought to express the complexity of the project, the risks involved and the amount of the investments made in the project, and that the average effective rate of the State Royalties in 2013-2020 should be lower.

3. It is noted that the effective rate of the State Royalties in the Tamar Project in 2018, 2019 and 2020, on which the Partnership relied in its financial statements, was 11.16%, 11.3% and 11.34%, respectively.[170]

4. The difference between the royalties actually paid by the Partnership to the State and the effective royalty rate used by the Partnership in its financial statements for 2013-2020 amounts to USD 16.8 million.

As at date of publication of the Report, there is still not agreement with the Commissioner of Petroleum regarding the actual method of calculation of the State Royalty from the Leviathan Project or other future projects that the Partnership will be party to, and it is unable to estimate how the market value at wellhead of the royalties that will be paid in these projects will be calculated.

For information about the claim for restitution of royalties paid to the State by the Partnerships and Noble for their revenue from the supply of natural gas, from their part in the Tamar Project, to their customers under the Yam Tethys agreements, see section 1.7.37(B) below.

5. On September 6, 2020, the Natural Resources Authority at the Ministry of Energy released the Directives of the Petroleum Commissioner regarding the method of calculation of the value of the

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169 It should be noted that the method for calculating the market value at wellhead of the royalties paid to the Royalty Holders was based on the calculation of the Effective Rate of the State Royalties.

53 It is noted that for the discounted cash flow figures of the Tamar Project the Partnership assumed that the Effective Rate of the State Royalties is 11.5%.

royalty at wellhead for the Tamar Lease[171] (in this section: the "Draft Directives") specified, among other things, the following principles:

The expenses that will be recognized for calculating the value of the royalty at wellhead:

a) Capital expenses (capex) – cost for the transmission pipeline from the main manifold to the Tamar platform (the "Platform") and from the Platform to the AOT terminal in Ashdod (the "Terminal"), will be recognized at a rate of 100%; the cost from the Platform to the Terminal, will be recognized at a rate of 82%.

b) Operating expenses (opex) – arising directly from the types of capital expenses specified below will be recognized at a rate of 82%: Payroll expenses of workers at the platform and the terminal; maintenance and repair expenses; expenses for travel and transportation to the platform; expenses for food for the workers at the platform and the terminal; expenses for guarding and security at the Tamar platform and the terminal; expenses for professional and engineering consultation; insurance expenses.

In addition, if the contract sale price includes a transmission tariff component that is paid to INGL, all of the transmission expenses paid by the lease holder will be recognized. Decommissioning costs will be recognized for the calculation of the royalty according to the general directives, see section 1.7.27(B) above However, the cumulative conditions applicable for the Tamar Lease are: a minimum of 170 BCM was produced from the gas from the reservoir and the decommissioning plan was approved by the Commissioner.

6. In view of the dispute that has arisen between the Tamar Partners and the State regarding the value of royalty at wellhead in the Tamar Project, as described in section 1.7.29(N)(1) above (the "Disputed Value of Royalty at Wellhead") and the dispute that has arisen between the Partnership and Noble and the State regarding royalties paid for gas that was marketed from the Tamar reservoir to customers of the Yam Tethys project as described in Note 24A2(3) to the Financial Statements (the "Yam Tethys Customer Gas Dispute"), in November 2020, the Partnership reached agreements with all the parties to which it had paid royalties from the Tamar Project over the years (including Delek Group and its affiliates) (in this section: the "Holders of Royalty Rights"), according to which,

a) with regard to the Dispute Value of Royalty at Wellhead, it was agreed that once this dispute with the State will be decided, and if it is found that the Holders of Royalty Rights received surplus payments from the Partnership, then the Holders of Royalty Rights will be required to return such surplus payments to the Partnership, as will be determined regarding the surplus payments by the Partnership in respect of the State Royalties, plus linkage differentials and interest pursuant to the Adjudication of Interest and Linkage Law, 1961. It was further clarified that should it come to light, after a binding method of calculation has been set, that the Holders of Royalty Rights were underpaid, then the Partnership will be required to return the foregoing surplus payments to the Holders of Royalty Rights, with the addition of linkage differentials and interest as aforesaid. It was further agreed that until the end of 18 months from the date on which the binding method of calculation was set, none of the parties will raise claims relating to time lapsed.

b) With regard to the Yam Tethys Customer Gas Dispute, it was agreed that the ruling in the claim of the Partnership and Noble against the State will apply, mutatis mutandis, also with regard to the Holders of Royalty Rights, and that if it is found that the Partnership underpaid royalties, then it will be required to pay the Holders of Royalty Rights the underpaid royalties with the addition of linkage differentials and interest and if it comes to light that the Partnership overpaid royalties, then the Holders of Royalty Rights will be required to return such royalties that were overpaid, with the addition of linkage differentials and interest as aforesaid. It was further agreed that until the end of 18 months from the date on which the binding method of calculation was set, none of the parties will raise claims relating to time lapsed.

C. <u>Rate of royalties from the Leviathan Project</u>

It is noted that, in January 2020, a letter was received from the Ministry of Energy regarding advance payments on royalties in the Leviathan Project for 2020, in which it stated that the effective rate of royalties to be paid as advance payments for 2020 and until notified otherwise will be 11.26%. It is noted that the effective rate of State royalties in respect of the Leviathan Project in 2020, on which the Partnership relied in its financial statements, was 10.81%.[172]

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172 It should be noted that in the discounted cash flow figures for the Tamar Project, the Partnership assumed that the effective rate of the State Royalties is 11.5%.

The difference between the royalties actually paid by the Partnership to the State and the effective royalty rate used by the Partnership in its financial statements for 2020 amounts to USD 2.6 million.

For further information concerning these matters, see Note 12N to the Financial Statements.

(6) Royalty rights from the Karish and Tanin Leases

In August 2016 the Partnership and Avner Partnership sole their interests in the Tanin and Karish leases to Energean.

Under the transaction the Partnership and the Avner Partnership received in return for the sold interests a right to royalties from the Karish and Tanin leases at a rate of 5.12% before payment of the petroleum profit levy under the Taxation of Profits from Natural Resources Law, 2011 (the "Levy") and before the ROI date; 2.47% before Levy payment and after the ROI date; and 3.22% from commencement of payment of the Levy and after the ROI date.

Under the transaction for the sale of interests in the Karish and Tanin leases to Energean, Energean assumed the Partnership's obligations to pay the royalties to the Royalty Holders, including the rights of the Company and Delek Energy to receive royalties as set out in the 1993 Agreement.

(O) Agreement for granting right of use for the Yam Tethys Project facilities

For further information concerning the agreement between the Yam Tethys partners (including the Company and Partnership) and the Tamar Partners (including the Partnership) dated July 23, 2012, see section 1.7.36(M) to the 2018 periodic report, noted here by way of reference.

(P) Agreement for the Acquisition of Rights in the new Ofek and Yahel Licenses

On October 10, 2019, a transaction was closed under which the Partnership acquired a 25% interest (out of 100%) in each of the new Ofek and Yahel licenses from SOA. On November 5, 2019, the Petroleum Commission announced that the transfer of the acquired rights was recorded in the Petroleum Register. For further information concerning the agreement, see section 1.7.36(O) to the 2018 periodic report, noted here by way of reference.

(Q) Agreement to sell the Partnership's interests in the Tanin and Karish Leases

On August 16, 2016, the Partnership and Avner signed an agreement with Energean under which Energean will purchase their interests in the I/16 Tanin and I/17 Karish leases. For further information concerning the agreement, see section 1.7.36(Q) to the 2018 periodic report, noted here by way of reference.

(R) Agreement for the Sale of the Interests to Tamar Petroleum

On July 2017, a sale transaction was signed between the Partnership as Seller and Tamar Petroleum, under which Tamar Petroleum purchased from the Partnership an interest of 9.25% (out of 100%) in the Tamar and Dalit leases. For further information concerning the agreement, see section 1.7.36(Q) to the 2018 periodic report, noted here by way of reference.

1.7.30. Legal proceedings

(A) On April 26, 2020, the Partnership was informed regarding the filing of a class action and motion for certification of a class action against the Partnership, the general partner, the Company, the controlling shareholder of the Company and the directors of the general partner of the Partnership (including the former chairman of the board), who were officers of the Company, and the former CEO of the Company and the CEO of the general partner of the Partnership ("the Respondents"). The petitioners claim in the motion that in the Partnership's reports the Respondents refrained from disclosing the Buyer's right to reduce the TOP volume in the Tamar-Dolphinus agreement and in the Leviathan-Dolphinus agreement, in a year during which the average daily price of Brent (as defined in the agreement) falls to below USD 50 per barrel, as described in sections 1.7.13(E)(1)b.5 and 1.7.13(E)(2)b.4 above, a failure to disclose that the petitioners claim, establishes cause of action under various sections in the Securities Law, on the grounds of the tort of breach of statutory duty and tort of negligence. The remedy sought in the motion for certification is compensation in the amount of NIS 55.5 million and any other remedy in favor of the class, as the court deems fit under the circumstances. On January 17, 2021, the Respondents filed their response to the motion for certification, together with an expert opinion. In brief, the response argues that during the period relevant to the motion for certification, the reduction clause was never material, and therefore was not required to be disclosed to the public It further argued in this context, inter alia, that the probability of the Brent price per barrel falling to below the annual average of USD 50 was very unlikely, at least until March 2020 with the outbreak of the Covid-19 pandemic and that the probability that Dolphinus would want to actually reduce the quantities it consumes even if the reduction clause takes effect, is very low, due to the excess demand for natural gas in Egypt and the structure of the agreements. The response further argues, among other things, that in its public reports, the Partnership informed the investors of the connection between its expected income from the Dolphinus agreements and the Brent price and the Dolphinus actual consumption and warned that this was forward-looking information, that it has evidence that there is no proximate cause between the disclosure of the reduction clause and the decrease in the prices of the Partnership's participation units, and that the petitioner's opinion has various methodological flaws that preclude the possibility of such a proximate cause. The court decided that the petitioners are required to respond to this position by March 31, 2021.

The Company believes, based on the opinion of its legal counsel, that it is more likely than not that the motion for certification will be dismissed.

In this context it is noted, with regard to the option given to the buyer under the export agreements to Egypt, to reduce the Take-or-Pay amount as described above, the Partnership received a request from the ISA to provide information and documents as part of an administrative inquiry into the Partnership. It should be noted that on November 10, 2020, the Partnership filed a response to the foregoing demand.

(B) With regard to a motion for certification of a class action filed by a consumer of the Israel Electric Corporation against Tamar partners, see Note 24A2(2) to the Financial Statements.

(C) With regard to the claim filed by the Partnership and Noble at the District Court of Jerusalem against the State of Israel, through its representatives at the Ministry of Energy, which concerns mainly the reimbursement of royalties paid by the Plaintiffs, see Note 24A2(3) to the Financial Statements.

(D) With regard to the motion to certify a class action, on the grounds that the merger transaction between the Partnership and Avner was approved in an unfair proceeding, and the consideration paid to the holders of the Avner minority units, as determined in the merger agreement, is unfair, see Note 24A3(2) to the Financial Statements.

(E) With regard to a motion for certification of a class action filed by a consumer of IEC against the Partnership and Noble and against the other holders of the Tamar and Leviathan projects (as parties against which remedy is not sought) with regard to the competitive process for the supply of natural gas conducted by the IEC and with regard to a possible amendment to the gas supply agreement from the Tamar Project to the IEC, as agreed by the other holders of the Tamar Project, without the involvement of the Partnership and Noble, see Note 24A2(7) to the Financial Statements.

(F) For information regarding legal proceedings relating to the Tamar Project ROI Date, see Note 24A3(3) to the Financial Statements.

(G) For further information concerning the legal proceeding conducted in the matter of the Leviathan partners winning of the tender conducted by the IEC, see section A14a of the third part of the revision of Chapter A of the report of the second quarter of 2020, in which the information contained therein is noted here by way of reference.

(H) Legal and administrative proceedings relating to licenses in which the Partnerships had rights:

(1) Following the decision of the Commissioner of Petroleum Affairs not to extend the Eran License, on October 3, 2013 the holders of rights in the Eran License (including the Partnership) filed an appeal against the Commission's foregoing decision with the Minister of Energy. On August 10, 2014 the Minister of Energy dismissed the foregoing appeal. On 17 November 2014, the rights holders in the Eran license, including the Partnership, appealed this decision. On June 2, 2016, the High Court of Justice gave the decision of the parties' consent to mediation the force of a ruling. At the consent of the parties, the retired President of the Supreme Court, Justice A. Grunis was appointed as Mediator. At the conclusion of the mediation, the parties reached agreements that were anchored in a mediation arrangement. On March 20, 2019, the court was petitioned to validate the mediation arrangement as a court judgment. Under the mediation arrangement, the parties agreed to mediation (with the consent of the Tamar partners) for the distribution of the Tamar SW reservoir between the area of the Tamar lease (78%) and the area of the Eran license (22%). In addition, it was agreed that the right in the area of the Eran license will be divided by 76% for the State and 24% for the rights holders in the Eran license, prior to its expiration. On April 11, 2019, the court validated the mediation arranged between the parties, as aforesaid, as a court judgment. As at the date of approval of the Report, the parties are continuing to work at formulating the agreements required for applying the mediation arrangement, as set out above, but there is no certainty that they can reach such agreement which would allow the development work to begin in the next period.

(I) For further information concerning the appeal filed by Lobby 99 Ltd. (Halutz) and Hatzlacha – For Promotion of a Fair Society (R.A.) on September 9, 2019 with the Competition Tribunal against the Competition Commissioner, EMED and EMG with regard to the Commissioner's decision to approve the terms and conditions of the merger between EMG and EMED, as set out in section (1.7.29)J) above, see Note 24A2(4) to the Financial Statements.

(J) On June 18, 2020, the partners in the Alon D license filed a petition with the Supreme Court, in its seat as the High Court of Justice. In the petition, the Court was moved to issue an order nisi ordering the Minister of Energy and the Petroleum Commissioner to give reasons why the Minister's decision denying the appeal should not be revoked, why the license should not be extended or the license holders granted a substitute license in its stead, and why the license holders should not be allowed to realize their economic interest in the natural gas from the Karish North reservoir, part of which lies within the license area. An interim order was also sought to prevent the expiration of the license, and alternatively to prohibit the launch of a tender for a new license for the license area (or part thereof) or the granting of such license to a third party pending a decision on the petition, and a preliminary order pending decision on the motion for the interim order. On the same day, a decision was handed ordering the Minister of Energy and the Petroleum Commissioner to file their responses to the motion for an order nisi by June 28, 2020. In this decision, the court denied the motion for a preliminary order, and the license therefore expired on June 21, 2020. On June 23, 2020, the Ministry of Energy published a tender for a license for natural gas and oil exploration in Block 72, the area that was covered by the license. On June 24, 2020, the partners in the license filed a notice to the court in which they advised that the Ministry of Energy had initiated a tender process as aforesaid, claiming that this stresses the need for an interim order and moved the court to set a date for hearing of the motion. On June 30, 2020, the Minister of Energy and the Petroleum Commissioner filed their responses to the motion for an order nisi, claiming that the motion for an order nisi should be denied since it is essentially a motion for a mandatory injunction (extension of the license after it had expired) and since it was filed late (three days before the expiration of the license and in close to the date on which the tender was launched). The Minister and the Commissioner further claimed that the chances of the petition being granted are not high since, according to their argument, the petition is aimed, in practice, against the Minister's decision from 2017, and therefore the filing of the petition at the present time constitutes *laches*. On July 6, 2020, the partners in the license filed their response to the responses of the Minister and the Commissioner to the motion for an order nisi, in which they specified the reasons why the Minister and Commissioner's claims should be denied. On July 7, 2020, the motion for an order nisi was denied. The hearing of the petition was scheduled for May 19, 2021.

1.7.31. Business strategy and goals

The strategy of the Company and the Partnership and their goals in the energy sector in Israel are to utilize the economic potential of the oil assets that they hold, while exploring options for acquiring additional petroleum assets. The strategy is implemented mainly by advancing additional development of the Partnership's on-production oil assets, first and foremost the Leviathan Reservoir, and advancing the development of the Partnership's non-producing oil assets, primarily the Aphrodite reservoir, improving production and operation of the Partnership's on-production oil assets, and to promote options to use, own, develop and expand the natural gas transmission infrastructure from the Partnership's oil assets to the domestic market and to export markets, including in LNG form.

For this purpose, the Group operates through the Partnerships, among other things, to increase the demand for natural gas by expanding and integrating the use of natural gas on the domestic market and by exporting natural gas to neighboring countries via pipelines and/or by liquefaction and/or compression, and marketing on global markets.

In addition, the Partnership is acting to exploit the potential of the gas and/or oil discoveries in its oil assets and/or in new licenses in Israel and/or overseas, if it engages in transactions for acquiring oil assets and/or if they are awarded. It is noted that the Partnership is exploring business opportunities related to its business sector, in and outside of Israel, including the possibility of joining as a partner in petroleum assets at various stages of exploration, development and production, and is also reviewing technological developments relating to its business sector.

While bearing in mind the provisions of the Gas Framework that require the Partnership to transfer all its rights in the Tamar and Dalit Leases to a third party by December 2021, as described in section 1.7.26(2) above, the Partnership intends to focus its efforts in the coming period on finding the best solution for complying with the Gas Framework requirements, and as part thereof to act primarily to promote the option of selling these rights to a third party.

At the same time, as part of the Partnership's strategy to promote the possibility of listing its key assets for trading on a foreign stock exchange, the Partnership has, over the past year, acted to push forward a possible plan for splitting its assets, according to which the Partnership's assets, other than its interests in the Tamar and Dalit Leases and in the Yam Tethys project, would be transferred to a new UK company (the "UK Company") against the allotment of shares that would be distributed among the holders of its participating units and later, the UK Company will issue shares to foreign investors and list its shares for trading on the London Stock Exchange and the Tel Aviv Stock Exchange (the "London Transaction"). As part of promoting the London Transaction, the Partnership has prepared a draft offering prospectus which was recently submitted on behalf of the U.K. Company for approval by the U.K. regulator (the FCA). As at the date of approval of the Report, the Partnership is continuing to promote the London Transaction and is acting, with the assistance of its advisors, to formulate the details of the transaction. It is emphasized that as of the date of approval of this Report, the board of directors of the general partner has not yet adopted a resolution approving the London Transaction, and that the London Transaction requires, among other things, obtaining regulatory approvals in Israel and abroad, and is subject, among others, to approval by the general meeting of the holders of the participating unit, obtaining various approvals and completing of additional actions the feasibility of which is uncertain, and consequently there is no certainty that the transaction will be materialize.

To the best of the Partnership's knowledge, as at the date of approval of this Report, the TASE and Securities Authority are working on an amendment of the TASE bylaws that will allow oil and gas partnerships to incorporate in their operations, renewable energy projects. Subject to the approval of the foregoing amendment and its terms and conditions, and subject to obtaining all the required approvals, the Partnership intends to examine. in the coming year, options for entering the renewable energies sector and to invest in energy technologies.

1.7.32. Insurance coverage

(A) From time to time, the Partnership purchases insurance policies as is customary in Israel in the energy sector for exploration, development and production of natural gas, with the changes as required in the law, regulation (in Israel and abroad), license terms, requirements of the financing entities and the scope of the Partnership's activities and exposures in Israel and abroad.

Part of the insurance cover is made under collective policies that include a number of policyholders and cover the assets and liabilities in their various activities, and this only against some of the possible risks, as is customary for exploration, development and production of natural gas, all subject to the provisions in this section. The insurance cover also covers, inter alia, expenses for loss of control of well, property damage and certain consequential losses, contracting work risks during the development of the assets (including during maintenance work related to the development of the Leviathan Reservoir) and third party liabilities for bodily injury and property damage due to drilling, construction and production operations, including pollution damage caused by accident.

It should be noted that the Partnership and Noble purchased insurance cover for physical damage to EMG's property under an all risk policy as well as in a policy for insurance of war and terror risks. Furthermore, the Leviathan Partners have taken out insurance coverage for interruptions in the supply of gas caused by physical damage to the Egyptian transmission pipeline in Sinai, due to acts of war and/or terror

(B) Some of the insurance policies listed above were drawn up independently and some as part of the Operator's insurance policies. The insurance policies are subject to mortgage agreements and assignment of rights according to financing agreements that are engaged from time to time.

(C) It is noted that from time to time, the Partnership monitors changes in the value of the policyholder's property and amounts of consequential damages due to damage to the insured property and/or due to the property of the customer and/or supplier, to adapt the scope of insurance purchased to the exposure relative to the cost of the insurance and the insurance available internationally for the energy sector. Consequently, the Partnership can decide to reduce the coverage purchased and/or the amount of the insurance purchased and/or can decide not to purchase any insurance for one risk or another.

(D) Based on the opinion of the Company's management, from time to time, policies are purchased to insure certain loss of income, that cover causal damages from drop in output in the Leviathan and Tamar projects. This insurance cover applies in the event of loss of output due to accidental physical damage to the Leviathan and Tamar assets and/or as a result of out-of-control well events and due to physical damage caused to the Leviathan and Tamar assets as a result of war or terror attacks. The insurance policies are subject to mortgage clauses and assignment of rights in favor of the financing entities, in accordance with financing agreements that are engaged from time to time. As at date of publication of this Report, the Company's management decided not to renew the foregoing policies, with the exclusion of special cover relating to the overriding royalty in the Leviathan project (see section 1.7.22(B) above).

(E) It is further noted that the Partnership engaged in an agreement with the Company, under which the Company provides performance collateral in favor of the Republic of Cyprus for the Partnerships' operations in Block 12, as set out in section 1.7.6(D)(11) above. As a precondition for providing the foregoing collateral, the Partnerships were required to purchase additional insurance to sufficiently satisfy the Company, over and above its customary insurance cover during the drilling stage, to cover higher third party liability limits and expenses pertaining to loss of control of well, including cover for bodily injury and property damage and cleaning costs incurred in accidental pollution risks.

For further information regarding the risks due to the absence of insurance coverage, see section 1.7.33(L) below.

1.7.33. Risk factors

Other than the risk factors to which the Company is exposed as set out in section 1.24 below, the Company's operations in the energy sector are exposed to the following risks:

(A) <u>Transfer of the interests in the Tamar and Dalit Leases and compliance with the conditions of the Gas Framework</u>

As set out in sections 1.7.1(G)(1) and 1.7.31 above, under the terms of the Gas Framework, the Partnership is required to transfer by December 2021 its entire interests in the Tamar and Dalit Leases to a third party. unrelated to the Partnership or the controlling shareholders of the Leviathan Reservoir or of the Karish and Tanin Reservoirs, subject to the approval of the Petroleum Commissioner (in this section below (the “Rights Transfer” and the “Effective Date”, respectively).

According to the provisions of the Gas Framework, if the Rights Transfer is not affected by the Effective Date, the unsold rights for the Rights Transfer will be transferred to a trustee (as defined in the Gas Framework), which will try to find buyers and obtain the highest bids for the sale of Transferred Tamar Rights, and all in accordance with the Gas Framework and the instructions received from the Competitions Commissioner. The trustee will sell the Transferred Tamar Rights while taking into account the market value and the highest price offered, and in any event no later than 12 months after the date of the transfer of the rights in Tamar (even if the price does not represent the real value of the Transferred Tamar Rights).

(B) <u>The Covid-19 Coronavirus Crisis</u>

The outbreak of the Covid-19 pandemic at the end of 2019 caused a significant decline in the demand for natural gas throughout 2020. As at the date of approval of the Report, the development of the Covid-19 crisis and its outcome on global and local economic activities remains shrouded in uncertainty. If the crisis continues, it could cause, inter alia, the imposition of restrictions on movement and impair economic activities, as well as a decrease in demand and prices of energy products in general and of the natural gas marketed by the Partnership in particular. For further information with regard to the effects of the Covid-19 crisis on the Company, see section 1.6.6 above and section 1.24 below.

(C) <u>Natural gas price formulas and linkage components in the supply contracts</u>

In the natural gas contracts, the gas price is fixed according to price formulas that include various linkage components, including linkage to the electricity generation tariff, the U.S. CPI, the Brent price per barrel and NIS/USD exchange rate. In a large part of the natural gas supply contracts that the Partnership has signed, price floor limits were set alongside the price formulas, that limit to a certain extend the exposure to volatility of the linkage components, but there is no certainty that the Partnership will also be able to set such price floors in new contracts that it will sign in the future.

A decrease in the electricity generation price (partly due to adjustment requested by the IEC, if requested, of the price in accordance with the mechanism set out in the agreement signed between the IEC and Tamar, as set out in section 1.7.13(D)(1)d above) and/or the decline in the Brent price and/or the US CPI and/or increase in the NIS/USD exchange rate (depreciation of the NIS against the USD) may adversely affect the Partnership's revenues from existing and future gas sales agreements.

It is noted that the frequent methodology changes made by the Electricity Authority in the method of calculation of the power generation tariff makes it difficult to forecast and could lead to dispute between the gas suppliers and customers regarding the method for calculating. It is noted in this context that, for some of the IPPs (including plants sold by the IEC as part of the reform as set out in section 1.7.28(E) above), the Electricity Authority has applied regulation referred to as SMP (System Marginal Price), according to which the wholesale electricity price is determined every 30 minutes according to the marginal cost of production of an additional KW/-hour in the sector, based on half-hour tenders conducted by the power grid manager between the various IPPs, every day. This pricing method may affect the prices of natural gas to be sold by the Partnership to the IPPs in the domestic market, in the event that the gas prices in future contracts are linked to such pricing.

(D) Changes in demand or in prices of fuels and other energy sources on international markets

The demand for natural gas of the Partnership's customers and its price are affected, among other things, also by significant changes in the prices of oil, natural gas, including LNG, and of other sources of energy, including coal and other substitutes to the natural gas produced from the Tamar and Leviathan reservoirs, both in the domestic market and international markets. Consequently, for example, low LNG prices in the international markets may lead to an increase in the import of LNG to Israel and/or to the regional markets, to a decrease in demand for natural gas in the markets relevant to the Partnership, and harm the Partnership's revenues from the Tamar and Leviathan reservoirs. An increase in supply, decrease in demand or decline in the prices of alternative sources of energy to natural gas (including coal and other substitutes) in the domestic market or in the global markets may reduce demand from existing and potential customers and lead to a drop in the price of the natural gas sold by the Partnership, which may adversely affect the Partnership, its financial position and the results of its operations.

Reforms and decisions relating to the electricity sector, as described in section 1.7.28 above, and in the energy sector in general, including changes in environmental laws, may also reduce the demand for natural gas sold by the Partnership and/or affect its price.

In addition, major events in the global economy, such as an economic slowdown, recession, inflation, irregular volatility in foreign exchange rates, trade wars, impairment of the efficient functioning of the global manufacturing and supply chains in general, and in the segments of engineering, manufacture and supply of components for the oil and gas industry in particular, as well as weather conditions, including global warming, the outbreak of epidemics such as the Covid-19 coronavirus and natural disasters, may also reduce the demand for the natural gas sold by the Partnership and/or affect its price and/or adversely affect the Partnership's revenues from existing and future gas sale agreements, as well as decisions concerning investment in new natural gas projects and/or expansion of existing projects. For further information regarding the effect of the Covid-19 coronavirus crisis on energy prices and demand, see section 1.7.2(G)) above.

(E) Global macroeconomic factors

The Partnership's ability to sell the natural gas it produces, as well as signing of new long-term agreements for the sale of natural gas, and to make investment decisions with respect to new natural gas production projects and/or expansion of existing projects, is dependent, among other things, on various global macroeconomic factors or major events in the large economies, such as the U.S., China and the EU. Among such macroeconomic factors that may have a significant impact on the Partnership's business are, among others, changes in growth rate or a global economic slowdown, global recession, global inflation, irregular volatility in foreign exchange rates, global trade situation, a rise in interest margins, efficient functioning of the global manufacturing and supply chains in general, and in the engineering, manufacture and supply segments of components for the oil and gas industry in particular, in climate and weather changes, including global warming, which contributes to the creation of warmer-than-expected weather conditions, as well as trade wars, such as the US-China trade war, which has led to a slowdown in economic activity; natural disasters, the outbreak of epidemics such as the Covid-19 coronavirus, and global political and social processes that could destabilize regimes. Global macroeconomic factors of this type, which in most cases are unforeseeable, may cause significant harm to the global economy, increase uncertainty in the markets, unravel the confidence of investors, the business community and consumers, and result in a decline in global consumption of energy products, including oil and natural gas, and make it difficult to refinance. Naturally, the Partnership is unable to influence factors with global impact of this type, and it is difficult to assess and estimate how such factors will evolve and affect the Partnership's business.

(F) Geopolitics

The security, economic and political situation in the Middle East in general and in Israel, Egypt and Jordan in particular, could affect the willingness of the countries and foreign entities, including in the Middle East, to engage in business relationships with Israeli organizations, including the Partnerships together with their partners in the various projects. Consequently, deterioration in the geopolitical situation in the Middle East and/or deterioration in the relationships between Israel and its neighbors in the relevant target markets, for security and/or political and/or economic reasons, may substantially impair the Partnership's revenues from its agreements for the export of gas to Egypt and Jordan, to Dolphinus and Nepco, which are the its main customers, and also the Partnership's ability to promote its business with these countries and entities, and to export gas to neighboring countries.

(G) Difficulties in obtaining financing

In order to make progress in additional development stages in the development of the Leviathan reservoir and/or the development of additional reservoirs in the future, such as the Aphrodite reservoir, if it is decided to implement them, the Partnership will require additional significant financial resources, including through future raising of bank debt or raising of private or public bonds.

Raising of additional financing may encounter difficulties, especially in the event of an economic crisis, reflected in a decrease in available sources of credit and in the tightening of the requirements of the financing entities for providing such financing. As at date of approval of the Report, against the backdrop of the Covid-19 crisis, a grave global economic crisis is liable to develop that will adversely affect the Partnership's ability to raise capital. In addition, the possibility of raising additional debt is subject to other undertakings and covenants set for its debentures, as set out in section 1.7.22 above.

(H) Competition for gas supply

The Partnership is exposed to competition in the supply of natural gas to the domestic market and to export markets, which has intensified significantly recently, including competition with existing competing gas reservoirs, or new reservoirs that may be discovered in the future in Israel or in neighboring countries, and the competition posed by alternative energy sources such as coal, liquid fuels (such as diesel oil and fuel oil) and renewable energy sources (such as solar energy and wind generated energy). The intensified competition has led to a decline in the natural gas prices that are set in new supply agreements, and if this trend continues in the future, it may lead to a drop in the demand for the natural gas sold by the Partnership and further decline in its price, which may lead to a material adverse effect on the Partnership's revenues and business.

In recent years, several significant gas reservoirs have been discovered in Israel, which are far greater than the Ministry of Energy's estimates for demand for gas in the domestic market. For further information regarding competition in natural gas and oil exploration in the Israeli EEZ, which could lead to new gas discoveries, see section 1.7.16(A) above. In Egypt and Jordan, to which the Partnership exports natural gas under the Dolphinus and Nepco supply contracts, the Partnership is exposed to competition that may intensify in the future from reservoirs that have been discovered (such as the Zohr natural gas field in Egypt) or new reservoirs to be discovered in the future, as well as from suppliers of alternative energy products.

As at date of approval of the Report, in addition to the Tamar and Leviathan reservoirs, which are at present producing in Israel, the Karish, Karish North and Tanin reservoirs, which are owned by Energean, are in advanced stages of development and the first one of them is expected, to the best of the Partnership's knowledge and based on Energean's press releases, to commence gas supply in the first quarter of 2022. These reservoirs, which are organized under a single production system, are expected to serve as additional significant natural gas suppliers. It is noted that, according to the provisions of the Gas Framework, the Karish and Tanin reservoirs are intended to supply natural gas to the domestic market only

In addition, according to the terms of the Gas Framework, the Partnership is required to sell off its entire holdings in the Tamar and Dalit reservoirs to unrelated third parties (as set out in section 1.7.25(A)(3)B above). Once such sale is completed, the Tamar reservoir will become a competitor of the Partnership's remaining oil assets.

As at Reporting Date, the gas produced from the Tamar reservoir was jointly marketed by all of the Tamar partners. For further details concerning the memorandum of understanding regarding the separate marketing of gas from the Tamar reservoir, see section 1.7.13(D)(1)f.4 above. The separate marketing of gas by the partners in the oil asset is liable to increase competition and lead to further decline in the prices of natural gas. As at Reporting Date, the gas from the Leviathan reservoir is jointly marketed by all of the Leviathan partners, however, under the JOA each partner is entitled, subject to certain conditions, to take its share of the gas produced from the reservoir and market it separately from the other partners, which, if it occurs, may lead to increased competition.

In view of the increased scope of demand for natural gas in the local market, the entry of other competitors to the domestic gas market and the restrictions on the quantity of gas that may be exported and incentives given for the development of renewable energy sources, the Partnership may encounter significant competition in selling the gas attributed to its oil assets in the future. For further information concerning the competition in the supply of natural gas, see section 1.7.16 above. For further information concerning the option granted to buyers of natural gas to reduce the volumes under the agreements signed with them, see sections 1.7.13(D)(1)c and 1.7.13(D)(2)b.2, above. For further information concerning the Electricity Authority decision regarding incentives for independent power producers to engage in the sale and purchase of natural gas at a price lower than the maximum price fixed in the Gas Outline Plan, and in addition to the incentives for independent power producers to engage in agreements for the purchase of natural gas with the new gas suppliers who are not Tamar partners, see section1.7.28(L) above.

(I) Export restrictions

The results of the Partnership's operations are dependent, to a great extent, on the possibility of exporting gas from the natural gas reservoirs in which the Partnership is a partner, and selling it in regional and international markets. The Government Decision concerning export, as set out in section 1.7.28(A) above, restricts the volume of gas that may be exported. Additional decisions are made regarding further reduction of the permitted exportable volume of natural gas could cause significant harm to the Partnership's business. Furthermore, the possibility of gas export and sales depend on several factors with high uncertainty, such as the foreign relations of the State of Israel and the Republic of Cyprus with countries that are potential target markets for exporting of gas, the establishment of an export and transportation system and receipt of relevant regulatory approvals, and the proper functioning and economic viability of establishing this system, identification of potential customers in the international market, and financing investments in development and establishment of the export system, and competition with local and international suppliers in the relevant target markets.

(J) Dependence on the development and proper function of the National Pipeline system

The Partnership's ability to supply the gas produced from its assets to existing customers and other potential customers in Israel and for export, is dependent, among other things, on the development and integrity of the National Gas Transmission pipeline, the regional distribution networks and pipelines connecting consumers in neighboring countries (jointly in this section: the "Pipelines"). Any significant malfunction or disruption in the Pipelines that it uses and/or that it will use in the future, may limit the Partnership's ability to supply gas to its customers, while exposing it to loss of revenues and legal proceedings that may have an adverse effect on the Partnership's business and the results of its operations. Furthermore, any delay in executing the development and expansion plan for the gas Pipelines system may impair the Partnership's ability to meet its forecasts relating to its natural gas sales.

(K) Operating risks

Oil and natural gas exploration, development and production operations in deep water entail considerable operating risks. Drilling in deep water requires the use of advanced drilling technologies, and generally takes longer and its costs are higher than its onshore equivalent, due to the considerable complexity of such operations and the need to hold and maintain long extensive supply systems. The development and production of natural gas from deep water reservoirs involves diverse risks, including, among others, uncontrolled gushing from the well, explosion, collapse and conflagration of the well, malfunctions, accidents and other events that could impair the performance of the production and delivery system. Lower than expected performance or efficiency, contractor or operator mistakes, work disputes or slowdowns, injuries, harm to health or fatalities, delay or failure in obtaining permits, failure to obtain approvals or permits, violation of requirements for permits or licenses, lack of workforce, equipment or spare parts, delays in transporting equipment or spare parts, pollution and other environmental risks, security breaches, and cyber attacks or acts of terror, as well as natural disasters.

The occurrence of any such events, may substantially reduce or halt the production or supply of natural gas, adversely affect the operating timetables and budgets, impair the quality of the hydrocarbons sold, and as a result lead to the imposition of penalties due to non-supply and even the termination of the Partnership's existing gas sales agreements.

(L) Inadequate insurance coverage:

Although the Partnerships have insurance policies to cover possible damages with regard to their operations, these policies do not cover all potential risks and therefore the insurance payout may not cover the full scope of damages and/or all potential losses (for third-party damages (including while crossing over infrastructures) and for potential loss of income, as well as costs for the establishment and rehabilitation of the production system in the case of an event that causes damage to the production system, war, cyber, out-of-control well and damage to any property in the well).

Furthermore, there is no certainty that appropriate policies may be purchased in the future under reasonable commercial terms, if at all. In addition, there are certain insurance policies which the Partnership may decide not to take out at all for various reasons, such as lack of economic merit.

The Partnership's activities in Jordan (as set out in sections 1.7.13(E)(1)a and 1.7.13(E)(2)a above) and in Egypt (as set out in sections 1.7.13(E)(1)b and 1.7.13(E)(2)b above) expose the Partnership to risks that can not be insured at all or can only be insured partially, including, among others, for damage to property of a supplier and/or customer and/or breach of agreements and cancellation of agreements for grounds forbidden under the agreement and/or a change in legislation and/or guidelines of competent authorities in Jordan and Egypt, which may harm the Partnership's businesses and property.

In the event of a large-scale loss or damage, the insurance amounts may not cover the full amount of the damages incurred by the Partnerships and/or to third parties, including with respect to pollution damage. These risks, if realized, may cause delays and setbacks in the Partnership's exploration, development and production operations, damage to the Partnership's business or have a material adverse effect on the Partnership's business, financial position, results of operations or forecasts, and in extreme cases may even cause the Partnership to default payment. It is noted that the decision regarding the type and scope of insurance policy is usually made separately for each operation, taking into account, inter alia, the cost of insurance, nature and scope of the proposed coverage, regulatory requirements, ability to obtain appropriate cover on the insurance market, available capacity for the Partnership in the insurance market, and the anticipated risks.

(M) Establishment risks, dependence on contractors, and providers of equipment and professional services

To date there are no suitable contractors in Israel involved in most of the operations conducted in the Partnership's assets. Therefore, the Partnership, through the Operator, is required to contract with foreign contractors for the necessary services. Furthermore, there are relatively few drilling rigs that are capable of drilling and carrying out development operations at sea in general, and in deep water in particular, and there is no certainty that an appropriate vessel will be available for carrying out the foregoing operations on the dates set for them. Therefore, these operations could involve high costs and/or significant delays in schedules set in the work plans. Furthermore, most of the suitable equipment and human resources for these operations cannot be ordered for short periods, therefore it is often necessary to order equipment and professional human resource services from abroad, long in advance, which is expensive and causes significant delay in operations. Contracting with foreign contractors for offshore oil and/or natural gas exploration, development and production operations (including maintenance and repairs contractors) could sometimes be difficult, also due to the security and political situation in the State of Israel. The price of services and costs of exploration, development and production operations are determined by market supply and demand, which are affected inter alia by commodity prices, regulatory changes, the supply of alternative products and the level of activity in the industry.

(N) Exploration risks and dependence on partial and estimated assumptions, assessments, and data

Oil and gas exploration involves high risk, among others, that failed exploration and appraisal drillings could result in the loss of the entire investment. The geological and geophysical means do not provide an accurate forecast as to the location, shape, features or size of oil or gas reservoirs. Therefore, determining exploration prospects and estimating the size of existing reservoirs and proven gas reserves are based, to a large extent, on partial or approximate data and on assumptions. It is obviously impossible to ensure that oil or gas will be found at all as a result of exploration operations, or that it will be commercially viable for production and exploitation. Furthermore, there is insufficient direct geological and geophysical information regarding some of the areas in the Partnership's oil assets. This is due, inter alia, to the limited number of drillings conducted in these areas and/or at these depths.

The estimated volumes of resources in the Tamar and Leviathan on-production oil and gas fields are constantly monitored and may be updated, based on the opinion of independent external resources valuators and additional information accumulated regarding the reservoirs. The assessment of the volumes of the resources in the Partnership's oil assets is subjective and is based on various estimates and assumptions and on incomplete information, and therefore the estimated reserves with respect to the same reservoirs by various experts could be significantly different. In view of the aforesaid, it is noted that the information appearing in the Report with regard to the volumes of resources attributed to the Partnership's oil assets is an estimate only, and should not be considered as information on exact volumes of recoverable natural gas and petroleum liquids from the various reservoirs. It is further noted that, the estimate of natural gas reserves is used for setting the amortization rate of the producing assets in the Partnership's financial statements, and in view of the significance of the depreciation of assets, the foregoing changes may have a material effect on the results of the operations and financial position of the Partnership.

In addition, the discounted cash flow figures that are attributed to the Tamar and Leviathan Projects and are included in this report are based on various assumptions, most of which are not in the Partnership's control, among others, with regard to the volumes of gas and condensate that will be produced, and the production rate, and sales and sale prices, regarding which there is no certainty that they will materialize. For information concerning the key assumptions underlying the cash flows included in this Report, see section 1.7.5(K)(1)b above. For further information concerning the key underlying assumptions for the Leviathan Project cash flows see the immediate report issued by the Company on March 10, 2021 (Ref. No: 2021-01-031128), where the information appearing in said reports are noted here by way of reference.

(O) Estimated costs and schedules and potential shortage of means

Estimated costs and schedules for exploration, development, operations and maintenance, and estimated schedules for their execution, are based on past experience and general forecasts and they could therefore contain significant variances, including due to events not in the Partnership's control. Exploration, development and operating plans could change significantly due to the discoveries made in such explorations, causing significant deviations in schedules and estimated costs of these operations. Malfunctions during exploration, development, production or maintenance, and other factors, could extend the operations far beyond schedule and expenses for completing such operations could be significantly higher than forecast.

(P) Forfeiture of the Partnership's rights in its oil assets and the financial robustness of the partners in the oil assets

Exploration, development, expansion and maintenance of the supply capacity in the Partnership's oil assets involve substantial financial costs that the Partnership may not have the means to cover. According to joint operating agreements, failure to pay the Partnership's share in the approved budget for executing the approved work plan on time constitutes a breach which could lead to forfeiture of the Partnership's rights in the oil asset for which the operating agreement and/or agreements that applies and/or apply.

In addition, in a situation where other parties to the JOAs fail to pay the amounts that they were required to pay, the Partnership may be required to lay out amounts that considerably exceed its pro rata share in such oil assets. Due to the particularly high costs of offshore drilling and development, such additional costs could prevent the Partnership from meeting its financial liabilities, resulting in forfeiture of its rights in the oil assets.

Furthermore, in view of the forgoing, the financial robustness of the partners in the Partnership's oil assets may have repercussions on its cash flows.

(Q) Dependence on other regulatory approvals

The exploration, development and production operations in the Partnership's oil assets require that it obtain numerous regulatory permits, primarily from the competent authorities pursuant to the Oil Law and Natural Gas Sector Law, as well as permits from state institutions, including the Ministry of Defense, Ministry of the Environment, Tax Authority and planning authorities, Ministry of Agriculture, Ports Authority and Ministry of Transportation (the "Permits"). The Permits required for the ongoing operation in the oil assets set out valid terms and conditions, a large part of which are not in the control of the Partnership. A breach of these terms and conditions could lead, among others, to cessation of production from the on-production reservoirs, imposition of restrictions on various operations and expose the partners in the oil assets to monetary, administrative and punitive sanctions. The partners in the oil assets have no control regarding the conditions that will be set in the new licenses that they will require in the future and therefore there is no guarantee that they can obtain the required approvals or comply with their conditions.

(R) Regulatory changes:

As a rule, the scope of regulation applicable to the Partnership's operating segment is constantly growing. For further information regarding regulation applicable for the Partnerships' operations as at Reporting Date, see section 1.7.27 above. The tightening of the regulation applicable, among others, to oil and gas exploration, development and production, terms for supply of natural gas, natural gas exports, taxes on oil and gas profits, regulations for allotting new petroleum rights, transferring and pledging petroleum rights, insurances and guarantees, restrictive trade practices, control of gas prices, and more, may adversely affect the Partnership's business. Furthermore, if additional changes are made in any applicable law, regulation under the Gas Outline Plan or any relevant regulation or policy, or if there is any delay in obtaining any regulatory approval, or if the Partnership or its customers do not receive the required regulatory approvals or fail to comply with their conditions, the Partnership or its customers may not be able to meet their obligations under the existing natural gas sales agreements.

(S) Possibility of price controls on natural gas

As set out in section 1.7.28(B), on April 22, 2013, the Commodity and Service Price Control Order (Application of the Law on Natural Gas and Level of Control) 2013, was published, applying control on the gas sector with regard to reporting profit margins and prices. Such duty of reporting applies separately to each project, and the price and profit margins of the natural gas sold must be reported semi-annually. Pursuant to the information that will be received, the need will be examined for price regulation for natural gas in Israel, requiring fixed maximum prices for the sale of natural gas. If such price controls are introduced and a maximum price is fixed that is lower than the prices set in the natural gas sales agreements of the Partnership, if such fixed price will be legally upheld, this could have an adverse effect on the businesses of Partnership, the volume of which derives from the maximum price that is set. The Gas Framework included binding provisions pertaining to the price of the gas and linkage alternatives of the price which may be presented to the customers of the Tamar and Leviathan reservoirs, as set out in section 1.7.25(A)(4)A above. In accordance with the Gas Outline Plan, application was made to the Price Control Committee, which decided that so long as the Partnerships and Noble comply with all the terms of the Outline Plan, supervision of reporting margins and prices must remain in place, as set out for the transition period are expected to end in December 2021.

(T) Motion for certification a class action with regard to the price fixed in the agreement between the Tamar Partners and the IEC

On June 18, 2014, a motion for certification of a class action was filed with the Tel Aviv District Court against the Tamar Partners by an IEC consumer, in which it was claimed, inter alia, that the price of the gas sold from the Tamar reservoir to the IEC is an unfair price that constitutes abuse of the position of the Tamar Partners as the holders of a monopoly in the Israeli natural gas supply market, in violation of Section 29A of the Economic Competition Law (in this section: the “Motion for Certification"). If the Motion for Certification is granted, and subsequently a final and non-appealable judgment is handed against the Tamar Partners, this may have a material adverse effect on the Partnership’s business, including on the discounted cash flow figures that appear in sections 1.7.4(J) and 1.7.5(K)(1)c above, and in the immediate report issued by the Company on March 10, 2021 (Ref. No.: 2021-01-031128) and on the prices at which the Partnership will sell natural gas to its customers, the scope of which will derive from the results of the claim. The Partnership estimates that such a decision may have an adverse effect on all oil and gas operations in Israel. For further information concerning these proceedings, see Note 24A2(2) to the Financial Statements.

(U) Environmental regulation

In their operations, the Partnerships are subject to various laws, regulations and guidelines relating to environmental protection, which refer to diverse issues such as: Oil or natural gas leaking into the marine environment, release of pollutants and various of types wastes (sewage, residue from drilling equipment, sludge, cement, etc.) and chemicals used in the various stages of the work into the sea, emission of pollutants into the air, light of noise nuisances, establishing pipeline infrastructure and related facilities on the seabed. Furthermore, the Partnership is required, through the Project Operator, to obtain approvals from agencies authorized under the Petroleum Law, the Natural Gas Industry Law and other laws (such as environmental protection laws) for the Operator’s operations as aforesaid.

Failure to comply with the foregoing environmental regulatory provisions could expose the Operator, the Partnership and its partners in the various oil assets to diverse enforcement measures, including lawsuits, fines and various sanctions, including criminal, and also to delay and even shut down the Partnerships operations. In addition, the Partnership may be held accountable for the actions of others, such as the Operator or third party contractors affiliated to the Operator, and pollution relating to the Partnership’s facilities or emanating from its operations.

Oil and natural gas exploration and production in deep water involve various risks, including the emission of environmentally hazardous materials and waste, as well as the exposure of people to these hazardous materials and waste. As a result, the Partnership may be held liable for any or all of the consequences arising from the risk of emission of or exposure to such hazardous materials and wastes.

As noted in section 1.7.28(J) above, in September 2016, the Ministry of Energy, jointly with the Ministry of Environmental Protection and other government ministries, published directives for regulating the environmental aspects involved in offshore oil and natural gas exploration, development and production. The foregoing directives could have an effect on the costs and the way the Partnerships operate, the scope of which as of date of approval of the Report cannot be estimated.

It is not at all certain whether the costs required of the Partnership with regard to the existing and expected legislation, regulation and directives relating to environmental protection and with respect to the consequences arising from emissions of substances into the environment, will exceed the amounts earmarked by the Partnership for these purposes, or that these costs will not have a material adverse effect on the financial position of the Partnership and the results of its operations. It should also be noted that the interpretation and enforcement of environmental laws and regulations vary from time to time, and may become more stringent in the future.

For further information concerning sanctions imposed by the Ministry of Environmental Protection, see section 1.7.24(F) above.

(V) Climate changes

The public discourse on climate changes and the impact humans have on it may lead to additional regulatory intervention and developments that may have a material effect on the Partnership's operating segment. International agreements, legislation and other regulatory measures that may be adopted with the aim of decreasing greenhouse gas emissions, if they take effect and are applied to the Partnership's operations, may lead, inter alia, to the payment of significant expenses for the purpose of complying with the new requirements and may materially increase the competition by suppliers of renewable energy sources.

In addition, the actions of organizations and activists that oppose the production and use of fossil fuels may adversely affect the Partnership's reputation and cause legal and other expenses that will be required in order to cope with such activity and its consequences.

Dependence on weather and sea conditions

Offshore operations are exposed to a variety of operational risks that are unique to the marine environment, such as capsizing, collisions and damage or loss caused by adverse weather conditions and sea conditions. These conditions can cause significant damage to the facilities and disrupt the operations. Rough seas and stormy weather could cause damage to the production and transmission systems and to the exploration equipment, and delay schedules of offshore work plans and extend the time frame for their completion. Such delays could increase expected costs and could also cause non-compliance with mandatory schedules to which the Partnership is committed. For information concerning the impact of climatic conditions on demand, see section 1.7.3(C) 1.7.3(D) above.

(W) Information security and cyber risks

The partners in the oil assets of the Partnerships, including the Partnerships and the Operator (directly or through sub-contractors) (in this section: ("the Companies"), are dependent on their information systems for their operations. Therefore, for example, production operations from the Tamar and Leviathan reservoirs involve the use of industrial control systems for supervision, control and data collection in industry ("ICS"), which monitor and control their large-scale processes including, inter alia, monitoring of the natural gas and condensate transmission pipeline. ICS based systems are exposed to a risk of cyber attacks. Furthermore, the Partnership and the Operator depend on computer systems, including IT and infrastructure systems, for processing and documenting financial and operating data, communicating with workers, advisors and business partners, analysis of seismic, geological and engineering data, estimating oil and gas reserves and other activities related to the Partnership business. The Partnership's business partners, including suppliers, customers and financial institutions, are also dependent on computer systems, including IT and infrastructure systems. As such dependency increases, the potential exposure to cyber threats, both intentional and unintentional, also increases. In addition, there has been an increase in the severity of cyber threats worldwide in terms of their sophistication and complexity, particularly at this time when, against the backdrop of the Covid-19 coronavirus crisis, many organizations have transitioned to operating primarily via remote connection to organizational networks, which create exposure to unauthorized access.

Malfunction and/or failures in IT systems, including in infrastructure systems and information security, hacking into the IT systems of corporations or of outside entities or internal entities that have, among other things, remote access to systems, infrastructures and information, may enable unauthorized access for the purpose of misusing the Partnership's assets, and causing deliberate harm to IT systems, and the infrastructure and information systems of the corporations, which may cause damage to the administration networks of the Partnership and the Operator, leaking of information to unauthorized entities, disruption of the information in the systems and damage to the integrity of the information. Damage to the ongoing operation of the systems that support business activities, in extreme cases, may even cause disruption or discontinuation of the supply of natural gas, loss of information, and incur material costs for restoration of the IT systems, thereby having a material adverse effect on the Partnership's business, financial position, operating results or capabilities.

The Partnership is acting to implement the directives of the Privacy Protection Authority, and the recommendations of the National Cyber Directorate (the "Corporate Defense Methodology" and ongoing recommendations), for effective management of information security and cyber protection. The Partnership has established an information security and cyber protection policy which defines the Partnership's outlook regarding its cyber and information security defense system, and is taking measures for implementing this outlook in organizational procedures and procurement of systems, infrastructures and services.

The Partnership routinely acts to increase the level of the employees' awareness of aspects of cyber and information security, including phishing attacks and remote working rules. In addition, the Partnership receives 24/7 monitoring and control services, 365 days a year from a third party, which are intended to flag irregular activity on the Partnership's network.

It is noted that the Partnership does not have access to the IT systems of the Operator and of its other partners in the oil assets, and in this regard, it does not have control over the central ICS systems which monitor and control the production operations that are under the Operator's responsibility and control. To the best of the Partnership's knowledge, the Operator is closely monitored by the National Cyber Directorate and implements adequate procedures and measures for effective management of information security and cyber protection with regard to these systems.

(X) Tax risks

The tax issues related to the Partnership's operations, including with regard to the method of calculation of the Levy under the Petroleum Profits Tax Law, have yet to be litigated in Israeli courts and it is impossible to determine or to anticipate how the courts will rule on such issues, if and when they are brought before them. Furthermore, for some of the legal issues there is no way to anticipate the position of the tax authorities. Since the Partnership's operations are subject to special taxes, any changes arising from changes in legislation, regulations or a change in the position of the Tax Authority, as set out above, could have material implications on the tax applicable to the Partnership and holders of partnership units.

For information concerning legal proceedings with regard to the appropriate balancing arrangement that the Partnership must implement, regarding the tax payments under section 19 of the Natural Resources Taxation Law (for fiscal years 2015-2016 and assessment differentials that may come to light in the future), see section 1.7.23**Error! Reference source not found.** above.

For further information concerning the draft Income Tax Regulations (Rules for Calculation of Tax on the Holding and Sale of Participating Units in an Oil Exploration Partnership) (Amendment), 2020, that was released on October 12, 2020, see section 1.7.23(B) above.

(Y) Financing liabilities

As set out in section 1.7.22(E) above, the terms of the debentures issued by the Partnership and special purpose subsidiaries that it established, events of default were defined and financial covenants and restrictions were set (see Notes 12K and 12L to the Financial Statements. Failure to comply with the undertakings that the Partnership assumed regarding the terms and conditions of the debentures, or compliance with the conditions, some of which are beyond the Partnership's control, which grant the debenture holders grounds for calling for immediate repayment of the debt, may lead to acceleration of the amounts due under the debentures for immediate repayment, to increasing of interest rates applicable to the Partnership's liabilities and/or to foreclosure of the collateral provided by the Partnership

For further information regarding the financial covenants that Partnership is required to comply with, see section 1.7.22(K)(2) above.

(Z) Dependence on customers

The IEC, NEPCO and Dolphinus are presently the Partnership's key customers, and in regard to this the Partnership is exposed to risks that are beyond its control, including changes in the economic and political situations in Egypt and Jordan which may affect Dolphinus and NEPCO or their ability to meet their obligations under the gas supply contracts. For further information concerning the Partnership's revenues from these customers, see section 1.7.13(C) above. The Partnership is unable to anticipate the changes (if any) that these customers will experience, and how such changes will affect their economic, financial and regulatory status. The IEC-Tamar agreement and the agreements signed with Dolphinus set dates at which each party to an agreement is entitled to request a price adjustment. If the IEC and/or Dolphinus requests adjustment of the price of the gas they purchase in accordance with the mechanism set out in their agreements, this may have an adverse effect on the Partnership's business and its operating results (for further information see sections 1.7.13(D)(1)d, 1.7.13(D)(2)c, 1.7.13(E)(1)b and 1.7.13(E)(2)b above).

The Partnership is exposed to risks beyond its control with regard to the financial robustness of its customers and their ability to meet their liabilities under the gas supply agreements. If the Partnership's customers in general and its key customers in particular, fail to meet their liabilities and if the Partnership fails to sell the contracted volume as set in these agreements to other customers, this will have an adverse effect on the revenues of the Partnership and on its financial results.

(AA) Dependency on the Operator

The Partnership depends to a large extent on Noble, in the oil leases in which it serves as the Operator, including in the Tamar, Leviathan projects and Block 12 in Cyprus and Yam Tethys projects, and this due to the provisions in the JOAs. The withdrawal and/or removal of the Operator, for any reason whatsoever, from the Tamar and/or Leviathan projects, or any change in its status and/or interests in a way that it will no longer be the operator for the various projects, such that it ceases to be the operator of these projects, this could have an adverse effect on the ability of the Partnership to meet its commitments under the work plans for the oil assets and/or under the agreements for the sale of gas. In such a case, the Partnership is not able to guarantee that a substitute operator will be found or a substitute operator will be found under the current conditions. The inability of the Partnership to find a substitute operator may adversely affect the operations of the various projects as aforesaid, and its commitments to supply gas under the existing gas sales agreements, and as a result may lead to a decrease in the Partnership's revenues. Furthermore, in the event that Noble fails to comply with its obligations as operator under the JOA or under agreements with third parties with which Noble engages as an operator, the Partnership may then bear expenses and losses that may derive from Noble's actions (or omissions).

(BB) Risk in development and production in the event of a discovery

The decision-making process for investing in the development of a field for its commercial production, intermediate operations prior to commercial production, and the execution of such development and commercial production (if it is decided that they are feasible) could be prolonged and involve the Partnership in substantial investments. It should be noted that there is no certainty that in every discovery defined as a commercial discovery the of the oil or gas field will be development, will be economically feasible for the Partnership and finance, inter alia, due to the duty to pay royalties to third parties. It should further be noted that deep water development and production (such as at the depths of the Tamar, Leviathan and Aphrodite natural gas discoveries) are complex and high-risk operations that require the establishment of special production facilities at significant costs.

(CC) Revocation or expiration of oil rights and assets

Oil rights are granted according to the Petroleum Law for a limited term, and are contingent on fulfilling commitments on dates specified in terms of the oil assets Failure to comply with the conditions could lead to revocation of the oil rights, subject to the Petroleum Law. Failure to comply with the terms and conditions set out in the petroleum rights could lead to forfeiture of the rights and loss of the funds invested in these rights. In this regard it is noted that the development plan of the Aphrodite reservoir prescribes, inter alia, that the partners are required to drill the A-3 appraisal will by November 2021, as set out in section 1.7.6(L) above. The partners in the oil asset applied to the Cypriot Government requesting approval of changes in the work plan, including a postponement of the date for such drilling. As of the date of approval, the Cypriot authorities have not yet approved this request.

(DD) Spillover of reservoirs

It is possible that oil or natural gas reservoirs that are discovered or will be discovered in the areas in which the Partnerships have rights may "spillover" (in terms of the spread of the geological formation and size of the reservoir) into other areas where Company or the Partnerships have no rights, and vice versa. If gas migrates to areas in which other parties have rights, negotiations may be required to reach agreement for joint exploitation and production from the reservoir or an alternative indemnification arrangement, to achieve effective utilization of the oil or natural gas resources, which could cause delays in the various operations that the Partnership will have to execute.[173]

(EE) Security risks

The production facilities of the Yam Tethys project and Tamar project which are located offshore, and the INGL gas transmission pipeline facilities, the EMG pipeline and additional infrastructures used for supplying the gas to Egypt are located relatively close to the offshore-onshore borders between Israel and Gaza, and therefore they are exposed to security risks, including acts of terror and sabotage. Furthermore, the Leviathan Project installations and the receiving terminal in Ashdod, the pipeline, infrastructures and facilities used for supplying gas to Jordan are exposed to security risks including terror attacks and sabotage.

These security risks, if realized, may, among other things, disrupt the production of gas from the reservoirs and/or the supply of gas to customers in the domestic market and/or in the export markets, and in an extreme scenario, may even lead to the revocation of the gas supply agreements or the reduction of the amounts the customers are required to pay due to claims of a "force majeure" event. Furthermore, such risks may restrict the ability of service and equipment providers to provide their services or the equipment required for the operation of the Leviathan and Tamar projects, and adversely affect the ability to recruit and retain the appropriate human capital. The materialization of such security risks may lead to a significant adverse effect on the Partnership's revenues and business, including its ability to execute operations that are contingent on prior coordination with the defense forces.

(FF) Volatility in the USD exchange rate

Changes in the NIS-USD exchange rate may impact the results of the Partnership in several ways, as follows: (a) The Partnership's operating currency is the US dollar. As some of the Partnership's expenses are in NIS or are affected by the NIS-USD exchange rate, a decrease in the NIS-USD exchange rate (appreciation of the NIS against the USD) increases such expenses in USD terms; (b) as the gas prices in the agreements for the sale of gas from the reservoirs in which the Partnership is a partner, are set by price formulas that include various linkage components, among others, linkage to the NIS-USD exchange rate and to the PUA's tariff, which is partly affected by the NIS-USD exchange rate. Depreciation of the NIS against the USD may have an immaterial negative effect on the Partnership's revenues; (c) as the Partnership reports its taxable income in NIS and pays tax advances for the holders of the Partnership's participation units in NIS, changes in the NIS-USD exchange rate affect the amount of the Partnership's taxable income and the scope of the cash flows used for payment of such tax advances.

(GG) The Partnerships' status as a monopoly in the supply of natural gas in Israel

In 2012, the Partnerships, together with the Tamar Project partners, were pronounced monopolies in the supply of natural gas to Israel. As a result of the foregoing declaration, limitations may be imposed on the Partnership's operations, including prohibition to refuse, for unreasonable reasons, to supply natural gas, and prohibition on the exploitation of its market position in a manner that may reduce competition in the sector or case public harm (for example, by setting unfair price or by different terms of engagement for similar transactions, giving certain customers an unfair advantage over their competitors). The restrictions on the Partnerships due to their status as a monopoly in the supply of natural gas in Israel could have adverse effect on their ability to expand their operations in Israel. For further information concerning the restrictive trade practices and economic competition law, see section 1.7.26 above.

(HH) Provision regarding force majeure events under existing natural gas sales agreements:

In most of the Partnership's agreements for the sale of natural gas ("the Agreements"), the customers have a take-or-pay agreement for a minimum annual quantity of natural gas, according to the mechanisms set out in the agreements. However, the customers may be exempt from this obligation, in the event of force majeure that prevents them from fulfilling their obligations, as defined in the Agreements. A force majeure event is defined as an event beyond the customer's control, which prevents it from fulfilling its undertakings under the agreement and which could not reasonably have been prevented under the circumstances. The Agreements list events that will not be considered force majeure, also where they are beyond the customer's control. It should be noted that the

173 In this regard, see section 1.7.30(H)(1) above regarding the spillover of a small part of the Tamar SW reservoir into the Eran license.

Partnership may also be exempt from its obligations under the agreements for sale of natural gas in the event of force majeure that prevents it from fulfilling its obligations s under the Agreements.

If a force majeure event continues over a prolonged period as set out in an agreement for the sale of natural gas (usually between one and three years) and it has a material effect on the ability of a party to fulfill its undertakings as aforesaid, this may constitute grounds for termination of the agreement. Accordingly, a force majeure event over a prolonged period, which suspends a customer's undertakings to buy a significant quantity of natural gas, may have a material adverse effect on the Partnership’s revenues.

The table below presents a summary of risk factors by type (macro risks, sector-specific risks and risks specific to the Partnership), according to the estimates of the Company based on the degree of their effect on the Company in the energy sector in Israel.

	Effect of the risk factor on Company’s business		
	Major	**Moderate**	**Minor effect**
Macro risks			
The Covid-19 Coronavirus Crisis		X	
Natural gas price formulas and linkage components in the supply contracts		X	
Changes in demand or in prices of fuels and other energy sources on international markets	X		
Global macroeconomic factors	X		
Geopolitics	X		
Sector-specific Risks			
Difficulties in obtaining financing		X	
Competition for gas supply	X		
Export restrictions		X	
Dependence on the development and proper function of the National Pipeline	X		
Operating risks		X	
Inadequate insurance coverage:		X	
Establishment risks, dependence on contractors, and providers of equipment and professional services		X	
Exploration risks and dependence on partial and estimated assumptions, assessments, and data		X	
Estimated costs and schedules and potential shortage of means		X	
Forfeiture of the Partnership’s rights in its oil assets and the financial robustness of the partners in the oil assets			X
Dependence on other regulatory approvals		X	
Regulatory changes:	X		
Possibility of price controls on natural gas		X	
The motion for certification a class action with regard to the price fixed in the agreement between the Tamar Partners and the IEC	X		
Environmental regulation	X		
Climate changes			X
Dependence on weather and sea conditions:			X
Information security and cyber risks		X	
Partnership-specific risks			
Transfer of the interests in the Tamar and Dalit Leases and compliance with the conditions of the Gas Framework	X		
Tax risks		X	
Financing liabilities		X	
Dependence on customers		X	
Dependency on the Operator	X		

	Effect of the risk factor on Company's business		
	Major	**Moderate**	**Minor effect**
Risk in development and production in the event of a discovery			X
Sale of rights in oil assets without receiving full consideration for them		X	
Revocation or expiration of oil rights and assets			X
Spillover of reservoirs			X
Security risks	X		
Fluctuations in the USD exchange rate		X	
The Partnerships' status as a monopoly in the supply of natural gas in Israel		X	
Provision regarding force majeure events under existing natural gas sales agreements :		X	

The impact of these risk factors on Company's operations is based on estimates alone and may actually be different.

Glossary

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

BCM - billion cubic meters

Commercial volumes - a volume of oil that is sufficient for commercial production

Condensate - (1) hydrocarbons produced from natural gas, which are separated from the gas, and liquefied in cooling and condensation processes; (2) gaseous hydrocarbons in the reservoir conditions, but which liquefy when transmitted from the reservoir to the surface; (3) thickened hydrocarbons from refining of petroleum.

Confirmation Well or Appraisal Well - a well that is drilled with the aim of verifying the size, quality and continuity of the oil field discovered through a successful exploratory well. The appraisal phase of the field formally ends when a final investment decision is made to develop the field

Contingent Resources - defined under the Petroleum Resources Management System (SPE-PRMS) as the estimated oil resources, at a given time, that are potentially recoverable from known reservoirs by executing a development plan, but are not yet considered mature enough for commercial development due to one or more conditions.

Development - drilling and equipping of the oil asset area to determine its production capacity and for oil production and marketing

Exploration - all operations related to exploration for oil and gas

Floating Production Storage & **Offloading Vessel (FPSO)** - a floating production facility usually in the form of a tanker with gas and/or oil storage tanks in the hull

Holder of participating units - an entity listed in the Register of Participating Holders as the owners of the participating units

Hydrocarbons - carbons, a generic name for oil and gas, which are coal and hydrogen compounds

Lease - as defined in the Petroleum Law

License - as defined in the Petroleum Law

LNG - Liquefied Natural Gas.

Logs - various tests carried out during the drilling operations for continuous recording of the different characteristics and contents of the drilled rocks

Miocene layer - rocks from a geological period dating from about 5 million to 24 million years ago

MMBBL - million barrels

MMBTU - million British thermal units

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

MMcf/D - millions of cubic feet per day

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

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 exploration –
all activities aimed at locating oil reserves and proving their existence, including geological, geophysical, geochemical, engineering and other surveys and analyzes. It is customary to determine the end of the exploration

phase after a successful drilling of an exploratory well, and after successfully proving the economic feasibility of the discovery, which sometimes requires additional drillings.

Oil field - an accumulation or accumulations of oil under the surface of the soil, which is usually composed of reservoir rock covered by a seal layer. The term is usually used to specify reservoirs that may be economically feasible for production.

Oil right - a license or lease, as defined in the Petroleum Law

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

Petroleum; Discovered; Discovery; Proved Reserves; Probable Reserves; Possible Reserves; Low Estimate; Best Estimate; High Estimate; 1C, 2C, 3C contingent resources; On Production; Approved for Development; Justified for Development; Development Pending; Development Unclarified or on Hold; Well Abandonment; Development not Viable; Condensate; Dry Hole; 1P/2P/3P Reserves Categories - as these terms are defined in SPE-PRMS

Preliminary permit - as defined in the Petroleum Law

Priority right to obtain a license - as defined in the Petroleum Law

Prospective Resources - defined under the Petroleum Resources Management System (SPE-PRMS) as estimated quantities of oil, at a given time, that are potentially recoverable from reservoirs that have not yet been discovered/drilled, by executing future development plans.

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 and regular (from assessment date); (4) based on the executed development project.

Seismic survey - a method that allows (on land or offshore) subterranean imaging and detection of geological formations. The survey is carried out by inserting subterranean seismic waves and recording the returning waves from the various aspects in the tested profile. At the present time, mainly 2D and 3D surveys are conducted and used. The 2D surveys are mainly used to obtain preliminary underground information in the survey area, and for general detection of formations that could serve as oil traps. The 3D surveys (with higher cost than 2D surveys, producing higher quality data and results) are carried out in areas identified as promising in the 2D surveys, and the picture obtained is detailed and enables, among other things, optimal location for drilling and a more accurate assessment of the size of the structure

TCF - trillions of cubic feet, which is 1,000 BCF or 28.32 BCM

Trial Well or Exploratory Well - a well that is drilled for the purpose of proving the existence of oil in the prospect and for calibrating the geological model that led to it being drilled. This is the essence of exploration activity. Depending on the size and complexity of the field, there may be more than one exploratory well in the field.

Working interest - an interest in an oil asset granting its owner the right to participate, pro rata, in the exploration, development and production of oil, subject to payment of a corresponding percentage of the expenses arising from these works, after acquiring the working interest

Conversion table for units used in the report:

MMCF	BCF	BCM
35,314.7	35.3147	1

BCM	MMCF	BCF

0.0283	1000	1

BCM	BCF	MMCF
0.00003	0.001	1

Geological ages and periods referred to in the Report

According to the International Commission on Stratigraphy, 2020 (in million years before present):

- Miocene: 23.0 – 5.3
- Oligocene): 33.9 – 23.0
- Upper Cretaceous: 100.5 – 66.0
- Lower Cretaceous: 145.0 – 100.5
- Jurassic: 201.3 – 145.0
- Triassic: 251.9 – 201.3
- Permian: 298.9 – 251.9

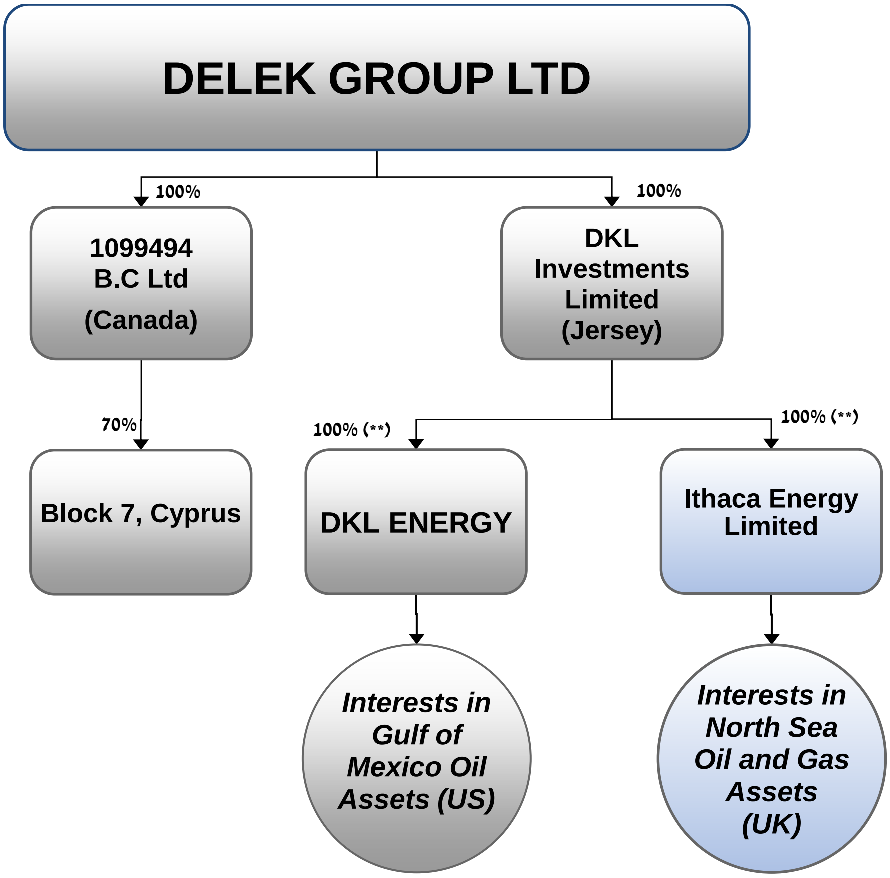
1.8. The Company's Foreign Energy Segment

1.8.1. General

As part of the Company's business strategy, and with the intention of establishing its operations in international energy markets simultaneously to the development of the Company's Mediterranean oil assets, the Company has invested in the energy sector in recent years in several companies and oil assets abroad.

As of the Reporting Date, the Company's operations in the foreign energy sector include mainly projects on the UK continental shelf in the North Sea region ("UK Continental Shelf") through Ithaca Energy Limited (formerly, Ithaca Energy Inc.) ("Ithaca"), wholly owned and controlled (100%) by the Company. In addition, the Company holds other oil assets in the Gulf of Mexico region of the US and an exploration license in Newfoundland in Canada, as set out in this chapter below

The following chart describes the Company's key holdings structure in the foreign energy sector as at December 31, 2020:



(*) The holding in the company is through a wholly-owned foreign subsidiary of the Company (Delek GOM Holdings LLC)

(**) The holding in the company is through two wholly owned foreign subsidiaries of the Company (DKL Energy Limited (130061) and Delek North Sea Limited (12263719)).

DKL Investment Limited ("DKL") is a private company registered in Jersey, wholly owned and controlled (100%) by the Company.

In June 2017 the Company (through DKL) completed the acquisition of all (100%) of Ithaca's shares by way of a tender offer addressed to all the shareholders of Ithaca. For further information, see section 0 below.

Ithaca was incorporated in Canada on April 27, 2004, and engages in the exploration, production and sale of oil and gas produced from oil assets located on the UK Continental Shelf in the North Sea region, and serves as the Operator in some of these assets, also through Ithaca's wholly owned and controlled (100%) subsidiaries and ("Ithaca Group") As at Reporting Date, Ithaca Group is the fifth largest producer and second largest Operator in the UK North Sea Continental Shelf from the aspect of 2P resources attributed to its assets.

In May 2019, Ithaca Energy (UK) Limited ("Ithaca UK"), a wholly owned and controlled (100%) subsidiary of Ithaca, engaged in an agreement with Chevron North Sea Holdings Limited (in this section below: (the "Seller"), for the acquisition of 100% of its shares of Chevron North Sea Limited, that was a subsidiary of the Seller. (the "Chevron Transaction"). After completing the Chevron Transaction, Ithaca changed the name of the acquired company to Ithaca Oil and Gas Limited ("IOGL").

IOGL was incorporated in 1981 in England and Wales, and since its incorporation, has engaged in the exploration, development and production of gas and oil assets in the UK Continental Shelf fields. IOGL's main assets include interests, at various rates, in on-production oil and gas assets on the UK Continental Shelf, for some of which IOGL serves as Operator. IOGL's primary areas of business and operations are similar to and synergistic with Ithaca's areas of operations and Ithaca's assets as they were before the transaction was completed.

On November 8, 2019 the Chevron Transaction was closed and the consideration was transferred after all the pending conditions set out in the transaction were met, including among others, receipt of customary regulatory approvals[174]. For further information concerning the Chevron Transaction and method of financing, including hedging transactions carried out by the Company and Ithaca, see section 0 and the financing paragraph in section 1.8.18 below.

For further information regarding Ithaca Group, its assets and operations, see section 1.8.4 below, and also Note 12.U to the annual Financial Statements included in Chapter C of this Report.

Delek GOM Investments LLC ("Delek GOM") is a private company registered in the US and is wholly owned and controlled (100%) by the Company.

In January 2018 Delek GOM engaged in an agreement to acquire 75% rights in two oil and gas assets located in the Gulf of Mexico area in the United States: Canoe and Tau. As at date of approval of the Report, the Company considers the Canoe Lease to be a discontinued oil asset. In September 2018, exploration drilling began in the TAU oil asset, and was discontinued in June 2019, and at the recommendation of the Operator the well was temporarily sealed in a way that will allow reentry to the well at a later stage. For further information, see section 0 below.

B.C Ltd. As of November 2016, 1099494 Ltd., a private company incorporated in Canada and wholly owned (100%) by the Company, holds rights in the "Block 7" license covering an area of 2,000 square kilometers at an estimated depth of 4,500 meters below sea level (the seabed depth is 1,500 m) which is located east of Newfoundland in the West Orphan basin off the coast of Canada. For further information, see section 1.8.6 below.

According to the strategy of the Company and of Ithaca, in 2019 the Company reviewed a number of proposals for bringing in investors to Ithaca, as part of the plan for issuing Ithaca shares and/or of its affiliates, on the London Stock Exchange. On December 18, 2019 DKL signed a USD 50 million investment agreement, which includes an automatic stock conversion mechanism under certain circumstances. For further information, see section 1.16 of the Report.

For definitions of some of the professional terminology used in this chapter, see the appendix attached to section 1.7 above.

1.8.2. Breakdown of resources

As at date of approval of the Report, the reserves attributed to the Company's overseas oil and gas assets are all in Ithaca's oil assets located on the UK Continental Shelf in the North Sea region.

For information concerning the resources survey report prepared for the Company by Netherland, Sewell & Associates Inc., the Company's independent reserves evaluator ("NSAI" or the "Reserves Evaluator"), which was prepared in accordance with the guidelines of the Petroleum Resources Management System (SPE-PRMS) and which contains, among other things, the NSAI assessments with regard to the volume of the reserves and contingent resources attributed to Ithaca's oil assets, as at December 31, 2020 (the "NSAI Report" or the "Resources Report"), see the immediate report issued by the Company dated March 22, 2021 (Ref. No.: 2021-01-040680), where the information appearing in said reports are noted here by way of reference. As at the date of approval of the Report,

174 On August 8, 2019, approval was obtained from the Oil and Gas Authority ("UK Oil and Gas Authority" or "OGA", accordingly) for transfer of the control of IOGL to Ithaca Group.

there has been no change to this information. A letter of consent from NSAI to include the Resources Report in this Report, including by way of reference, and NSAI's letter about the absence of significant changes with respect to all of Ithaca's oil assets are also attached as **Appendix B**.

According to the NSAI Report, Ithaca's oil assets are divided into four main groups, as follows:

The oil fields in the Captain area that include the on-production Captain reservoir and adjacent Nutmeg, and Surprise assets (the "Captain Area");

The Greater Stella Area project, comprising three on-production assets (Stella, Vorlich and Harrier) and several additional assets that, as at Reporting Date, are non-producing (the "GSA Project").

A cluster of oil fields for which Ithaca's subsidiaries serve as Operator ("Group of Operated Assets");

A cluster of oil fields that are not operated by Ithaca Group companies (the "Group of Non-Operated Assets").

Below is a breakdown of information regarding the volume of proved and probable (2P) reserves and the volume of best estimate contingent (2C) resources, attributed to Ithaca's share in all its oil assets (consolidated), as at December 31, 2020, in ("MBOE")175 For further information with regard to the resources attributed to Ithaca's oil assets, see section 1.8.4 below and the Resources Report.

From the asset portfolio	2P Reserves Thousand barrels of oil equivalent (MBOE)	2C Contingent resources Thousand barrels of oil equivalent (MBOE)
Captain Region Assets	89,103.8	25,672.6
GSA Project	30,896.3	29,092.8
Ithaca Group Operated Assets	29,130.5	38,387.2
Non-Operated Assets	46,363.3	8,961.2
Total for all Ithaca assets	**195,493.8**	**102,113.8**

1.8.3. General information about the area of operations176

The Company's operations in the foreign energy segment vary according to the location of the projects, among other things, due to the regulatory regime applicable in the various operating areas

Structure and changes to area of operations

Oil and natural gas exploration, development and production operations are complex, involving considerable costs and significant uncertainty as to costs, schedules, availability of oil or natural gas and the ability to produce it while maintaining economic viability. Consequently, notwithstanding considerable investments, drilling sometimes does not achieve positive results and does not generate any revenues whatsoever, or result in loss of most or part of the investment. For general information about the nature of exploration, development and production of oil and natural gas, see section 1.7.3(a) above.

In most of the areas where the Company's oil assets are located on the UK Continental Shelf and in the United States, there is a very sophisticated market for both oil and gas, and in most cases the hydrocarbons produced can be sold and supplied directly through an existing transmission pipeline only a few kilometers from a new development at a usage fees. In some cases, this would be an Open Access pipeline, the price for which is usually (not always) supervised. In many cases, the

175 Conversion key - the conversion to MMBOE was estimated considering the following data: conversion rate of natural gas is 1: 6 BOE to mmcf, i.e., each 6 mmcf is equivalent to 1 BOE. The key to the conversion of oil and LPG units is 1:1 bbl to BOE, i.e., every 1 bbl is equivalent to 1 BOE.

Caution - MMBOE units may be misleading, especially when used without taking into account additional characteristics; the conversion is made according to the energy ratio at the burner and does not represent a value equivalent

176176176 Unless stated otherwise, the information contained in this section is mainly based on the BP Statistical Review of World Energy (June 2019, and are to the Company's best knowledge.

https://www.bp.com/content/dam/bp/business-sites/en/global/corporate/pdfs/energy-economics/statistical-review/bp-stats-review-2019-full-report.pdf hydrocarbons can even be sold at the entrance to the pipeline at a price that includes a certain discount on the market price at an amount similar to the costs of alternative transmission means.

In the UK, the US and Canada, an oil or gas field lies in the area of a single license or concession or of a number of licenses or concessions that are granted by the relevant gas and oil authorities, and each field may contain a number of oil and/or natural gas reservoirs. For further information regarding the authorities regulating the Company's oil assets, see section 1.8.22 below.

For licenses that have multiple partners, joint operating agreements have been signed that regulate the exploration, development and production operations between the partners in the oil assets (the “Joint Operating Agreement” or “JOA”). With regard to some of the oil and gas fields that cover the areas of more than one license, the various partners have signed additional Unitisation and Unit Operating agreements or Unitisation and Joint Development Operating agreements, regulating operations in the unitized fields, including the production of oil and gas in the asset ("Unit Agreement").

United Kingdom

To the best of the Company’s knowledge, the UK is the second largest natural gas and oil producer in Europe, and the vast majority of natural gas and oil produced in the UK are from offshore reservoirs in the UK Continental Shelf in the North Sea. In the area of the UK Continental Shelf there is an extensive pipeline network for piping the oil and natural gas produced on the offshore rigs to the onshore terminals in the UK.

USA

To the best of the Company’s knowledge, the US is the world's leading natural gas and oil producer and Canada is the fourth largest oil and natural gas producer worldwide.

In the US Gulf of Mexico region, where the Tau oil field is located, there has been extensive experience in exploration, development and production of oil and gas assets, and as a result, oil treatment and pipeline infrastructures are very developed. In most cases, the development of oil and gas assets in the areas where the Company's oil assets are located is based on local know-how and experience accumulated with regard to nearby and similar assets, as well as regarding the extensive use of existing infrastructures. These circumstances often result in shorter development time of oil fields and less capital expenditure needed than in many other places worldwide.

Canada

With regard to the Company's oil asset in Canada, it should be noted that since it is located in deep waters about 350 km east of Newfoundland in eastern Canada, if a substantial oil or gas discovery is made that will enable commercial development of the asset, the development costs will be relatively high.

Restrictions, legislation and special constraints that apply to this area of activity

For further information regarding applicable regulation in countries where the exploration, development and production of oil and natural gas is carried out, see section 1.8.22 below

Changes in the volume of the operations and its profitability

The global oil and gas industry is seriously affected by changes in supply and demand, and crude oil prices are known to be highly volatile. Three major factors affecting crude oil prices are volume of oil supply from OPEC (Organization of the Petroleum Exporting Countries)[177] and from non-OPEC countries, and the global demand for crude oil. Crude oil prices are also affected by production capacities and costs, and the development of cleaner or cheaper energy production capacities.

United Kingdom

UK oil production peaked towards the end of the 1990s and declined over the following years, leveling out in 2014. In 2017-2018 the UK increased its oil production by 8.5% and 9.2%, respectively. Oil consumption in the UK peaked in 2005, and has been falling since.

UK natural gas production peaked towards the beginning of the 2000s and declined over the following years, leveling out in 2014. In 2015-2017 the UK increased its natural gas production and in 2018 it

177 At Reporting Date, OPEC member countries are Algeria, Angola, Ecuador, Iran, Gabon, Equatorial Guinea, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, United Arab Emirates and Venezuela.

declined by 3.1%. The downward trend continued in the following years. In 2020, there was an increase in the demand for natural gas that can be attributed to the Covid-19 pandemic. Natural gas consumption peaked in 2010, and has been falling since.

Since 2010, oil production declined faster than the decline in consumption, with the UK becoming dependent on importing crude oil and fuel products.

Despite being an importer of crude oil and fuel products, the UK is still one of the largest oil producers and exporters in Europe.

According to the Oil and Gas Authority ("OGA") publications, oil and natural gas will remain an important part of the UK's energy mix, and offshore production from the UK Continental Shelf remains essential in order to meet the UK energy demand. According to a report published by the OGS in September 2020, the UK Continental Shelf region contains, as of the end of 2019, reserves of between 10 to 20 BBOE.

USA and Canada

In recent years there has been a significant decline in oil and natural gas prices, inter alia, due to a significant increase in oil and gas production in the US. The US is the largest oil and natural gas producer and consumer worldwide. In 2018 and 2019, US oil consumption accounted for 19.7% and 20.3%, respectively, of the global oil consumption, and during those years, US natural gas consumption accounted for 21.2% and 21.5%, respectively, of the global natural gas consumption. Since 2004 and 2008, natural gas and oil production, respectively, in the US has been rising steadily, and since 2009 and 2012, natural gas and oil consumption, respectively, has been rising steadily. The US is expected to continue topping the list of world oil consumers in the coming years. In light of the increase in the production of oil and natural gas in the US, the US has become a net exporter of oil and natural gas in recent years (namely, it exports more oil and gas than it imports). It should be noted that the US oil and natural gas market is a sophisticated and well developed market, in which most of the oil and gas produced is sold on the local market, which can absorb the total output volume[178].

Canada is also a net exporter of oil and gas. In 2018 and 2019, Canadian oil consumption accounted for 5.7% and 2.4%, respectively, of global oil consumption, and during those years, Canadian natural gas consumption accounted for 3% and 3.1%, respectively, of the global natural gas consumption. Most of Canada's oil production comes from tar sands and heavy oil fields in the western part of the country. Canada's natural gas supply now exceeds domestic demand. Furthermore, Canada's natural gas market is integrated with the US market; Canada exports the excess supply of its natural gas to the United States and imports a smaller amount of natural gas from the US to the center of Canada.

Market developments or changes in the characteristics of customers

Fluctuations in the oil and gas prices, as well as the prices of alternative fuels, may affect the prices that the Company can obtain from its customers for the oil and/or natural gas that it sells (if it is able to achieve its goals and reach commercial production in its assets in the US and Canada), which will affect the viability of production, the Company's decision whether the development of any particular field will be economically viable, and the decision whether or not to engage in exploration and/or development operations.

For example, the 50% drop in oil prices from June 2014 through January 2015 led to a decline in demand for drilling equipment and services, and consequently the prices of the service providers and the drilling equipment decreased.[179]

According to the findings of the annual energy forecast published by the US Energy Information Administration (EIA) in February 2021,[180] the US is expected to continue to be a major global supplier of crude oil and natural gas.

According to the EIA, the price of oil is the main motive for future drilling and affects production rates. According to them, the uncertainty surrounding demand for oil in the post-Covid era translates into uncertainty in supply, which is reflected in price fluctuations. Consequently, in view of the current

178 See website of the U.S. Energy Information Administration ("EIA"): https://www.eia.gov/outlooks/aeo/pdf/AEO_Narrative_2021.pdf

179 From the EIA website: "Oilfield costs fall following decline in oil prices" http://www.eia.gov/todayinenergy/detail.cfm?id=21712

180 U.S Energy Information Administration, https://www.eia.gov/outlooks/aeo

economic downturn, the EIA expects that, due to the low oil prices in the short and mid-term, the rate of US oil production will decrease in 2021 compared to 2020. If oil prices rise rapidly, it appears that oil production will also increase as a result.

According to EIA estimates, record volumes of oil production is expected over the next 30 years with the rate of oil and natural gas production expected to remain high from 2023 through 2050. Furthermore, they estimate that the US will continue to be an integral part of the global oil and natural gas market and a significant source for global consumption.

Technological Changes

In recent years there has been a significant increase in US commercial production of oil and natural gas from shale reserves. Shale is a sedimentary rock (clay or flakes) with low conductivity and porosity. Oil and gas production is possible by using hydraulic fracturing, or fracking technologies and horizontal drilling. According to EIA data, in 2000 shale gas accounted for about 1% of US natural gas production, and in 2010 it accounted for more than 20% of US natural gas production. According to EIA estimates, by 2035 about 46% of US gas production will be based on shale gas.

A large quantity of the oil in the reservoirs is not recoverable by normal production processes, but now can be recovered by using more complex production techniques such as injection of heat, chemicals, carbon dioxide (CO2) or other gases. These techniques have been successfully used in several countries for decades and are known as EOR - Enhanced Oil Recovery techniques. EOR production techniques account for 2% of the world's total oil production. IEA expects this rate to increase to 4% by 2040.

For further information regarding technological developments, see section 1.7.3(E) above.

Critical success factors in the area of operations

For information concerning critical success factors in this operating segment, see section 1.7.3(F) above.

Changes in raw materials and suppliers

For information concerning changes regarding raw materials and suppliers, see section 1.8.16 above.

Entry and Exit Barriers

The main entry barriers in the oil and gas sector are the need to obtain permits and licenses for exploration, development and production of oil and natural gas from the competent authorities in each country in whose territory the Company's assets are located and subject to the regulations applicable in each region[181] and/or the land owners and the availability of a financial resources to make the large-scale and relatively high financial investments required to carry out such operations. In addition, engaging in these operations requires considerable expertise, including the ability to locate suitable assets for exploration or production.

The main exit barriers are the obligation to dismantle production facilities before abandoning the oil and natural gas fields, which sometimes involves very significant costs. In addition, due to the professional and economic capabilities required for these operations, the number of potential buyers for oil and gas assets is sometimes limited, which may delay the ability to sell the assets at the appropriate price and exit the industry.

Substitutes for products of the area of operations

The use of renewable energy in the UK, particularly in the electricity sector, has doubled in the last decade. Nonetheless, oil and natural gas continues to be a major share of energy consumption in the UK. According to the International Energy Agency publications, by 2030 the use of renewable energy may be as high as 50% in the UK.

A growing trend in the US and Canada is the generation of energy from renewable sources (mainly electricity generated from solar energy, wind and waterfalls) that replace the use of oil, gas and coal. Thus, in recent years, efforts have been made in the US to increase the use of alternative and less polluting energy sources. Following the change in the US government in December 2020, the new administration undertook to promote and increase the volume of production from renewable energies through supporting legislation.

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181 For further information concerning the regulation applicable to this operating segment, see section *1.8.22* below

Structure in the industry

For information regarding the structure of the competition in this operating segment, see section 1.8.11 above.

The Covid-19 coronavirus crisis and its potential impact on the operating segment

As set out in section 1.6.6 above, an unprecedented and challenging macroeconomic environment was created at the beginning of 2020. The decrease in demand for oil due to the spread of the Covid-19 coronavirus ("Covid-19") and cancellation of OPEC agreements led to extreme volatility in the petroleum market and financial markets. These effects led to sharp declines in the Brent and WTI indices, which led to a decline in prices on the petroleum market and of the results of energy companies. The market is experiencing increased volatility, which has led, among other things, to extreme volatility in prices. The market fluctuates acutely between expected sharp declines in future prices of energy products and expected increases and recovery in prices of future contracts, as oil stockpiles continue to fill up and traders slowly move to floating storage facilities. Concern about storage capacities caused significant pressure on market prices and price volatility.

Due to the Covid-19 crisis, Ithaca decided to freeze a certain portion of its 2020 work plans in order to reduce its capital expenditure (Capex) in 2020 from USD 250 million to USD 124 million, while at the same time, Ithaca worked to reduce the average production cost per unit.

In view of the spread of the virus, Ithaca has adopted a number of actions aiming to allow it to continue its operations also at the present time. Ithaca has been focusing its efforts to reduce the risk of the virus spreading among its employees and its suppliers, with the aim of protecting its employees' health as well as its operational aspects. The most serious business risk identified by Ithaca in view of the spread of the virus is the possibility that contagion among its employees who work in the various offshore facilities might lead to a complete halt in production activities. Such contagion could harm the ongoing operations in the GSA project and the Captain area oil assets, which are the most significant of all Ithaca's assets. Accordingly, Ithaca has recognized the gravity of the risk and has acted as aforesaid.

To mitigate the risk, Ithaca has reduced the number of employees on its offshore production facilities in accordance with the OGA and based on industry guidelines. Measures have also been taken ensuring that, if positive cases are found among the workers on the facilities, Ithaca is able to isolate workers suspected of being infected and send them back onshore. Since the outbreak of the Covid-19 pandemic, all offshore employees who were infected with the virus were immediately quarantined and flown back onshore, in accordance with the guidelines.

As at the date of approval of the Financial Statements, and after a whole year of working alongside the Covid-19 virus, we can now say that the production efficiency levels have returned to Ithaca's pre-Covid levels, and at times even exceeded them. As at the date of approval of the Financial Statements, almost all maintenance work and the Capex are back on track and Ithaca's management believes that the company can continue operating safely and effectively, despite the pandemic. It is noted that the vaccination campaign in the UK is currently in full swing and Ithaca estimates that the risk to its employees will drop and will directly impact increasing production. For further information see section 1.8.26(C) below.

Breakdown of the Company's oil assets abroad

1.8.4. Ithaca's oil assets on the UK Continental Shelf in the North Sea.

General

In June 2017, as aforesaid, DKL completed the acquisition of Ithaca's total share capital, by way of a tender offer, following which Ithaca's shares were delisted from the Alternative Investment Market (AIM) in London and the Toronto Stock Exchange (TSX) in Toronto Canada[182]. For further

[182] The acquisition of the total share capital of Ithaca, through DKL, was carried out in several stages since October 20, 2015, when the Company held 19.9% of the issued shares of Ithaca, and after completing the tender offer between May 3, 2017 and June 4, 2017 it held 94.2% of Ithaca's issued share capital, and on June 5, 2017 the forced acquisition of the remaining Ithaca shares was completed, after which the Company (through DKL) holds all of Ithaca's share capital (100%). *Consequently, all the information in this chapter relating to the share of the Company's equity holders in the cumulative investment, income and expenses of Ithaca's oil assets for the years 2016-2018 reflects the relevant rates of holdings in Ithaca shares.*

information regarding the tender offer, see the immediate reports issued by the Company on May 4, 2017 and June 6, 2017 (Ref. Nos. 2017-01-045465 and 2017-01-057558, respectively).

In September 2020, Ithaca was granted seven new licenses in a tender conducted by the OGA for oil and gas licenses in the UK continental shelf area. Two of the licenses are in the vicinity of the Captain Field, two in the vicinity of the Alba Field, two in the vicinity of the Cook Field and one in the vicinity of the Stella Field.

The Chevron Transaction

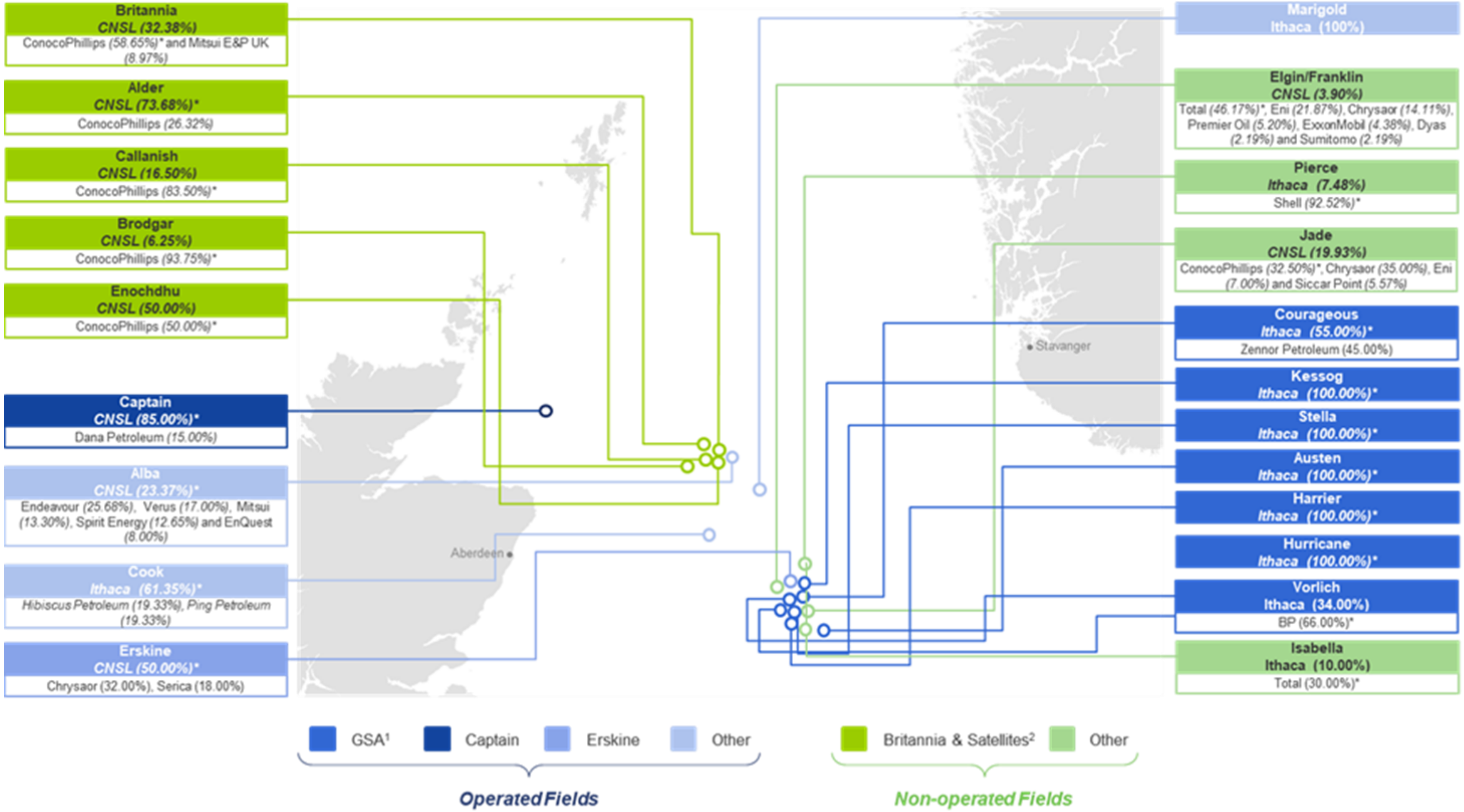
As set out in section 0 above, in May 2019 Ithaca Energy (UK) Limited, a wholly owned and controlled subsidiary (100%) of Ithaca, engaged in an agreement with Chevron, under which it acquired 100% of the shares of IOGL, and on November 8, 2019 the transactions were completed and the consideration was transferred, once all the contingent preconditions of the transaction were met. Under the transaction, the Seller transferred to Ithaca full title in the share capital of IOGL and Ithaca paid the Seller a total amount of USD 1.477 billion (excluding an amount of USD 200 million deposited on the date of signing of the Acquisition Agreement). In addition, an amount of USD 50 million was paid for working capital and 450 of IOGL workers continued their employment once the transaction was completed. As of date of closing, Ithaca assumed all the rights and liabilities of IOGL with regard to IOGL's assets, which included, among other things, ten on-production oil and gas fields in the UK Continental Shelf zone[183], as well as production, treatment and storage facilities, and all as set out below, other than two non-producing assets owned by IOGL, Heather and Strathspey, with regard to which it was agreed that IOGL will retain responsibility. However, the sealing and abandonment costs incurred by IOCL will be borne by the seller. For further information regarding the financing of the transaction, see the paragraph on financing in sections 1.8.18 and 1.14 below.

[183] Including the on-production Captain oil field, the cluster of on-production oil fields Alba, Erksine, Alder that are operated by Ithaca Group and the cluster of on-production oil fields Britannia, Brodgar, Callanish, Enochdhu, Jade, Elgin-Franklin, that are not operated by Ithaca Group. *For further information concerning these assets, see the table below.*

<u>Map of Ithaca's Assets</u>

Ithaca's oil assets are divided, as aforesaid, into four main groups: Captain Region Assets, GSA Project, Ithaca Group Operated Assets and Non-operated Assets Group.

Below is a map indicating the location of Ithaca's oil assets on the UK Continental Shelf in the North Sea.



Resources and cash flow information with regard to Ithaca's oil assets (consolidated)

General

For further information concerning the resources and discounted cash flows relating to all of Ithaca's assets (consolidated) as at December 31, 2020, see section 2 of the NSAI Report. As at the date of approval of the Report, there has been no change to this information. A letter of consent from NSAI to include the foregoing Resources Report in this Report, including by way of reference, and a letter from NSAI concerning the absence of significant changes with respect to all of Ithaca's oil assets (consolidated) are also attached as **Appendix B** to this Report.

Reconciliation between the data in previous reports with regard to the volume of reserves attributed to the oil asset

On July 13, 2020, the Company published NSAI's Resources Report, which included an evaluation of resources attributable to the oil assets as at June 30, 2020 (Ref. No.: 2020-01-074451) ("the Previous Report"). Below is a breakdown of key data regarding the major differences between the volumes of resources attributed to Ithaca's oil assets in the current Resources Report and the Previous Report (in MBOE):

	June 30, 2020		December 31, 2021		
	Total according to the Previous Report	Total Output in the second half of 2020	Total according to current NSAI Report	Total change in volume	% change
Total 2P Reserves	190,839	11,042	195,494	4,655(1)	Increase of 2%
Total 2C Contingent Resources	67,547	-	102,113	34,566(2)	Increase of 51%
Total 2P + 2C Resources	258,386	11,042	297,607	39,221	Increase of 15%

The differences between the data presented in the Previous Report and that in the current NSAI Report, as set out in the foregoing table, are mainly due to:

The estimated remaining reserves in the Captain, Erskine, Elgin Franklin, Britannia, Jade fields increased according to the NSAI Report by a volume of 21.9 MMBOE. The estimated remaining reserves in the Alder and Cook fields, and the GSA Project decreased by 6.2 MMBOE.

Total output in the second half of 2020 amounted to 11 million MMBOE.

The net remaining 2P reserves amounted to 4.6 MMBOE.

The NSAI Report attributed an additional volume of 35 MMBOE of 2C contingent resources to the Marigold and Isabella fields.

Below is a breakdown of Ithaca's key assets groups.

Captain Area Assets

General

The primary asset in this cluster of assets is the Captain field, that covers an area of 85 sq. km and contains heavy oil and natural gas (the "Captain Field"). The Captain Field is divided into three areas: (1) Area A, which is the central area of the Field and contains 19 production wells; (2) Area B, which is the eastern part of the Field and contains 14 production wells; and (3) Area C, which is located in the far eastern part of the Field and contains 3 production wells. These areas fall under the P.324 license, in which Ithaca Group holds 85% of the rights.

In addition to the Captain Field, to the west of the Field area are two non-producing assets (Nutmeg and Surprise). These assets are located in the P.2356 license area that is wholly owned (100%) by Ithaca Group. Furthermore, north of this license area there are two additional exploration stage licenses, P. 2513 Captain Extension and P.2514 Housedon.

In the Captain Field Ithaca applies the EOR production method that is designed to increase the pressures in the field by injection of sea water into the wells. In addition, this method is intended to improve the flow rate of the oil by increasing viscosity by injecting polymers into the wells. As at date of approval of the Report, the Captain Field Area A has 3 production wells in which sea water injection is used and 5 polymer injection wells. In addition, the Captain Field Area B has 4 production wells in which sea water injection is used. It is noted that, under the Chevron Transaction, a mechanism was provided for polymer use as well as the use of rights that were not purchased.

The crude oil produced from Captain Field is treated via two production and treatment facilities, and from there stored in a floating production storage and offloading vessel (below in this section: the "Floating Facility") that is stationed in Area A of the Field and is wholly owned (100%) by the partners in the Captain Field (License P.324) From the Floating Facility the crude is transferred to shuttle tankers used for marine transport of the crude, and from there directly to customers.

General Details:

General Details	
Name of oil asset:	Captain
Location:	The Captain Area is located on the UK Continental Shelf about 145 km off the UK shoreline, at marine depth of 105.5 meters.
Type of oil asset and description of permitted operations according to the type	Exploration, development and production licenses for oil and gas resources issued by the UK government
Original grant date of the oil asset	Captain P.324 - Jun 10, 1981 Nutmeg, Surprise P.2356 - Sept 20, 2018 Captain Extension P.2513 - Dec 1, 2020 Housedon: P.2514 – Dec 1, 2020
Original expiry date of the oil asset:	Captain P.324 - Mar 15, 2018 Nutmeg, Surprise P.2356 - Sept 30, 2022 Captain Extension P.2513 – Dec 1, 2026 Housedon P.2514 – Dec 1, 2025
Date of decision regarding extension of the term of the oil asset:	Captain P.324 - Mar 12, 2018
Current expiry date of the oil asset	Captain P. 324 - a producing asset and therefore no expiry date was set The license may expire if production is discontinued for 12 consecutive months. Nutmeg, Surprise p.2356 – Sept 30, 2022 Captain Extension P.2513 – Dec 1, 2026 Housedon P.2514 – Dec 1, 2025
Note whether there are additional options for extending the term of the oil asset; if such option exists - the term of the possible extension should be noted:	P.2356 - subject to completing certain operations in the work plan, the term of the license may be extended until September 30, 2026, with an additional extension through to September 30, 2044. P.2513 - subject to completing certain operations in the work plan, the term of the license may be extended until December 1, 2042. P.2514 - subject to completing certain operations in the work plan, the term of the license may be extended until December 1, 2029, with an additional extension through to December 30, 2047.

General Details	
Note name of Operator:	IOGL
Names of the direct partners in the oil asset and their direct share in the oil asset and, to the best of the Company's knowledge, the names of the controlling owners in the partners	Captain P.324: Ithaca Group - 85% Dana Petroleum (E&P) Limited ("Dana Petroleum")[184] - 15% Nutmeg, Surprise, Captain Extension, Housedon P.2356, P.2514 & P.2513: Ithaca Group - 100%

General information about the Company's share in the oil asset	
Acquisition Date:	P.324, P.185, P.2365 The interests were acquired under the Chevron Transaction that was signed on May 29, 2019 and is valid since January 1, 2019. P.2514 & P.2513: The interests were acquired in Tender No. 32 for license tenders in England.
Description of the Company's holding in the oil asset	Through the Company's holdings (direct) in Ithaca shares.
Effective share of oil asset revenues attributable to equity holders of the Company (subject to closing of the transaction):	Captain P.324- 85% Nutmeg, Surprise, Captain Extension, Housedon P.185, P.2356, , P.2514, P.2513: 100%
Total share attributed to the equity holders of the Company in the cumulative investment in the oil assets in 2020 (whether recognized as an expense or as an asset in the financial statements):	179

<u>Past operations and additional information:</u>

The Captain Field was discovered in 1977 by a third party, and development of the field began in 1995. In Areas A, B and C, which lie in the license P.324 area, production began in 1997, 2001 and 2006, respectively.

The Floating Facility and production and treatment facilities were installed in Area A of the Field in 1996. In 2000 an additional production and treatment facility was installed, that was connected to the first facility in 1996, as aforesaid. In addition, in 2000 a submarine pipeline was installed in Area B of the Field. Another submarine pipeline was laid in 2006 to allow further development of Area C of the Field. All these facilities are owned by the partners in the Captain Field (License P.324).

In 2000, IOGL's rights in the P.324 and P.185 licenses were acquired, and in October 2018 the OGA granted IOGL the rights in License P.2356 under a tender.

In November 2018, the Captain Field partners obtained OGA approval for the field development plans that refer to the EOR development method. The development plan will be implemented in two stages (Stage A, Area A of the Field and Stage B, Areas B and C of the Field) and includes mainly, an undertaking to drill seven additional wells and injection of polymers to the field to accelerate the oil recovery rate. As at the approval date of the Report, Stage A of the development plan, which included drilling of five production wells and two polymer injection facilities in Area A of the field, has been completed. Due to the Covid-19 pandemic, drilling of three wells and one injection were postponed until 2021/2022.

Under the terms of License P.2356 (Nutmeg, Surprise), is a mandatory undertaking to drill an exploratory well by September 2022. Failure to comply with this undertaking will cause the rights in

[184] To the best of the Company's knowledge, a wholly-owned private company (100%) of Korea National Oil Corporation, the national oil and gas company of South Korea.

the license to expire. As at Reporting Date, an exploratory well has not yet been drilled in License P.2356.

Compliance with Work Schedule:

To the best of the Company's knowledge, the binding work schedule for the foregoing assets, until the date of publication of this report, has been fully implemented.

Actual and planned work schedule:

Breakdown of the main operations actually carried out and summary of planned operations:

Period	**Summary of operations implemented in the period and the planned work schedule**	**Estimated total budget for operations per oil asset USD Millions**	**Actual participation of the Company's equity holders in the budget USD Millions**
2018	• Area A - Captain Field - further drilling of wells and polymer injection • West Wick - exploratory drilling	69[185]	-
2019	• Area A - Captain Field - completion of Stage A for EOR	92	78
2020	• A number of projects, including replacing undersea pipelines, maintenance work on the rig and integrated control and safety system (ICSS).	38	32
2021	• Continuing drilling in Area A and upgrading the facilities in • Areas B and C - Captain Field - approval of plan to expand the use of the EOR method in these areas and development of the reservoir lower strata • Nutmeg, Surprise - decision regarding execution of exploratory drilling as per the terms of the license. • Further polymer injection as part of the restoration	142	121
2022	• Continuing drilling in Area A and upgrading the facilities in • Captain Field - Area B and C	233	198
2023 onwards	• Continuing drilling in Area A and upgrading the facilities in • Captain Field - Area B and C	1,457	887

Forward-looking information - the information concerning the planned operations in the oil field, including with regard to costs, time schedules and actual execution, is forward-looking information, as defined in the Israel Securities Law, and are based the assessments of Ithaca Group that depend, among other things, on third parties, climate conditions, economic conditions, regulatory changes, technical capacities, availability of equipment and other factors that are not in the Company's control. Consequently, implementation of the work schedule, including timetables and costs, may differ materially from the estimates described above.

Share in the actual expenses and revenues relating to the Captain Area Assets:

The actual rate of participation in the expenses and revenues regarding the group of assets that were attributed to the equity holders of the Company are equivalent to Ithaca's rights in these assets, as specified in the foregoing tables in section (2) above (under General Details), as no royalties are paid

185 It is noted that this refers to the total budget for the operations described above that was invested in 2018.

with regard to these assets to the UK government or third parties, and no other derivative royalties whatsoever are paid from the income and expenses.

Description of material agreements between the partners in the Assets:

1. Captain Field (License P.324) JOA:

The exploration, development and production operations under License P.324 are carried out through a joint operating agreement signed on April 25, 1997 that is amended from time to time (hereinafter in this section: the "JOA" or the "Agreement"). As at Reporting Date, the parties to the agreement are Ithaca Energy (UK) Limited ("IEUK"), Ithaca Minerals (North Sea) Limited and Dana Petroleum (E&P) Limited, and it provided, inter alia, regarding the following issues: regulating the interests of the various parties in the oil asset; ownership of the asset; supervision, control and distribution of the risks involved in the exploration, development and production of oil and gas in the assets; procedures and methods for submitting and approving of work schedules, budgets and AFE authorizations, and for executing the operations in the fields that the JOA relates to. The JOA provisions also relate to the following matters: the joint venture parties; the role and authority of the designated operator for the asset; the joint operating committee, its powers, voting interests and how decisions will be made; exploration, development and production decision making mechanisms, and procedures for determining budgets; transfer of rights in an oil asset; decommissioning guidelines; obligations; dispute resolution; and accounting procedures. It is noted that the JOA permits transfer of participating rights of a party to the asset, in whole or in part, only if the transferee has financial and/or technical resources, including if the transferee is not a related party. A licensee partner's right of transfer as aforesaid is subject to the first refusal rights of the other partners (other than when transferring to an affiliate of the transferring partner), which gives them priority to purchase the rights before they are offered to a third party.

The Operator (IEUK), will act both as a holder of rights in the asset and on behalf of all the partners as the Operator under the supervision of the joint operating committee. The definition of the Operator's role includes: (i) submitting and approval of work plans, budgets, and authorizations for expenditure (AFE) for the executing the operations in the fields that the JOA applies to, subject to the approval of the joint operating committee; (ii) planning, ordering and receiving necessary materials and services; (iii) providing technical, accounting and consulting services required for the joint operation of the asset

A party that fails to pay its pro rata share in the joint expenses on time, including advance payments and interests, will be considered to be a breaching party ("the Breaching Party"). If the breach continues for a period as set in the JOA (usually 6 business days from the Breaching Party's receipt of notice of arrears) the non-breaching parties will pay the Breaching Party's debt (pro rata to their interest), and the Breaching Party will not be entitled to receive its share of the oil, and this share will become the property of the non-breaching parties, and they will be entitled, subject to the procedures set out in the JOA, to collect their due from this share up to full payment of the amount in the breach. If the breach continues for longer, as set out in the JOA (exceeds 60 days), the Breaching Party's rights may be forfeited and allocated among each of the non-breaching parties pro rata to their holdings.

Given the fact that IEUK holds 85% of the rights in the JOA, based on a mechanism in the JOA, it will make most decisions, other than decisions with regard to waiving part of the areas under the License, and any decision that would mean waiving the License, which would require a unanimous decision.

2. As IOGL owns all (100%) the interests in the P.2356 and P.185 licenses, there is no JOA for these licenses.

Captain Project resources and discounted cash flow data

For further information concerning the resources in the Captain Field and discounted cash flows deriving from them as at December 31, 2020, see section 3 of the NSAI Report. As at the date of approval of the Report, there has been no change to this information. A letter of consent from NSAI to include the foregoing Resources Report in this Report, including by way of reference, and a letter from NSAI concerning the absence of significant changes with respect to the assets in the Captain Field are attached as Appendix B to this Report.

GSA Project

General

The GSA Project is made up of the on-production Stella, Vorlich and Harrier fields and four additional fields; Abigail (which was previously known as Hurricane), Courageous, Austen and Kessog, which, as at Reporting Date, are non-producing fields. Ithaca UK serves as the Operator in all these licenses. In all the GSA Project oil assets, exploratory and appraisal drillings were carried out by third parties in the past, and petroleum reserves were discovered, as will be detailed below.

Production from the GSA Project on-production fields is carried out using the floating production facility, FPF-1, that is owned by Ithaca (the "Floating Production Facility"). The floating production facility is connected to the submarine infrastructure that includes two main pipelines to the UK market: the Central Area Transmission System ("CATS") and the Norpipe pipeline that lies in the North Sea and supplies oil to the UK shore, as an alternative to using tankers.

Production from the Stella oil field commenced in February 2017. Ithaca's total investment in establishing the GSA Project production infrastructure and the development of the Stella field amounted to USD 700 million.

In 2018 Ithaca completed the development of the Harrier oil asset and its connection to the floating production facility, and in 2019 Ithaca drilled an additional production well in the Stella Field and participated in a joint venture with BP for drilling two additional production wells in the Vorlich Field.

In 2020 Ithaca completed connecting Vorlich Field to the floating production facility and to begin acquiring the necessary items for developing the Hurricane oil asset. In the next few years, Ithaca intends continuing to connect the rest of the reservoirs in the GSA Project to the floating production facility, other than the Austen and Kessog fields, which may be developed using third party infrastructures.

The use of the Floating Production Facility as the key infrastructure of the GSA Project fields contributes to lowering the costs involved in development and in production of oil and natural gas from the close-by fields, over many years.

On December 12, 2018, Ithaca closed a transaction to acquire additional interests from its partners in the GSA Projects and to date Ithaca Group holds all the rights in the Floating Production Facility and all the rights in the GSA Project licenses, other than the Vorlich and Courageous licenses, and all as set out in the table below. In return for the purchase of the additional rights, Ithaca paid an amount of USD 190 million and agreed to a new payment schedule for Ithaca's existing debt to Petrofac, in the amount of USD 140 million. Accordingly, on the closing date of the transaction, Ithaca paid USD 130 million (net of cash flows received as of the effective date of the transaction (January 1, 2018) plus an additional USD 20 million, that constituted an advance payment with respect to the existing debt), and this in addition to the remaining payments to Petrofac in the amount of about USD 120 million, which will be paid off from 2020 through 2023. In addition, one of the sellers is entitled to an additional consideration of up to USD 25 million, which is contingent on the performance of the Stella and Harrier reservoirs until 2020. The total acquisition costs amounted to USD 132 million,

General Details

General Details	
Name of oil asset:	The GSA Project includes a cluster of oil fields, as set out below, with three on-production reservoirs, Stella, Harrier and Vorlich reservoirs, three assets under development: Austen, Hurricane and Courageous.
Location:	North Sea, some 250 km east of the UK shoreline
Type of oil asset and description of permitted operations according to the type	Exploration, development and production licenses for oil and natural gas resources issued by the UK government

General Details	
Original grant date of the oil asset	Stella & Harrier: P.011 - Sept 18, 1964 Austen: P.1823 - Jan 10, 2011 Vorlich: P.363 - Dec 17, 1980 P.1588 - Feb 12, 2009 Abigail (formerly Hurricane): P.1665 - Feb 12, 2009 Courageous: P.2397 - Oct 1, 2018 Kessog: P.2554 – Dec 1, 2020
Original expiry date of the oil asset:	Stella & Harrier: P.011 - Sept 17, 1970 Austen: P.1823 - Jan 9, 2015 Vorlich: P.363 - Dec 16, 1986 P.1588 - Nov 11, 2014 Abigail (formerly Hurricane): P.1665 - Feb 11, 2013 Courageous: P.2397 - Sept 3, 2023 Kessog: P.2554 – Dec 1, 2025
Date of decision regarding extension of the term of the oil asset:	Stella & Harrier: P.011 – Sept 17, 2013 Vorlich: P.363 – Dec 16, 2020 P.1588 – Oct 12, 2018 Abigail (formerly Hurricane): P.1665 – Nov 30, 2020

General Details	
Current expiry date of the oil asset	Stella & Harrier P.011 - fields under a production license and therefore no expiry date was set. The license may expire if production is discontinued for 24 consecutive months. Austen P.1823 – Mar 9 2022 Vorlich P.363 - fields under a production license and therefore no expiry date was set. The license may expire if production is discontinued for a period of 12 consecutive months. P.1588 - Feb 11, 2035 (estimate) Abigail (formerly Hurricane): P.1665 – Nov 30, 2020 Courageous P.2397 – Mar 30, 2023 Kessog: P. 2554 - Dec 1, 2025
Note whether there are additional options for extending the term of the oil asset:	Austen P.1823 - subject to compliance with the terms and conditions of the license, the term of the license may be extended through to May 9, 2022, with an additional extension through to January 9, 2037 (estimate only). Abigail (formerly Hurricane): P.1665 - subject to completion of certain operations in the work plan, the term of the license may be extended through to February 11, 2035 (estimate only). Courageous: P.2397 - subject to completion of certain operations in the work plan, the term of the license may be extended through to September 30, 2027, with an additional extension through to September 30, 2045 (estimate only). Kessog: P.2554 - subject to completion of certain operations in the work plan, the term of the license may be extended through to December 1, 2031, with an additional extension through to December 1, 2049 (estimate only).
Note name of Operator:	Ithaca UK serves as the Operator in all these licenses.

General Details	
Names of the direct partners in the oil asset and their direct share in the oil asset and, to the best of the Company's knowledge, the names of the controlling shareholders in the partners	**Stella & Harrier:** P.011 - Ithaca Group - 100% **Austen:** P.1823 - Ithaca Group - 100% **Vorlich:** P.363 (Block 30/1c Lower): Ithaca Group - 50% BP Exploration - 50% P.363 (Block 30/1c Upper): Ithaca Group - 20% BP Exploration - 80% P.1588 - Ithaca Group - 100% **Abigail (formerly Hurricane):** P.1665 - Ithaca Group - 100% **Courageous:** P.2397: Ithaca Group - 55% Zennor North Sea Limited[186] - 45% **Kessog:** P.2554: Ithaca Energy (UK) Limited - 100%

General information about the Company's share in the oil asset	
Acquisition date of the lease for the acquired oil asset	Ithaca first acquired interests in the Stella, Harrier and Abigail (formerly Hurricane) licenses in 2008-2009. Ithaca first acquired the rights in the other GSA licenses in 2016-2020.
Description of the Company's holding in the oil asset	Through the Company's holdings of all of Ithaca shares.
Effective share of oil asset revenues attributable to equity holders of the Company:	Stella & Harrier - 96.67% Abigail (formerly Hurricane) - 100% Austen -100% Vorlich - 34% Courageous - 55% Kessog – 100%
The total share of equity holders of the Company in the cumulative investment in the oil assets in 2017 through 2020 (whether recognized as an expense or as an asset in the financial statements):	Stella & Harrier – USD 65 million Abigail Field (formerly Hurricane) – USD 16 million Austen Field - USD 4 million Vorlich Field - USD 109 million Courageous Field – USD 0 million Kessog Field - USD 0 million

Compliance with the work schedule

To the best of the Company's knowledge, the binding work schedule for the foregoing assets, until the date of publication of this report, has been fully implemented.

186 To the best of the Company's knowledge, a private company wholly owned and controlled (100%) indirectly by the Kerogen Energy Fund II LP investment fund.

Actual and planned work schedule

Below is a breakdown of the main operations actually carried out in the GSA Project oil and gas assets from January 1, 2018 through publication of this Report and of the planned operations:

Period	Summary of actual operations in the period or of the planned work plan	Estimated total budget for operations on the level of the oil asset (USD thousands)	Actual participation of the Company's equity holders in the budget (USD thousands)
2018	• Harrier Field: Installation of the submarine structures in the Harrier field were completed to allow the production from the field to start. • Vorlich Field as part of advancing the field development plan	344,000	21,000
2019	• Vorlich Field: Completion of planning and development of Vorlich field, including drilling of two production wells • Stella Field: Completing drilling of an additional well in the Stella Field, the purpose of the well is to increase production from the field. • Engineering work in the Austen, Abigail (formerly Hurricane) and Courageous fields	235,000	117,000
2020	• Connection of the Vorlich reservoir was completed and commercial production began • Execution of further operations necessary for developing the oil asset in the Abigail (formerly Hurricane) license • Engineering work in the Austen and Courageous fields	27,000	17,000
2021	• To complete necessary operations for developing the Abigail (formerly Hurricane) oil asset	26,000	26,000
2022	• To complete necessary operations for developing the Abigail (formerly Hurricane) oil asset	88,135	88,135
2023 onwards	• To complete necessary drilling of a second well in Harrier	77,646	77,646

Forward-looking information - the foregoing estimates concerning the planned operations in the GSA Project, including with regard to costs, time schedules and actual execution are forward-looking information, as defined in the Israel Securities Law, and are based the assessments of Ithaca Group that depend, among other things, on third parties, climate conditions, economic conditions, regulatory changes, technical capacities, availability of equipment and other factors that are not in the Company's control. Consequently, implementation of the work schedule, including timetables and costs, may differ materially from the estimates described above.

Further information concerning the GSA Project

3. Stella/Harrier oil field:

There are two fields in the Stella/Harrier area oil field: The Stella field, discovered by a third party in 1979, covers an area of 22 sq. km and contains oil, natural gas and condensate, and the Harrier field, discovered by a third party in 2002, lies about 10 km south of the Stella field, and contains a reservoir of oil and gas. As at Reporting Date, Ithaca holds all the rights (100%) in the asset and serves as the Operator.

Ithaca first acquired rights to 66.67% of the Stella/Harrier fields in 2008 from third parties, and under the transaction undertook to pay the sellers an overriding royalty of 5% for the rights purchased from them (i.e., 3.33%). Ithaca acquired the remaining rights in the license in 2018.

Prior to the acquisition of the rights, third parties carried out 10 exploratory and appraisal drillings in the license area.

In the Stella field, in 2013-2015, Ithaca completed drilling of five development wells and began production from the field via the FPF-1 in February 2017. Ithaca's total investment in the Stella field development plan amounted to USD 700 million.

Implementation of the Harrier field development plan began in early 2017. The development included one drilling that consisted of two sidetracks into two target layers, which were completed in September 2017. In 2018, installation of a 7.5 km long submarine pipeline was completed, connecting the field to the Floating Production Facility. Initial production from the Harrier field began in July 2018. Ithaca's total investment in the Harrier field development plan amounted to USD 62 million (for 66.67% of the participating interests).

4. Abigail (formerly Hurricane) oil field:

The rights in the Abigail (formerly Hurricane) field (100%), which is located about 10 km west of the Stella and Harrier fields, were granted to Ithaca by the UK authorities in 2009. The existing reservoir in the oil field was discovered by a third party in 1995, and it contains natural gas and condensate. In 2012, Ithaca conducted appraisal drilling in the field, and production verification tests. In 2020 Ithaca submitted a detailed development plan to the Authority that supervises operations in the field, according to which production from this field is planned to begin in 2022. It is noted that the authorities officially changed the name of the field from Hurricane to Abigail.

5. Vorlich oil field:

The Vorlich field, discovered by third parties in 2014, lies in the area of two licenses, the Vorlich (P363) license (“Vorlich-1”) and Vorlich (P1588) license (“Vorlich-2”). Vorlich-1 is divided into two blocks: Block 30/1c Lower and Block 30/1c Upper; in each of which Ithaca has different interests, as set out in the foregoing table ("Vorlich Field").

Ithaca acquired the rights in the Volrich licenses from third parties in 2016. The area in which the Vorlich Field is located is subject to a unitisation agreement uniting Vorlich-1 and Vorlich-2 licenses, which was signed on September 2018 between Ithaca and BP Exploration, which is the operator in the Vorlich licenses. Under the agreement it was agreed that, inter alia, Ithaca's interests and liabilities in the Vorlich licenses will be 34%. For further information regarding this agreement, see section 1.8.4(D)(7)b below.

The Vorlich field contains light oil, and is located about 10 km north of the Stella field. Once the exploration and appraisal plan were completed in 2014, ongoing and focused assessments were made in order to formulate an optimal development plan for the field. In 2018, a detailed plan was submitted for the development of the field, which was approved by the competent authority. The development plan for the field includes the drilling of two production wells in 2019, and connecting the wells to the Floating Production Facility via new submarine infrastructure in 2020. Production from the Vorlich reservoir began on November 8, 2020.

6. Austen oil field:

The existing reservoir in the Austen oil field, located close to the Stella and Harrier fields, was discovered by third parties in 1990, and contains oil, gas and condensate reserves. Since its discovery in 1990 and until 2012, five exploratory and appraisal wells were drilled in the field by third parties. In 2016, Ithaca purchased 75% of the participation rights in the license, and in May 2017 Ithaca acquired the remaining rights from a third party. As a result, Ithaca currently holds all of the rights in the license and serves as its Operator. In 2020, Ithaca plans to conduct engineering tests in preparation for drilling a development well and construction of the submarine facilities, in order to appraise and formulate an optimal development plan for the field. Production begins from the Austen field is expected to begin only after the start of production from the Vorlich and Abigail (formerly Hurricane) fields.

7. Courageous oil asset:

The existing reservoir in the Courageous oil field, was discovered in the past by third parties, and contains oil, natural gas and condensate reserves. In the past, six exploratory and appraisal drillings were carried out in the field by third parties, the last of which was in 2014. Ithaca was granted 55% of the rights in the license, by the UK authorities in 2018. The remaining rights are held by a third party, and Ithaca serves as Operator. In 2021, Ithaca plans to carry out engineering tests in the field to locate the optimal point for drilling two development wells. The field development plan includes submarine connection to the Floating Production Facility, similar to the other GSA project fields.

Production is expected to begin in the Courageous field only after the start of production from the Abigail (formerly Hurricane) field.

8. Kessog license:

The existing reservoir in the Kessog oil field, was discovered in the past by third parties, and contains oil, natural gas and condensate reserves. In the past, five exploratory and appraisal wells were drilled in the field by third parties, the last of which was in 2009. In 2020, the UK authorities granted Ithaca full (100%) of the rights in the license, and Ithaca also serves as the Operator in this field. In 2021, Ithaca plans to carry out engineering tests to locate the optimal point for drilling

Actual share in the expenses and income of the GSA Project

The actual rate of participation in the income and expenses of the Abigail (formerly Hurricane), Austen, Vorlich, Courageous and Kessog oil fields that is attributed to the equity holders of the Company are equivalent to Ithaca's rights in these fields, as specified in the foregoing tables in subsection (2) above (under General Details), as no royalties are paid with regard to these assets to the UK government or third parties, and no other derivative royalties whatsoever are paid from the income and expenses.

The actual rate of participation in the income and expenses of the Stella/Harrier oil field are as set out in the table below:

Participation rate	%	Percentage grossed up to 100%	Explanations
Actual rate attributable to equity holders of the Company in the oil asset	100%	100%	
Actual rate attributable to equity holders of the Company in revenues from the oil asset	96.67%	96.67%	A royalty of 5% for 66.67% of the rights (i.e., net 3.33%) is paid to third parties from which the rights were purchased.
Actual share of expenses for exploration, development, and production in the oil field, attributable to equity holders of the Company	100%	100%	

Description of material agreements between the partners in the GSA Project

9. Subsequent to the acquisition of the additional rights in the GSA Project in December 2018, Ithaca holds all the rights (100%) in the GSA Project licenses, other than in the Vorlich and Courageous fields. In the licenses in which Ithaca has partners, a joint operating agreement was signed, regulating the exploration, development and production operations between the partners in the oil fields (below in this section: the "JOA" or "The Agreement"). The provisions of the JOA deal with, among other things, the following matters: regulating the interests of the various parties in the oil asset; ownership of the asset; supervision, control and risks involved in the exploration, development and production of oil and natural gas in the assets; procedures and methods for submitting and approving of work schedules, budgets and authorizations, and for executing the operations in the fields that the JOA relates to. In addition, the JOAs define, among other things, the duties and powers of the Operator; the joint operating committee, its powers, voting interests and how decisions will be made; exploration, development and production decision making mechanisms, and procedures for determining budgets; exchange and transfer of rights in an oil asset; decommissioning guidelines; obligations; dispute resolution; and accounting procedures.

The relevant operator of each oil asset, that also holds interests in the oil asset, will act both as a holder of rights in the asset and on behalf of all the partners in the oil asset as an operator under the supervision of the joint operating committee. The definition of the operator's role includes: (i) submitting and approval of work plans, budgets, and authorizations for expenditure (AFE) for the executing the operations in the fields that the JOA applies to, subject to the approval of the joint operating committee; (ii) planning, ordering and receiving necessary materials and services; (iii) providing technical, accounting and consulting services required for the joint operation of the asset

A party that fails to pay its pro rata share in the joint expenses on time, including advance payments and interests, will be considered to be a breaching party ("the Breaching Party"). If the breach continues for a period as set in the JOA (usually between 3 and 6 business days from the Breaching

Party's receipt of notice of arrears) the non-breaching parties will pay the Breaching Party's debt (pro rata to their interest), and the Breaching Party will not be entitled to receive its share of the output, and this share will become the property of the non-breaching parties, and they will be entitled, subject to the procedures set out in the JOA, to collect their due from this share up to full payment of the amount in the breach. If the breach continues for longer, as set out in the JOA (usually between 30 and 60 days), the Breaching Party's rights may be forfeited and allocated among each of the non-breaching parties pro rata to their holdings.

10. Furthermore, the Vorlich field is subject to a pre-development and pre-license consolidation agreement (in this section: the "Agreement"), which applies to Ithaca and BP Exploration, the holders of the interests in the license. The Agreement stipulates, among other things, that the rate of Ithaca's rights and liabilities in the Vorlich license will be 34% The provisions of the Agreement, inter alia, deal with the following matters: the duties and powers of the operator in the asset, the withdrawal of the operator and removal as operator; the powers, duties and composition of the joint operating committee, the direction and management of pre-development operations; work plans and budgets for pre-development activities; the rights of the parties to the Agreement and costs of pre-development activities; provisions relating to the engagement in a license consolidation agreement which will take effect after receiving approval of the development plan; sanctions imposed on the parties to the Agreement and the conditions for such imposition; provisions and conditions regarding transfer and reassignment of rights under the Agreement; and provisions regarding the exchange of information between the parties to the Agreement; and provisions regarding the correlation between the provisions of the Agreement and the provisions of other agreements signed by the partners.

<u>GSA Project resources and discounted cash flow data</u>

For further information concerning the resources in the GSA Project and discounted cash flows deriving from them as at December 31, 2020, see section 4 of the NSAI Report. As at the date of approval of the Report, there has been no change to this information. A letter of consent from NSAI to include the foregoing Resources Report in this Report, including by way of reference, and a letter from NSAI concerning the absence of significant changes with respect to the assets in the GSA Area are attached as **Appendix B** to this Report.

<u>Ithaca Group Operated Assets</u>

<u>General</u>

The cluster of assets operated by Ithaca Group consists of four on-production oil assets (Alba, Erskine, Alder and Cook), in which Ithaca Group has varying interests (as set out in the table below) and in which it serves as Operator. Below is a breakdown regarding these reservoirs.

11. <u>The Alba oil asset</u> consists of two areas: (1) Alba Reservoir, covers an area of 45 sq. km, is located under License P.213, contains heavy oil and has 20 production wells; (2) the southern part of Alba Field falls under License P.2373. As at date of approval of the Report, an exploration well has not yet been drilled in License P.2373. There are applicable JOAs for each of these assets.

The crude oil produced from Alba Field (License P.213) is conveyed to the production and treatment rig and from there to a floating storage unit via a 12 inch subsea pipeline, and from there shuttle tankers are used for marine transport of the crude oil. The rig and the floating storage unit are wholly owned by all the partners in the License.

12. <u>The Erskine oil asset</u> consists of an on-production reservoir that covers an area of 27 sq. km., and contains high pressure and high temperature (HPHT) natural gas and condensate. The reservoir lies in the area of two licenses that are held at different rates by Ithaca Group, as set out below. The partners in these licenses signed a Unit Agreement to regulate the joint operations in the licenses. There are 5 production well in Erskine reservoir.

The gas and condensate produced from the reservoir are processed on an unmanned rig owned by the Erskine Field partners. The rig is located over the wells to regulate the pressure and is tied in, via a subsea pipeline, to the Lomond rig that is wholly owned by Chrysaor Limited ("Chrysaor"), which is one of the partners in the reservoir. The gas is then transmitted to the CATS pipeline and the condensate is transmitted via the Forties Pipeline system.

13. <u>The Alder oil asset</u> consists of an on-production reservoir that covers an area of 23 sq. km., and contains high pressure and high temperature (HPHT) natural gas and condensate and lies in the area of License P.119, as set out below. The reservoir has one production well.

The gas and condensate produced from the reservoir is processed on the Britannia rig that is wholly owned by the Britannia Field partners, as set out below. From there the gas is transmitted via the Sage pipeline system and the condensate via the Forties Pipeline to the St. Fergus terminal.

14. The Cook oil asset consists of an on-production reservoir that covers an area of 12 sq. km., and contains high pressure and high temperature (HPHT) natural gas and condensate. The reservoir has one production well.

The gas and oil produced from the reservoir are treated on a floating production, storage and offloading facility (FPSO) that is wholly owned by a third party (The Anasuria Operating Company), as set out below. [please check]. From there the gas is transmitted via the Fulmar pipeline system to the St. Fergus terminal and the crude is transferred to shuttle tankers used for marine transport of the crude, and from there directly to customers

General Details:

General Details	
Name of oil asset:	Four on-production reservoirs, and adjacent exploration licenses, as well as a development license: Alba; Erskine; Alder; Cook Marigold
Location:	The oil and gas assets are located in the middle of the North Sea on the UK Continental Shelf.
Type of oil asset and description of permitted operations according to the type	Exploration, development and production licenses for oil and gas resources issued by the UK government
Original grant date of the oil asset	Alba: P.213 - July 10, 1972 P.2373 - Sept 20, 2018 P.2536 – Dec 1, 2020 P.2525 – Dec 1, 2020 Erskine: P.057 - Nov 25, 1965 P.264 - Nov 24, 1977 Alder: P.119 - Jun 9, 1970 Cook: P.185 - Mar 16, 1972 P.2532 – Dec 1, 2020 P.2534 – Dec 1, 2020 Marigold P.2158 – Dec 1, 2014
Original expiry date of the oil asset:	Alba: P.213 - Mar 15, 2018 P.2373 - Sept 20, 2022 P.2536 – Dec 1, 2025 P.2525 – Dec 1, 2025 Erskine: P.057 - Nov 24, 1971 P.264 - Nov 23, 1981 Alder: P.119 - Jun 8, 1976 Cook: P.185- Mar 15, 1978 P.2532 – Dec 1, 2024 P.2534 – Dec 1, 2026 Marigold P.2158 – Dec ,1, 2014

General Details	
Date of decision regarding extension of the term of the oil asset:	Alba: P.213 - Mar 12, 2018 Erskine: P.057 – Mar 8, 2011 P.264 – Nov 18, 2014 Alder: P.119 – Jun 6, 2016 Cook: P.185 - Mar 15, 2018
Current expiry date of the oil asset	Alba: P.213 - a producing asset and therefore no expiry date was set The license may expire if production is discontinued for 12 consecutive months. P.2373 – Sept 30, 2022 P.2536 – Dec 1, 2025 P.2525 – Dec 1, 2025 Erskine: P.057 - a producing asset and therefore no expiry date was set The license may expire if production is discontinued for 24 consecutive months. P.264 - similar to the P.213 license, see above. Alder: P.119 - similar to the P.213 license, see above. Cook: P.185 - similar to the P.213 license, see above. P.2532 – Dec 1, 2024 P.2534 – Dec 1, 2026 Marigold: P.2158 – Dec 1, 2022
Note whether there are additional options for extending the term of the oil asset; if such option exists - the term of the possible extension should be noted:	Alba: P.2373 - the term of the license can be extended through to Sept 30, 2026.
Note name of Operator:	Ithaca UK serves as Operator in the Cook, Alder and Erskine fields and IOGL serves as Operator in the Alba and Marigold fields.

General Details	
Names of the direct partners in the oil asset and their direct share in the oil asset and, to the best of the Company's knowledge, the names of the controlling owners in the partners	**Alba:** P.213: Ithaca Group - 23.4% Waldorf Production UK Limited[187]- 25.7% NEO Energy (SNS) Limited (“NEO”) [188]- 17% Mitsui E&P UK Limited[189] - 13.3% Spirit Energy Resources Limited[190] - 12.6% EnQuest Heather Limited[191] - 8% P.2373: Ithaca Group - 60% Spirit Energy Resources Limited - 40% **Erskine:** Ithaca Group - 50% Chrysaor[192] - 32% Serica Energy (UK) Limited[193] - 18% **Alder:** Ithaca Group - 73.7% Chrysaor Production (U.K) Limited ("Chrysaor")[194] - 26.3% **Cook:** P.185 & P.2532 Ithaca Group - 61.34% Ping Petroleum (UK) Limited[195] - 19.33% Anasuria Hibiscus (UK) Limited[196] - 19.33% P.2534 Ithaca Energy (UK) Limited - 100% **Marigold** P.2158 – Ithaca Oil and Gas Limited – 100%

187 To the best of the Company's knowledge, a private company mostly held by Norwegian Private Capital.

188 To the best of the Company's knowledge, a wholly-owned private company (100%) of Hitec Vision, which is a private company.

189 To the best of the Company's knowledge, a wholly-owned private company (100%) of Mitsui & Co. Ltd, a public company traded on the Tokyo Stock Exchange.

190 To the best of the Company's knowledge, a wholly-owned private company (100%) of Centrica Plc, a public company traded on the London Stock Exchange, without a controlling core.

191 To the best of the Company’s knowledge, a public company listed on the NASDAQ, the London Stock Exchange and the Stockholm Stock Exchange.

192 To the best of the Company's knowledge, an indirectly wholly-owned private company (100%) of Chrysaor Holdings Limited.

193 Chrysaor Holdings Limited (below in this section - the Buyer) acquired the operations of ConocoPhillips UK Oil and Gas in the gas and oil sector on September 30, 2019. As a result of the transaction, the Buyer became the operator in the relevant assets. Harbour Energy holds 90% of the share capital of the Buyer and provides financial support for carrying out its operations.

194 To the best of the Company's knowledge, a public company traded on the New York Stock Exchange, *without a controlling core. It is noted that on* April *18, 2019, Chrysaor announced that it is in the process of acquiring ConocoPhillips and replacing it as operator in the relevant assets. As at Reporting Date, this acquisition transaction is yet to be closed.*

195 To the best of the Company's knowledge, a wholly-owned private company (100%) of Ping Petroleum Limited, which is a private company.

196 To the best of the Company's knowledge, a wholly-owned private company (100%) of Hibiscus Petroleum Bhd, a public company listed on the Malaysia Stock Exchange, without a controlling core.

General information about the Company's share in the oil assets	
Acquisition Date:	All of these assets, excluding Cook Field, were acquired under the Chevron Transaction that was signed on May 29, 2019, and which became effective on January 1, 2019. Ithaca's interests in Cook Field were acquired between 2011 and 2014. Ithaca's interests in Marigold Field were acquired in March 2020 from Total E&P. Ithaca's interests in P.2536, P.2525, P.2532 and P.2534 were acquired under UK Government Tender 32.
Description of the Company's holding in the oil asset	Through the Company's holdings (indirect) in Ithaca shares.
Effective share of oil asset revenues attributable to equity holders of the Company (subject to closing of the transaction):	Alba: P.213- 23.4% P.2373 - 60% P.2536- 50% P.2525- 25% Erskine - 50% Alder - 73.7% Cook - P.185, P.2532 - 61.34% P.2534- 100% Marigold P.2158- 100%
Total share of equity holders of the Company in the cumulative investment in the oil asset in the five years preceding the last day of 2020 (whether recognized as an expense or as an asset in the financial statements):	Alba reservoir – USD 29 million Erskine reservoir – USD 38 million Alder reservoir – USD 12 million Cook reservoir – USD 20 million Cook reservoir – USD 3 million

Past operations and additional information:

15. Alba Reservoir was discovered in 1984 by IOGL, and development of the reservoir began in 1991. Production in the License P.213 area began in 1994.

In 1993, the permanent production and treatment facility, Alba Northern Platform, was established in the P.213 license area and is owned by all the partners in the license.

As set out above, licenses P.2373, P.2536 and P.2525 are exploration licenses adjacent to License P.213.

16. Erskine Reservoir was discovered in 1981 by a third party. Development of the reservoir began in 1995, and production began in 1997. In 2000 IOCL acquired the rights in Licenses P.264 and P.057, and IOGL became the Operator.

In 1996 a permanent production and treatment platform was established in Erskine Reservoir, which is wholly owned by all the partners in the license

17. Alder Reservoir was discovered in 1975 by a third party. Development of the reservoir began in 2014, and production began in 2016. In 2000 IOCL acquired the rights in License P.119, and became the Operator of the asset.

It should be noted that Alder Reservoir was developed by drilling of a subsea well that is tied-in via a pipeline to the Britannia Field platform.

18. The Cook field was discovered in 1983 by a third party. Development of the reservoir began in 1998, and production began in 2000. Ithaca Group acquired additional participation rights in the reservoir at a rate of 61.5% from 2011 through 2014. In 2017 Ithaca UK was appointed the Operator of the oil asset. Licenses P.2532 and P.2534 are exploration licenses that were granted in December 2020, and are located adjacent to the License P.185.

19. The Marigold reservoir is located in Block 15/18B and was discovered by a third party in July 2015. Appraisal wells were drilled in March 2018 by a third party. The field contains oil, gas and findings that indicate the existence of gas in the Palaeocene Balmoral sands. Ithaca acquired the interests in

the oil asset in March 2020 from Total E&P UK Ltd. Part of the consideration was paid on closing of the acquisition in March 2020 and the second part will be paid with the approval of the development plan for the field and once a certain minimum production of reserves is attained.

Compliance with Work Schedules:

To the best of the Company's knowledge, as at date of approval of the Report, the binding work schedules for these assets have been fully implemented.

Actual and planned work schedule:

Breakdown of the main operations carried out in the oil and natural gas fields prior to the holding:

Period	Summary of actual operations carried out in the period and the planned work schedule [Note:	Estimated total budget for operations according to oil asset (USD millions)	Actual participation of the Company's equity holders in the budget (USD million)
2018	• Alba Reservoir - drilling of supplementary wells • Eskine Reservoir - repair work was carried out on the pipeline that ties the platform in the reservoir in to the CATS, due to a blockage. • Cook Reservoir - preparations for drilling in the Cook reservoir	96 5,500	- 3,400
2019	• Alba Reservoir - capex and additional expenses for operations regarding the completion of the drilling campaign that began in 2018. • Cook Reservoir - water injection drilling for the purpose of increasing the pressure in the reservoir and escalating production. • Cook Reservoir - laying of a submarine pipeline and tying in to the water injection well.	135,000	56,000
2020	• Alba Reservoir - beginning driller that was stopped due to the Covid-19 pandemic	22,000	7,000
2021	• Alba Reservoir - review the possibility for drilling supplementary wells •	13,000	3,000
2022	• Alba Reservoir - drilling of supplementary wells	81,000	19,000
2023 onwards:	• Alba Reservoir - drilling of supplementary wells	218,000	51,000

Forward-looking information - the information concerning the planned operations in the oil and gas fields, including with regard to costs, time schedules and actual execution, is forward-looking information, as defined in the Israel Securities Law, and are based the assessments of Ithaca Group that depend, among other things, on third parties, climate conditions, economic conditions, regulatory changes, technical capacities, availability of equipment and other factors that are not in the Company's control. Consequently, implementation of the work schedule, including timetables and costs, may differ materially from the estimates described above.

Actual participation rates in the income and expenses in the Ithaca Group Operated Assets:

The actual rate of rights and participation attributed to the equity holders of the Company are equivalent to Ithaca's rights in these assets, as specified in the foregoing tables (under General Details), as no royalties are paid with regard to these assets to the UK government or third parties, and no other derivative royalties whatsoever are paid from the income and expenses.

Description of substantial agreements between the partners in the assets operated by Ithaca Group:

Exploration, development and production in the assets operated by Ithaca Group are carried out under a joint operating agreement (JOA) signed between the partners with respect to each asset. With regard to the Erskine asset, the operations are also carried out under the unit agreement (UUOA), which also includes the criteria set under the JOA. For further information concerning the issues and material provisions included in the Unit Agreements and JOAs, see section 1.8.4(C)(7)a above.

It is noted that the Operating Agreement in the Alder field and the Unit Agreement in the Erskine field includes the right of transfer of a partner in the license, subject to the first refusal transfer rights of the other partners (other than when transferring to an affiliate of the transferring partner), which gives them priority to purchase the rights before they are offered to a third party.

Each of the JOAs and the Unit Agreement in the assets operated by Ithaca Group provide a different majority for decisions of the partners. Contrary to the Eskine and Alba assets, and considering the fact that IOGL holds rights of 73.7% in the Alder JOA, based on a mechanism in the JOA, the majority of decisions in the Alder asset will be made by IOGL.

Reserves and Contingent Resources and Discounted Cash Flows in Ithaca Group Operated Assets

For further information concerning reserves and contingent resources in the Ithaca Group Operated Assets and discounted cash flows deriving from them as at December 31, 2020, see section 5 of the NSAI Report. As at the date of approval of the Report, there has been no change to this information. A letter of consent from NSAI to include the foregoing Resources Report in this Report, including by way of reference, and a letter from NSAI concerning the absence of significant changes with respect to the Ithaca Group Operated assets are also attached as Appendix B to this Report.

The Non-Operated Assets

General:

This cluster of assets consists of eight on-production oil assets and an exploration license, in which Ithaca is a partner but does not serve as Operator. For information concerning the rights of Ithaca and the operators in these assets, see the following table. Below is a breakdown regarding the reservoirs in these assets:

20. The Britannia oil asset consists of a reservoir that covers an area of 250 sq. km and contains natural gas and condensate. The oil asset includes four licenses that are held at various rates by Ithaca Group, as set out below. The partners in these licenses signed a Unit Agreement regulating the operations in the licenses. There are 35 production wells in the Britannia reservoir.

    As at date of approval of the Report, part of the gas produced from Britannia reservoir is sold under several long-term binding gas sales agreements, and the rest of the natural gas and the condensate are sold on the free market.

    It is noted that the three reservoirs, Brodgar, Callanish, and Enochdhu that are noted below were developed as satellite reservoirs of the Britannia reservoir and were tied in to its facilities so that the gas and condensate is processed on the Britannia platform that is wholly owned by the Britannia reservoir partners and the gas and condensate are transmitted separately to the St. Fergus terminal. The gas is transmitted via the Sage pipeline system and the condensate via the Forties Pipeline.

21. The Brodgar oil asset consists of a reservoir that covers an area of 65 sq. km and contains natural gas and condensate, and includes one license (P.118) as set out below. The partners in License P.118 have signed a unitisation agreement with the partners in License P.741 which overlaps into the area of Brodgar reservoir and is not owned by the partners in License P.118, in order to regulate the joint operations in the reservoir. The Brodgar reservoir (P.118) has three production wells, and as at Reporting Date, another production well is under construction.

22. The Callanish oil asset consists of a reservoir that covers an area of 19 sq. km and contains oil. The oil asset includes two licenses that are held at various rates by Ithaca Group, as set out below. The partners in these licenses signed a Unit Agreement regulating the operations in the licenses. There are four production wells in the Callanish reservoir.

23. The Enochdhu oil asset consists of a reservoir that covers an area of 6.25 sq. km and contains oil, and includes one license as set out below. The reservoir has one production well.

24. The Jade oil asset consists of a reservoir that covers an area of 7 sq. km and contains natural gas and condensate. The oil asset includes two licenses that are equally held by the partners in the licenses, as set out below, and consequently, no unitisation agreement was signed regarding these

licenses. The joint operating agreements for each separate license are all relevant for this field. There are 9 production wells in the reservoir.

The natural gas produced from the Jade reservoir is processed on a production and treatment platform (Judy) that is owned by ConocoPhillips, Eni and Chrysoar, and from there is transmitted to the CATS pipeline. The processed condensate is transmitted to the Norpipe pipeline and terminal.

25. The Elgin-Franklin oil asset consists of the Elgin-Franklin reservoir that covers an area of 180 sq. km and contains natural gas and condensate. The oil asset includes four licenses that are held at various rates by Ithaca Group, as set out below. The partners in these licenses signed a Unit Agreement to regulate the joint operations and development in the licenses. The Elgin-Franklin reservoir has 14 production wells.

The natural gas and condensate from the Elgin-Franklin reservoir is processed on the reservoir's production and treatment platform and from there the gas is transmitted via a dedicated pipeline system (Shearwater Elgin Area Line) to the onshore reception facility located at Bacton. The condensate is transmitted via the Forties Pipeline.

26. The Pierce oil asset consists of a reservoir that covers an area of 40 sq. km and contains natural gas and condensate. The oil asset includes one license as set out below. There are 8 production wells in the reservoir.

The processed crude is transferred to shuttle tankers used for marine transport of the crude and from there directly to customers, and the gas produced from the reservoir is consumed for production.

27. The Isabella oil asset consists of a reservoir that covers an area of 72 sq. km. In October 2019, exploratory drilling was carried out in the oil asset area[197]. On March 16, 2020 Total E&P North Sea UK Ltd., the operator for the oil field, announced that while drilling, signs of oil were discovered in the well target layers, however the high pressure and temperature conditions do not allow production appraisals to be performed using the existing equipment. According to the information given to Ithaca, the operator intends exploring a few options for conducting production appraisals in the oil field at a later d[198].

General Details:

General Details	
Name of oil asset:	Group of nine on-production assets: Britannia, Brodgar, Callanish, Enochdhu, Jade, Elgin-Franklin, Pierce, Isabella
Location:	The oil assets are located in the middle of the North Sea on the UK Continental Shelf.
Type of oil asset and description of permitted operations according to the type	Exploration, development and production licenses for oil and gas resources issued by the UK government
Original grant date of the oil asset	Britannia: P.103 - Jun , 9 1970 P.119 - Jun 9, 1970 P.213 - Mar16, 1972 P.345 - Dec 17, 1980 Brodgar: P.118 - Jun 9, 1970 Callanish: P.347 - Dec 17, 1980 P.590 - Jun 4, 1987

[197] For further information concerning the exploratory drilling, see the immediate report issued by the Company on October 2, 2019 (Ref. No: 2019-01-084900).

[198] For further information see the immediate report issued by the Company on March 18, 2020 (Ref. No: 22020-01-026124)

General Details	
	Enochdhu: P.103 - Jun 9, 1970 Jade: P.1589 - Mar 1, 2002 P.672 - Jul 20, 1989 Elgin-Franklin: P.188 - Mar 16, 1972 P.362 - Apr 9, 1981 P.666 - Jul 15, 1989 Pierce: P.111 - Jun 9, 1970 Isabella: P.1820 – Jan 10, 2011
Original expiry date of the oil asset:	Britannia: P.103 - Jun 8, 1976 P.119 - Jun 8, 1976 P.213 - Mar 15, 1978 P.345 - Dec 16, 1986 Brodgar: P.118 - Jun 8, 1976 Callanish: P.347 - Dec 16, 1986 P.590 - Jun 3, 1993 Enochdhu: P.103 - Jun 8, 1976 Elgin-Franklin: P.188 - Mar 15, 1978 P.362 - Dec 16, 1986 P.666 - Jun 19, 1995 Jade: P.1589 - Nov 11, 2014 P.672 - Jul 19, 1995 Pierce: P.111 - Jun 8, 1976 Isabella: P.1820 – Jan 10, 2020
Date of decision regarding extension of the term of the oil asset:	Britannia: P.103 – Jun 6, 2016 P.119 – Jun 6, 2016 P.213 - Mar 12, 2016 P.345 - Nov 14, 2016 Brodgar: P.118 – Jun 6, 2016 Callanish: P.347 - Nov 14, 2016 P.590 - June 1993 Enochdhu: P.103 – Jun 6, 2016 Jade: P.1589 - February 2017 P. 672 - July 2007 Elgin-Franklin: P.188 - Mar 12, 2018 P.362 - Oct 24, 2016 Pierce: P.111 – Jun 8, 2016

General Details	
Current expiry date of the oil asset	Britannia An on-production oil asset and no expiry date was set. The licenses may expire should production be discontinued for 12 consecutive months. Brodgar (P.118): An on-production oil asset and no expiry date was set. The license may expire if production is discontinued for 12 consecutive months. Callanish: P.347 - an on-production oil asset and no expiry date was set. The license may expire if production is discontinued for 12 consecutive months. P.590 - Jun 2, 2023 Enochdhu (P.103): An on-production oil asset and no expiry date was set. The license may expire if production is discontinued for 24 consecutive months. Jade: P.1589 - Feb 11, 2035 P.672 - Jul 17, 2025 Elgin - Franklin P.362 & P.188 - an on-production oil asset and no expiry date was set. The licenses may expire should production be discontinued for 12 consecutive months. P.666 - Jul 19, 2025 Pierce: P.111 - an on-production oil asset and no expiry date was set. The license may expire if production is discontinued for 12 consecutive months. Isabella: P.1820 - July 18, 2022
Note whether there are additional options for extending the term of the oil asset; if such option exists - the term of the possible extension should be noted:	-
Note name of Operator:	• Chrysaor and its affiliates serve as Operator in the following assets: • Chrysaor (UK) Britannia Limited is the Operator in the Britannia asset; • Chrysaor Production (UK) Limited is the Operator in the Brodgar asset; • Chrysaor Production (UK) Limited is the Operator in the Callanish asset; • Chrysaor Production (UK) Limited is the Operator in the Enochdhu asset; • Chrysaor Petroleum (UK) Limited is the Operator in the Jade asset; • Total is the Operator in the Elgin-Franklin and Isabella assets; • Enterprise is the Operator in the Pierce asset;

General Details	
Names of the direct partners in the oil asset and their direct share in the oil asset and, to the best of the Company's knowledge, the names of the controlling owners in the partners	**Britannia:** Chrysaor - 58.65% Ithaca Group - 32.38% Mitsui E&P UK- 8.97% **Brodgar:** Prior to production of 10 MMboe from supplementary well H4: Chrysaor - 93.75% Ithaca Group - 6.25% Since beginning of production from supplementary well H4 and until production of 10 MMboe from supplementary well H4[199]: Chrysaor - 87.5% Ithaca Group - 12.5% Subsequent to production of 10 MMboe from supplementary well H4: Chrysaor - 93.75% Ithaca Group - 6.25% **Callanish:** Chrysaor - 83.5% Ithaca Group - 16.5% **Enochdhu:** Chrysaor - 50% Ithaca Group - 50% **Jade:** Chrysaor - 67.5% Ithaca Group - 19.93% Eni S.p.A ("ENI")[200] - 7% Siccar Point Energy E&P Limited [201] - 5.57% Elgin-Franklin: TOTAL[202] - 46.173% Eni Elgin/Franklin Limited[203] - 21.867% Chrysaor - 14.11% Premier Oil UK Limited[204] - 5.2% Exxon Mobil Corporation[205] - 4.375% Ithaca Group - 3.9% Dyas UK Limited[206] - 2.1875% Summit Exploration and Production Limited[207] 2.1875% **Pierce** Enterprise[208] 92.52% Ithaca Group - 7.48% **Isabella:** Ithaca Group -10% Neptune E&P UK Limited[209] - 50% Total[210] - 30% EurOil Exploration Ltd.[211] 10%

199 It should be noted that the change in the rate of rights is also contingent on the fact that the Ithaca group will give full authorization for expenditure (AFE) with respect to the supplementary well. As at Reporting Date, production has not yet commenced from supplementary well H4.

200 ENI is a public company listed on the New York Stock Exchange and the Italian Stock Exchange. The Italian government is the primary controlling shareholder through the government company, National Promotional Institution.

General information about the Company's share in the oil assets	
Acquisition Date:	The interests in the Pierce asset were acquired by Ithaca Group in 2014. The interests in the Isabella asset were acquired by Ithaca Group in 2013. The rest of these assets were acquired under the Chevron Transaction that was signed on May 29, 2019, and which is effective as of January 1, 2019.
Description of the Company's holding in the oil asset	Through the Company's holdings (indirect) in Ithaca shares.
Effective share of oil asset revenues attributable to equity holders of the Company:	Britannia - 32.3% Brodgar - Prior to production of 10 MMboe from supplementary well H4, as aforesaid: 6.25% Since beginning of production from supplementary well H4 and until production of 10 MMboe, as aforesaid: 12.5% Subsequent to production of 10 MMboe from supplementary well H4, as aforesaid: 6.25% Callanish - 16.5% Enochdhu - 50% Jade - 19.93% Elgin - Franklin - 3.9% Pierce - 7.48% Don Southwest and Conrie - 40% Isabella – 10%
Total share attributed to the equity holders of the Company in the cumulative investment in the oil assets in 2020 (whether recognized as an expense or as an asset in the financial statements):	Enochdhu - USD 0 million Jade - USD 1 million Elgin-Franklin - USD 7 million Pierce - USD 18 million Don Southwest, Ythan, Conrie and West Don - USD 16 million Broom - USD 0 million Isabella - USD 0 million

a. <u>Pre-holding operations and additional information with regard to the Non-Operated Assets</u>

28. <u>Britannia Reservoir</u> was discovered in 1975 by a third party. Development of the reservoir began in 1994, and production from the reservoir began in 1998. IOGL acquired its interests in Licenses P.213, P.119, P.103 and P.345 in 1984.

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[201] To the best of the Company's knowledge, a wholly-owned private company (100%) of Siccar Point Energy Limited.

[202] To the best of the Company's knowledge, wholly-owned private company (100%) (indirect) of Total S.A., a public company listed on the NASDAQ and on the European Euronext Stock Exchange, without a controlling core.

[203] To the best of the Company's knowledge, a wholly-owned private company (100%) (indirect) of ENI, a public company listed on the New York Stock Exchange and on the Italian Stock Exchange. The Italian government is the primary controlling shareholder through the government company, National Promotional Institution.

[204] To the best of the Company's knowledge, a wholly-owned private company (100%) of Premier Oil Plc, a public company listed on the London Stock Exchange.

[205] To the best of the Company's knowledge, a public company traded on the New York Stock Exchange, without a controlling core.

[206] To the best of the Company's knowledge, a wholly-owned private company (100%) of SHV Holdings N.V.

[207] To the best of the Company's knowledge, a wholly-owned private company (100%) of Sumitomo Corporation, a public company traded on the Tokyo Stock Exchange, without a controlling core.

[208] To the best of the Company's knowledge, a private company controlled by the global Shell Group.

[209] To the best of the Company's knowledge, a private company that is part of the Neptune group, whose key shareholders are China Investment Corporation, Carlyle Group and CVC Capital Partners;

[210] To the best of the Company's knowledge, wholly-owned private company (100%) (indirect) of Total S.A., a public company listed on the NASDAQ and on the European Euronext Stock Exchange, without a controlling core.

[211] To the best of the Company's knowledge, a private company belonging to the Edison Group, controlled by Electricité de France Group ("EDF France").

In 1997 a production and treatment platform was established, which is wholly owned by all the partners in the reservoir.

29. Brodgar Reservoir was discovered in 1985. Development of the reservoir began in 2004, and production from the reservoir began in 2008. IOGL acquired its interests in License P.118 in 1984.

In 2006, a production and treatment platform, owned by the partners in the asset, was set up in the reservoir, which is tied in to the Britannia reservoir via a bridge.

Callandish Reservoir was discovered in 1999. Development of the reservoir began in 2004, and production from the reservoir began in 2008. IOGL acquired its interests in Licenses P.347 and P.590 in 1984.

In 2006, a production and treatment platform, owned by the partners in the asset, was set up in the reservoir, which is tied in to the Britannia reservoir via a bridge.

30. Enochdhu Reservoir was discovered in 2005. Development of the reservoir began in 2013, and production from the reservoir began in 2015. IOGL acquired its interests in License P.103 in 1984.

In 2006, a production and treatment platform, owned by the partners in the asset, was set up in the reservoir, which is tied in to the Britannia reservoir via a bridge.

31. Jade Reservoir was discovered in 1996. In 2000 IOGL acquired the rights in the asset and began development of the reservoir, and in 2001, a production and treatment platform owned by the partners in the asset was set up. In 2002 production from the reservoir began.

32. Elgin-Franklin Reservoir consists of two reservoirs that were united under a JOA dated February 1997. The Franklin reservoir and the Elgin reservoir were discovered by Eni Elgin/Franklin Limited in 1986 and 1991, respectively. Development of the reservoir began in 1999, and production from the reservoir began in 2001. In 2000, IOGL acquired the rights in the Elgin-Franklin Reservoir.

This reservoir has 5 production and treatment platforms, 3 of which are tied into one another via a bridge that was constructed in 1999-2000, and 2 are unmanned platforms that were installed in 2007 and 2014. All the platforms are owned by the partners in the asset.

33. Pierce Reservoir was discovered in 1975 by a third party, and production from the reservoir began in 1999. In 2014 Ithaca acquired participation rights of 7.5% in the asset. Production in the field is carried out by using a leased floating facility for production, storage and transport.

Compliance with Work Schedules:

To the best of the Company's knowledge, at Reporting Date, the binding work schedules for the foregoing assets have been fully implemented.

Actual and planned work schedule:

Breakdown of the main operations carried out in the oil and natural gas fields prior to the holding:

Period	**Summary of actual operations carried out in the period and the planned work schedule**	**Estimated total budget for operations according to oil asset (USD millions)**	**Actual participation of the Company's equity holders in the budget (USD million)**
2018	• Brodgar: Drilling of supplementary well • Elgin-Franklin: Drilling of another supplementary well • Pierce: Beginning of pressure reduction in the Pierce field, and ongoing operating and maintenance costs, including expenses of the rig. • West Don: Submarine maintenance work in the West Don field	170[212] 73 8.7	- 5.4 3.5
2019	• Bodgar: Drilling of supplementary well • Britannia: Work was carried out on the Britannia Platform for improving compression.	390	

[212] It is noted that this refers to the total budget for the operations described above that was invested in 2018.

Period	Summary of actual operations carried out in the period and the planned work schedule	Estimated total budget for operations according to oil asset (USD millions)	Actual participation of the Company's equity holders in the budget (USD million)
	• Elgin-Franklin: Further drilling of the supplementary well		41
2020	• Callandish: Drilling of well • Elgin-Franklin: Drilling of well • Pierce: Drilling of two supplementary wells and continuing the project for lowering pressure in the reservoir	380	122
2021	• Pierce: Continuing the project for lowering the pressure in the reservoir • Jade: Drilling of supplementary well • Elgin-Franklin: Drilling of supplementary well	319-כ	33-כ
2022	• Jade: Drilling of supplementary well	40-כ	8-כ
2023 onwards:	• Elgin-Franklin: Drilling of supplementary well	26-כ	1-כ

<u>Actual participation in the expenses and income of the other Non-Operated Assets:</u>

The actual rate of rights and participation attributed to the equity holders of the Company are equivalent to Ithaca's rights in all the Non-Operated Assets, as specified in the foregoing tables in subsection (2) above (under General Details), as no royalties are paid with regard to these assets to the UK government or third parties, and no other derivative royalties whatsoever are paid from the income and expenses.

<u>Description of material agreements between the partners in the oil assets:</u>

The exploration, development and production operations in the other Non-Operated Assets described above are carried out under a JOA that was signed by the partners for each asset, and in the Britannia, Callanish, and Eglin-Franklin fields operations are carried out under a unit agreement (UUOA or UJDOA, which are essentially similar). It is noted that the unit agreement also includes the criteria set under the JOA.

For further information concerning the issues and material provisions included in the unit agreements and JOAs, see section 0 above.

In the majority of the JOAs applicable for the assets in this cluster, the right of a partner in the asset to transfer its rights to a third party will be subject to the first refusal rights of the other partners in the asset.

Each of the JOAs and unit agreements in the other Non-Operated Assets provide a different majority for decisions by the partners. In view of the rate of IOGL's rights in the Non-Operated Assets, based on mechanisms in the JOA's and unit agreements, the decisions in these assets will not be made by IOGL alone.

<u>Contingent Reserves and Resources in the Non-Operated Assets</u>

For further information concerning reserves and contingent resources in the Other Non-Operated Assets and discounted cash flows deriving from them as at December 31, 2020, see section 6 of the NSAI Report. As at the date of approval of the Report, there has been no change to this information. A letter of consent from NSAI to include the foregoing Resources Report in this Report, including by way of reference, and a letter from NSAI concerning the absence of significant changes with respect to the other (Non-Operated) assets are also attached as Appendix B to this Report.

<u>Negligible Oil Assets</u>

Ithaca has rights in an additional exploration phase license, Thundercat, that the Company considers to be a negligible oil asset for the Company's operations, its total assets and its business results. Accordingly, below is a brief description of this assets:

General Details

General Details	
Name of oil asset:	Thundercat,
Location:	The oil and gas asset is located in the middle of the North Sea on the UK Continental Shelf.
Type of oil asset and description of permitted operations according to the type	Exploration, development and production license of oil and gas resources issued by the UK government
Original grant date of the oil asset	Thundercat: P.2345 - Sept 30, 2018
Original expiry date of the oil asset	Thundercat: P.2345 - Sept 30, 2023
Decision date for extension of the term of the oil asset	-
Current expiry dates of the oil assets	See above
Note whether there is an additional option of extending the period of the oil asset: if there is such an option, note the period of the possible extension	Thundercat: P.2345 - the term of the license can be further extended until September 30, 2027
Name of Operator	Ithaca UK serves as Operator in the Thundercat license;
Names of the direct partners in the oil asset and their direct share in the oil asset and, to the best of the Company's knowledge, the names of the controlling shareholders in the partners	**Thundercat:** Ithaca Group - 50% Equinor[213] - 50%

34. Actual and planned work schedule

Thundercat - The license was granted to Ithaca by the UK government. Ithaca intends (through its subsidiary) to drop the license before it expires.

1.8.5. Oil Assets in the US Gulf of Mexico

General

1. In January 2018, Delek GOM (below in this section: the “Buyer”) a wholly owned foreign subsidiary of the Company, engaged in an agreement to acquire oil and gas interests with GulfSlope Energy Inc. and Texas South Energy Inc. (in this section below: the “Transferors”), public companies whose shares are listed for trading in the USA (OTC). The oil assets under this agreement are 12 federal leases for exploration, development and production of oil and gas in the Gulf of Mexico, USA, in shallow waters (less than 150 m depth). In the area of these oil assets, the Transferors identified nine prospects for exploration drilling, seven of which are in deep layers and two in shallow layers.

The agreement included acquisition of the interests held by the Buyer of 75% rights in two oil and gas assets located in the Gulf of Mexico area in the United States: Canoe and Tau. Under the foregoing agreement, the Buyer was granted an option to acquire interests in additional prospects, subject to certain conditions as set out in the agreement (below in this section: ("Acquisition Agreement"). Under the Acquisition Agreement, the Buyer undertook to finance 90% of the cost of drilling in each of the two oil assets, in return for receiving 75% of the interests in these assets. The operator in these oil assets is GulfSlope Energy, Inc. (“Gulfslope”), which, on the closing date of the Acquisition Agreement held all (100%) the rights in each of the assets. For a description of the highlights of the purchase agreement, see section 1.8.6(C)(10) of the Company's periodic report for 2018, as published on March 31, 2019 (Ref. No. 2019-01-029344), which includes information presented here by way of reference.

The exploration drilling in the Canoe oil asset was completed in August 2018, and once the Operator did not report a discovery, the Company amortized the total costs of its investment in this asset in its

[213] To the best of the Company's knowledge, a wholly-owned private company (100%) of Equinor ASA, a public company traded on the NASDAQ and the Oslo Stock Exchange, without a controlling core.

financial statements for the third quarter of 2018. As at Reporting Date, the lease agreement for the Canoe oil asset has expired and the Bureau of Safety and Environmental Enforcement ("BSSE") has confirmed that the Canoe oil property has been decommissioned in accordance with the terms of the lease.

An appraisal well was drilled in the TAU oil asset, which began in September 2018 and discontinued in May 2019. According to information received from the Operator, the well encountered problems that caused delays in the time schedules and required significant additional budget. According to the Operator's report at the end of the drilling, the drilling did not penetrate recoverable hydrocarbon bearing layers, but signs of hydrocarbons were found. The Operator did not announce a discovery. At the recommendation of the Operator the wellhead was sealed and abandoned in a way that will allow reentry to the well at a later stage. For further information, see the immediate report issued by the Company on May 13, 2019 (Ref. No. 2019-01-045886). On June 4, 2019, the Operator completed sealing of the well. The Operator intends exploring various possibilities relating to further operations in the future in the area of the well and in testing the deeper layers of the prospect, that have not yet been drilled.

The cost of the well (100%) until it was sealed and abandoned as aforesaid amounted to a total of USD 95 million (100%) (the Company's share is USD 72 million). In November 2019, the insurers approved partial insurance coverage for the event underlying suspension of the drilling at a depth of 15,245 feet (as set out above). In view of the uncertainty created and the ambiguity surrounding the plan for further drilling, which as at the date of approval of the Report, have even increased, the Company's management decided, to include a provision for impairment in the 2019 financial statements with regard to the investment in the Tau asset, in the amount of USD 53 million (NIS 182 million). During 2020, an insurance reimbursement was received of USD 18 million (NIS 65 million).

The Company regards the License to be a negligible oil asset in relation to its operations in the energy sector, and accordingly, below is a brief description of the oil asse.

<u>Information regarding the Tau oil asset</u>

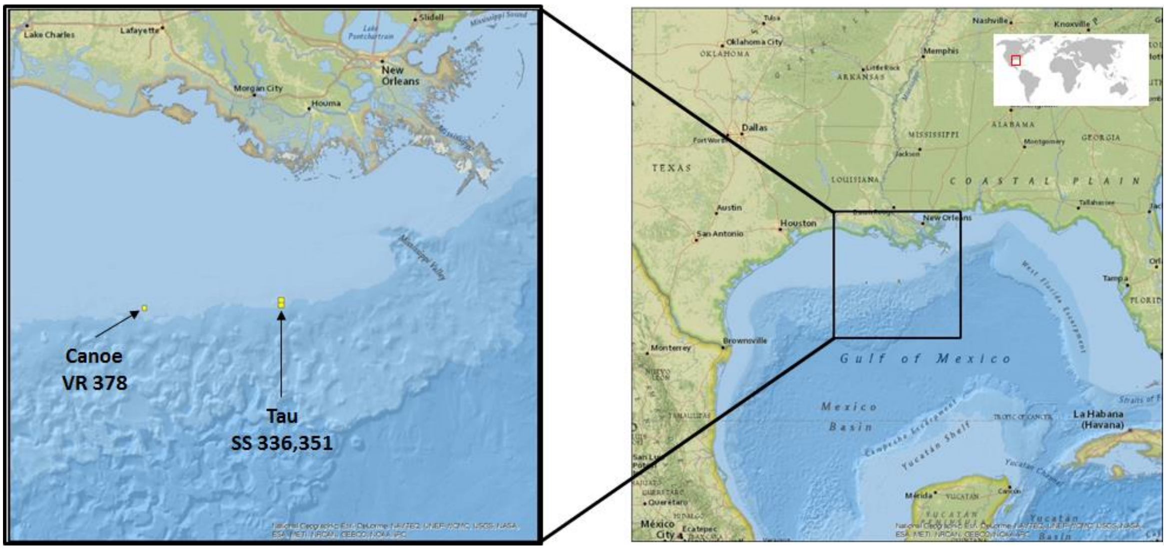
<u>General Details</u>

General information about the oil asset	
Name of oil asset:	Tau
Location:	The Tau Prospect is located within the area of two US federal concessions. The prospect is located in the Gulf of Mexico, offshore Louisiana, about 218 km southwest of New Orleans, USA.
Area	The area of each Concession is 5,000 acres (20.23 sq.km).
Type of oil asset and description of permitted operations according to the type	Federal Lease; Permitted operations - exploration, development and production of oil and gas in a defined area called a lease in accordance with US government regulation.
Original grant date of the oil asset	OCS-G 35244 (Block Ship Shoal 336) - Jul 1, 2014 OCS-G 36121 (Block Ship Shoal 351) - Nov 1, 2017
Original expiry date of the oil asset:	OCS-G 35244 - Jun 30, 2019 OCS-G 36121 - Oct 31, 2022
Date of decision regarding extension of the term of the oil asset:	OCS-G 35244 (Block Ship Shoal 336) – Jul 15, 2019 OCS-G 36121 (Block Ship Shoal 351) – Dec 16, 2019
Current expiry date of the oil asset	OCS-G 35244 (Block Ship Shoal 336) – Jun 30, 2022 OCS-G 36121 (Block Ship Shoal 351) – Oct 31, 2025

General information about the oil asset	
Note whether there is an additional option of extending the period of the oil asset: if there is such an option, note the period of the possible extension	Subject to the approval of a BOEM inspector (in the OCS-G 36121 concession) and subject to the approval of a BSEE inspector (Bureau of Safety and Environmental Enforcement) (in the OCS-G 35244 concession), the licenses can be extended to eight years from the date of the original grant, subject to the drilling of a well deeper than 25,000 feet TVD (true vertical depth) from the surface, in the first five years. It is noted that from the time of discovery, the concession will remain valid as long as oil or gas is produced in commercial quantities, subject to the approval and requirements of the BOEM and relevant regulations.
Note name of Operator:	GulfSlope
Names of the direct partners in the oil asset and their direct share in the oil asset and, to the best of the Company's knowledge, the names of the controlling owners in the partners	Delek GOM Investments, LLC – 75% GulfSlope[214]. - 20% Texas South Energy Inc.[215] - 5%

General information about the Company's share in the oil asset	
Acquisition date of the lease for the acquired oil asset	January 8, 2018, pursuant to the terms and conditions of the acquisition agreement.
Description of the Company's holding in the oil asset	Holding through a wholly owned foreign subsidiary.
Effective share of oil asset revenues attributable to equity holders of the Company:	63.3% (see calculation below).
Total share of equity holders of the Company in the cumulative investment in the oil asset in the five years preceding the last day of the reporting year (whether recognized as an expense or as an asset in the financial statements):	USD 35 million

<u>Map of the Tau oil asset</u>



214 A US public energy company whose main shareholder is Mr. John N. Seitz. As set out below, as at Reporting Date, GOM holds 22% of the share capital of GulfSlope.

215 A US public energy company without a controlling shareholder.

Operations prior to holding of the Tau oil asset

To the best of the Company's knowledge, prior to the date of the Interests Acquisition Agreement, no significant operations were carried out in the oil asset other than the acquisition and processing of seismic information.

Compliance with work schedule:

According to the terms and conditions of the Tau oil asset, there is no detailed work schedule that obligates the asset holders, however, extension of the concession is contingent on the execution of an exploration drilling during the concession period, as set out in the table in section 1.8.6(B)(1) above. As aforesaid, in September 2018, an exploration well was drilled in the Tau oil asset and accordingly, it was decided to extend the concession for an additional term of 3 years, as set out in section 0 above.

Work schedule for the Tau oil asset

Breakdown of the carried out and planned operations in the drilling of the oil asset:

Period	Summary of actual operations in the period or of the planned work plan	Estimated total budget for operations on the level of the oil asset (USD thousands)	Actual participation of the Company's equity holders in the budget (USD thousands)
2018	• Preparations for drilling to obtain regulatory approvals, engineering preparations to carry out the drilling; environmental, geophysical and archaeological risk surveys. • Exploratory drilling, including the release of the drilling rig and plugging and abandonment of the well and related expenses.	738 39,000	664 35,000
2019	• Exploration drilling, including releasing the drilling rig, sealing and abandonment of the well, and related expenses.	33,000	25,000
2020	• Further seismic assessments by the Operator	-	-
2021 onwards	• Further seismic assessments by the Operator	-	-

Forward-looking information: The Company's estimate regarding the planned operations in the Lease, including the costs, schedules, and actual performance, is forward-looking information as defined in the Securities Law, based on assessments regarding the components of the work plan and their costs, which may change from time to time. Implementation of the actual work plan, including schedules and costs, may differ materially from the above estimate and is subject, among other things, to market conditions, regulation, many external circumstances, including technical requirements and capacity, and economic viability.

1.8.6. Exploration license in Block 7, in Canada.

At the end of 2016 the bid filed by the Company jointly with Navitas Petroleum Limited[216] ("Navitas") under a tender for offshore exploration licenses in the area east of Newfoundland in Canada, for an exploration license in the Block 7 area, was accepted (below in this section: "the license")[217]. The Company's share in the License is 70% and Navitas' share is 30%. The Company regards the License to be a negligible oil asset in relation to its operations in the energy sector, and accordingly, below is a brief description of the oil asset.

[216] A subsidiary owned by Navitas Petroleum Limited that is traded in Israel.

[217] For further information regarding the tender, see the immediate report issued by the Company on November 10, 2016 (Ref. No: 2016-01-076017), the information appearing therein is hereby noted by way of reference.

General Details

General information concerning the oil assets	
Name of oil asset:	EL1147
Location:	An offshore asset located 350 km east of Newfoundland eastern Canada, at marine depth of 1,500 meters (estimated drilling depth of 4,750 m)
Area	2,000 sq. km
Type of oil asset and description of permitted operations according to the type	Exploration license allowing its holders to conduct oil and gas exploration, including seismic surveys and exploratory drillings.
Original grant date of the oil asset	January 15, 2017 (Tender date - November 9, 2016)
Original expiry date of the oil asset:	6 years from date granted
Decision date for extension of the term of the oil asset	-
Current expiry date of the oil asset	January 14, 2023
Possibilities for extending the term of the oil asset:	The license was granted for a term of 6 years from the date on which granted. The license may be extended by three years, subject to additional guarantee payments that will be released against drilling in the license. At the end of the period, the license will expire and the license areas will be returned, with the exception of areas in which a discovery is declared, (if any is proclaimed), and a material discovery or development license will be received for it.
Note name of Operator:	Navitas Petroleum Canada Inc. (controlled by Navitas)
Names of the direct partners in the oil asset and their direct share in the oil asset	1099494 B.C Ltd[218] – 70% Navitas Canada - 30%

Actual and planned work schedule

The table below includes a summary of the main operations actually performed in the License area up until Reporting Date and a breakdown of the planned operations in the License[219]:

Period	Summary of actual operations in the period or of the planned work plan	Estimated total budget for operations on the level of the oil asset (USD thousands)	Actual participation of the Company's equity holders in the budget (USD thousands)
2017	Purchase of 2D seismic surveys, processing and decoding	467	330
2018	Purchase of 2D seismic surveys, processing and decoding	233	163
2019	Further processing and decoding of the data obtained from the seismic survey purchased in 2018.	67	47
2020	Review of options for purchasing another seismic survey	43	30

218 A wholly owned subsidiary of the Company, incorporated in Canada, which was established for the purpose of holding the rights in the License.

219 Excluding annual lease fees.

Period	Summary of actual operations in the period or of the planned work plan	Estimated total budget for operations on the level of the oil asset (USD thousands)	Actual participation of the Company's equity holders in the budget (USD thousands)
2021 onwards	At this stage, the project partners will wait for the expected drillings by BP Exploration and its partners in the adjacent blocks, and afterwards they will decide whether to carry out additional operations in the Block, based on the results of these operations	50	35

Forward-looking information: The Company's estimate regarding the planned operations in the licenses, including the costs, schedules, and actual performance, is forward-looking information as defined in the Securities Law, based on the Operator's assessments regarding the components of the work plan and their costs, which may change from time to time. Actual execution of the work schedule, including timetables and costs, may differ materially from the foregoing and is subject, among other things, to market conditions, applicable regulation, numerous external circumstances, technical requirements, technical capacities, and economic viability.

1.8.7. Products and services

As at Reporting Date, the Company's revenues in the foreign energy sector are mainly from its subsidiary Ithaca, whose revenues are from the sale of oil, natural gas, condensate and other supplementary petroleum products.

The key nature of the Company's products are: (1) oil is a liquid material consisting essentially of a hydrocarbon compound and its density ranges from 9 degrees to 55 degrees API, indicating the relative density of liquid oil compared to water, and the color of the oil ranges from yellow to black; (2) natural gas is a compound containing mainly methane, and the difference between wet gas and dry gas is that dry gas does not contain liquid hydrocarbons, and methane accounts for almost all of its composition; (3) condensate is a natural product of the condensation process of various components in natural gas and is caused due to the pressure and temperature differences in the reservoir and those on the surface.

The distinction between heavy oil and medium and light oil is due to the density of crude oil and the typical amount of distillates that determine its classification as light or heavy. Heavy oil has heavier components, a higher density and higher boiling points than light oil, and heavy crude oil is usually needs a thinner added to the pipeline sections to facilitate its flow. Heavy crude oil products include asphalt, lubricants, waxes and fuel oil. Light crude oil produces large quantities of light fuels (distillates) and small amounts of residual. As noted above, Ithaca's oil and natural gas assets generate heavy oil from Captain and Alba fields as well as light and medium oil from the rest of the on-production assets.

For further information concerning the operating segment, including trends and changes occurring in it, see section 01.8.3 above.

1.8.8. Trade receivables

As at date of approval of the Report, Ithaca Group provides oil and natural gas to several large international marketing companies that operate, among others, on the UK Continental Shelf in the North Sea region, and which sell the products to the end consumers. The price of oil varies between the fields and is based on several components, including the density and consistency of the oil produced from each field, and payment is made on the basis of an estimated monthly production volume that Ithaca sends to the companies each month. The agreements for selling natural gas set a price calculation that is based on standard UK market prices, as published from time to time, with a discount on entry fees and additional discounts in some cases.

Most of Ithaca's revenues from the sale of oil and natural gas in 2020-2017 were from two key sales agreements: (1) an agreement for the sale of produced hydrocarbons (the agreement covers the oil supply to the onshore reception terminals (Terminal Grades) in the UK as well as the oil supplied via marine oil tankers (Niche Grades), from the Cook (Anasuria) and Pierce Fields) to Shell International Trading and Shipping Company Limited ("Shell") which in 2018, 2019 and 2020 constituted 70%, 42% and 10% of the total revenues in those years, respectively; and (2) an agreement for the sale of produced hydrocarbons (natural gas) that are supplied to UK NTS for BP Gas Marketing Limited ("BPGM"), which in 2018, 2019 and 2020 constituted 33%, 43% and 17% of the total revenues in these years, respectively.

Under the Chevron Transaction, additional agreements were signed with BP International and BPGM for the sale, purchase and/or marketing of natural gas and crude oil from the Acquired Assets. These agreements were signed for a term of 5 years from date of signature and also cover aspects related to the supply of oil recovered from Ithaca's on-production assets via the Forties Pipeline network and the Forties reception terminal. Furthermore, the agreements cover aspects related to the supply of oil recovered from the Alba and Captain Fields via marine tankers, as well as for the supply of the bulk of the natural gas produced and processed, via onshore natural gas reception terminals in the UK. Furthermore, after the Vorlich Field was set up in November 2020, new sales agreements were signed for the sale of oil with ENI and for the sale of natural gas with Gazprom.

Changes in the agreements with Shell and/or BPGM, or the inability to comply with their commitments towards Ithaca Group could have a material effect on the cash flows of Ithaca Group and of the Company.

Effect of the Covid-19 Coronavirus Crisis:

As set out in section 0 above, the cancellation of OPEC+ agreements and the economic impacts involved in the spreading of the Covid-19 coronavirus has led to further stockpiling of oil inventories and increasing use of floating storage facilities. This trend has raised concerns with regard to storage capacities that are expected to cause substantial stress on market prices and price curve volatility. The issue of storage relates mainly to petroleum products and does not directly affect the supply agreements for natural gas produced from Ithaca's reservoirs.

The sales agreements between Ithaca and its customers do not include commitments to purchase or supply minimum or maximum volumes of the energy products produced from its reservoirs, therefore Ithaca has the discretion to decide the monthly volume it wishes to supply. Furthermore, and as aforesaid, Ithaca's agreements with its customers are based on payment for the estimated volume Ithaca will supply each month and are not based on its customers' utilization of the actual production rate.

Ithaca's key customers, BPGM and Shell, are two of the largest energy companies in the UK market and as at date of approval of the Report, Ithaca's contractual relationship with them is stable and to the best of Ithaca's assessment it has the capacity to continue receiving the volumes of oil and gas produced from its oil assets. Nonetheless, due to the Covid-19 crisis and its consequences, as at date of approval of the Report, there is substantial surplus supply of oil on the markets and the reservoirs which have capacity for storing the surplus oil are running out. Consequently, as at date of approval of the Report, there is much uncertainty and it is not possible to assess the levels of supply and demand for energy products and their prices in the coming months and years, and whether it will be possible to store the surplus volumes in the reservoirs.

For further information in this regard see section 1.8.26(C) in the section on Ithaca's risk factors.

1.8.9. Marketing and distribution

The oil and natural gas produced from the Ithaca Group's on production assets are supplied via a subsea pipeline to onshore reception terminals in the UK, and by supplying directly to the end consumers via shuttle tankers and to floating facilities, and all as described with regard to Ithaca Group assets in section 1.8.4 above.

The subsea pipeline and the shuttle tankers through which Ithaca Group supplies its products, as aforesaid, are owned and operated by third parties. Restrictions on the use of these transport infrastructures, if any, could have an adverse effect of the production rate of oil and natural gas from the Ithaca Group assets.

Effect of the Covid-19 Coronavirus Crisis:

As set out in section 4(A) above, Ithaca has agreements with international marketing companies and not with end customers that consume the hydrocarbon products produced from Ithaca's reservoirs. These agreements are based on payment for the estimated monthly production volumes that Ithaca intends to provide to the companies and payment does not require actual consumption of committed volumes. As a result, Ithaca does not see the global decline in demand for energy products as a material risk to its marketing and distribution networks, that are based on the agreements described in section 1.8.8 above.

1.8.10. Order backlog

As noted in section 0 above, Ithaca's commercial agreements are based on payment for the estimated monthly volumes that Ithaca intends to supply to its customers every month. Therefore, Ithaca does not have significant end order backlogs.

1.8.11. Competition

As a rule, the oil and natural gas industry is highly competitive from all aspects. Ithaca Group competes with numerous players in oil and natural gas exploration and acquisition in the UK North Sea region, as well as in recruiting and retention of professional experienced work force. Ithaca's main competitors are companies with greater financial resources, human resources and facilities than those of Ithaca. Moreover, the oil and gas sector in the US and Canada is even more competitive.

Competition is reflected, among other things, in exploration, production rate and marketing of the oil and gas, and the price obtained. Many companies and private entities with vast experience and proven know-how, large-scale workforce and diverse financial means, operate in the oil and gas sector. Furthermore, competition in the industry in the US and the UK is mainly in the acquisition of concessions from the State or Federal Government or private entities (accordingly). In addition, the competition in the oil and natural gas for industry sector may be significantly affected by the applicable regulation in the energy industry in the regions where the oil and natural gas assets are located. The effect of regulation and regulatory changes can not be foreseen and therefore may affect oil and natural gas exploration, development, production and marketing costs. The oil and natural gas industry also competes against other producers of renewable energy, such as solar energy, water generated energy and wind generated energy. Oil is a global commodity and its price is dictated by world-wide supply and demand fluctuations. Natural gas is considered a commodity in the US (natural gas futures contracts are traded on the New York commodities exchange (NYMEX), the US Future Exchange (USFE) and the Multi Commodity Exchange (MCX), therefore competition with the other oil and/or gas producers is not expected to materially impact the Company's oil and/or gas sales.

<u>Effect of the Covid-19 Coronavirus Crisis:</u>

As set out in section 0 above, against the background of the Covid-19 crisis, the macroeconomic environment in first trimester of 2020 has been unprecedented and challenging. The sharp drop in demand for oil and other energy products and cancellation of the OPEC+ agreements led to substantial surplus in supply that generated accelerated competition and freefall of the prices of energy products and Brent and WTI rates. As at date of approval of the Report, the Company is unable to estimate how the supply and demand for energy product will change in the coming months and years, and how this will impact the energy prices and Ithaca's operations.

1.8.12. Seasonality

Energy consumption in the winter months in the UK, US and Canada has increased, and thus also the demand for fuels used for heating. Moreover, in August every year there is usually an increase in demand for transportation fuels due to the increased civilian use of cars during this period in the US and UK. The effect of this seasonality is usually an increase in energy prices during these months, in general; nonetheless, energy prices are affected by numerous other factors in the global market, as set out in section 1.8.3 above. In addition, climatic conditions also affect demand for natural gas, therefore in the first and fourth quarters of each year, demand rises and as a result, the price of natural gas also rises. It should be noted that the climatic conditions in the UK and in the US, particularly during the winter months, may restrict or stop drilling and production operations for certain periods in the oil and natural gas assets. Furthermore, climate conditions are liable to affect demand for equipment, supply and human resources, thereby generating additional costs and delaying operations.

1.8.13. Production capacity

Based on the work plans that Ithaca drafted at the beginning of 2020, it estimated that the average production rate from the on-production oil and gas assets in which Ithaca Group has interests would amount to 70,000 - 75,000 BOE per day (rate of liquids - 66%). Ithaca estimates that the maximum rate of production in these assets is 80,000 barrels per day.

Due to the outbreak of the Covid-19 coronavirus and economic crisis, the Company estimates that the Covid-190 crisis and its consequences are liable to have an adverse and material effect on the actual production volume from these oil assets (for further information see section 0 above). Based on the work plans that Ithaca drafted at the beginning of 2021, it estimated that the average production rate from the on-production oil and gas assets in which Ithaca Group has interests would amount to 60,000 - 65,000 BOE per day.

1.8.14. Property, plant and equipment

Part of Ithaca Group's assets are grouped into production hubs. The inherent advantage of production hubs is the use of one central infrastructure into which a number of fields close to the hub are tied, thereby minimizing development and production costs. Ithaca Group owned production hubs include the FPF-1 facility that serves the Greater Stella Area, the Captain reservoir facilities that include two permanent rigs and a FPSO facility, the Brittania Field infrastructures that serve the Alder, Brodgar, Callanish and Enochdhu fields. For further information regarding the facilities see section 0 above. With regard to the other fields owned by Ithaca Group, they either operate independently with designated infrastructures or are tied-in to other hubs, and all as set out in section 0 above.

1.8.15. Human resources

As at December 31, 2020, Ithaca and the Group companies employed 435 full time employees. Furthermore, Ithaca and the Group companies receive a range of services from independent subcontractors who provide professional and consultation services on a one-time or ongoing basis.

As at Reporting Date, the Company does not employ a workforce for its operations in its US Gulf of Mexico and Canadian oil assets, and at this stage makes use of various independent consultants, including professional geologists and experts, lawyers, and financial advisors, if such advisors are needed.

1.8.16. Raw materials and suppliers

For each project or field in which the Company has rights in oil and gas assets, directly or indirectly, an operator is appointed for the project. The operator contracts with professional contractors, which have the relevant equipment, for each field or project, accordingly. Any increase or decrease in crude oil prices usually affects the availability of contractors and required equipment, as well as their costs. It should be noted that Ithaca serves as Operator in three of the on-production oil and gas assets, in three development phase fields and one exploration stage field, in which it has rights, and as such Ithaca is responsible for contracting with the service contractors and suppliers of materials and equipment required for carrying out the exploration, development and production operations in these fields. As the Operator in its key assets, Ithaca is able to effectively manage the timing and cost of its various investments in the assets. Such management enables Ithaca the control and flexibility to plan future investment.

1.8.17. Working capital

According to its financial statements as at December 31, 2020, Ithaca has a working capital deficit of USD 119 million, mainly due to changes in the market value of short-term financial derivatives. Breakdown of Ithaca's working capital:

	The amount included in Ithaca's 2020 financial statements USD Millions
Current assets (mainly accounts receivable from transactions and inventory)	244.4
Current liabilities (mainly accounts payable to suppliers)	358.7
Surplus current liabilities over current assets	(114.3)

For further information concerning the financial position of the Ithaca, see Note 1D2 to the Financial Statements.

1.8.18. Financing

Ithaca funds its operations from equity (operating cash flows), credit facilities, debentures and loans.

As set out below, to finance the Chevron Transaction, Ithaca completed refinancing that included, among other things, increasing its reserve based lending facility (“RBL”) in the amount of USD 1,650 million, deferring its repayment date to April 2024 (instead of December 2022) and the repayment of a bank load of USD 300 million. For further information see Notes 10F2 and 18C4 to the Financial Statements attached to this Report.

Furthermore, in July 2019, Ithaca issued unsecured debentures in an amount of USD 500 million.

For further information concerning additional loans provided to Ithaca's parent companies in August and November 2019, including for the purpose of financing the Chevron Transaction, see the fourth part of this Chapter, section 1.14.

RBL Facility

In July 2019 Ithaca finalized an agreement with a consortium of international banks for the provision of an RBL Facility in the amount of USD 1,650 million.

The facility was provided for a term of 5 years. Most of the RBL Facility bears annual interest of Libor + 3% in the first four years and 3.25% in the fifth year. A facility of USD 550 million out of the total amount will serve as an unused facility, half of which was used by Ithaca to provide collateral for obligations regarding the abandonment of oil assets acquired under the Chevron Transaction, and annual fees will be paid with respect to this amount at a rate of 1.5% in the first four years and 1.625% in the fifth year. The other half can only be utilized if certain conditions are fulfilled, based mainly on the expected production rate and forecasted prices of oil and gas.

As at December 31, 2020, the balance of the RBL Facility amounts to USD 720 million. As at the approval date of the Report, the balance of the RBL Facility amounts to USD 570 million.

The RBL Facility is secured by guarantees of some of the Ithaca Group companies. Under the terms of the RBL Facility, insolvency of any of the guarantors will be grounds for calling for immediate repayment of the balance of the debt.

The terms of the RBL Facility provide a number of restrictions that if breached will serve as grounds for immediate repayment, as is customary for such loans, and including:

1. Additional borrowing - the RBL Facility includes a restriction on additional borrowing other than certain types of credit that are classified as permitted under the terms of the Facility;
2. Sale and purchase of assets - Ithaca and the Ithaca Group companies may not sell the assets with regard to their underlying reserves the RBL Facility was granted. Ithaca may also not purchase new assets, other than in circumstances under which such purchase is included in the projected cash flows and according to the projected cash flows the expected amount of sources exceed the expected amount of uses, and without such purchase of assets causing a digression.
3. Liens and guarantees - Ithaca is not permitted to create liens on its assets, provide guarantees or provide loans unless in certain exceptional cases stipulated in the RBL Facility.
4. Restrictions on distribution or payment of dividends, as set out below.

To secure the RBL Facility, Ithaca pledged in favor of the lenders, in first degree liens, the shares of the subsidiaries that directly hold interests in the oil assets, and Ithaca created floating and fixed liens on the assets of the subsidiaries, as is standard practice in this type of transaction.

The terms and conditions of the RBL Facility include restrictions on distribution of dividends if the following conditions are met at time of distribution:

5. All payments that Ithaca undertook under the terms of the RBL Facility were paid in full.
6. Value of collateral provided is sufficient to cover the balance of the debt.
7. Ithaca's cash flows do not indicate lack of financial ability to support its operations.
8. Distribution is permitted under the terms of the Company's debentures.

Under the terms of the RBL Facility, Ithaca undertook maintain the financial and operational covenants, as follows:

9. The total amount of sources should be above the total expected uses for the next 12 months (or for a longer period to start production from the development, if possible). Compliance with this criterion is tested according to the liquidity test every 6 months. In addition, the liquidity test is also performed in the event of the acquisition of a new asset or in the event that Ithaca intends to distribute a dividend;

10. The ratio between the net present value of the secured cash flows under the RBL Facility for the life of the projects and the amount drawn under the RBL Facility will not fall below 1:1.15.

11. The ratio between the net present value of the secured cash flows under the credit facilities for the life of the RBL Facility and the amount drawn under the credit facility will not fall below 1:1.05.

Failure to comply with each of the foregoing criteria constitutes an event of default for which the debt will be called for immediate repayment.

As at December 31, 2020, and at the date of approval of the Report, Ithaca is in compliance with the financial criteria and operating covenants set out above.

Unsecured debentures

12. In July 2019, Ithaca completed an issue of debentures amounting to USD 500 million. Under the terms of the issue, the principal of the debentures will be repaid within five years and the annual interest rate set in the tender is 9.375% (paid every six months). The debentures were issued without any collateral, and Ithaca used the consideration from the issue to finance the Chevron Transaction. The consideration of the issuance was held in trust until completion of the acquisition agreement.

13. Some of Ithaca Group companies serve as guarantee for the Group's liabilities in the debentures. Under the terms of the debentures, insolvency of any of the guarantors will be grounds for calling for immediate repayment of the balance of the debt.

14. The terms of the debentures provide a number of restrictions that if breached will serve as grounds for immediate repayment, as is customary for such loans, and including:

Additional borrowing - Ithaca and Ithaca Group companies may not take additional borrowing other than the types of credit classified as permitted in the terms of the debentures;

Sale and purchase of assets - the ability of Ithaca and the Ithaca Group companies to sell their assets is restricted to a threshold defined in the terms of the debentures.

15. The terms of the debentures do not include current financial or operational covenants other than certain financial limitations and covenants on the distribution or payment of a dividend by Ithaca, according to which Ithaca may distribute a dividend only if the following cumulative conditions are met at the time of the distribution:

There has been no breach of the terms of the debentures;

Ithaca will be able to bear at least USD 1 additional debt without fixed charge coverage ratio falling below 2.25:1, as these figures are reflected in the quarterly statements of the fiscal year prior to assuming the debt, or by maintaining the ratio as was prior to taking the debt.

Compliance with leverage ratio of not more than 1.3.

The total amount of the dividend is equal to or does not exceed 50% of the consolidated net income of Ithaca on the date of issue of the debentures and until the last quarter, and 100% of cash income, in the investments and dividends that Ithaca received.

16. Furthermore, the terms of the debentures stipulate that in the event of an IPO of Ithaca shares, Ithaca's portfolio will have available funds, in addition to the terms that it met, that will allow Ithaca to distribute a dividend to the shareholders.

As at December 31, 2020 and the date of approval of the Report, Ithaca is in compliance with all the restrictions and terms set out in the debentures.

Hedging transactions

Ithaca executed hedging transactions (mainly PUT and SWAP transactions) on oil and gas prices with regard to part of the expected future output in the next three years of its assets purchased in the North Sea. These transactions are in addition to Ithaca's existing hedging transactions.

In the first trimester of 2020, Ithaca exercised some of the hedging transactions and, on the other hand, acquired additional hedging transactions. The total (net) proceeds Ithaca received from the transactions executed in 2020 up to date of approval of the Report amounted to USD 156 million.

Breakdown of open hedges on the prices of oil and gas, as at December 31, 2020 and close to date of approval of the Report:

17. Transactions on Price of Oil

	At December 31, 2020			Close to Report approval date		
	Term of hedge	Quantity (K barrels of oil)	Exercise price per share (USD/barrel)	Term of hedge	Quantity (K barrels of oil)	Exercise price per share (USD/barrel)
Swap	Q1, 2021 - Q4, 2022	7,540	40	Q1, 2021 - Q4, 2022	8,526	43
Put	Q1, 2021 - Q4, 2021	1,928	56	Q1, 2021 - Q4, 2021	5,528	56
Collar	N/A	N/A	N/A	Q3, 2020 - Q4, 2020	460	50-62

18. Hedging the Price of Natural Gas220

	At December 31, 2020			Close to Report approval date		
	Term of hedge	Quantity (ktherms)	Average exercise price (penny per thermal unit)	Term of hedge	Quantity (ktherms)	Average exercise price (penny per thermal unit)
Swap	Q1, 2021 - Q1, 2023	305,250	45	Q1, 2021 - Q1, 2023	305,250	45
Put	Q1, 2021 - Q4, 2022	191,500	44	Q1, 2021 - Q4, 2022	191,500	44

19. The cost for purchasing the open hedging transactions, close to the date of approval of the Report, amounted to USD 46 million, most of which will be repaid over the term of the transactions (deferred premium).

Year	USD Millions
2021	42
2022	4
Total	46

For further information, see Note 10F3 to the Financial Statements included under chapter C of this Report.

220 The volume of gas transactions as at December 31, 2020 and close to approval date of the Report are equivalent to 8,565 MBOE.

1.8.19. Liens

Other than the liens pledged to secure the RBL Facility, as described in section 1.8.18(A) above, Ithaca did not create any additional charges on its assets. For further information concerning the charges provided with regard to loans that Ithaca's parent companies received, see section 1.16 of the Report.

1.8.20. Taxation

Ithaca's oil and gas exploration activities are subject to specific UK tax arrangements, which include, inter alia, corporate income tax, supplementary charge and petroleum revenue tax. As at December 31, 2020, Ithaca had cumulative tax losses in a total amount of USD 1.8 billion. Based on the current commodity prices, the cumulative losses are expected to fend off tax liabilities for the Group in the medium term. As at December 31, 2020, the effective tax rate applicable to oil and gas companies in the UK was 30%, the supplementary charge tax was 10%, and the tax on oil revenues, if applicable, was 0%.

Profits of the US company will be taxed in the United States under federal corporate tax at a rate of 21%. In addition to the federal tax, revenue arising from the projects in Louisiana will be subject to state tax at the rate of 4% - 8%.

The Company's profits in Canada will be subject to corporate tax at a total rate of 30% (15% federal tax rate and 15% tax rate in Newfoundland and Labrador).

1.8.21. Environmental risks and means for their management

Drilling operations and oil and gas production involve various environmental risks, inter alia, as a result of gushing and/or spills and/or leaking of oil and/or natural gas, that may occur due to malfunction of equipment and/or work procedures and/or unexpected incidents. The severity of the risks vary for each incident and therefore the method for handling and treating them also varies. The main provisions of the environmental laws applicable to the Company in the energy sector overseas are set out below:

United Kingdom

Ithaca is subject to the provisions of laws, regulations and permits issued by the competent authorities in the sector of its operations, relating to the protection of the environment. The British law fixed limits and restrictions regarding discharge or emission of substances into the environment and regulates methods for supervising storage and transportation of the substances produced or used in the oil industry. In addition, legislation requires drilling sites and facilities to be abandoned in a manner that the supervisory authorities deem satisfactory. It should be noted that, the environmental assessments of the projects involve increased liability of the companies and their officers and employees. Violation of legislative provisions could lead to suspension or cancellation of the licenses and permits required for Ithaca's operations in the field, as well as imposition of personal liability and company liability for any pollution damages and imposition of fines and sanctions against the Company and its officers. Furthermore, compliance with the legislative provisions involve substantial costs. Environmental legislation and policy is subject to frequent changes, which creates uncertainty as to the nature of future changes that could aggravate existing standards and result in significant additional costs.

1. USA

Oil and gas development in the US is highly regulated, at both the Federal and State levels, for environmental protection (such as emission of particles into the air and the protection of land in which oil and gas production has been carried out). Several Federal and State agencies are responsible for enforcing environmental legislation, and its implementation has high operational and financial costs. This legislation imposes civil and criminal liability on operations that violate its provisions. Certain laws impose restrictions on oil and/or gas drilling and exploration in areas defined as sensitive, as well as various duties to prevent pollution, including methods for sealing and abandoning of wells. In certain cases, the law imposes absolute liability for pollution, and the various agencies responsible for protecting the environment are authorized to impose responsibility for costs involved in preserving the environment (damages, clean-up costs, etc.) on those operating in the sector without the need for proof of guilt or negligence on their part, for example the Federal Compensation and Liability Act - Comprehensive Environmental Response, according to which the landowners and companies operating in a particular area can be held liable for damages caused in the said area and close to it due to their contribution to environmental pollution in the areas in which these bodies operate.

2. Canada

The Canada - Newfoundland Offshore Petroleum Board (below in this subsection: the “Board”) requires an enterprise to conduct a strategic environmental survey to assess all the possible environmental impacts of the project, including finding and analyzing potential risks to the quality of the environment. The Board requires operators to find and analyze potential risks to the quality of the environment. In addition, the operators are required to set out procedures, aimed at minimizing and containing the risks, to train their staff how to recognize and respond to possible scenarios, and to monitor the integrity of their equipment. Operators are required, by law, to conduct drills and training aimed at improving their preparedness for the occurrence of oil spills into the sea. These schedules are routinely inspected. The Board appoints a chief environmental officer whose job is to enforce compliance with the legislatory provisions concerning conservation in the oil and gas sector, as well as environmental protection in the offshore oil and gas industry in the Newfoundland and Labrador Provinces.

1.8.22. Restrictions on and supervision of the Partnerships' operations

Regulatory compliance in the UK

The UK North Sea oil and gas licensing is regulated by the Oil and Gas Authority (OGA).

Exploration and production licenses are issued through tenders conducted periodically. Companies seeking to participate in exploration and production in the UK file application for a license in a license allocation round or acquire rights in existing licenses, subject to OGA approval. Each application is reviewed on the basis of a work program submitted by the license applicant. The license holder also bears annual license costs based on the area and nature of the license. There are three types of licenses:

Offshore production license - awarded for oil and gas fields for the duration of the useful life of the asset (exploration, development and production). Recently, the Petroleum and Gas Authority began issuing a new subtype of offshore license, which allows the license holder considerable flexibility in formulating a work schedule for the license periods.

Onshore production license - equivalent to the offshore production license granted for oil and gas fields for the entire life of the asset (exploration, production and drilling). This license was previously known as Petroleum Exploration and Development Licenses (PEDLs).

Exploration license - usually intended for seismic surveyors which conduct surveys for the purpose of later sale of the fields to oil and gas producers.

Licenses are issued for predefined terms and automatically expire at the end of the term, unless sufficient progress has been made for granting an extension. The Oil and Gas Authority does not usually automatically halt operations once a license has expired. In such cases, the issued license is usually extended for a limited period, as needed, to allow the required work to be completed. In view of the fact that most oil and natural gas exploration, development and production in the North Sea is offshore, the extensive marine engineering know-how developed in the UK focuses on overcoming the difficult climatic conditions and terrain while carrying out these operations.

Regulatory compliance in the US

Oil and gas exploration, development and production of in the US is highly regulated, on the Federal and the State level. Various legislation provisions regulate the exploration, development, production and marketing of oil and/or gas, and among other things, granting of drilling and exploration permits, positioning of wells, drilling methods, sealing, removal of materials used for drilling and abandonment of wells, royalties to be paid to the State and to the Federal Government if they are the owners of the land on which production is carried out), as well as transportation of oil and gas between the states in the US and matters related to environmental protection.

Production, transmission and marketing of oil and natural gas in the US are subject to regulatory supervision, such as by the Federal Energy Regulatory Commission, US Department of, Energy US Department of Interior, US Department of Transportation, and other Federal and State regulatory agencies. US Department of the Interior units that oversee oil and natural gas operations on federal land: the Bureau of Land Management, Bureau of Ocean Energy Management (BOEM), [221] - Bureau

[221] The BOEM is the federal body responsible for management of the development of offshore oil resources in the USA. Its functions include granting of federal offshore licenses, resources assessment, management and supervision of oil and gas exploration and development plans, development of renewable energy, National Environmental Policy Act (NEPA) analysis and environmental surveys.

of Safety Environmental Enforcement (BSEE) and the Office of Natural Resources Revenue[222] (that regulates leasing fees, royalties and other income from federal lands). Companies that produce and market oil and natural gas on state and federal land are required to hold approved drilling permits from the relevant government body prior to beginning drilling.

The Submerged Lands Act

Since 1953, the US Submerged Lands Act (SLA) regulates distribution of the lands located on the continental shelf between the US and the shoreline of the States. According to the SLA, and recent judgments issued by the US Supreme Court, the border of each State extends 4.8 km off the shoreline, other than Texas and Florida, each of which were allocated an area of 16.66 km off the shoreline. According to the OCSLA (as defined below), the lands located outside of the foregoing State lands, are federal lands of the United States. Production of gas or oil from federal lands are supervised by the BOEM and BSEE, and the production of gas and oil from fields located within State lands are supervised by the supervisory agencies in each State.

Outer Continental Shelf Lands Act

The 1953 American Outer Shelf Land Act (OCSLA), as amended in 1978, regulates the granting of concessions for oil and gas exploration in those areas of the continental shelf located outside the territory of the states, i.e., under US ownership (the outer continental shelf). Under this law, the drilling fields are put up for leasing under a tender process. The first stage of the tender examines whether the bids comply with the requirements of the tender and the amount offered in the bids. Each tender stipulates a minimum price for submitting bids based on the size of the field area and the marine depth at which it is located. The second stage of the tender reviews the highest bid against the government's assessments concerning the possible future income that could be attained if the bid is rejected and the concession is sold at a later date. The foregoing is subject to change. The bid that wins a license is required to comply with the terms of the tender and to comply with the federal government's expectations concerning income from accepting the bid. This criterion does not constitute an official minimum limit and there are other parameters based on which the winning bid is decided.

According to the OCSLA, in consideration for the concession, the concession holder will pay the federal government a lump sum (payable immediately after winning the tender), annual leasing fees to be paid over the term of the concession, which are fixed based on the size of the concession area, and royalties to be paid for oil or gas production from the license fields. The annual leasing fees are set according to size and marine depth of the license area, and the OCSLA determines the minimum leasing fee based mainly on these parameters, while the actual leasing fees are set by the BOEM. The minimum rate of royalty is 12.5%, but in 2007 the Mineral Management Services (MMS)[223] set the rate of royalties on production from new federal offshore concessions granted since then at 18.75%.

The OCSLA further determined that a license will be granted for a term of 5-10 years (depending of marine depth)[224], and in certain cases it is possible to extend the term of a license for a further three years if a well has been drilled to the target depth during the initial term.

If gas or oil production has commenced then the license will remain valid all the while that the well produces paying quantities or for as long as new drilling and processing operations are carried out, as approved in the US, or as decided otherwise by the federal regulator (for example, temporary suspension decided by BSEE).

Granting drilling and production permits; transfer of rights

In the United States, exploration and production rights for minerals found on State or Federal land are granted under lease agreements. A lessee of a Federal-owned concession, may transfer its rights

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222 The BSEE is the federal agency in charge of security and environmental supervision of offshore oil and gas operations, including granting permits and conducting inspections of offshore gas and oil operations. Its functions also including development and enforcement of security and environmental regulation, granting offshore exploration, development and production permits, conducting inspections, marine regulation projects, addressing oil leaks and implementing compliance plans.

223 *The* MMS was split in 2011 into two authorities, the Bureau of Ocean Energy Management (BOEM) and the Bureau of Safety and Environmental Enforcement (BSEE).

224 The law provides that licenses in fields at marine depths of up to 400 m will be granted for a term of five years, at marine depths of 400-800 m for a term of five years with option to extend for a further three years, at marine depths of 800-1,600 m for a term of seven years with option to extend for a further three years and at marine depths of more than 1,600 m for a term of ten years.

in the concession area (lease rights or operating rights) subject to approval of the BOEM. On the State level, transfer of rights may be subject to the approval of State agencies.

Oil and gas transportation

Transmission of oil and gas in the US is regulated under two main laws: The Natural Gas Act of 1938, which regulates the transmission of natural gas, and the Interstate Commerce Act of 1887, which regulates the transmission of oil. In general, a basic principle is that access to transmission infrastructure (including storage) should be permitted equally to all players operating in the market. Based on a\directive of the Federal Energy Commission, that is responsible for inter-state transportation of natural gas in the US, operators of natural gas pipelines are required to allow equal open access to the various gas suppliers in the US, and transportation prices and conditions for providing the transportation services are supervised by the Chairman of the Committee. It is not mandatory to allow access to new customers if the gas pipelines do not have available capacity or if there are no facilities for allowing it, however, the gas pipelines must be able to provide available capacity without distinction of service quality, duration of service, types, prices or volume of the transported gas for all existing customers. On the other hand, oil pipelines must provide transportation services to anyone seeking such service, even when the capacity is limited. Therefore, when a new consumer seeks access to a pipeline with limited capacity, existing customers may lose capacity to allow the new customer access to the transportation services. Additional Federal Energy Commission guidelines state that anyone who does not operate an inter-state pipeline may purchase natural gas from a third party or sell natural gas to third parties at unregulated market prices and without being bound by additional Federal Energy Commission rules.

Safety

The partners in the oil asset are subject to the provisions of the Federal Occupational Safety and Health Act, as well as state legislation concerning the protection of workers' health and the safety of the work environment. Under the Safety and Health Act, the Partners must provide their employees, the authorities and the public with information regarding any hazardous substances they produce or use.

Import and Export of Oil and Gas

According to the Natural Gas Act, import or export of natural gas, including liquefied natural gas, require the approval of the Department of Energy.

According to the Energy Policy and Conservation Act of 1975, the export of crude oil from the US was prohibited. Nonetheless, on December 18, 2015, the US enacted a law permitting export of US crude oil without requiring a license. The export of refined petroleum products is permitted in general and does not require any form of approval, other than for export to countries regarding which an embargo or sanctions have been imposed, requiring permit.

Foreign investment and global obligations

Every transaction with or of a foreign individual that could lead to foreign control of a US business is under the supervision of the Committee for Foreign Investments in the US (CFIUS) It is not necessary to notify the CFIUS of transactions, however the CFIUS may initiate audits of transactions, also after they are signed, if application for a permit application is not filed before signing. Furthermore, the Mineral Leasing Act of 1920 prohibits foreign ownership of leasing contracts unless through holdings in a local US company.

Specific legislation applicable in Cyprus

In 1985, the Atlantic Accord was signed between the Government of Canada and the Provincial governments of Newfoundland and Labrador, two of Canada's ten provinces, with regard to regulation of oil and gas assets located in the Newfoundland and Labrador offshore area, including joint management of oil and gas resources and division of revenues from them. The Accord recognizes the equal interests of both governments in resource management ("the Atlantic Accord"). The Atlantic Accord was validated with the enactment of the Atlantic Accord Implementation Act, by both governments concurrently (below in this section: "the Law")[225.]

[225] Canada-Newfoundland and Labrador Atlantic Accord Implementation Newfoundland and Labrador Act, R.S.N.L. 1990, c. C-2/ Canada-Newfoundland and Labrador Atlantic Accord Implementation Act, S.C. 1987, c.3). For further information see http://www.cnlopb.ca/legislation/statutes.php.

The Act deals with three main issues: “The Board"), the process for granting oil concessions and operating rights in oil assets. [226]

The Board was established in 1986 under the Atlantic Accord and is responsible for all decisions concerning the regulation and administration of offshore oil operations. Other than fundamental decisions, all of the Board’s decisions are final. The fundamental decisions include, among other things, calls for bids with regard to granting of rights and the decision of which of the bids will be granted the rights, as aforesaid; setting of the terms to be included in the exploration license; guidelines for the rights holder concerning implementation of the drilling; requirements for beginning, continuing, expanding or suspending production; and rescinding of any of a holder’s rights.

When the Board makes a decision classified as a fundamental decision, the Board is required immediately after the decision to notify, in writing, the Canadian government minister and the Provincial government authority regarding the decision. Within 30 days of receiving such notice, each of the ministers are required to inform the Board whether they ratify or do not ratify the decision. As a rule, a fundamental decision will not become effective unless both of the ministers ratify the decision.[227]

Types of licenses

The Board issues three main types of licenses: exploration license, significant discovery license and production license, as follows:

1. Exploration license - confers the right to explore for and the exclusive right to drill and test for petroleum; exclusive right to develop those portions of the offshore areas in order to produce petroleum; and exclusive right to obtain a production license. An offshore exploration license will be valid for a maximum of 9 years, constituting two consecutive periods - the initial period and the second period. The rights holder is required to drill or start drilling one exploratory well by the end of Period 1 as a condition to continue in Period 2. Failure to comply with this condition will cause the fields to which the license applies to become fields without a valid license, and forfeiture of the deposit for the license. If the holder of the rights complies with the requirements of the license with regard to the initial period, he will be eligible to continue holding the license for the second period. The only requirement with regard to the second period is an advance payment of the leasing fees for two years in accordance with the terms of the license. If at the end of the term of the exploration license no significant discovery license or production license, as defined below, is granted, the rights of the holder of the exploration license in the oil asset will expire.

2. Significant discovery license - if a drilling program results in a significant discovery, the holder of the rights in the license is entitled to a significant discovery license. [228] Upon receipt of an application to pronounce a significant discovery, the Board will first check that there has in fact been such discovery and will indicate in which of the offshore areas it is reasonable to assume that a significant discovery exists. The Board will notify the applicant on its decision, subject to a hearing. Notwithstanding the foregoing, and pursuant to the provisions of the law, the Board may also initiate pronouncing a significant discovery. A significant discovery license confers the same rights as an exploration license. A significant discovery license is effective from application date and remains in force so long as the relevant declaration of significant discovery is in force or until a production license is issued for the relevant fields. Each allocation of a production license will require negotiations regarding the royalty regime or other rewards to the Province. In Canada, it is possible that the Newfoundland and Labrador Provinces will demand capital rights in future offshore oil projects that require development plan approval.

3. Production license - once a commercial discovery is declared,[229] the rights holder is entitled to a production license. A commercial discovery is declared in a similar process as the pronouncement of a significant discovery. A production license confers the following rights: The right to explore for and the exclusive right to drill and test for petroleum; exclusive right to develop those portions of the offshore area in order to produce petroleum; exclusive right to produce petroleum from those portions

[226] According to the definitions in the law, "oil" also includes natural gas.

[227] Nonetheless, it is noted that the law provides circumstances under which also without ratification of both ministers, the decision will be deemed as ratified.

[228] A significant discovery is defined in the law as follows: "a discovery indicated by the first well on a geological feature that demonstrates by flow testing the existence of hydrocarbons in that feature and, having regard to geological and engineering factors, suggests the existence of an accumulation of hydrocarbons that has potential for sustained production".

[229] A commercial discovery is defined in the Act as: "a discovery of petroleum that has been demonstrated to contain petroleum reserves that justify the investment of capital and effort to bring the discovery to production".

of the offshore area; and title to the petroleum so produced. A production license is effective for a term of 25 years or more if the commercial production continues.

Health and Safety

The Board imposes strict health and safety requirements. For example, if the health or safety of an employee is at risk, the Board may take all appropriate measures, including stopping the corporation's activity. The Board appoints a Chief Safety Officer to ensure the safety of employees as well as compliance with health and safety regulations in the workplace.

1.8.23. Material Agreements

For further information concerning the allotment agreement signed by DKL with the BP International Limited financial institution (“BP”), under which BP invested an amount of USD 50 million in DKL, see section 1.14.8 below.

For further information concerning the Chevron Transaction, under which 100% of IOGL’s shares were acquired by a subsidiary of Ithaca, see section 0 above.

1.8.24. Legal proceedings

On May 26, 2015, a class action lawsuit was filed against Ithaca at the High Court of Justice in Alberta, Canada, by an investor who alleges that Ithaca published information that constitutes a false representation, regarding the expected timetable for completion of the installation of the floating production facility(“FPF-1) in the GSA project. According to Ithaca, the claims of the class action lawsuit have no grounds. On March 7, 2019, the petition raising the argument concerning the existence of a secondary market of investors, as defined in the Securities Law of Alberta, and the clarification that this argument establishes cause for class action, was heard. On February 24, 2019, the petition was approved and later, it was certified as a class action. Nonetheless, the court found that the class plaintiff failed to provide prima facie evidence regarding certain parts of the claim, thus the cause for class action was limited to events that occurred between October 7, 2014 and February 25, 2015. In December 2019, Ithaca filed the statements of claim of Ithaca and the CEO, and the parties agreed on a discovery protocol.

Ithaca has insurance cover for this claim and Ithaca believes that the insurance cover is sufficient to cover its liability, if the claim is accepted. At this stage, Ithaca believes, based on the opinion of its legal counsel, that it is not possible to estimate the chances of the claim and the financial exposure arising from the claim, and therefore Ithaca did not include a provision for this claim in the financial statements.

Forward-looking Information - The information set out above with regard to Ithaca's assessment regarding exercising the insurance coverage and the scope thereof constitutes forward-looking information as defined in section 32A of the Securities Law, for which there is no certainty that it will materialize, in whole or in part, in the foregoing manner or in any other manner, and which may materialize in a materially different manner than that described above, and this due to various factors that are not in the Company's control.

1.8.25. Business strategy and goals

For further information regarding the Company's goals and strategy for the overseas energy sector, see section 1.20 of the Report.

Ithaca's strategy is to create long-term value by building a profitable oil and gas company in the North Sea region with focus on the following key activities:

Maximization of cash flow and output from the existing asset base;

Achieving long-term, low-risk growth of the operations, through assessment and development of undeveloped discoveries;

Further growth, increasing existing reserves and diversifying the cash flow base by acquiring new assets for production, development and evaluation through focused acquisitions and participation in licensing cycles;

Making low-cost acquisitions of licenses and discoveries in the GSA project area in order to expand the number of Ithaca's assets in the project area.

It is hereby clarified that, achieving the foregoing goals and strategy is dependent on various external factors that could prevent their achievement, or lead to changes in them.

1.8.26. Risk factors

In addition to the risk factors to which the Group is exposed in the energy sector in Israel, many of which also apply to its energy operations abroad, the Company's operations in the overseas energy sector is also exposed to the following additional risk factors:

(A) Currency risks

Ithaca's operations are subject to exchange rate fluctuations. Ithaca's expenses are primarily incurred in GBP while most of its agreements for the acquisition of assets as well as its oil sales agreements are denominated in USD or Euro. Such fluctuations may affect Ithaca's cash flows. Consequently, Ithaca engaged in agreements to hedge this risk, to minimize the risk of currency rate fluctuations. Nonetheless, there is no certainty that these actions can prevent impairment of Ithaca's cash flows due to the severe volatility of the exchange rates, mainly due to the current economic environment with extreme volatility in financial markets, as set out in section 0 above.

(B) Economic recession

Deterioration of the US economy in particular and the global economy in general may adversely affect the volume of consumption of oil and natural gas, and therefore may cause a decline in oil and gas prices.

(C) The Covid-19 coronavirus crisis and its impact on the demand for and prices of oil and other energy products

The Covid-19 crisis constitutes a significant risk to global demand for oil and other energy products, and this when the cancellation of OPEC+ agreements generated the potential for extreme volatility of global supply. For further information, see also section 0 above. In 2020, the market experienced increased volatility, which has led, among other things, to extreme volatility in prices. The market fluctuates acutely between expected sharp declines in future prices of energy products and expected increases and recovery in prices of future contracts, as oil stockpiles continue to fill up and traders slowly move to floating storage facilities. Concern about storage capacities caused significant pressure on market prices and price volatility.

If the Covid-19 pandemic continues, whether due to the entry of new variants and/or increase of the infection coefficient, and depending on the pace of the campaign to vaccinate the population and the efficacy of the vaccines against new variants, it is liable to have an adverse effect on Ithaca's operations and adversely affect it from various aspects, and including its revenues from the sale of oil and natural gas, cause delays and disruptions in Ithaca's work plans in the various oil assets; impair its ability to raise funds for refinancing or raise the costs of refinancing; impair Ithaca's ability to meet the repayment of its liabilities to banks and debenture holders (interest and principal); lead to default events that could cause lenders grounds for calling for immediate repayment of the Partnership's loans, impair the economic robustness of Ithaca's customers and partners in some of its oil assets, which could have an adverse effect on Ithaca, directly or indirectly.

Ithaca is acting on various levels to mitigate the impact of the crisis on its business operations, however it not at all certain that these actions can prevent the ongoing crisis from adversely affecting aspects of the operations set out above and prevent disruptions in Ithaca's business operations.

(D) The Covid-19 crisis and its possible effect on production operations

Ithaca is acting to minimize the risk involved in spreading of the Covid-19 virus by focusing on maintaining the health of its employees and suppliers, by reducing the risk of contagion.

One of the most serious risks identified by Ithaca in view of the Covid-19 crisis, is the possibility of infection among its employees who work in the various offshore facilities, which could cause a complete halt in production activities. Such contagion is liable to harm the ongoing operations in the GSA project and the Captain area oil assets, which are the most significant of all Ithaca's assets. Ithaca is acting to mitigate this risk, and as part of this effort has reduced the number of employees on its offshore production facilities to the minimum necessary for maintaining production and performing critical maintenance work. Measures have also been taken to ensure that if positive cases are found among the workers on the facilities, Ithaca will be able to isolate such workers that need treatment and isolation and send them back onshore. As at date of approval of the Report, the output efficiency of Ithaca's assets, which is a significant production index, has returned to the pre-Covid-19 level. This index is an indication of the Company's ability to manage the operational risks involved in coping with the Covid-19 pandemic. Nonetheless, there is no certainty that Ithaca's actions as set out above can prevent the outbreak of the virus among the workers on the production facilities or prevent severe disruptions to the production activities due to the Covid-19 crisis.

(E) The UK decision to leave the European Union (Brexit)

Brexit is the decision by the UK to withdraw from the European Union (below in this section: "Brexit" and the "EU", respectively. This decision was made following the outcome of the nationwide referendum in 2016 in which 52% of the voters voted in favor of withdrawing from the EU, against 48% that voted for the UK to remain in the EU. The UK government officially announced the start of the withdrawal process in March 2017; however, this process was prolonged due to the difficulty in moving it forward in the British Parliament, which remained divided for an extended period. After holding a general election, the Parliament approved the government's withdrawal plan and on January 31, 2020, at 11:00 PM, the UK officially withdrew from the EU. Once Brexit came into force on February 1, 2020, a transition period began that ended on December 31, 2020. As of this date, the UK is no longer subject to EU institutions and laws.

Consequently, Ithaca adopted measures to adjust its operations and its agreements to ensure that the effects of Brexit will not adversely impact the flow of the raw materials to its facilities, its ability to employ foreign workers and the sale of its oil and gas. To date, Brexit has not had any material effect on the operational continuity. Notwithstanding the foregoing, there is no certainty that Brexit will not impact Ithaca's operating and business operations, such as recruiting of human resources, trade activities and the flow of the resources and materials required for its facilities.

(F) Competition

The oil and gas sector in the UK, US and Canada is more competitive. Competition is reflected, among other things, in exploration, production rate and marketing of the oil and gas, and the price obtained. Many companies and private entities with vast experience and proven know-how, large-scale workforce and diverse financial means, operate in the oil and gas sector.

(G) Changes in fiscal policies

In the United States, a number of initiatives were proposed in the past which could change the current tax regime applicable to companies in the oil and gas industry, in a manner that would increase the applicable taxes on operations in this industry. Implementation of these initiatives, if applied, in whole or in part, is expected to adversely affect companies operating in this industry in the United States, including the Company. In Canada, it is possible that the Newfoundland and Labrador Provinces will demand capital rights in future offshore oil projects that require development plan approval.[230] Each allocation of a production license will require negotiations regarding the royalty regime or other rewards to the Province. However, to date, there is no initiative to change the fiscal policy of the Canadian government or the Newfoundland and Labrador or the UK, which could have a material impact on the Company's operations in Canada or the UK.

(H) Dependence on weather and sea conditions:

Ithaca's assets and facilities located in the North Sea are subject to damage and hazards due to extreme weather or tidal conditions typical of this region, particularly in the winter months. Moreover, installation and maintenance of submarine facilities in the North Sea could be extremely challenging in winter. The typical extreme weather conditions in the North Sea could cause unexpected delays and additional costs in Ithaca's operations.

(I) Dependence on processing and transportation infrastructures for marketing oil and gas

In the event of a commercial discovery in the United States and Canada, the Company's ability to market oil and gas from its oil assets may depend on the availability, proximity and capacity of oil and gas pipelines and other existing oil and gas collection and processing facilities owned by third parties and not under the Company's control.

(J) Reliance on key personnel

Ithaca's development and future potential are dependent upon the continued services and performance of its executive officers and key personnel. The loss of the services of any of the senior officers or key personnel may have an adverse impact on Ithaca. Generally, there is significant demand for management and employees skilled in the areas of the development, production and acquisition of oil and natural gas reserves. This demand is amplified in the UK North Sea region and it is possible that Ithaca may not be able to attract or retain qualified individuals, or its key personnel, in the future.

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[230] The energy program of the Newfoundland and Labrador Provinces promoted by the previous administration indicated that the Province would demand capital rights of 10%. The current administration has not yet expressed its position on the issue. For further information see http://www.nr.gov.nl.ca/energyplan/EnergyReport.pdf.

(K) Interests in licenses

In order to hold the Company's assets located in the territory of foreign countries, the Company is required to obtain licenses, concessions, permits and regulatory approvals (below in this section: (the "Permits"). In the majority of its licenses Ithaca is a joint interest-holder with other third parties. Permits may be revoked by the relevant regulatory authority in the UK if one of the other interest holders of a certain asset is no longer deemed to be financially credible, when there is no assurance that any of the obligations required to maintain the Permits will be met by third parties that are unrelated to Ithaca. The Company's interests in the foregoing oil and gas assets are limited in time and are subject to regulatory provisions and requirements. The Permits are valid for predefined terms and expire automatically at the end of the term, therefore there is no assurance that such Permits will be renewed for a further term or that new Permits will be granted following expiry. In addition, the areas in which the assets held by Ithaca are located, are subject to or may be subject to agreements with private landowners, and therefore if these agreements are canceled and are found to be invalid, Ithaca may be significantly affected.

(L) Difficulties in obtaining the required funding

Financing for oil exploration, development and production operations involves obtaining substantial funds from financing entities and other third parties. At times of financial crisis or economic slowdown there is a shortage of funding sources, and the financing institutions toughen the conditions for providing the required funds. In such cases, the Company's overseas energy operations may encounter difficulty in obtaining the required financing for these operations at favorable terms, if at all.

(M) Regulation applicable to operations in foreign countries

The Company's operations are in the territory of countries in which its oil and gas assets are located. The Company has rights that are subject to complex and changing regulations on various issues, such as granting of licenses in oil and gas assets for exploration and development, environmental protection and pollution control, safety for offshore and onshore operations, competition and antitrust, money laundering, export-import restrictions, quality of the environment, taxation, liquidation and abandonment of facilities and wells, and the possibility of expropriation or cancellation of contractual rights.[231] Such regulation may be changed from time to time, implementation of new legislation or regulations or the modification of existing legislation or regulations could reduce demand for natural gas and crude oil, increase costs and may have a material adverse impact on the Company's business. In addition, failure of the Company and/or its subsidiaries and/or their employees to comply with these laws and regulations may result in the imposition of severe criminal or civil fines and/or sanctions. Moreover, the Company is exposed to political and economic changes, including frequent changes in energy policies, cancellation or changes in rights in assets, currency restrictions, changes in tax are royalty rates payable to the State, oil and natural gas export rates and other risks that could adversely affect the Company's operations and profitability.

(N) Jurisdiction in a foreign country

In the event of a dispute arising in connection with its operations, the Company may be subject to the exclusive jurisdiction of foreign courts or may not be successful in subjecting foreign persons to the jurisdiction of courts in Canada. Consequently, the Company’s foreign exploration, development and production activities could be substantially affected.

(O) Oil and gas prices:

Global oil and gas prices, which are determined by supply and demand and by economic and political parameters, are volatile and changes in them may affect the results of the international energy sector. A decline in global oil and gas prices could affect Ithaca's current cash flow or the value of assets and economic viability of international energy projects. This may also lead to a change in investment decisions and decisions to develop new fields. All these parameters may lead to a decrease in the Group's production volume abroad. A significant decline in oil and gas prices compared to the average prices in recent years could limit or reduce Ithaca's ability to withdraw its credit line. For example, Ithaca carries out hedging transactions for oil and gas prices, but if the price of oil and gas rises above the scope of its derivatives, Ithaca will not be entitled to benefit from the proceeds.

As at date of approval of the Report, the prices of oil and gas are being materially affected by the Covid-19 crisis. For further information, see also sections 0 and 0 above.

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231 For further information regarding regulation applicable for the Partnerships' operations, see section 1.8.22 above.

The table below presents a summary of risk factors by type (macro risks, sector-specific risks and risks specific to companies operating in the energy sector), according to the estimates of the Company based on the degree of their effect on the Company: major, moderate or minor effect.

Effect of the risk factor on Company's business			
	Major	**Moderate**	**Minor**
Macro risks			
Currency risks			X
Economic recession	X		
The Covid-19 coronavirus crisis and its impact on the demand for and prices of oil and other energy products	X		
Covid-19 and its possible effect on production operations	X		
The UK decision to leave the European Union (Brexit)			X
Oil and gas prices:	X		
Difficulties in obtaining the required funding	X		
Sector-specific Risks			
Competition		X	
Changes in fiscal policies		X	
Dependence on weather and sea conditions:			X
Dependence on processing and transportation infrastructures for marketing oil and gas		X	
Specific risks in the overseas energy sector			
Reliance on key personnel		X	
Interests in licenses		X	
Regulation applicable to operations in foreign countries	X		
Jurisdiction in a foreign country	X		

The impact of these risk factors on Company's operations is based on estimates alone and may actually be different.

1.9. Fuel Products in Israel

The Group's operations in the Israeli fuel products segment are conducted through Delek Israel and companies that it owns. As at the approval date of the report, the Company holds (through Delek Petroleum) 30% of Delek Israel's issued and paid up capital, when the remaining Delek Israel shares are jointly held by Lahav LR Real Estate ("Lahav") and BGM Ltd. ("BGM"). Delek Israel and companies that it owns will be referred together in this Section 1.9 below as: "Delek Israel".

Delek Israel engages in the sale of fuels products at public gas stations (including those operated by third parties) and operation of convenience stores located at most of these gas stations ("Convenience Stores" and "Gas Station and Commercial Compounds"); development, operation and maintenance of public gas stations and convenience stores; and direct marketing and distribution of fuel products and gas outside the gas station and commercial compounds ("Direct Marketing").

On January 2, 2020, Delek Israel signed an agreement to purchase the control of Delek Gas Ltd. (formerly Koraz Gas Ltd.) and Delek Gas Holdings Ltd. (formerly Koraz Gaz Haifa Ltd.), companies that operate in the LPG marketing segment ("LPG") for household use (jointly: "Delek Gas Companies").

Until October 25, 2020, the Company held 100% of Delek Israel's issued and paid up capital. On October 26, 2020, the transaction for the sale of 70% of Delek Israel's issued and paid up capital, fully diluted, was completed (when it was prescribed that 10% thereof was held in trust), in return for NIS 525 million, to Lahav and BGM. Part of the proceeds are a deferred consideration and the buyers were given the option to purchase another 5% of Delek Israel shares. On February 15, 2021, the Company announced bring forward of half of the deferred consideration and exercise of 1.666% of the options granted to the buyers. On February 24, 2021, the Company reported that the remainder of the options granted to the buyers, i.e., 3.334% of the share capital of Delek Israel, were exercised. As a result, the Company's holdings in Delek Israel after payment of half of the deferred consideration and exercise of the option is 30%.

As at the approval date of the report, Delek Israel is working to establish a fellow subsidiary to consolidate the title of the land on which Delek Israel's Gas Station and Commercial Compounds are located and intends to develop and increase the volume of operations in this area, when Delek Israel will continue be the operator of the compounds and the title to the land will be transferred to the fellow subsidiary.

1.9.1. Exercise of holdings and assets in 2020 and until shortly before publication of the report:

In 2020 and until the approval date of the report Delek Israel sold several holdings and assets as follows:

(A) On July 6, 2020, a transaction for the sale of all Delek Israel's rights in Pi Glilot Limited Partnership ("Pi Glilot") and in the land on which the terminals are operated by Pi Glilot in Haifa, Ashdod, Beersheba, and Jerusalem to A.Y.Z.Y Abou Holdings Ltd and Otzar Aviv Investments Ltd. in return for NIS 720 million ("Pi Glilot Sale Transaction"). For further information regarding the Pi Glilot Sale Transaction, see the Company's immediate reports of May 7, 2020, June 7, 2020 and July 7, 2020 (Ref. Nos: 2020-01-045153, 2020-01-057975 and 2020-01-072168, respectively), which include information presented here by way of reference. For information about the fuel storage and supply segment in which Delek Israel operated until completion of the Pi Glilot Sale Transaction, see Section 1.9.2(A)(1) below.

(B) On February 22, 2021, the transaction for the sale of two power stations that were held by Delek Israel to Rapac Energy Ltd in return for NIS 367 million was completed ("Power Station Sale Transaction"). For further information about the Power Station Sale Transaction, see immediate reports of July 23, 2020 (Ref. No: 2020-01-078138), October 21, 2020 (Ref. No: 2020-01-114678), November 15, 2020 (Ref. No: 2020-01-122937), and February 23, 2021 (Ref. No.: 2020-01-021270), which include information presented here by way of reference.

1.9.2. General information about the operating segment

(A) Structure of the operating segment

In Israel's fuel industry, there are infrastructure companies providing infrastructure services such as unloading, storage, supply and transmission of fuel, and fuel companies involved in marketing, distribution and sale of fuel products and lubricants at the Gas Station and Commercial Compounds, and the development, establishment and operation of gas stations and convenience stores. The four main gas companies, Paz Oil Company Ltd. (“Paz”), Delek Israel, Sonol Israel Ltd. (“Sonol”) and Dor Alon Energy in Israel (1988) Ltd. (“Dor-Alon”), together own 927 gas public stations in Israel. Other fuel companies together own about 285 public gas stations[232].

Delek Israel’s operations include the sale of fuels and LPG at public gas stations (including marketing them at gas stations operated by third parties) and operating the gas stations, including refueling services using automatic refueling devices (“Dalkan”) and selling oils and other products at public gas stations. Delek Israel also develops, establishes and operates gas stations and convenience stores. At some of the compounds, Delek Israel leases space to third parties for commercial purposes (gas stations with a commercial compounds in which Delek Israel leases space to third parties: “Retail Areas”). Delek Israel also engages in marketing, distribution and supply of fuel products and gas outside the public gas stations directly to the customers' sites, which are not open to the general public and also recently purchased Delek Gas Companies that operate in the household LPG segment and develops this operating segment.

As at December 31, 2020., Delek Israel marketed fuel products to 238 public gas stations[233] nationwide, 174 of which are operated by Delek Israel and 158 included convenience stores. At the end of 2019, Delek Israel marketed fuel products to 239 public gas stations, 159 of which included convenience stores. For further information on Delek Israel gas stations, classified according to proprietary rights to the land and terms of station operation, as at December 31, 2020, see Section 1.9.8 below.

Delek Israel takes continuous measures to maximize its retail potential in the gas station compounds, inter alia, by enlarging buildings, utilizing building rights and managing the business in each of its compounds properly. As at the approval date of the report, Delek Israel has 12 gas stations under development in order to expand the commercial activity and commercial compounds.

On September 23, 2019, Delek Israel purchased all Cup-O-Joe shares from the Company’s private shareholders and is currently its sole shareholder (100%).

Following is a description of the Israeli fuel industry structure, which also addresses the importation, transportation, storage, supply and trucking of crude oil and fuel products to the gas stations.

(1) <u>Importation, purchase and storage of fuel products</u>

Fuel companies are permitted to import crude oil and fuel products to Israel. In practice, as at the date of the report, the oil refineries import crude oil to Israel and refine it into products. The selling prices of distillates (fuel products) sold by the refineries to the fuel companies are not controlled, except for the price of two types of bitumen (PG-68 and non-blown) and LPG. Delek Israel does not import crude oil, but in 2018-2019 it imported gasoline in a volume of between 33% and 63% of its gasoline purchases and small volumes of diesel. In 2020, Delek Israel did not import any gasoline or diesel.

Imported fuel products (as opposed to crude oil) may currently be offloaded at three ports throughout Israel. Fuel products are stored and supplied at infrastructure company depots, the refineries and the facilities of the major fuel companies deployed nationwide. The central storage and supply facilities used by Delek Israel are located Haifa and Ashdod, both of which it owns. As part of the Pi Glilot sale transaction, it was prescribed that Delek Israel will continue to receive storage and supply services for a 10-year period with an option for a further 5 years. The infrastructure service rates (unloading, storage, supply and transmission) of fuel products were set in the Commodity and Service Price Control (Infrastructure rates in the fuel economy) Order, 2014 (“the Infrastructure Price Control Order”). For further information, see Section 1.9.16(B)(4) below.

(2) <u>Transmission, supply and trucking</u>

Oil products manufactured at the Haifa or Ashdod refineries and imported oil products are transported to the various storage facilities through a pipeline owned by external companies. The fuel products are stored at the supply sites in tanks and from there, supplied to road tankers based on product type, or directly to the terminals of institutional customers.

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232 Based on Ministry of Energy information dated February 11, 2020.

233 Excluding 180 internal stations (i.e. a station not located on major roads at which, in accordance with the building permit or business license granted, fuel may be supplied for self-use only ("Internal Station"), which are part of the direct marketing segment.

As at the date of the report, over 80% of the fuel products sold by Delek Israel are transported by a wholly owned subsidiary of Delek Israel. The remainder (about 20%) is transported by subcontractors hired by Delek Israel or customers using their own fleet of tankers or parties acting on their behalf.

Marketing of fuel products and gas

To the best of Delek Israel's knowledge, more than 30 fuel companies are registered with the Fuel Administration and licensed to purchase fuel products directly from the refineries. Delek Israel believes that additional entities operate in this market (companies, agents, distributors, and wholesale customers), purchasing fuel products from the licensed fuel companies and selling them to customers. To the best of Delek Israel's knowledge, in addition to Delek Israel, another five natural gas distribution companies (Pazgas, Amisragas, Supergas, Oshrad and Dorgas) operate in the natural gas segment. It should also be noted that Supergas constructed a CNG supply facility in northern Israel. On January 1, 2018, Delek Gas Partnership receive a gas supplier license to purchase LPG and market it in through stationary tanks and to vehicles at gas stations. Also, as noted above, Delek Israel recently purchased Delek Gas Companies, that specialize in household LPG.

(B) Material changes in the segment

(1) Increased competition – the increasing competition in marketing fuel products to the end customers is reflected in provision of discounts for fleets, granting of discounts on fuel prices at the gas stations, competition over customer credit terms, and an ongoing rise in the number of gas stations and convenience stores. It should be noted that entry into force of the Fuel Industry Regulations (Promotion of Competition) (Rules for Universal Automatic Fueling Devices), 2011 ("the Universal Refueling Device Regulations") on January 1, 2018 led to even fiercer competition in the segment. For further information about the Universal Refueling Device Regulations, see Section 1.9.16(A)(8) below. In addition, as from January 1, 2019, marketing fuel through non-universal refueling devices is prohibited.

The increasing competition in the direct marketing segment is expressed mainly in lower marketing margins.

As at the date of the report, as a result of lifting the control of Bazan ex-refinery prices together with the supply fees in the north, the Haifa refinery is able to compete with the import of fuel products.

(2) Regulatory developments in the fuel segment - For information about the Universal Refueling Device Regulation see Section 1.9.16(A)(8) below.

(C) Restrictions, legislation and standardization

The operations of the fuel companies are subject to various restrictions, legislation and regulation. For information, see Sections 1.9.15 and 1.9.16 below.

(D) Changes in the volume of operations and profit of the segment

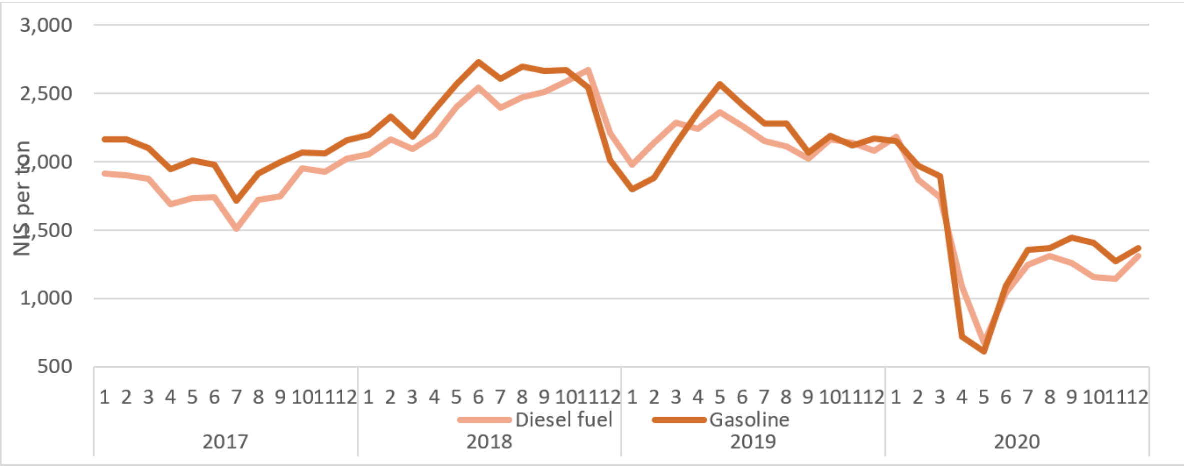
Global fuel prices directly affect the price of the fuel products marketed by Delek Israel. When crude oil prices decrease, Delek Israel's profitability declines due to a drop in the value of its fuel product inventory and erosion of profits, impairing its gross profitability. On the other hand, when global crude oil prices rise, Delek Israel's profits may improve due to selling its fuel product inventory at higher prices, along with other possible consequences, such as a decreased demand, fiercer competition and increased discounts. It is also emphasized that the higher the fuel prices rise, the greater the need for working capital and the greater the financing costs resulting from the hike in financial liabilities.

In the reporting period, there was a slight decline in quantities of fuel products sold in the gas station and commercial compound segment.

Consequences of the Covid-19 Crisis:

Due to the Covid-19 crisis and the traffic restrictions imposed by the Israeli government from time to time, in March and April 2020, the quantities of fuel purchased in Israel plummeted, materially impacting the quantities of fuels sold by the Company, including jet fuel sales, which have decreased in volume. In addition, in May 2020 until the date of the report, the effect of the Covid-19 crisis are still evident in the quantities of fuels sold, which are not in line with the expected fuel sales for 2020, in a manner that materially impacts Delek Israel's profits. For further information, see Section 1.9.20(A) below.

The following graph shows the fluctuations of Lavera prices (as defined in Section 1.9.11(B)(1) below) of oil distillates (gasoline and diesel fuel) from January 2018 to December 2020:



Most of the lease and fuel storage agreements are short-term, while the supply agreements are usually for unlimited periods and/or without quantity obligations. The Pi Glilot Sale Transaction led to a substantial reduction in revenues.

(E) Market developments or changes in customer characteristics

Delek Israel's operations are affected by various market developments, including the state of the Israeli economy. In recent years, there is a trend by fuel companies, including Delek Israel, of developing their gas stations into retail areas that, in addition to fuel products and lubricants, also offer a range of services such as convenience stores, restaurants, cafés, car wash services etc.

The Covid-19 crisis that started at the end of 2019 and deteriorated in the first quarter of 2020 together with the sharp decline of energy prices in the global markets had a material negative effect on the Company's fuel business in this period. For further information, see Section1.9.20(A) below.

(F) Technological changes which materially impact the operating segment

For information about the Universal Refueling Device Regulations, see Section 1.9.16(A)(8) below.

The Company is also reviewing the Bank of Israel's directives concerning the EMV standard for credit card transactions. The date for completing the installation and converting to operating according to the EMV standard is July 2022. It is noted that as at the date of the report, the standard is not mandatory. The significance of converting the systems to comply with this standard are estimates at NIS millions. Delek Israel is exploring the alternatives.

(G) Key success factors in this segment and the changes in them

Delek Israel estimates that the key success factors in the segment are:

(1) Nationwide deployment of the gas stations and convenience store chain.

(2) Successful integration of fuel operations alongside the commercial operations.

(3) Business focus, specialization and a high level of professionalism of managers and employees in all segments.

(4) Identification and retention of quality staff, mainly to manage and operate the gas station compounds.

(5) Financial strength that allows supporting the existing gas stations, including making financial investments if necessary.

(6) Capacity to raise capital from banking and non-banking sources.

(7) Capacity to grant customer credit.

(8) Revision and improvement of the terms of the lease agreements for gas station compounds, with attractive terms that express the size of the Company and allow coping with the competition in a variable market. Striving for proprietary rights to strategic gas station compounds.

(9) Availability and storage capacity of fuels and various products and capacity to transport them to the end-users.

(10) Competitive prices offered in the tenders of major institutional clients.

(11) Highly advanced marketing & logistics, credit collection & control and compound control systems.

(12) In the direct marketing segment, the other important success factors are goodwill, know-how, professionalism, quality control systems and human capital.

(13) Expansion of synergetic-business activities in the energy and retail segments as well as other activities in view of the fuel economy forecasts.

(H) Changes in the segment's array of suppliers and raw materials

For further details, see Section 1.9.11 below.

(I) Main entry and exit barriers in the fuel segment:

(1) The high financial costs involved in location and construction of gas stations, which are affected, among other things, by the required gas station construction standards.

(2) The length of time required to license and construct gas stations.

(3) Tightening of regulatory restrictions, including legislation and regulation relating to planning, construction, firefighting and environmental protection, Israel Police requirements, and laws and regulations relating to accessibility to buildings, industry, the environment and services.

(4) Competition with other well-established fuel companies in all segments.

(5) The need for substantial sources of credit to finance purchasing fuel product inventories and granting credit to the station operators and fleet customers.

(6) A key entry barrier into the direct marketing segment is the financial strength required of a marketing company that distributes the products which it manufactures, due to the need to extend customer credit, because of the high fuel prices and diesel oil excise tax.

(7) The key exit barrier of the Gas Station and Commercial Compound segment is rental/lease/operating contracts with land/station owners.

(8) Structure and changes in competition in the operating segment

(J) For a description of the competition in this segment, see Section 1.9.5 below.

1.9.3. Breakdown of revenue and profits of products and services

Breakdown of Delek Israel’s revenue from fuel products and oils in 2018 to 2020 (including and less excise taxes):

		Total sales in NIS millions		% of revenue of operating segment	
Year	**Product**	**Including excise tax**	**Less excise tax**	**Including excise tax**	**Less excise tax**
2020	Fuels and oils*	7,065	2,386	94.0	85.0
2019	Fuels and oils*	9,287	4,375	94.5	89.1
2018	Fuels and oils*	9,433	4,558	95.2	90.5

* Most of the revenue is from the sale of fuels.

The operating profits of price-controlled and uncontrolled fuels are not materially different. Delek Israel's revenues from controlled products (excluding excise tax and VAT) out of the Group's total revenues in 2020, 2019 and 2018 amounted to **31.4%**, 32.1%, and 31.8% respectively.

1.9.4. Customers

(A) Delek Israel’s customers may be classified into several groups as follows. The first includes gas station and convenience store customers that are divided into two main groups: (a) Private customers, who purchase fuel products, lubricants or retail products at the gas stations and convenience stores operated by Delek Israel. Customers pay a price for fuel and oil products which is set at each station, whereas the price for 95 octane gasoline is controlled as set out in Section 1.9.16(B)(2) below, and the payment is usually in cash or by credit card. The difference between the sale price to end users and the cumulative Bazan ex-refinery gasoline price, including excise taxes and infrastructure service payments, is known as the "marketing expense basket" or "marketing margin". The sale price at stations operated by an external operator is set in an agreement between the parties, whereas the operator sets the price for random customers; (b) Corporate customers, including fleets that subscribe to the Dalkan service, tender customers (Dalkan customers) and gas stations associated with Delek Israel under operating contracts on its behalf and supply contracts for the purchase of fuel and oil products234. These customers differ from the private consumers mainly in the credit terms (which are longer) and discounts which they receive.

Due to the fact that the maximum marketing margin for 95 octane unleaded gasoline is a fixed amount (because of government control and an order determining the update rate), which is not affected by price gasoline price or excise tax fluctuations (whether controlled or not), there is no built-in compensation for the credit risk costs when the customer credit rises due to increases in fuel prices and the excise tax component. It should be noted that during the ordinary course of business, and as usual in the fuel segment, Delek Israel enables gas station owners to take loans for several purposes: (1) Enterprise loans - to a third party (the land buyer) to purchase the land; (2) commercial loans as part of agreements for renewal of the engagement with the gas station owner under a rental or supply agreement: (3) debt rescheduling agreements (converting the debt into a loan) of gas station operators (on behalf of Delek Israel or independent). Most enterprise and commercial loans are backed by a lien on the land where the gas station is located and most debt rescheduling loans are without collateral.

The second group includes direct marketing customers, which include private customers, tender customers (both government and commercial companies), and corporate customers such as industrial plants, infrastructure contractors, etc.

(B) Breakdown of segment sales by customer type

(1) Breakdown of sales at the Gas Station and Commercial Compounds (including excise) in 2020, 2019 and 2018 by customer type (in NIS millions and as a percentage of total segment revenues in that year):

Type of customer	2020		2019		2018	
	NIS millions	% of total segment revenue	NIS millions	% of total segment revenue	NIS millions	% of total segment revenue
Corporate (incl. tenders and Dalkan)[235]	2,028	38%	2,530	38%	2,667	38%
Operating/supplying stations[236]	1,517	29%	1,820	27%	1,764	25%
Private	1,759	33%	2,337	35%	2,570	37%
Total	**5,304**	**100%**	**100%**	**7,001**	**100%**	**6,397**

234 On July 29, 2013, Delek Israel was awarded the Ministry of Defense tender to supply fuel and provide refueling services at its gas station chain to IDF and Ministry of Defense vehicles, for three years with an option for the Ministry of Defense to extend the contract for a further two years. The service term under the tender was extended by the Ministry of Defense again until a new tender is published soon. On June 21, 2020, Delek Israel was awarded a new Ministry of Defense tender to provide refueling services to IDF and Ministry of Defense vehicles in its gas station chain for 3 years with an extension option of up to a further two years (one at a time). The Ministry of Defense tender for the supply of fuels was separated from provisions of refueling services and Delek Israel is considering competing in it together with a storage and supply company.

235 The operating profit percentages from sales to tender and Dalkan customers are not materially different.

236 Delek Israel's sales to operating/supplying stations include sales to Dalkan customers through these stations. It is clarified that sales data in the table do not represent the sales of those stations to Dalkan customer, but Delek Israel's sales to the stations.

(2) Breakdown of fuel sales through Delek Israel gas station chain to fleet end-users by customer seniority/length of the contract[237]:

Seniority	Net transaction amount
One year (2%)	61
Two to five years (19.9%)	493
Over five years (78.1%)	2,076
Total (100%)	**2,630**

(3) Breakdown of sales in the direct marketing segment (including excise) in 2020, 2019 and 2018 by customer type (in NIS millions and as a percentage of total segment revenues in that year):

	2020		**2019**		**2018**	
Type of customer	**NIS millions**	**% of total segment revenue**	**NIS millions**	**% of total segment revenue**	**NIS millions**	**% of total segment revenue**
Tenders	58	3%	85	3%	88	3%
Corporate	1,704	97%	2,966	97%	2,754	97%
Private	-	-	-	-	-	-
Total	**1,762**	**100%**	**3,051**	**100%**	**2,842**	**100%**

1.9.5. Competition

(A) According to data published by the authorities, there are more than 30 registered fuel companies in Israel that are licensed to import fuel products or purchase them directly from the refineries in Israel. As set out in Section 1.9.2(A) above, four companies operating in the Gas Station and Commercial Compound segment (including Delek Israel) hold the major share of the Israeli market. To the best of Delek Israel's knowledge, based on Ministry of Energy data, it is the second largest fuel marketing company in Israel (19% of all the gas stations). Paz owns 21% of all the gas stations, whereas Sonol and Dor-Alon own 18% and 17%, respectively. Delek Israel believes that each of its three main competitors has a nationwide gas station chain and the capability to provide fleet services. It is also noted that there are many small companies in the market, which together, as at the report date, operate 25% of the public gas stations in Israel.

(B) The Israeli fuel economy is currently characterized by fierce competition in all of Delek Israel's operating segments, as follows:

(1) Updating and renewing the deployment of the gas stations of the fuel companies and their location when the demand for gas stations in strategic locations leads to increased rent or purchase price to be paid to the land owner, eroding the margins of fuel companies.

(2) Competition in marketing to end-users and sales at gas stations, granting discounts and holding various sales campaigns, and improving the service provided at gas stations and the range of services offered to the customer.

(3) Competition in marketing to fleets, primarily between the major fuel companies, which is reflected mainly in competition over the prices offered to the fleets, credit terms and other services provided by the fuel companies.

(4) Competition in the direct marketing segment is characterized by low operating investments, but there is a credit risk due to the credit terms and credit score. The activity under tenders with government institutions and companies with large fleets is characterized by very low margins.

[237] The sales to fleet end-users shown in the table are the total sales to these customers through Delek Israel stations, including stations operated by third parties on its behalf and supply stations, and not necessarily the sales recognized in Delek Israel's financial statements. The sales to Dalkan customers through stations operated by Delek Israel are fully recognized as revenue in the financial statements, while the sales to Dalkan customers through stations operated by third parties on behalf of Delek Israel and supply stations are only partially recognized, based on the accounting with the station owner.

(5) The control of storage and supply rates hamper flexible competition and, therefore, the storage and supply operation is affected mainly by the relationship between the distillate consumer of these services and its geographic location and the source of the fuels, namely the refineries or import alternatives.

(C) Key ways in which Delek Israel deals with competition and factors affecting its competitive position:

(1) Delek Israel provides an adequate competitive solution with respect to deployment of gas station compounds throughout Israel. It also takes steps to revise the range of services provided at the gas station compounds for the convenience of its customers.

(2) Financial resilience and a professional and focused marketing system with a high level of command and control.

(3) In the fuel storage and supply segment, the key manner in which Delek Israel deals with competition is providing better service and waiting times. This action is highly significant for the length of time a tanker waits for supply and the time it takes to fill a tanker from the moment of entry to the supply facility until departure at the end of the process.

1.9.6. Seasonality

Delek Israel is generally not affected by seasonality.

1.9.7. Direct marketing production capacity

For information, see Section 1.9.2(A)(1) above.

1.9.8. Fixed assets and facilities

(A) As at December 31, 2020, Delek Israel owns or leases from ILA 55 gas stations (including 17 jointly owned with third parties) and 105 stations nationwide leased or rented under long-term agreements (more than three years), which are deployed nationwide. Delek Israel gas stations, by proprietary rights to the land and the station operating characteristics, as at December 31, 2020 (all the gas stations are branded Delek and Discount and sell Delek Israel products):

Group's proprietary rights		Operated by Delek Menta	Operated by Delek Israel-appointed operator	Operated by contractor	Total
Ownership/long-term lease	No third party rights granted	42	12	0	54
	Third party rights granted	1	0	0	1
Total stations owned		43	12	0	55
Sublease of stations of IDF veterans	Excluding rental	0	0	6	6
	Including rental	20	1	0	21
Total stations of IDF veterans subleased		20	1	6	27
Sublease	Excluding rental	0	0	2	2
	Including rental	6	1	0	7
Total stations subleased		6	1	2	9
Rental		105	8	0	113
No proprietary rights		0	0	34	34
Total		**174**	**22**	**42**	**238**

(B) Proprietary rights in station land

Delek Israel's gas stations are divided into four categories from the aspect of ownership of the land where the stations are located as follows:

(1) Gas stations in which Delek Israel has ownership rights to the land on which they are built (in some cases, joint ownership with a third party) or in which Delek Israel is the primary lessee from Israel Land Administration or another institutional authority.

(2) IDF veteran stations, which were established pursuant to an interministerial agreement between the State and the fuel companies. This arrangement stipulates that ILA land would only be allocated to establish gas stations unless the right to operate them is granted to a disabled IDF veteran selected by the Rehabilitation Department of the Ministry of Defense for his rehabilitation. This provision was modified in the 1990s and a disabled IDF veteran is now granted primary leasing rights for 49 years with an extension option for a further 49 years. At the same time, the fuel companies are granted secondary leasing rights for the same term in return for leasing fees equal to those paid by the veteran to ILA. Delek Israel would lease the land to establish the gas station, install the equipment needed for its operation and maintain its systems. After establishing the station, Delek Israel appoints the veteran as an operator on its behalf, so that he must purchase all fuel products exclusively from Delek Israel, and the fuel product prices to the station (i.e. the sale prices to the veteran) are determined by Delek Israel. It is noted that these agreements are subject to various Ministry of Defense directives and restrictions. If Delek Israel's rental agreements with the 21 disabled IDF veteran stations are canceled, this will not affect it materially.

(3) Rented stations include those in which Delek Israel is sub-lessee or primary lessee from a third party which is not ILA and stations under long-term or short-term rental. Delek Israel usually commits to establish the station at its expense, install most of the equipment required for normal operation, and maintain all its systems. At these stations, the operator is obligated to purchase fuel products exclusively from Delek Israel and their price to the station operator is determined by Delek Israel.

(4) Stations for which Delek Israel has no proprietary, holding or usage rights are those in which it has signed agreements with station owners usually granting it exclusivity in supplying fuel products for a one-year term, with the owner alone having the option to demand renewal of the agreement for a further one to three years (total); and the remaining cases include provisions with regard to commercial terms. In many of these agreements there is no collateral for the supply of fuel product. For information of restrictions in competition laws applicable to Delek Israel's contracts with the owners of rights in gas stations, see Section 1.9.16(E) below.

(C) <u>Gas stations are operated in several ways:</u>

(1) By Delek Israel through Delek Menta.

(2) By a third party appointed by Delek Israel. Gas stations in this arrangement bear Delek Israel signage and purchase all products from it exclusively, in various arrangements set out in agreements. The operator pays Delek Israel fixed and/or variable rent, based on the volume of sales at the station.

(3) By an independent third party not appointed by Delek Israel. In these stations there are actually short-term supply agreements of a year, with the operator alone having the option to request renewal of the agreement for another one to three years. The supply agreements require operators to purchase fuel products and lubricants from Delek Israel at agreed prices and credit terms and sell them under Delek Israel trademarks and name, within price control restrictions and according to Delek Israel's instructions concerning various procedures. Delek Israel usually owns the gas station equipment and lends it to the station operator. Delek Israel installs the equipment required to operate the station and provides the owner of the rights with maintenance services and professional training under the contractual agreement. In most cases, there is no collateral to secure the sale of fuel to stations. In some cases, Delek Israel has no exclusivity in supplying fuel products.

(D) All Menta convenience stores are operated by Delek Israel through Delek Menta, except for 25 stores operated by franchisees. All employees of Menta stores (which are not operated by franchisees) are Delek Menta employees. Delek Menta purchases inventory and bears all the risk involved in operating the convenience stores, other than in case of franchisees. The other franchisees purchase the inventory and bear all the risk involved in operating the stores.

(E) Delek Israel's property, plant and equipment in the gas station and convenience store segment include the buildings and equipment in most public gas stations where it has ownership rights. It also has equipment installed in all its stations where it has no ownership rights or where it has short-term lease agreements. At some of these stations, Delek Israel also has property, plant and equipment in station buildings constructed many years ago, when it had proprietary rights (including long-term lease contracts) there. It also has vehicles and trucks to transport the fuel products and lubricants.

(F) Delek Israel's fixed assets in the direct marketing segment include the equipment at customer premises and facilities (mainly designated tanks and pumps) and equipment at the internal stations, including infrastructure, tanks, pipelines, electronic pumps, and electronic refueling and control systems.

1.9.9. Intangible assets

Delek Israel operates under several well-known, protected brands: Delek, Menta, Delek Dalkan (electronic refueling service brand) and Cup-O-Joe.

1.9.10. Human resources

(A) As at December 31, 2020 and December 31, 2019, the employees engaged by Delek Israel are divided as follows:

Segment	No. of employees at December 31, 2020	No. of employees at December 31, 2019
Gas stations and commercial compounds	1654	1969
Direct marketing	70	55
Storage and supply	36	36
Other	229	39
Total	**1989**	**2,099**

(B) Most Delek Israel employees are engaged under personal employment agreements and are not subject to a special collective agreement, whereas special or general collective agreements apply to some by virtue of membership of the companies in employers organizations or by virtue of expansion orders. On March 4, 2020, Delek Israel signed a collective agreement with the National Labor Federation for a 4-year term, which will be extended for a further one year term.

(C) On January 9, 2017, Delek Menta signed a collective agreement with the National Labor Federation for a 4-year term, which will be extended for further terms of two years unless any of the parties notifies that it wishes to revise or cancel the agreement. As part of the understandings of the special collective agreement in respect of the sale of the Company, it was agreed that the parties will enter into negotiation no later than mid-February 2021 and will act to complete them and sign a new collective agreement by August 2021. On February 17, 2021, the parties began such negotiations.

(D) Delek Israel only employs road tanker drivers who are licensed to transport hazardous materials. Also, employees who work in the gas stations or come into contact with fuel materials, undergo fire-fighting and hazard prevention training and environmental protection courses.

(E) As part of the Pi Glilot Sale Transaction, Delek Israel’s liability with respect to Delek Pi Glilot employees ended, including requirements that arose for the sale transaction.

(F) Officers and senior management staff at Delek Israel are employed under personal employment contracts which include executive insurance contributions. Delek Israel customarily grants performance-based bonuses to its employees, including senior staff, subject to the approval of the competent organizations.

1.9.11. Fuel products, raw materials, and fuel and oil product suppliers

(A) <u>Main fuel products used by Delek Israel</u>

The main fuel products used by Delek Israel in both fuel marketing at public stations and direct marketing are distillates produced from crude oil which are also purchased and traded on global exchanges. In most of the direct marketing operations, Delek Israel purchases finished fuel products and not raw materials. In recent years until 2018, Delek Israel purchased over 90% of the fuel products that it sells from Bazan. Delek Israel signed an agreement with Vitol SA to import most of the quantity of 95 octane gasoline in 2019. For information of the risk factors involved in dependence on Bazan, see Section 1.9.20(H) below.

(B) <u>Agreements with major suppliers</u>

(1) <u>Local suppliers</u>

As at the date of the report, Delek Israel’s main fuel product supplier is Bazan and a small quantity is purchased from the ORA. The purchases from Bazan are made under an annual agreement according to which Bazan will sells and supplies fuel products to Delek Israel. This agreement stipulates that Delek Israel purchases fuel products the basis of monthly orders. With respect to 95 octane gasoline and diesel fuel for transportation, the monthly order will be placed on the basis of an annual plan (listed by month) which was submitted to Bazan, while Delek Israel is permitted to update the volume of monthly and annual purchases by the deviation specified in the agreement. The price of fuel products purchased from Bazan is determined according to a formula derived from the CIF Lavera prices (“Lavera Price”). Import of fuel products

In 2020, Delek Israel did not import any diesel or gasoline. The import price for international trade companies is determined by a formula based on the local price. For 2019, Delek Israel signed an agreement with Vitol SA to import 95 octane gasoline at a rate of more than 60% of the annual quantity.

1.9.12. Working capital

(A) Composition of working capital: Delek Israel's working capital includes the total current assets (cash, trade and other receivables, and current operating inventory) less the current liabilities (including current liabilities to banks, current maturities of debentures and other long-term loans, and trade and other payables).

(B) The main change between the net working capital as at December 31, 2020 and December 31, 2019 is due to repayment of short-term loans and a decrease in trade payables and inventory balances.

Delek Israel's policy is for the working capital requirements to correspond with the working capital financing sources, if possible, and for the non-current investment and asset requirements to correspond with the long-term sources. Its considerations concerning short-term financing sources derives from the lower costs and the fact that they are more readily available than long-term sources

(C) As at December 31, 2020, Delek Israel has a working capital deficit of NIS 143 million, mainly due to long- and short-term liabilities assumed to finance long-term investments, which are due to be repaid in the coming year. Breakdown of Delek Israel's working capital:

	Amount included in Delek Israel's financial statements as at December 31, 2020 (NIS millions)
Current assets	1,877
Current liabilities	2,020
Surplus current liabilities over current assets	143

(D) The management of Delek Israel believes that it is able to convert short-term loans into long-term loans or to continue to receive short-term loans and/or dispose of assets that it owns to continue to finance its investments and repay its obligations. This estimate is based partly on the cash flow from operating activities, available credit facilities and a substantial volume of non-pledged assets.

(E) In this context, it should be noted that the Covid-19 crisis may have a material adverse effect on the results of Delek Israel's future operations, among other things, depending on its duration. It is noted that in 2020, a material decline in the volume of Delek Israel's activity was observed. For further information, see the risk factor chapter in Section 1.9.20(A) below and Note 10 to the Financial Statements.

1.9.13. Financing

(A) Delek Israel's operating activities are financed mainly by cash flows from operating activities and short-term bank loans.

(B) Below are the average effective interest rates on loans from bank and non-bank sources effective in 2020 and not intended exclusively for specific use by Delek Israel:

		Average and effective interest rates	
		Short-term credit	**Long-term credit**
Banking sources	NIS loans	1.4% -1.6%	2.45% -3.5%

(C) Credit facilities – As at December 31, 2020 and shortly before the publication date of the report, Delek Israel's bank credit facilities (separate) amounted to NIS 1,008 million, of which it has utilized NIS 857 million.

(D) Financial covenants and restrictions applicable to Delek Israel under financing agreements – In receiving the bank loans and credit facilities, among other things, the following main financial covenants, restrictions and terms were laid down:

(1) As part of the bank loans (as defined in Section (3) below), Delek Israel committed to some of the banks not to pledge its fixed assets in any form without the prior written approval of the banks (excluding fixed assets pledged in favor of the entities that financed the purchase of those items).

(2) An interbank agreement from 2002 between eight banks (which Delek Israel is not party to) to regulate the relationship among them concerning exercise of the floating lien given to them on Delek Israel's inventory and the proceeds thereof, as set out in Section (C) below, stipulates that if one of the banks enforces and/or exercises the lien generated for its benefit that leads to the appointment of a receiver or receiver and manager for the pledged property (as defined in this agreement), the other banks may exercise the lien given in their favor by Delek Israel.

(3) Agreements with local banks for long-term fixed-interest loans for period of up to six years (average duration of three years) totaling (as at December 31, 2020 and as at the approval date of the report) NIS 265 million (in this section: "the Bank Loans") stipulate that non-compliance with any of the following covenants may grant the lenders the right to immediate redemption of the Bank Loans: (a) If the financial ratio changes so that Delek Israel's equity to balance sheet[1] is less than 12% and its equity[2] is less than NIS 600 million (in this subsection: "the Lowest Level") and this financial ratio remains below the Lowest Level in three consecutive Delek Israel financial statements; (b) if most or all of Delek Israel's operations in the Gas Station and Commercial Compound and Direct Marketing segments are sold and as a result, the profit of Delek Israel's ordinary operations in these segments (cumulatively) falls below 25% of the total consolidated profit of its ordinary operations in all segments, as appears in the first financial statements published subsequent to the sale of such operations.

As at December 31, 2020 and the publication date of the report, Delek Israel complies with all the above financial covenants, as specified in Section (5) below.

(4) As at the approval date of the report, Delek Israel's current rating is Aa3.il with a stable outlook.

(5) Information regarding Delek Israel's compliance with the financial covenants under the Bank Loans:

Financial covenant	Tested ratio as at December 31, 2021
Equity to balance sheet higher than 12% and equity higher than NIS 600 million.	Total equity = NIS 691 million. Total balance sheet = NIS 3,598 billion. Equity to balance sheet ratio = 19%.
Tangible equity ratio of no less than 12%, net of the effect of IFRS16 standard	20%
Coverage ration does not exceed 3.5	1.73

(E) Variable interest credit:

Details of the variable interest credit (PRIME-linked) obtained by Delek Israel as at December 31, 2020 and immediately before the approval date of the report:

Track	Range of interest rates as at December 31, 2020	Interest rates proximate to report date
On Call	1.35% - 1.75%	1.35% - 1.75%

(F) Liens and guarantees - To secure the Bank Loans, the balance of which at December 31, 2020 is NIS 265 million, Delek Israel placed an unlimited lien on all its inventory. The proceeds and rights thereof are defined in the lien documents.

1.9.14. Taxation

The primary tax rate applicable to Delek Israel is different to the effective tax rate, mainly due to the timing differences between expenses, unrecognized discounted expenses, exempt income, losses

[1] The ratio between the total equity attributed to the shareholders, excluding non-controlling interests, and Delek Israel's balance sheet total in its audited or reviewed consolidated financial statements.

[2] Delek Israel's equity, excluding non-controlling rights, as appearing in its audited or reviewed financial statements.

of affiliates and tax expenses for previous years. Besides the regular corporate tax laws applicable to companies (see further information in Note 31 to the Financial Statements), it is noted that under the Fuel Excise Tax Law, 1958 (“the Excise Tax Law”) and the Fuel Excise Order, 1980, a given amount of tax is imposed on the fuel products listed in the order, which is updated every three months on the basis of CPI fluctuations. The excise tax component in fuel prices is highly significant. Fuel companies are charged excise tax directly upon issuing the fuel, with 10 days credit, whereas the number of credit days granted by Delek Israel to its customers is significantly higher, especially for diesel fuel sales.

1.9.15. Environmental risks and mitigation thereof

Main provisions of environmental laws applicable to Delek Israel are summarized below:

(A) Maintenance of Cleanliness Law

The Maintenance of Cleanliness Law, 1984 imposes criminal liability on whoever dirties and/or disposes waste (including fuels) in the public domain. This law also grants authority to levy fines, issue an order requiring the polluter to restore the polluted area or impose double the expenses for restoration of the site by the authorities.

(B) Water Law and Regulations

(C) The Water Law, 1959 (“the Water Law“) and the various pursuant regulations impose liability for pollution of water sources and sets out provisions aimed at regulating this area and preventing soil, water or air pollution. The Water Law grants state authorities extensive powers, including the authority to demand cessation of the pollution, restoration, levy fines and charge expenses. As part of this, the liability to ensure that the stations comply with the provisions of the law and regulations and to adapt the stations and the activities performed there to the provisions of the Water Law is imposed on the station operations (including Delek Israel in some of the stations).

(D) Environmental Protection (Polluter Pays) (Legislative Amendments) Law, 2008

The objective of this law is to protect, maintain and improve the environment, prevent damage to the environment or public health, and rule out the economic viability of harming the environment by means of punishment which takes into account the value of the damage caused and the benefit or profits gained by committing environmental crimes. In addition to stricter penalties for environmental violations, the courts are authorized, for a violation by a person resulting in that person gaining a benefit or profit, to impose a fine to the value of the benefit or profit in addition to any other punishment.

(E) Ministry of Environmental Protection’s soil pollution policy

In 2017, the Ministry of Environmental Protection published a revised policy documents on the method of dealing with and treating polluted soil. The policy addresses, among other things, prevention of soil pollution, treatment of polluted soil and rehabilitation of soil that contains pollutants, and is expressed in the Ministry of Environmental Protection’s professional guidelines, the terms of business licenses and poison permits in this regard, and other actions taken by the Ministry of Environmental Protection considering the “polluter pays” principle.

(F) Additional environmental requirements

(1) Delek Israel was required by the Ministry of Environmental Protection to conduct tests (soil surveys and groundwater monitoring bores to identify land and water pollution) at 129 old stations. As at the date of the report, Delek Israel carried out tests in all old stations and treatment at most of them. Since Delek Israel's old stations were built to standards predating the Water Regulations and accumulated knowledge indicates that the required standards of that period cannot ensure soil and/or water damage prevention, Delek Israel cannot estimate which of its old stations have polluted the soil or the water surrounding them. Tests conducted detected several stations where the soil and/or groundwater is contaminated. Delek Israel has started implementation of a soil and/or groundwater rehabilitation plan at the stations where the survey was completed and contamination was discovered. In this matter, Delek Israel is in compliance with the arrangement signed with the Ministry of Environmental Protection in 2008 with respect to the timetables for locating and rehabilitating contaminated soil at old gas station.

(2) In August 2011, the Minister of Environmental Protection published guidelines obligating the gas companies to install such vapor retrieval systems in the German standard at all gas stations by the end of 2015 (in this subsection: “the Guidelines"). Following postponements, the new date was set for April 2017. This demand is presented in the business license terms and also appears as a guideline under the Clean Air Law, 2008 ("Clean Air Law") As at the date of the report, Delek Israel has completed the installation of Stage 2 vapor retrieval systems in all gas stations.

(G) Legal and administrative proceedings relating to environmental protection

Non-compliance with the provisions of the Water Law and Water Regulations is likely be a criminal offense, carrying a one-year prison sentence or a fine of up to NIS 350 thousand[238], and heavier penalties in the event of an ongoing offense.

(H) Stricter enforcement to prevent blended fuel sales

As at the reporting date, subsequent to approval of the settlement in a judgment, Delek Israel fulfilled all of its obligations under the settlement agreement and completed implementation of the outline of the settlement.

(I) Hazardous materials - poison permit

Under the Hazardous Materials Law, 1993 ("the Hazardous Materials Law"), oil distillates are defined as hazardous materials. The law imposes an obligation to hold a poison permit from the commissioner authorized to issue such by the Environment Minister. Delek Israel has permits to hold the hazardous materials defined in it, and to trade in fuels without storing them.

(J) Green Tax Reform

The Green Tax Reform entered into force in August 2009, prescribing vehicle tax incentives based on their pollution emission level, aimed at encouraging the purchase of more environmentally friendly vehicles Under the reform, the purchase tax of a new vehicle sold in Israel is determined according to the air pollution emissions from the vehicle. In 2019, a reform aimed at increasing the use of natural gas in public transport, industry and electricity generation and reducing the use of diesel fuel and coal was adopted. The Company is unable estimate the impact of the reform on Delek Israel's operations and results.

(K) Delek Israel's environmental risk management policy and steps taken to decrease these risks

Delek Israel takes ongoing measures to minimize and prevent possible damage to the environment and invests substantial resources on environmental protection, including regular maintenance of facilities and infrastructures, and employee training in accordance with statutory requirements on this matter. It is noted that Delek Israel has an internal environmental protection compliance plan (in this subsection: "the Compliance Plan") and operates according to it in its different operating segments. The aim of the Compliance Plan is to ensure compliance with the statutory provisions and Delek Israel's procedures on environmental protection, while constantly improving its environmental performance and drawing conclusions.

(L) Incurred and expected material environmental expenses

In 2020, 2019 and 2018, Delek Israel's total environmental expenses amounted to sums which are not material for the Group. In the forthcoming years, the total environmental expenses are also expected to amount to non-material sums for the Group.

Forward-looking information: The information in this Section 1.9.15 and its subsections regarding the expected environmental expenses and the expected effects is forward looking information, as defined in Section 32A of the Israel Securities Law, based on information available as at the report date. In practice, the information may be significantly different to the above for various reasons, including discovery of material deviations in Delek Israel's activities, discovery of pollution at additional stations, further Ministry of Environmental Protection and/or Water Authority demands, changes in environmental laws, etc.

1.9.16. Restrictions and supervision of Delek Israel's operations

Below is a description of the main restrictions and supervision applicable to Delek Israel, in addition to the above environment supervision:

(A) Legislation specific to the fuel economy:

(1) State Economy Arrangements (Legislation amendments to achieve 2001 budget and economic policy targets) Law, 2001 ("the Arrangements Law") – This law states that a fuel company must be registered before starting its operation and may continue to operate so long as it is registered in the register maintained by the Fuel Administration "the Administration"). Delek Israel is registered in the Fuel Administration register as fuel companies. In addition, the Arrangements Law prescribes that a fuel company must maintain, at its own expense, the fuel inventory determined by the Minister of

[238] The fine is in addition to the expenses involved in treating the contamination.

Energy in consultation with the Ministers of Defense and Finance, and, pursuant to the Arrangements Law, regulations239 regulating this matter have been enacted accordingly. It is noted that in November 2002, the Supreme Court approved an interim arrangement requiring the maintenance of a security inventory, but the State can change the present status to require maintaining a civilian inventory as well.

(2) Fuel Economy (Promotion of competition) Law, 1994 – This law prescribes restrictions on establishment of new gas stations or engaging in exclusive agreements (as defined in the law) with gas stations near stations marketing the products of the same fuel company or operated by the same operator. The section in the law dealing with the restrictions concerning a regional engagement between gas stations of a single fuel company is in force through the end of July 2021. In December 2007, the law was amended in a way that regulates how prices are published at gas stations to increase competition and prevent deceit in prices.

(3) Fuel Economy (No sale of fuel to specific gas stations) Law, 2005 – This law prohibits the sale and supply of fuel to public gas stations unless they are on the list maintained by the Fuel Administration. As at the date of the report, all Delek Israel public gas stations that require registration are included in the list published by the administration.

(4) Excise – Under the Excise Law, no person shall manufacture or engage in the sale of fuel without a license from the Customs and Excise Administration. Delek Israel has been issued such a manufacturing license, which it renews annually. Excise is levied on fuel when it is issued at a supply facility or released from customs in the case of import. As a result, only companies holding such a manufacturing license may purchase oil distillates directly from refineries in Israel or import them. The Excise on Fuel (Levying Excise) Order, 2004 sets specific excise rates for every oil product. In addition, the Excise on Fuel (Exemption and Drawback) Order, 2005 prescribes that fuel used by civil commercial ships transporting passengers or cargo are exempt from excise payment, provided that the vessel departs from an Israeli port for a destination outside Israel after refueling. Increasing the excise tax rate leads to increased exposure of Delek Israel to customer credit and a rise in its financing expenses. It should be noted that in the last two years, the excise tax was updated according to the index fluctuations and the changes were minor compared with those in the base price of distillates.

(5) Hours of Work and Rest Law, 1951 – Most Delek Israel public gas stations and some of its convenience stores operate on Saturdays. Under Section 9 of this law, employment of Jewish staff on Saturday, which is part of the statutory weekly rest period, must be approved by the Minister of Labor. The Hours of Work and Rest Law also stipulates that on rest days defined in the Law and Administration Ordinance, 1948, no store owner will conduct business in his store. This law lays down a fine or up to one month's imprisonment or both for whoever employs staff in breach of the law. To date, the restrictions imposed by these laws have not materially impaired the Company's business results, and based on past experience it estimates that they will not do so in the future either.

Forward-looking information: The foregoing estimate is forward looking information, as defined in Section 32A of the Israel Securities Law, which may not materialize partly due to stricter enforcement of the provisions of the Hours of Work and Rest Law throughout Israel, which could lead to convenience stores being closed on Saturdays.

(6) Vehicle Operation (Engines and fuel) (Supply of fuel by tanker) Order, 2007 ("the Fuel Supply Order") – This order imposes liability on fuel companies to take all reasonable precautions to ensure that every fuel product that it supplies to a gas station meets the requirements of the official Israeli standard and the Operation of Vehicles Law, including by installation of an electronic seal (that meets the requirements set out in an addendum to the Fuel Supply Order) on fuel tankers transporting fuels to gas stations. The order also imposes responsibility on the supply facilities and gas station owners. The Fuel Supply Order sets out additional provisions. As at the date of the report, the fuel tankers of Delek Transportation and Delek Israel comply with the provisions of the order.

(7) Commodity and Service Price Control (Maximum Prices at Gas Stations) Order, 2002 – This order stipulates, inter alia, that at least a third of the refueling nozzles at every gas station must be self-service. As at the date of the report, the Fuel Administration is reviewing increasing the number of self-service nozzles from a third to 75%. At this stage, the fuel companies are required to respond on the matter and verbal hearings before the Fuel Administration and the relevant team are most

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[239] The State Economy Arrangements (Legislation amendments to achieve 2001 budget and economic policy targets) (Maintaining inventory and security inventory of fuel) Regulations, 2001.

likely to be scheduled in future. At this preliminary stage, it is impossible to determine whether the foregoing, if decided, will have a negative or positive effect on Delek Israel.

(8) Universal Refueling Device Regulations: On October 23, 2011, the Universal Refueling Device Regulations were published in the Official Gazette imposing the duty on fuel companies that seek to sell fuel using a refueling device to install a universal refueling device that allows the consumer to sign a contract with various fuel companies and refuel using the same device at gas stations of different fuel companies. According to these regulations, the universal refueling system will be established on the basis of universal refueling device specifications approved by the administration. As at the date of the report, Delek Israel complies with the regulations. The Company believes that conversion of the Dalkan refueling devices into universal devices will increase the number of fuel marketing companies and the number of stations where customers can purchase fuel products using a Dalkan device, which could lead to a reduced number of customers purchasing fuel products through the Company's automatic refueling system and/or a decrease in the quantity of fuels purchased by them. At this stage, Delek Israel is unable to estimate the effect the regulations will have on its fuel sales and financial results, if any, and the effect on the market competition is unclear.

(B) Price control

(1) Supply of fuel products by Bazan to the fuel companies - prior to privatization of the refineries, Bazan was declared a monopoly of crude oil refining in Israel. Only two types of bitumen are currently sold by Bazan, subject to maximum Bazan ex-refinery prices set under the Commodity and Service Price Stability Order (Temporary order) (Maximum Bazan ex-refinery oil product prices) 1992 ("the Bazan Ex-Refinery Price Order"), which sets the maximum Bazan ex-refinery prices for the various fuel products. These prices are updated on the first of every month on the basis of the external fuel product price plus or minus an amount set by the administration, with the approval of the Ministers of Energy and Finance.

(2) Consumer price - Commodity and Service Price Control (Maximum Prices at Gas Stations) Order, 2002 - The maximum price for 95 octane unleaded gas sold at a public self-service pump is fixed as well as the date and methods of its update are set out in this order. In May 2018, the marketing margin was decreased (after being reduced and revised in 2011 and 2012) in a manner that negatively impacted Delek Israel and to the best of its knowledge, other fuel companies in the market as well. It should be noted that the margin erosion is still evident at Delek Israel, which is expressed in low financial results if not for the margin decrease. It is also noted that Delek Israel is still trying to maintain its current margin in the face of fierce competition in the fuel market, the main implications of which is future margin erosion. In 2018, the Ministry of Energy issued a public hearing on the control policy of the 95 octane gasoline price at gas stations. Delek Israel submitted its written position supporting full deregulation. To the best of Delek's knowledge, the other fuel companies have also submitted their written position. The Ministry of Energy's position has not yet been received.

(3) Price control of diesel fuel for transportation - On July 31, 2012, the Commodities and Services Price Control Order (Application of the diesel fuel law and determination of the control level), 2012 (in this subsection: "the Order") was published. The Order stipulates that the control of diesel fuel for transportation will be at the profit and price reporting level as set out in chapter G of the Commodities and Services Price Control Law, 1996. The provisions and amendment of the Order do not materially affect Delek Israel's financial results. If, in practice, the control applies to diesel fuel prices (beyond such reporting), this may have a material effect on Delek Israel, which cannot be estimated at this stage. Delek Israel recently was requested to provide a response on the feasibility of the fuel price control Order in emergencies. Delek Israel sent its response and is awaiting for a verbal hearing at its request.

(4) Control of infrastructure prices - Infrastructure services relating to fuel products in Israel include unloading and loading services at the fuel port, transmission, storage of fuel products, etc., and their prices are controlled by the Infrastructure Price Control Order that was recently amended on November 14, 2019. Under the amendment, the infrastructure prices set in it were increased slightly.

(5) Essential enterprise - Delek Israel, its gas stations and storage and supply depots have been declared an essential enterprise as authorized by the Ministry of Energy and Industry. Under this authorization, Delek Israel's fleet and fuel storage and supply installations are recruited in national emergencies to enable the regular supply of fuel and gas.

(C) Weights and Measures Ordinance, 1947 ("the Weights Ordinance") - The Weights Ordinance sets various standards for weights and measures. The Weights Regulations were established pursuant to this ordinance and set out various provisions for instruments that measure oil distillates assembled on tankers, including installation of a calibration seal on these instruments. The use of such instruments is prohibited unless they have been calibrated and sealed in accordance with the weights regulations.

(D) Gas station operating licenses

The licensing procedures for new gas stations are long and complicated and require large investments in obtaining approvals, permits and licenses from numerous entities. This procedure is regulated by numerous laws, granting licensing powers to various governmental authorities. According to the business licensing reform, from January 1, 2019 it will not be possible to issue a permanent business license of any kind and the existing licenses were opened so that action will be required to re-obtain them. The new term of the licenses is five years for convenience stations and three years for gas stations. Delek Israel has already been working to renew licenses as part of the ongoing activities in this area.

Below is the main legislature granting licensing powers to the various governmental authorities:

(1) Planning and Building Law, 1965 ("the Planning Law") and its regulations - Under the Planning Law and its regulations, a permit is required for any use of land, meaning construction and the use of any structure, etc. is subject to a permit. A building permit for the construction of a gas station often also requires rezoning the land. Under this law, the National Planning Council approved the National Outline Plan for Gas Stations - NOP 18, 1986 ("NOP 18) setting conditions and criteria for the construction of gas stations. The plan permits the construction of mini stations that require smaller capital investment than required for public gas stations. A mini gas station is any station which can serve up to four 4-ton vehicles simultaneously and no structure can be added to such station other than a roof over the gas pumps and the services required to operate the station on a total area that does not exceed 10 sq.m. On July 7, 2016, Amendment No. 1 to NOP 18/4 was published, setting out rules for the construction of CNG refueling stations. On June 16, 2019, Amendment No. 2 to NOP 18/4 was published, setting out the minimum distances from gas stations supplying LPG and CNG, and changing the method of calculating the permitted built up areas in gas stations.

(2) Business Licensing Law, 1968 its Regulations and Orders issued pursuant thereto:

A. Business Licensing (Businesses requiring a License) Order, 1995 - Under this order, a gas station is a business that is required to be duly licensed. To operate a gas station, approval is required from the following authorities: Israel Police; the Ministry for Environmental Protection, Ministry of Economy and Industry; National Fire and Rescue Authority; and the relevant Planning and Building Committee.

B. Business Licensing (Fuel Storage) Regulations, 1976 - Regulations enacted under the Business Licensing Law setting out specific provisions for obtaining a gas station business license. These regulations describe the fuel safety and storage conditions to obtain a license.

C. Business Licensing (Sanitary Conditions at Gas Stations) Regulations, 1969 - These regulations set out provisions concerning the sanitary conditions and facilities required at gas stations.

D. Business Licensing (Hazardous Plants) Regulations, 1993 - Under these regulations, a business that stores, produces, processes or sells hazardous materials must have a special license to do so and must comply with the safety provisions laid down in or under any law.

E. Business Licensing Law Amendment No. 26 (Temporary Order), 2010 - Under this amendment, a business that serves or sells alcoholic beverages, including food chains, kiosks and convenience stores, is prohibited from serving or selling them between 11:00 pm through 6:00 am the following day.

F. Supervision of Commodities and Services (Garages and Vehicle-related Plants) Order, 1970 - prohibits opening or operating a gas station without a license from the Division of Vehicles and Maintenance Services at the Ministry of Transport.

(3) Most of Delek Israel's public gas stations and convenience stores have received business licenses or temporary permits pending receipt of permanent permits. With respect to other gas stations and convenience stores, Delek Israel or the station owner are taking necessary measures to obtain business licenses or temporary permits, and Delek Israel believes there is nothing material preventing receiving them. There are several indictments are pending against Delek Israel, its subsidiary and officers relating to the operation of gas stations and/or convenience stores without a business license or in contradiction to the permit. From past experience, Delek Israel estimates that apart from insignificant fines and/or issuing a closure order until a business license and/or temporary permit is obtained, it has no material exposure in this regard.

Forward-looking information: The estimate regarding the exposure in this section is forward-looking information, as defined in Section 32A of the Israel Securities Law, based on Delek Israel's past experience. This forward-looking information may not materialize due to the occurrence of events contrary to the Company's and Delek Israel's expectations.

(4) The storage and supply operations require business licensing under the Business Licensing Law and subsequent regulations. The supply facilities in Ashdod, Beersheba and Jerusalem have permanent valid business licenses. The Haifa facility has a temporary license, subject to compliance with certain conditions, valid until August 15, 2020 and Delek Israel is taking steps to obtain a permanent business license.

(5) With regard to the internal gas stations at kibbutz or moshav settlements, ILA Agricultural Division provides that an internal non-commercial gas station may be set up within the area of the agricultural settlement without requiring payment to the ILA, subject to certain conditions. The establishment of an internal station requires obtaining a building permit and operating permits.

(E) Antitrust

(1) Exclusive supply agreements with gas stations:

According to the arrangement between the Competition Commissioner and Delek Israel that was approved on March 29, 1998 and reduced the applicability of the commissioner's previous decision in this regard, exclusive long-term supply arrangements between the fuel companies and gas stations that are not owned or under primary lease from the ILA and with which Delek Israel does not have an accepted lease agreement, (i.e. a lease agreement under which the lease fees paid exceed a certain amount, as defined in the agreement with the Commissioner) are restrictive arrangements. The arrangement also set terms for Delek Israel's contract with gas stations when engaging in exclusive fuel supply agreements of between one and 14 years, based on the circumstances of each contract. These conditions include an obligation for Delek Israel to apply for approval of these agreements from the Competition Tribunal. The arrangement also stipulates that is will not apply to contracts with IDF veterans, and that special terms will be prescribed for them. As at the report approval date, such special terms have not yet been prescribed. The Commissioner announced that he would recommend that the Tribunal approve exclusive supply agreements for limited periods of between one and 14 years, depending on the special circumstances of the station for which the approval of the agreement is requested. On April 28, 1998, based on the arrangement, Delek Israel petitioned the Tribunal for approval of the supply agreements. The Tribunal partially accepted Delek Israel's petition by approving exclusive fuel supply agreements for certain periods of between three to six years

(2) On July 9, 2017 and December 26, 2017, the Competition Authority published a report for public comments, which, in its opinion, examines competition in the gas station segment. According to the report, there are significant price differences between the large and small fuel companies. It further indicates that in areas with a small gas station, this also affects the fuel prices of the large companies. Accordingly, the report also recommends measures that are allegedly supposed to assist in increasing the deployment of small companies and promoting competition in the industry. On March 18, 2018, Delek Israel submitted its response to the report, including economic and legal considerations. At this stage it is difficult to estimate the effect of adoption of the recommendations of the report in its present state, because there is no certainty that they will be adopted and in what form, and there is no certainty as to how they will affect Delek Israel.

Forward-looking information: The estimate regarding the exposure in this section is forward looking information, as defined in Section 32A of the Israel Securities Law, that may not materialize or may materialize in a different manner partly due to events in contradiction to Delek Israel's expectations.

(3) Commissioner and Fuel Authority approval for the Pi Glilot Sale Transaction - The approval of the Competition Authority and Fuel Administration for the Pi Glilot Sale Transaction was received a while ago, allowing the transaction to be completed.

(F) Recognized Ministry of Defense Supplier

Delek Israel participates in tenders published by the Ministry of Defense containing standards and preconditions, and complies with all of them. Delek Israel and Delek Industries are approved suppliers, recognized by the ministerial committee for the approval of suppliers for the Ministry of Defense.

(G) Standardization

Israel has standards for the fuels that are marketed in Israel. Delek Israel markets only products that comply with these standards. Delek Israel has also received international safety standard marks in the storage and supply segment.

1.9.17. Material Agreements

(A) Most of the fuel products sold by Delek Israel are purchased from Bazan (see Section 1.9.11(B) above), except for 2019 in which most gasoline purchases (60%) were made through Vitol SA. Therefore, the agreement between Delek Israel and Bazan is material for Delek Israel.

(B) In the Gas Station and Commercial Compound segment, there is generally no single material agreement regarding title and the method of operating gas stations, but all agreements in the segment are material for Delek Israel.

1.9.18. Legal proceedings

For a description of legal proceedings (including motions to certify class actions) to which Delek Israel is party, see Note 24 to the Financial Statements.

1.9.19. Business strategy and goals

Delek Israel reviews its strategic and business plans from time to time and updates them according to developments in the energy market, the gas station and retail roadway segment, the competitive map and macro-economic effects. Delek Israel's operations in the coming years are expected to focus on the following activities:

(A) The Company's structure will be tailored to this focus and specialization, with emphasis on a narrow, effective organizational structure and improvement of the professional capabilities of the different entities, including professionalism of the employees operating the gas station compounds, with emphasis on improving the proficiency of the procedures required to operate the compound.

(B) Improvement of the appearance of the gas station compounds, including optimization of the refreshment services to customers.

(C) Business focus on the retail and sales segment, including emphasis on the coffee segment.

(D) Analysis of the competitive environment in the different regions and targeted reference for each gas station compound or group of compounds, respectively.

(E) Expansion of the marketing of LPG and natural gas at additional gas compounds and to industrial end users.

(F) Strengthening of relations with large heavy-vehicle fleets (such as heavy trucks and buses) which Delek Israel believes are an initial potential for the transition to refueling with natural gas.

(G) Discontinuation of activities that are unprofitable and not in Delek Israel's core operating segment.

(H) Renewal of rental agreements with station owners, with emphasis on economic viability and profitability of the Company, irrespective of the geographic location of the gas station.

(I) Development of the retail roadways segment, while leveraging the wide geographical deployment and converting some of the gas stations into retail compounds containing a variety of businesses. In this regard and as part of other activities, Delek Israel aspires to significantly increase the volume of sales from operations not originating from fuel.

(J) Examining the operation of the compounds by Delek Israel and outsourcing compounds to operators on behalf of the Company with emphasis on the Company's profits and increasing the quantities sold.

1.9.20. Risk factors

Besides the risk factors set out in Section 1.24 below, the Group's operations are also exposed to the following risk factors in the fuel product segment in Israel:

(A) <u>Effect of the Covid-19 crisis on the fuel segment</u>

As set out in Section 1.6.6 above, against the background of the Covid-19 crisis, global economic activity has slowed down and unprecedented measures are being taken in countries worldwide to eradicate the pandemic, including restrictions on movement in open spaces, restrictions on the activity of the private and public sectors and cancellation of flights. Under these circumstances, the Covid-19 crisis poses a global macroeconomic risk that has generated intense uncertainty about future economic activities worldwide, and particularly regarding the operating segment. If the crisis lasts long, and particularly if the preventive measures in Israel intensify and lengthen, this is expected to have a significant economic impact on Delek Israel's operations, business and profits. As at the report approval date, the main implications expected in the operating segment are:

(1) Impact on fuel and convenience store sales - the restrictions imposed by the government have led to a significant reduction on the business activity in the economy and in the movement of vehicles. Accordingly, from the second week of March 2020, a significant decline in the consumption of fuels in Israel has been observed, which intensified as the restrictions on the economy tightened. As at the approval date of the report, it is impossible to estimate how the Covid-19 crisis will affect future road traffic and demand for Delek Israel's products and services.

(2) Decrease in oil prices - In 2020, there was an exceptionally sharp decline in the prices of energy products, which may be attributed, among other things, to the Covid-19 crisis. If the economic crisis continues and the oil prices remain at low levels over time, this is expected to adversely impact the Company's business.

(3) Demand for jet fuel - A significant drop in the number of flights worldwide, including the number of inbound and outbound flights in Israel has led to a substantial decrease in the jet fuel sales in the reporting year.

(4) As at the report approval date, due to the economic uncertainty, because of the dynamic nature of the crisis and depending on when the pandemic is eradicated, it is difficult to predict the intensity of the crisis and the scope of its impact. Therefore, the Company is reviewing the foregoing implications on Delek Israel as well as additional implications that are currently immaterial, and is taking measures and adjusting its activities.

(B) <u>Changes in in oil and fuel product prices</u> – Instability of global fuel prices, which is likely to lead to high volatility with respect to decreases in the value of fuel inventories within a short space of time. For these changes due to the Covid-19 pandemic, see Section (A) above.

(C) <u>Construction of additional gas stations</u> – In recent years, there is a trend of constructing dozens of new gas stations annually. Continuation of this trend will strengthen competition in the fuel market. See Sections 1.9.5(B)(1) and 1.9.16(D)(1) above. The trend of constructing new competing gas stations adjacent to Delek Israel gas station compounds is also continuing.

(D) <u>Fuel taxation</u> – Since the credit terms which Delek Israel receives from the fuel suppliers to pay for fuel product (include the excise) is far shorter than that offered to its customers, its financial exposure will increase with any rise in excise rates (including on diesel fuel), which could impair its business results. An increase in excise taxes could also lead to a decline in demand for the products sold.

(E) <u>Marketing margin changes</u> – Since the maximum profit margin on 95 octane gasoline is a fixed amount (due to government control) and not materially affected by Bazan ex-refinery fuel price fluctuations or changes to excise tax values and infrastructure prices, if global market prices and the tax applicable to them increase, a situation arises in which there is no built-in compensation for the credit risk costs when customer credit rises. It is also noted that the lack of correlation between the increased returns with respect to operating a gas station and the marketing margin fluctuations may decrease the profit.

(F) <u>Exposure to legal proceedings for hazardous and toxic materials</u> – Since Delek Israel deals in hazardous and toxic materials, it is exposed to damages which may be caused by these materials. Claims for these damages could impair its business results and goodwill. Delek Israel is also exposed to legal, civil and criminal proceedings due to alleged environmental pollution caused in the past and which could be caused from its operations in future, as part which tests and investigations are carried out by the enforcement authorities.

(G) <u>Development of alternative energy sources</u> – Transition to using alternative energy sources is likely to affect Delek Israel's fuel product sales, compel it to invest substantially in adapting its stations to new customer requirements and may also create competition beyond gas stations. If these sources are developed, there is concern that the use gas stations for refueling and/or charging energy might decrease accordingly.

(H) <u>Dependence on refineries</u> – As set out in Section 1.9.11 above, companies operating in the oil distillates segment are almost completely dependent on the Bazan. This dependence is decreased slightly by 95 octane gasoline import agreements.

(I) <u>Failure to obtain required gas station operation approvals and licenses</u> – At some of its stations, Delek Israel does not have all the required approvals and licenses to operate a gas station, while in other cases these have expired and require renewal. If Delek Israel fails to obtain these approvals and licenses, this could impair its operating results.

(J) <u>Credit risk (credit score)</u> – The fuel industry is characterized by provision of a great deal of credit to customers. Most customer credit offered by Delek Israel is not secured by any collateral or guarantees, thereby exposing it to credit risks. These debts are not secured by any collateral or guarantees. An economic slowdown and stricter regulation of the banking system exposes companies operating in the industry, because of the risk that such credit will not be fully repaid.

(K) Developing environmental regulation - which imposes heavy expenses in accordance with additional requirements from time to time and impairs the proper course of conduct of the gas station compounds.

(L) Developing competition regulation - For further information, see Section 1.9.16(E) above.

(M) Ownership structure of gas stations – Due to the ownership structure of gas stations, some of which are rented by Delek Israel and some with which it only has a fuel supply contract, there is a risk that these stations will switch to marketing the products of other fuel companies at the end of the term of the rental/supply agreements. At stations that it neither owns nor operates, Delek Israel is also exposed to greater pressures from operators/owners, and therefore, the profits of such stations is eroded. The rental contracts, which at some of the stations are long-term, do not include an adjustment component between the rent and the marketing margin changes, which may lead to substantial losses for Delek Israel.

Summary of the above risk factors, by type (macro risks, sector-specific risks and risk specific to Delek Israel's fuel product segment), rated according to the Group's estimates by extent of impact on the Group in the fuel product segment in Israel (major, moderate, minor):

	Impact of risk factors on the Group's business in the Israeli fuel product segment		
	Major	**Moderate**	**Minor**
Macro risks			
The Covid-19 coronavirus crisis	X		
Changes in prices of oil and petroleum products		X	
Sector-specific Risks			
Establishment of additional service station		X	
Fuel taxation		X	
Marketing margin changes	X		
Exposure to legal proceedings for hazardous and toxic materials and environmental pollution		X	
Development of alternative energy sources	X		
Dependence on refineries		X	
Risks specific to Israel's fuel product segment			
Failure to obtain required gas stations operation approvals and licenses		X	
Credit risks (credit score)		X	
Developing environmental regulation		X	
Developing competition regulation		X	
Ownership structure of gas stations		X	

The impact of these risk factors on the Company's operations is based on an estimate only and the actual the impact might be different.

Part Four – Matters Pertaining to the Group as a Whole

1.10. Property, plant and equipment and investment property

The Company holds several real estate properties. Below is a breakdown of the main ones (that do not belong to the operating segments described above):

(A) Delek House

As at the date of publication of the Report, the Company holds .71.74% of the rights in the office, commercial and hotel building in Herzliya, of 25,500 sq.m. with four floors above ground and 3 levels of underground parking (below in this paragraph: the "Property"). 1,300 sq.m. of the building is used as offices for the Company, its subsidiaries and companies owned by the controlling shareholder.

In March 2018, the Company received a permit for rezoning to a hotel, and a lease agreement was signed between the Company and Fattal Hotels Ltd. ("Fattal") for the hotel that was constructed in May 2018. Under the agreement, Fattal will operate the hotel in the hotel area leased to it, which has 180 rooms as well as a swimming pool, spa, restaurant, bar, conference hall, lounge. conference rooms, commercial space, etc. The term of the lease is for 5 years from May 15, 2018 and the base rental fee is fixed at NIS 725,000 per month, linked to the CPI. In addition to the fixed rental fees, Fattal will also pay additional rental at a rate equivalent to half of its remaining operating profits as defined in the lease agreement. It is noted that, due to the Covid-19 pandemic, the hotel has not been in operation since March 2020.

In February 2019 a sales transaction was concluded under which the Company sold to Fattal 28,265/100,000 of the Company's title rights in the Property (which, until then, was wholly owned by the Company) whereby 1/3 of the rights in the hotel were transferred to Fattal and 1/3 of the rental paid by Fattal under the foregoing rental agreement were refunded to Fattal, for a consideration of NIS 80 million. A partnership agreement was also signed between the Company and Fattal, both to regulate the joint management of the hotel and to split the land between the shared hotel and the offices that will remain exclusively owned by the Company, and to move forward with planning to increase rights in the land and exercise other rights, if approved to the land (below in this paragraph: ("Partnership Agreement"). In accordance with the Partnership Agreement, Fattal paid the Company an amount of NIS 24 million for its investment in the construction of the hotel. Furthermore, as part of the transaction, the Company engaged in a loan agreement with Fattal, under which the Company provided Fattal with a loan of NIS 39 million, linked to the CPI and bearing interest at a rate of 2.96%, to pay the consideration. In January 2021, the Company and Fattal received a loan from a third party for refinancing the Property in Herzliya, as set out in section **Error! Reference source not found.** below. Concurrent to receiving the financing, Fattal paid the Company the entire amount of the loan provided by the Company.

Since 2017, the Company has been working to advance plan HR/2374/A, which is designed to increase rights and generate mixed-use zoning for hotels, industry, public and residential building and utilization of the space above the existing building, based on the Herzliya Municipality's strategic plan for the city's western industrial zone. On February 15, 2021, the Tel Aviv District Planning and Building Committee objections subcommittee held a hearing on the objections to the plan filed by the Company (self-objection) and the Municipality of Herzliya. Following the objections, the subcommittee on objections decided to approve the plan on condition that it will include, among other things, prime space of 6,000 sq. m. for residential use, 20,000 sq. m. for industry and hotels, and 1,800 sq. m. for commercial space.

For further information relating to Delek House, see section 11(A) to the Notes to the Financial Statements.

(B) Property in Acre

A wholly owned subsidiary of the Company (the "Subsidiary") owns 430 dunam of land near the beach in Acre (the "Land"). As set out below, on March 25, 2021, the Company signed an agreement for the sale of the Land.

As at December 31, 2020, the Land was recorded in the Company's books at a cost of NIS 135 million (after deducting the estimated liabilities relating to the Land). Located on the Land are building ruins, various equipment items, debris and materials, including hazardous materials, and there may also be actual ground contamination. The Subsidiary has engaged in an agreement for right of use, for a fee, which is renewed from time to time, with a company that operates a station for pumping brine into the sea. In 2019, the Company paid the Israel Lands Authority (ILA) an amount of NIS 37 million in respect of past debts and capitalization fees for regulating the lease contracts with the ILA. The cost of the land includes the payment of the foregoing debt, but does not include the estimated liability for the treatment of the Land as is required for the development of the Land. The Company, together with a third party, filed with the Acre Municipality a detailed town building plan for residential, hotel and industrial areas, based on the master outline plan for Acre, which was approved in 2017. On March 25, 2021, the Subsidiary signed a detailed sale agreement for the sale of its rights in the Land, as is, for consideration in the amount of NIS 200 million. For further information see the immediate reports issued by the Company on January 14, 2021 (Ref. No: 2020-01-113067), on February 10, 2021, (Ref. No.: 2021-01-017248), on February 28, 2021, (Ref. No.: 2021-01-024300), on March 16, 2021, (Ref. No.: 2021-01-036285), and March 25, 2021, (Ref. No.: 2021-01-046893), whereby the information appearing in said reports are noted here by way of reference.

For further information concerning the motion for certification of a class action that was filed with respect to the quality of the environment regarding real estate, see Note 24A4(2) to the Financial Statements.

1.11. Human resources

1.11.1. Organizational structure

The Group's executive officers and other administrative staff are also involved in the management of some of the companies held by the Company and which are considered to be part of the Company's Staff Companies. (For a flowchart illustrating the structure of holdings of the Group and definition of its Staff Companies, see section 1.1 above).

The description in the sections concerning the Company's entire operations refers to the Company and its Staff Companies (100%) as a single entity.

1.11.2. Employee headcount

The Company employs a staff (including service providers) of 25, of whom five are executive officers and the rest are head office and administration employees.

1.11.3. Officers and executive management employees in the Group

The officers and executive management employees are employed under personal contracts or management fees agreements. The officers are eligible for insurance, waiver and indemnification in respect of activities performed in their official capacity. For further information concerning the executive officers, see Regulation 26 in Chapter D to the Periodic Report.

For further information pertaining to remuneration of senior officers in the Group pursuant to Regulation 21 in the Periodic and Immediate Reports Regulations, including information relating to the revised officers’ compensations policies, see Chapter D to the Periodic Report, below.

1.12. Operating Capital and its Composition

The Company's working capital consists of the Company's current assets, including cash of deposits in banks and investments in securities. On the other hand, the Group has current liabilities with regard to its obligations to banks and debenture holders which are due for repayment as of the coming year.

As at December 31, 2020, the Company (separate) has a working capital deficit of NIS 5.2 billion, and the Group (consolidated) has a working capital deficit of NIS 4.3 billion, mainly due to classification of debentures (beyond current maturities) in the amount of NIS 4.3 billion to short term. This classification is mainly in due to the fact that some of the waiver items in the amended the deed of trust of the debenture series of June 2020 (see Note 19) are for less than twelve months from the date of the Financial Statements. For further information, see Note 1C to the Financial Statements.

1.13. Financial assets

Breakdown of the liquid balances of the Company and its wholly owned subsidiaries, as of December 31, 2020:

	At December 31, 2020 (in NIS millions)	**Close to the approval of the Report** (in NIS millions)
Cash and deposits*	159	70
Securities portfolio	24	-
Deposit pledged in favor of the debenture holders	92	-
Total	**275**	**70**

* The cash and deposits are in held in Israeli and in foreign banks.

For further information regarding investments in securities and with regard to financial assets, see Notes 4 and 9 to the Financial Statements.

1.14. Financing

(A) General

For the Group’s financing purposes, from time to time the Company issues tradable debenture series and receives, directly or through its Staff Companies, loans and credit facilities from banks and financial institutions, which are mostly secured with liens. The procedure is that material financing transactions executed by the Headquarters Companies are not only approved within these companies, but are also submitted for approval by the Company's Board of Directors.

In the wake of the Covid-19 pandemic and in view of the steep decline and high volatility recorded in the prices of securities of the Company and its investees in the first half of 2020, the Company negotiated with its creditors during this period, regarding the conditions set out in the financing agreements, particularly with regard to the required financial covenants and causes for calling the borrowings for immediate repayment. During this period the Company adopted measures to repay loans it received from banks and financial institutions, and added collateral in order to meet the criteria and/or to avoid calling for immediate repayment and/or exercising of collateral.

In June 2020, the Company engaged in agreements with financial creditors and signed an amendment to the deed of trust for each of its debenture series, as set out below.

In accordance with a deed of consent with the banks, which was signed in June 2020, during 2020 and at the beginning of 2021, the Company and its Staff Companies repaid most of their secured debts to the banks and financial institutions, in a total amount of NIS 1.6 billion.

As at December 31, 2020, the Company and its Staff Companies have repaid all loans received from banks and financial institutions, other than a loan in the amount of USD 8 million to a foreign bank, that is due for whose repayment as of May 2021, and a loan in the amount of NIS 120 million to the Israeli financial institution Amitim, which was repaid in January 2021, and shortly after repaying it, the Company was granted a loan from a third party, in the amount of NIS 104 million, as described in section 1.14.7, below.

For further information concerning the credit facilities and loans provided to Delek Drilling, Ithaca and Delek Israel, see the sections on financing in the description of the operating segments, in sections 1.7.22, 1.8.18 and 1.9.13, above.

In addition, for further information concerning the Group's financing sources see Notes 1 and 10 to the Financial Statements.

1.14.2. Breakdown of the average interest rate on loans from bank and non-bank sources effective during the reporting period and which are not designated for specific use:

			Short-term loans		Long-term loans	
			Average interest rate	Effective Interest rate	Average interest rate	Effective Interest rate
Banking sources	Unlinked NIS credit at variable interest		3%	3.1%	-	-
	USD linked credit		6.8%	7%	-	-
	Euro linked credit		4%	4.1%	-	-
Non-banking sources	Unlinked NIS credit		-	-	-	-
	Linked NIS credit	Members	3.4%	3.5%	-	-
		Debentures	5.2%	5.3%	-	-
	Unlinked NIS credit	Debentures	3.8%	3.9%	5.2%	5.3%

1.14.3. Amendments to the deeds of trust between the Company and the debenture holders of the various series

(A) On June 17, 2020, the general meeting of the holders of the various series of the Company's debentures approved the amended deed of trust of each of the Company's debenture series, (the "Amended Deed"). Description of the highlights of the Amended Deed:

(1) Capital raising: the Company undertook to raise capital in an aggregate amount of NIS 500 million by April 8, 2021, by means that where decided. Of the foregoing amount, the Company raised, in May, August and December, 2020, a total amount of NIS 450 million (including the proceeds from exercising options for the Company's shares).

(2) Negative pledge, prohibition of early payment and other liabilities: the Company's undertaking that in the stipulated period (as defined below), the Company and the private companies under its control:

a) Will not create liens, will not increase amounts secured by existing liens, and will not provide guarantees, other than liens and guarantees that are exempt as set out in the deed of trust.

b) Will not pay creditors on a date that is earlier that the date set out in the repayment schedule, other than payments that are exempt as set out in the deed of trust.

c) Will not transfer funds and/or assets to Ithaca companies and/or their creditors and will not assume liabilities and/or guarantees regarding Ithaca companies[240] and/or their debts, other than payments that are exempt or that the Company is permitted to perform as set out in the deed of trust.

(3) In the Amended Deed the term "the record period" means the period from the approval date of the deed of trust until seven days have elapsed from the publication date of the Company's immediate report on the expiration condition; "the expiration condition" means that the following conditions were fulfilled at that date: (a) the Company's equity as recorded in its financial statements and the reports for the preceding quarter exceed the higher of (i) NIS 2.8 billion less any amount of cash that the Company will raise as equity that exceeds the amounts it is required to raise as set out in paragraph (1) above; (ii) NIS 2.1 billion; (b) the ratio of equity to the balance sheet in the Company's statements (separate) and in the statements of the prior quarter is not less than 22.5%; (C) the rating of the Company's debentures is at least A (according to S&P Maalot scale).

(4) <u>Liens</u>: the Company undertook to create a lien on the various assets of the Group, in favor of the Company's trustees and debenture holders, including the following assets:

(a) Participating units that confer interests in the rights of the limited partner in Delek Drilling Limited Partnership, representing 40% of the capital in the Partnership's issued units: as at December 31,

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240 DKL Investment Limited ("DKL") and any company under its control.

2020 and close to the Reporting Date, the Company has pledged, in accordance with its undertakings under the amendment to the deed of trust, 469,525,878 participating units, constituting 40% of the Partnership's equity. As of January 1, 2022, the Company may have the right to demand the release of some of the participating units pledged in favor of the debenture holders, in the amount and subject to the terms set out in the Amended Deed;

(b) The shares and rights in various companies that are controlled by the Company and/or for it; as at December 31, 2020 and close to date of approval of the Report, the following liens were recorded: a fixed and exclusive lien on Delek Energy shares (and underlying rights); a fixed lien on the shares of Israel Delek Holdings (and underlying rights); fixed and exclusive lien on Delek Energy shares (and underlying rights); fixed lien and endorsement of rights with respect to the Company's rights of any and all kinds in Delek Financial Investments Partnership. A lien was also recorded on shares of Delek Israel held by Delek Petroleum and on participating units held by Delek Energy and by Israel Delek Holdings.

c) The rights under the loans provided to the Company and/or companies under its control: As at December 31, 2020 and close to Reporting Date, liens were recorded on all the Company's rights under the loans (including capital notes) that the Company provided to Delek Gom Holdings; DKL Investments Limited; DKL Energy Limited; Ithaca Energy Limited; Delek Sea Maagan 2011 Ltd.; Delek Power Stations Limited Partnership;

(d) The assets of Delek Financial Investments Partnership Ltd: As at December 31, 2020 and close to Reporting Date, all debentures and shares of the Company that are held by Delek Financial Investments;

(e) Rights under loans provided to third parties: as at December 31, 2020 and close to Reporting Date a lien was recorded with regard to a loan that the Company provided to Belenus Lux S.a.r.l. For further information regarding this agreement, see section 1.15.3(A), below.

(5) <u>Grounds for calling for immediate repayment in the amendment to deed of trust:</u>

A. For the period up to May 31, 2021, the trustee and the debenture holders will not call for immediate repayment of the debentures based on the established grounds, but only on the state of the Company's business as it was at the publication date of the amendment to the deed of trust and/or by virtue of the grounds relating to a low rating of the Company's debentures. If, after May 31, 2021, the S&P Maalot rating of the debentures is lower than BBB-, then on that date the Trustee and the debenture holders will have cause for calling for immediate repayment and for exercising collateral under such cause, without the need for a further period after the date of the cause.

B. Up to the publication date of the statements for the first quarter of 2021, the grounds for immediate repayment included in some of the deeds of trust regarding low equity will not apply. For the statements as from the second quarter of 2021 and up to the annual financial statements for 2021, the debenture holders will have grounds to call for immediate repayment if the equity net of the additional capital from revaluations is lower than the total equity of the Company the second quarter of 2020 (i.e., NIS 1.6 billion) the "Benchmark Equity"). For the statements as from the first quarter of 2022 and up to the annual financial statements for 2022, the debenture holders will have grounds to call for immediate repayment if the equity net of the additional capital from revaluations is lower than the Benchmark Equity, with the addition of NIS 1 billion, or if the equity in the financial statements is less than NIS 2 billion. For the statements as from the first quarter of 2023 and up to the annual financial statements for 2023, the debenture holders will have grounds to call for immediate repayment if the equity net of the additional capital from revaluations is lower than the Benchmark Equity, with the addition of NIS 1.4 billion, or if the equity in the financial statements is less than NIS 2.4 billion. As of the statements for the first quarter of 2024, and thereafter, the debenture holders will have grounds to call for immediate repayment if the equity in the Company's statements falls below NIS 2.6 billion.

C. Up to date of publication of financial statements for the first quarter of 2021, the grounds for immediate repayment included in some of the deeds of trust regarding equity to balance sheet ratio will not apply. With respect to financial statements from the second quarter of 2021 and up to the annual financial statements for 2021, increments were set concerning the equity to balance sheet ratio regarding which, if the Company will fail to comply, the debenture holders will have grounds to call for immediate repayment. In 2021 - 12.5% of (separate) balance sheet; in 2022 - 15% of (separate) balance sheet; in 2023 - 17.5% of (separate) balance sheet; As of the first quarter of 2024, the debenture holders will have grounds to call for immediate repayment if the equity to total equity to balance sheet ratio in accordance with the Company's separate financial statements falls below 20% over two consecutive quarters.

(6) The amendment to the deed of trust includes various declarations and undertakings of the Company, including: (a) In connection with the uses to be made of the proceeds from the capital issuances and/or dividends and/or sale and/or pledge of certain assets; (b) a commitment not to deposit funds and/or securities in banks that are creditors of the Company or companies under its control, other than the exceptions that were established; (c) a commitment not to acquire assets and/or to make investments and/or to take credit and/or to make financial liabilities to financial creditors and/or to change the terms of certain credit agreements, other than the exceptions that were established; (e) in the record period: The Company's general and administrative expenses will not exceed the amounts that were established, the Company will not perform a distribution, the Company and the companies under its control will not enter into transactions in which the controlling shareholder has a personal interest (other than officers, insurance and existing agreements as set out in the statements), the Company and private companies under its control will not sell or purchase the Company's debentures; (e) an obligation to cover the expenses and fees of the trustees and their representatives. It was further established that a breach of any of the Company's obligations under the amendment to the deed of trust will serve as grounds for the trustees and debenture holders to call for immediate repayment and the right to exercise all the collateral provided to the trustees. With regard to the Company's compliance with its liabilities, see Note 1C and Note 19 to the Financial Statements.

For further information concerning the amendment to the deed of trust, see the immediate reports issued by the Company on June 14, 2020 (Ref. No: 2020-01-061782), June 15, 2020, (Ref. No.: 2020-01-062244), June 16, 2020, (Ref. No.: 2020-01-062382), June 17, 2020, (Ref. No.: 2020-01-062943), June 21, 2020, (Ref. No.: 2020-01-064374), the information appearing in said reports are noted herein by way of reference.

1.14.4. Repayment in full of credit facilities and loans to the relevant banks under the deed of consent with the banks

On June 15, 2020, the Company, Delek Energy and DKL signed a deed of consent with various banks that provided the Company and/or Delek Energy with credit secured by a lien on the participating units of the Partnership, and with a foreign bank that provided a loan to DKL ("the Relevant Banks"), in the deed of consent, which includes (inter alia) provisions concerning pledging all Delek Israel shares in favor of the Relevant Banks. Pursuant to the provisions of the agreement, the Company acted to sell Delek Israel shares and the proceeds that will be received from such sale, was used to repay the borrowings to the Relevant Banks, pro rata according to the share of each bank in the total borrowings. For further information concerning the sale of Delek Israel, see section 1.9, above. Under the deed of consent, in July and August, 2020, the Company made a payment of NIS 504 million to the Relevant Banks and on October 28, 2020, the Company paid an additional amount of NIS 340 million, and thereby paid up in full all the credit facilities and loans to the relevant Banks. For further information concerning the schedule with the Relevant Banks, see the immediate reports issued by the Company on June 4, 2020 (Ref. No: 2020-01-057492), June 14, 2020, (Ref. No.: 2020-01-061782), June 15, 2020, (Ref. No.: 2020-01-062244), June 16, 2020, (Ref. No.: 2020-01-062382), June 21, 2020, (Ref. No.: 2020-01-064374), the information appearing in said reports are noted herein by way of reference.

1.14.5. Addendum to the support agreement signed with Bank Mizrahi and consortium of financiers

The Company engaged in an agreement (the "Support Agreement") with a consortium of financial institutions led by Bank Mizrahi Tefahot Ltd. ("Bank Mizrahi") (jointly: the "Lenders"), under which it assumed the undertakings concerning funding in the amount (principal) of NIS 548 million (the "Funding"), that the Lenders provided for the acquisition of shares of The Phoenix Holdings Ltd. ("the Phoenix"), in an acquisition transaction that was concluded in November 2019. For further information about the loans provided to buyers of the Phoenix shares, see section 1.15.3(A), below.

Under the addendum to the Support Agreement that became effective at the same time as the amendment of the foregoing deed of trust came into effect, the Lenders and the Company concluded as follows: a lien was placed on the participating units in Ratio Petroleum Energy - Limited Partnership in favor of the Lenders; and a cash deposit of NIS 74 million from the sale of the all the shares of Mehadrin Ltd. held by the Company were pledged. The lien was fixed in full, based on the number of installments as set out in the appendix to the Support Agreement.

It was further agreed with the Lenders in the addendum to the Support Agreement that (notwithstanding all the provisions of the Support Agreement) by the earliest date of - (1) calling for immediate repayment of the debt to the debenture holders of the Company in accordance with a resolution adopted by any meeting of the debenture holders; and (2) fulfillment of the expiration condition (as defined in the amendment to the deed), and other than the exceptions set out below, the Lenders may not demand any requirement of the Company under the Support Agreement or the addendum to the Support Agreement, and it was further determined that the Lenders may not demand that the Company create additional liens or other collateral, and/or additional deposits and/or payments, subject to the following exceptions: (a) the liens granted to lenders are as described above; (b) effective from the date on which the expiration condition was met (as defined in the amendment to the deed of trust) and/or under circumstances where the holders of the Company's debentures of any series have called the debt owing to them for immediate repayment - the provisions of the Support Agreement will apply, and the Lenders will not be restricted under the Support Agreement, which will terminate immediately; (c) interest payments in respect of the Funding (directly for the Lenders, or the pledged "interest deposit"), if it arises that the Company is required under the Support Agreement to pay them; (d) if one or more of the conditions set out in the Support Agreement that relate to the Phoenix and that, under the Support Agreement, establish an obligation for the Company to provide supplementary collateral ("Phoenix Events")[241], then the Company will provide a cash deposit in the amount required as per the Support Agreement, provided that the amount of the foregoing deposit will not in any case exceed NIS 40 million cumulatively (the "Additional Deposit"). For the avoidance of any doubt, as agreed - the Additional Deposit (if provided) will be limited to the amount of NIS 40 million, even if more than one Phoenix Event occurs. For the avoidance of doubt, it is emphasized that the Additional Deposit will be in addition to and over and above the lien on Ratio participating units and the lien on the Mehadrin deposit; (e) expenses and/or fees (including commissions for early redemption) paid in respect of the Funding (if it arises that the Company is liable under the Support Agreement) and in respect of the addendum to the Support Agreement.

1.14.6. Credit facilities

In view of the repayment in full of all borrowings to the Relevant Banks, in accordance with the deed of consent described above, as at December 31, 2020 and close to date of approval of the Report, the Company and Delek Energy do not have bank credit facilities.

1.14.7. Loans

(A) As at December 31, 2020, the Company and its Staff Companies have a financial loan from a foreign bank in the amount of USD 8 million and an additional loan from the Israeli financial institution Amitim, in the total amount of NIS 113 million. Subsequent to balance sheet date, in January 2021, the loan from Amitim was paid off in full and close to this date a third party provided a loan in the amount of NIS 104 million, as set out below.

(B) The following table and notes below the table set out information concerning such loans that were in effect on December 31, 2020 and close to the approval date of the Report "the Loans").

As is standard practice in such financing transactions, the loan agreements included grounds for immediate repayment in the occurrence of default events, subject to remedy periods and specific conditions that were specified in the agreements. Grounds for immediate repayment may be: failure to comply with financial covenants set out in the agreement, extraordinary events, change of control, appointment of a liquidator or receiver, events of default, cross default events, downgrading of ratings, substantial impairment of the Company's businesses, going concern caveat in the Financial Statements, etc.

[241] The Phoenix Events are only the following events: (a) the Phoenix leverage ratio (as defined in the Support Agreement) exceeds 22.5%; (b) the Phoenix net debt (as defined in the Support Agreement) exceeds NIS 1,800,000,000; (c) the debt-to-collateral ratio (as defined in the Support Agreement) increasing above the rate stipulated in the Support Agreement; (d) downgrading of the Phoenix credit rating to BBB+ or lower by S&P Maalot (or corresponding rating of another company); (e) execution of a distribution (as defined in the Support Agreement) by the Buyer.

#	Borrower	Lender	Loan received on	Original amount of Loan	Loan principal as at December 31, 2020	Loan principal balance close to Report approval date	Principal maturity dates	Interest and linkage	Collateral
1	DKL Energy	Foreign bank	Nov 4, 2019	USD 200 million	USD 7.5 million	USD 7.5 milion	The balance will be paid in May 2021.	As at December 31, 2020 and close to date of publication of the Report, the interest is 3-month LIBOR + 10.5% margin with StepUp of 0.50% after 12 and 15 months from date of receipt of the loan. Interest is paid every 3 months from the date of receipt of the loan.	100% of DNSL shares, the parent company (100%) of Ithaca; 100% of Ithaca shares; Guarantees of the Company on accrued and unpaid interest, on the first margin call and certain events of default (mainly distributions or inter-company transactions prohibited under the agreement). A negative charge was placed on Delek Drilling participating units at a rate of 6.6%.
2	The Company	Israeli financial institution	July 21, 2016 (Repaid)	NIS 160 million Shekel.	NIS 113 million	-	Was repaid on January 2, 2021	Interest of 3.46% linked to the CPI.	Lien on the land rights and other rights in the office building in Herzliya.
3	The Company	Third party	Jan 25, 2021	NIS 104 million Shekel.	-	NIS 104 million Shekel.	Due on January 24, 2024	Interest of 7% linked to the CPI.	Lien on the land rights and other rights in the office building in Herzliya.

(*) Repaid at beginning of January 2021.

(C) Notes and additional information concerning the Loans

Below is further information concerning the loans specified in the above table and with regard to the financial criteria set in their terms.

(1) Loan No. 1

A. Financial undertakings, financial criteria and grounds for immediate repayment:

1. The original agreement set out margin call events, according to which the Borrower is required to deposit cash in the event of a 20% impairment of benchmark companies similar to Ithaca (as defined in the agreement - "Benchmark Companies") or decline of 20% in the FTSE100 index, the Borrower will be required to deposit cash to the value of the decline as defined in the agreement. In an amendment to the agreement signed in August 2020, all such margin call events set out in the agreement were canceled.

2. The loan stipulates commitments to comply with financial covenants, according to which the ratio of total net debt to net profit before taxes and financing, net of depreciation and amortization and net of appraisal and exploration expenses (EBITDAX) does not exceed 2.5. Testing of this ratio is required as of Ithaca's 2019 reports. Based on Ithaca's financial statements for 2020, the Borrower is in compliance with this financial criterion.

3. The original agreement set out rating events that give the Lender cause to call for immediate repayment of the entire loan. In the amendment to the agreement of August 2020, these events were canceled.

4. The amendment to the agreement of August 2020 provides that the Lender is entitled to demand immediate repayment of the loan, inter alia, in the event of insolvency or impairment of the annual value of the S&P Global Oil Index below the level set in the agreement, and in the event of cross default and in the event of early repayment of another debt.

5. Under the agreement, any dividend that will be paid in the Ithaca Group companies will first be used to repay the Loan and the shareholders' loans provided by the Company to the Ithaca Group companies will be subordinated. Other restrictions were also set, among others, with regard to limiting the amount of the existing debt.

B. Repayments made during 2020:

1. Towards the end of February 2020, due to impairment of the mix of the Companies, a margin call event occurred and in accordance with the terms of the agreement the Borrower - DKL Energy - made a cash deposit in the amount of USD 43 million.

2. Further to the foregoing, in March 2020 events occurred that could have led to a call for early repayment and with regard to all the foregoing events, the Borrower received a notice from the Lender that it reserves its right to partial and full early repayment of the loan, but did not require the Borrower to repay the loan.

3. On April 7, 2020, the parties signed an amendment to the agreement, according to which it was agreed, inter alia, that the amount of the foregoing cash deposit will be used for partial repayment of the loan principal.

4. In May 2020, an amount of USD 20 million was repaid and in November 2020, an additional USD 100 million was repaid. Furthermore, of the proceeds received from the sale of Delek Israel, in October 2020, USD 30 million was repaid, so that the balance of the loan following such repayments is USD 7.5 million.

(2) Loan No. 2

In the amendment to the deed of trust as set out in section 1.14.3, above, the Company reached agreements with the financial corporation that funded the Property in Herzliya, according to which the Company repaid the loan from the financial corporation in full on January 2, 2021.

(3) Loan No. 3

A. In January 2021, the Company together with Fattal Hotels Ltd. received a loan from a third party for refinancing the Property in Herzliya in the amount of NIS 145 million (the Company's share is NIS 104 million) for a period of 3 years, that is secured by the mortgage on the Property.

B. The outstanding loan principal bears fixed annual interest of 7% and is linked to the CPI.

C. Customary events were set for the calling the loan to be immediate repayment, including: breach of the agreement for a period exceeding 45 days, incorrect statement that is not amended for a period of 45 days, structural changes in the Borrower, including transfer of assets, default proceedings for a debt in excess of NIS 40 million that is not settled within the periods stipulated in the agreement, negotiations or settlement between the Borrower and various creditors, change of control without obtaining the consent of the lender, cessation of the Borrower's operations, and in the event of a material adverse change in the Borrower's ability to repay the loan, impairment of collateral or cross-default of a debt exceeding NIS 50 million, other than if the Borrower satisfies the lender that such demand for payment will not prevent the Borrower from meeting its obligations under the loan agreement, in full and on time, in event of failure to pay rent, and if a going concern caveat is again recorded in the Company's financial statements. The agreement stipulates that in the occurrence of any of the events as set out for early repayment with regard to the Company alone or with regard to Fattal Hotels Ltd. alone, it will constitute grounds for immediate repayment with respect to the other borrower as well.

1.14.8. Conversion undertaking

On December 18, 2019, DKL together with the Company signed an agreement with a financial institution with regard to an investment of USD 50 million in DKL with an automatic conversion mechanism, under certain conditions, into ordinary shares of the issuing company in the event of an IPO of Ithaca or its affiliate. For further information, see Note 19I to the Financial Statements.

1.14.9. Debentures

For further information concerning the Company's debentures, see section E in the Company's Board of Directors' Report. For further information regarding restrictions under the debentures, see section 1.14.11(A)1.14.11(A), below.

For further information concerning the issue of debentures in a total amount of USD 180 million, which Delek Overriding Royalty Leviathan Ltd., a special purpose subsidiary of Delek Energy, issued to foreign and Israeli classified investors, and which are secured by the Leviathan overriding royalties and the rights attached to the royalties, see section 1.7.22(B) above.

1.14.10. Borrowings at variable interest

Breakdown of variable interest credit received by the Company in 2020:

Variation Mechanism	Interest Range in 2020	Interest Rates close to date of publication of the report
Bank of Israel Interest +	2.6% - 3.5%	-
USD - LIBOR+	2.8% - 8.7%	8.7%
EUR - LIBOR+	4%	-

1.14.11. Restrictions on the Company under the financing agreements

(A) The Amended Deeds of Trust for the Company’s debentures set out financial ratios as described in section 1.14.3, above.

(B) Under the Amended Deeds of Trust all the causes for immediate repayment in any of the deeds of trust were added to all of the series, so that each of the series has the same causes.

1.14.12. Liens

1. For further information concerning liens registered in favor of debenture holders, see section 1.14.3, above.

2. For further information concerning liens in favor of the Support Agreement, see section 1.15.13(A), above.

3. With regard to a lien on the rights to receive overriding royalties from the Leviathan Project, see section 1.7.22(B), above.

4. For further information concerning liens provided to Delek Drilling, Ithaca and Delek Israel, and their investees, see the sections on financing in the description of the operating segments, sections 1.7.22, 1.8.18 and 1.9.13, above.

1.14.13. Credit limits

Under the amended deeds of trust, the Company undertook, among other things, that during the effective period it and all private companies under its control (other than Delek Drilling, Delek Israel companies and Ithaca companies), will not purchase assets; will not make investments of any kind whatsoever; will not take any credit, will not assume additional financial liabilities towards an existing financial creditor (this restriction does not apply to the purchase of assets in the ordinary course of business that will not exceed, for the entire effective period, an aggregate amount of NIS 20 million). The amended deeds set out a number of exceptions to the foregoing restrictions.

The Group is subject to the Proper Banking Management Directives issued by the Supervisor of Banks in Israel, which include, inter alia, restrictions on the volume of loans which the Israeli banks may extend to a single borrower and the largest borrower group in the bank (as these terms are defined in the aforementioned directives).

1.14.14. Credit rating

(A) On March 23, 2020, Midroog announced that it was downgrading the rating of Debentures (Series B13, B18, B19, B22, B31, B33, B34) issued by the Company from A2.il to Ca.il and changing the direction of the review from review for downgrade to review with direction uncertain. For further information see the immediate reports issued by the Company on March 23, 2020 (Ref. No: 2020-01-028470), where the information appearing in said report noted here by way of reference.

(B) On April 1, 2020, S&P Maalot rating agency announced that it was downgrading the rating for Debentures (Series B13, B22, B31, B33 and B34) issued by the Company, from ilA/Stable to ilBBB-/Negative. For further information see the immediate reports issued by the Company on April 1, 2020 (Ref. No: 2020-01-034443), where the information appearing in said report noted here by way of reference.

(C) On April 13, 2020, the Company notified the rating agency Midroog Ltd. of the termination of its engagement with them. According to the Company's notice, in view of the fact that the Company has another rating company (S&P Maalot), that rates the Company’s debentures in accordance with the requirements of its deeds of trust, the Company resolved that there is no need for the services of two separate rating companies and therefore the Company gave notice of the termination of the engagement as of April 13, 2020, thereby, as of this date, Midroog Ltd. will cease to be the rating company for the series of the Company's debentures and they will be rated by S&P Maalot. On April 16, 2020, Midroog Ltd. Announce the termination of its rating of the Company's debentures.

(D) On May 5, 2020, S&P Maalot announced that it was downgrading the rating for Debentures (Series B13, B22, B31, B33 and B34) issued by the Company from ilBBB-/Negative to ilCCC/Negative. For further information see the immediate reports issued by the Company on May 5, 2020 (Ref. No: 2020-01-044400), where the information appearing in said report noted here by way of reference.

(E) On September 30, 2020, S&P Maalot announced that it was upgrading the outlook for Debentures (Series B13, B22, B31, B33 and B34) issued by the Company to Developing. For further information see the immediate reports issued by the Company on September 30, 2020 (Ref. No: 2020-01-106689), where the information appearing in said report noted here by way of reference.

(F) Subsequent to balance sheet date, on January 31, 2021, P&S Maalot announced that it was upgrading the rating for Debentures (Series B13, B22, B31, B33 and B34) issued by the Company from illCCC/Developing outlook to ilB with Developing outlook, due to the measures adopted by the Company to reduce the debt and improve its sources. For further information see the immediate reports issued by the Company on January 31, 2021 (Ref. No: 2021-01-012097), where the information appearing in said report noted here by way of reference.

1.15. Loans and Guarantees provided by the Company

1.15.1. Breakdown of material loans to the Company's subsidiaries and affiliates, as at December 31, 2020 (in NIS millions):

Lender	Borrower	Loan amounts at December 31, 2020
Delek Group	Delek Sea Maagan 2011 Ltd.	136
Delek Group	Ithaca	881

1.15.2. Breakdown of guarantees provided to the Company's subsidiaries and third parties, as at December 31, 2020 (in NIS millions):

Guarantor	Guaranteed	Guarantee amount At Dec 31, 2020
Guarantee for liabilities of subsidiaries and related companies		
Delek Group	Block 7	21
Delek Group	Yam Tethys assets	2
Delek Group	Municipality of Herzeliya	1
Total		**24**

The Company signed an unlimited performance guarantee in favor of the Republic of Cyprus to secure full implementation of all undertakings of the Partnership in accordance with the PSC agreement as set out in section 1.7.6, above.

1.15.3. Breakdown of Seller's loans provided on date of sale of assets as, set out in Note 8 to the Financial Statements (in NIS millions):

Lender - the Seller	Borrower - the Buyer	Loan amounts at December 31, 2020
Delek Group	Fattal Hotels	33 *
Delek Group	Centerbridge and Gallatin - The Phoenix Deal	143
Total		**176**

* The loan was repaid in January 2021

(A) **<u>The Phoenix Loan</u>** - on November 3, 2019, the Company completed a transaction for the sale of 32.5% of the share capital of The Phoenix to Belenus Lux S.a.r.l, a company controlled by the Centerbridge Foundation and Gallatin Point Capital Foundation (the "Buyers"), The consideration for the transaction as at closing date amounted to NIS 1.57 billion (after adjustments for dividends distributed by The Phoenix by closing date). Of this, an amount of NIS 1.335 billion was received in cash on closing date and the balance, in the amount of NIS 235 million, was provided to the buyers as a loan by the Company (the "Seller's Loan").

Part of the consideration paid in cash to the Company by the buyer was financed by a first-degree loan of NIS 548 million that the Buyer received from financial institutions ("the First-Degree Loan"). With regard to the First Degree Loan, the Company signed an agreement with the financial institutions, that includes and undertaking to make certain payments if not paid by the buyer, in the occurrence of certain conditions as set out in the agreement, among others: (a) to pay the interest on the First Degree Loan if the buyer has no resources for paying it (in which case this amount will be added to the Seller's Loan principal); (b) to pay certain fees, including early repayment fees, with regard to the First Degree Loan; (c) to guarantee part of the buyers' liabilities and with regard thereto, to deposit certain securities and if the conditions set out in the letter of undertaking to deposit additional securities are met; and (d) to pledge cash deposits to secure the foregoing undertakings. The amounts that the Company is required deposit in the pledged deposits and the dates on which it is required to deposit them are defined in the agreement, and the amounts may exceed a maximum amount of up to 50% of the amount of the First Degree Loan (plus the amount deposited in a reserve to guarantee interest on the First Degree Loan), if the events defined in the agreement occur, including: 1. if certain financial conditions set out in the agreement arise, such as: (a) the Phoenix leverage ratio (as this term is defined in the agreement) exceeds 22.5%; (b) the net debt (as this term is defined in the agreement) of the Phoenix Holdings exceeds NIS 1,800,000; 2. a downgrade in the credit rating of the Phoenix Holdings (below a rating of BBB+); 3. a material debt of the Company (as this term is defined in the agreement) was called for immediate repayment due to an event of default; 4. the Company breached a commitment to pay a debt of least NIS 25 million for a material debt; 5. a downgrade in the credit rating of the Company which constitutes an event of default in respect of the material debt. If the Company breaches its obligation to deposit the required amounts and in the event of a breach of representation for the financial statements of The Phoenix, the maximum amount it may be required to deposit may exceed 100% of the amount of the First-Degree Loan, and then the Company has the right to call for the endorsement of the First Degree Loan, subject to certain conditions.

The First Degree Loan and the Seller's Loan were provided for an initial period of five years, with two options for extension of one year each, subject to the fulfillment of certain conditions.

The Seller's Loan bears interest at a rate that will result in the total interest to be paid by the buyer for both loans together will be 4% per year for the first five years, 7% for the sixth year, and 8% for the seventh year. As a result, during the first 5 years, the interest on the Seller's Loan is lower than the forgoing interest rate (weighted average calculation, based on the ratio between the amounts of the principal of each of the Loans, from time to time). During each of the sixth and seventh years, the interest on the Seller's Loan may be 7% and 8%, respectively, or lower, in accordance with the criteria set in the agreements.

In the loan period, the interest and principal of the Senior Loan and the seller's loan will be paid out by the buyer out of the proceeds from the dividend from The Phoenix, in consideration for the sale of the Phoenix Shares by the Buyer and indemnification of The Phoenix Shares by the Buyer and indemnification payable (if any) and adjustments to the price that the Company undertook to pay the buyer under certain conditions (if any, as aforesaid, in the loan period). Provisions were set under the agreements for anchoring the subordination of the Seller's Loan to the First Degree Loan, including with regard to the order of repayment of the Loans depending, inter alia, on the source of the funds used for the repayment. As a rule, the borrower is required to repay significant amounts of the First Degree Loan principal, before being able to or required to repay amounts in respect of the Seller's Loan principal. The Seller's Loan agreement also stipulated, among other things, the buyer's obligations, certain events requiring mandatory early repayment by the buyer (subject to the foregoing provisions), and events of default defined in the agreement,

To secure its obligations, the buyer undertook, subject to obtaining required regulatory approvals, to pledge in favor of the Company, in a second-degree lien (subject to the First Degree Loan), among other things, The Phoenix shares that it purchased.

The relationship between the Company and the financiers of the First Degree Loan was also regulated under an agreement between the financiers. This agreement regulates, among other things, the subordination of the Seller's Loan to the First Degree Loan and restrictions on the exercise of the Company's rights (including in the event of a breach) with respect to the borrower, until the First Degree Loan has been repaid.

For information concerning the accounting treatment, see Note 10E to the Company's Financial Statements.

1.16. Taxation

For a description of the tax laws applicable to the Company see Note 31 to the Company's Financial Statements and Note 8 to the Company's Separate Financial Information.

1.17. Restrictions and Supervision of the Corporation's Operations

With the exception of the restrictions and supervision applicable to the Company and its subsidiaries under the various operating segments, as set out in each of the operating segments, as a public company the Company is subject to applicable restrictions under the Company's Law and corresponding regulations, the Securities Law and corresponding regulations, and the transportation laws. In addition, the Company is affected by the various directives concerning capital and debt raising on the financial market in Israel or for non-banking finance,

1.17.1. Market Concentration Law

In December 2013, the Market Concentration Law was published in the Official Gazette. The Market Concentration Law consists of three main chapters: (a) Multiple-sector concentration considerations when granting rights for use of national resources (essential infrastructures and privatized assets) to conglomerates (as they appear in a list of conglomerates to be published by the concentration reduction committee and the criteria set in the Law, according to which a significant non-financial corporation, as defined in the Market Concentration Law, will be considered to be a concentration group) ("Concentration Groups" and "List of Concentration Groups", respectively), and taking into account the promotion of competition when allocating rights in essential infrastructures and in sectors where the number of players among whom the rights are to be allocated is limited ("Concentration Considerations When Allocating Rights"); (b) Constraints on the control of multi-tiered pyramid structured conglomerates: limiting multi-tiered control to two tiers only and applying increased corporate governance regulations on multi-tiered conglomerates ("Constraints on Control of Multi-tiered Companies"); (c) separation of significant financial corporations and significant non-financial corporations as defined in the Concentration Law and under which, inter alia, a significant non-financial corporation is prohibited from controlling and holding the means of control in a significant financial corporation ("Separation of Non-financial Corporations from Financial Corporations").

The Market Concentration Law affects the Company and its subsidiaries directly and/or indirectly.

(A) Concentration Considerations when Allocating Rights

This chapter deals with two key and separate aspects for allocation of rights by the State: multi-sector concentration and sectoral competitiveness, and stipulates that when granting rights and setting the terms for those rights, the regulating agency authorized to grant such rights must take into account, in addition to all other legal matters regarding the allocation of rights, sectoral competitiveness and multi-sector concentration considers, as set out below.

The provisions of the Market Concentration Law concerning the allocation of rights could have implications on the Company's subsidiaries abilities to renew licenses as defined in the Market Concentration Law.

(1) Multi-sector concentration considerations when allocating rights:

This part of the chapter provides that when the regulating agency allocates rights in an essential infrastructure domain (defined as a domain that makes use of an essential infrastructure or national resource or which provides an essential public service, as listed in an addendum to the Market Concentration Law ("Essential Infrastructure Domain")), to a concentration group, may not permit a concentration group to participate in the rights allocation process unless multi-sector concentration considerations have been taken into account in consultation with the committee for reducing concentration. It is noted that the duty to consult with the committee for reducing concentration applies to the regulator that allots the rights within its jurisdiction. With regard to this part, the term "right" is a license, contract or significant holding, as defined in the Market Concentration Law. Without derogating from the foregoing, the regulating agency may refrain from allocating rights to a concentration group also after finding that it is unlikely that real harm would be caused to the sector in which the rights are allocated or to the regulation of the sector due to non allocation. This part also provides that the regulating agency must take into account considerations concerning avoidance of expanding the operations of the concentration group while noting the sectors of operations relating to the matter and considering the relationship between them.

On March 2, 2020 a revised list of concentration groups was published and the Company and all the companies under its control appear in the list (and in the list of significant non-financial corporations).

According to the list of essential infrastructures, the Group’s natural gas and oil segment, fuels segment, and LPG segments are all considered to be essential infrastructure domains.

It should be noted that extension or renewal of a rights period is subject to the same rules as for the allocation of rights and the provisions as described above will also be apply thereto if the two following conditions exist: (a) the holder of the rights to be extended has held these rights for a period exceeding 10 years, whether under a single allocation or accumulated under several allocations; (b) the allocation or previous extension of the rights were not assessed in accordance with the provisions of the Market Concentration Law during the 10 years preceding the requested extension.

(2) Sector-specific competition considerations when allocating rights:

This part of the chapter provides that when allocating rights and prescribing the terms of such rights, the regulating agency (allocating the rights) must also take into account, in addition to all other matters to be considered under the law regarding allocation, advancement of sectoral competitiveness considerations. Under certain circumstances, taking into account the advancement of sectoral competitiveness considerations obligates consultation with the Commissioner for Competition. The applicability of this part is broader than that of the previous part since it applies to all rights allocations (as defined above) in an essential infrastructure domain, and all licenses required in any sector that is not an essential infrastructure domain if, due to the nature of the right, its economic value or applicable laws, there are a limited number of players in the sector in which it is allocated. It should be noted that this part of the chapter also applies to organizations that are not a concentration group. It is also noted, that similar to the part regarding multi-sector concentration, the rules that apply to the extension or renewal of a right are the same as those applicable for the allocation of a right, and consequently sectoral competitiveness considerations at the time of the extension/renewal of rights, must be taken into account if the two conditions as set out at the bottom of this section (1) exist.

Furthermore, allocation of certain rights in the sectors that appear in the list of rights published by the Commissioner for Competition (last revised list was published on September 3, 2017), requires consultation with the Commissioner for Competition. It is noted that the duty to consult with the Competition Commissioner applies to the regulator that allots the rights within its jurisdiction.

These requirements could prevent the Company and companies under its control, from expanding their operations in such sectors and/or prevent them from entering such segments of operations.

(B) Constraints on the Control of Multi-tiered Structured Conglomerates

With regard to restrictions on the control of multi-tiered structured conglomerates that have a first-tier company, second-tier companies and “other tier” companies, as defined in the Concentrations Law, the Company's subsidiaries do not hold “other tier” companies.

(C) Separation of Non-financial Corporations from Financial Corporations

The provisions of this chapter impose restrictions and conditions for separating significant financial corporations from significant non-financial corporations Under the provisions of the Market Concentration Law, a financial corporation may be, inter alia, an insurance company, provident fund management company, bank and auxiliary corporation, mutual investment fund manager and investment portfolio manager. A real corporation is defined as a non-financial corporation.

On February 16, 2020 the Competition Authority announced that the separation between the significant non-financial corporations from the significant financial corporations was completed and this, among other things, following conclusion of the sale of the Company's holdings in The Phoenix on November 3, 2019.

1.18. Material Agreements

For further information concerning material agreements under the various operating segments, see sections 1.7.29, 1.8.23, and 1.9.17 above.

The Staff Companies' material financing agreements are set out in section 1.14 above.

From time to time, the Company engages in significant sales agreements or in sales agreements which, other than the business terms and conditions, also include provisions concerning representation, indemnification and transfer of information, which could become material if problems arise subsequent to closing such transactions.

1.19. Legal proceedings

For a description of the material legal proceedings to which the Group's companies are party, see Notes 12 and 24 to the Financial Statements.

1.20. Business strategy and goals

1.20.1. General

The primary strategy of Delek Group is to focus its operations on the energy sector by further developing its core upstream energy assets, inter alia, by improving and exploiting the potential of the Group’s assets in the East Mediterranean Sea and North Sea. At the same time, the Group is working to ensure its financial robustness and reduce its financial debt.

In this context, since 2014, Delek Group has focused on disposing of non-core holdings. As at the end of 2020 and up to date of publication of the Financial Statements, the majority of these assets have been sold. The scope of transactions for the disposal of assets that the Company carried out during this period amounted to NIS 3.4 billion.

1.20.2. Foreign Energy Segment

As part of the strategy to focus on the energy sector and to invest in this sector in international markets, and after acquiring the full share capital of Ithaca in 2017, in November 2019 the Company completed, through Ithaca, the acquisition of 100% of the shares of Ithaca IOGL (formerly Chevron North Sea Limited) for an amount of NIS 1.7 billion. The acquisition includes ten on-production oil and gas fields in the UK North Sea region, as well as production, processing and storage facilities, and its operations are synergetic with Ithaca’s operations and those of the entire Group. Following the acquisition, Ithaca's production capacity has more than quadrupled (average daily output in 2020

- 66,000 BOEPD) and the volume of reserves increased by almost threefold. For further information, see section 1.8.1(D) above. The acquisition positions Ithaca as one of the leading oil and gas production companies in the UK North Sea.

Ithaca is focusing on streamlining measures to reduce production costs and improve its Capex, and decommissioning costs. The Company also promotes initiatives to increase the volume of reserves and resources, including through acquisitions and bolt-on mergers, while maintaining financial robustness and further reducing financial debt.

As part of the Group's efforts to reduce its financial debt and improve liquidity, in 2020 and 2021 the Company made early repayment of the majority of its debts to the amount of USD 200 million to a foreign bank in favor of which Ithaca shares were pledged (the balance of the loan at Reporting Date is USD 7.5 million). The Company is working to raise new debt of a similar amount, against a pledge on some of the Ithaca shares it holds.

As at date of approval of the financial statements, the Company is exploring a number of possible options that could unlock the value of its holdings in Ithaca by listing Ithaca shares for trading on the Tel Aviv Stock Exchange and the London Stock Exchange, whereby, among others, the options under consideration include replacing part of Delek Group's debentures with Ithaca shares and/or issuing an IPO of Ithaca (including a tender offering) and/or taking a partner. The cash flow that the Delek Group aspires to achieve from such a move is USD 400 million. It is hereby noted that as at date of approval of the Report, the feasibility of the foregoing possible transactions has not yet been clarified, and there is no certainty that any of these transactions could be executed during the coming year, if at all.

1.20.3. Energy in Israel

The Group strives to realize the economic potential of the gas reservoirs held by the Partnership. At the end of 2019, Stage 1A of the development of the Leviathan reservoir was completed and marketing to customers in Israel, Jordan and Egypt began at the beginning of 2020. The current production capacity from the Leviathan Reservoir is 12 BCM per year, and the Partnership continues to explore and promote possible alternatives to increase the output rate by BCM 4-12 per year. In addition, the Partnership is continuing to push forward optimum Tamar Reservoir production and opportunities to utilize, develop and expand the natural gas pipeline network from the Partnership’s oil assets to the local and export markets.

For this purpose, the Group operates through the Partnership, among other things, to increase the demand for natural gas by expanding and integrating the use of natural gas on the domestic market and by exporting natural gas to neighboring countries via pipelines and/or by liquefication and/or compression of the natural gas and marketing on global markets.

While bearing in mind the provisions of the Gas Framework that require the Partnership to transfer all its rights in the Tamar and Dalit Leases to a third party by December 2021, as described in section 1.7.26(2) above, the Partnership focuses its efforts on finding the best solution for complying with the Gas Framework requirements, and intends to act primarily to promote the option of selling these rights to a third party.

At the same time, as part of the Partnership's strategy to promote the possibility of listing its key assets for trading on a foreign stock exchange, the Partnership has, over the past year, acted to push forward a possible plan for splitting its assets, according to which the Partnership's assets, other than its interests in the Tamar and Dalit Leases and in the Yam Tethys project, would be transferred to a new English company against the issue of shares that would be distributed among the holders of its participating units and later, the English company will issue shares to foreign investors and list its shares for trading on the London Stock Exchange and the Tel Aviv Stock Exchange. It is hereby clarified that the foregoing transaction requires, among other things, obtaining regulatory approvals in Israel and abroad, and is subject, among other things, to the approval of the participating unit holders' meeting, obtaining various approvals and completing additional actions, the feasibility of which is uncertain, and therefore there is no certainty that these actions will take place.

The scope and diversity of the Partnership's operations requires investment of substantial financial means. The Partnership intends exploring and utilizing the range of means available to it for raising capital, while maintaining its financial stability. As part of this, in August 2020, the Partnership successfully completed the refinancing of its holdings in the Leviathan Project by raising USD 2.25 billion in four debenture series repayable from 2023 through 2030 at interest rates of 5.75% - 6.75%, lower than previously estimated.

Below is a description of the Company and Partnership’s strategy regarding specific projects:

Tamar Project

In 2019, the Company sold its rights to receive overriding royalties from the Tamar Project. As aforesaid, the Partnership intends to focus its efforts in the near future on achieving an advantageous transaction for the sale of its rights in the Tamar Project, as required under the provisions of the Gas Framework. Until its remaining rights in the Project are sold, the Partnership is working to unlock the value of the Project, and this, among other things, by continuing to ensure the supply of natural gas and condensate from the Project, in accordance with the agreements signed, as well as conducting negotiations and engaging in additional agreements for the sale of natural gas and condensate to various potential consumers in Israel and in the region.

Leviathan project

The Partnership is acting to ensure ongoing supply of natural gas and condensate from the Project, in accordance with the agreements it signed, and is negotiating to close additional agreements in the local market and in neighboring countries. The Partnership is also working to advance additional development stages of the Leviathan Reservoir (beyond Phase 1- First Stage, which has been completed) for the purpose of supplying natural gas to target markets and additional customers; to explore the techno-economic feasibility of erecting a FLNG facility, based on natural gas from the Leviathan Reservoir, and a review of setting up an oil exploration prospect in the Leviathan Lease.

Block 12 - Cyprus

The Partnership is focusing on promoting the plan for developing the Aphrodite reservoir, and to trade the gas on the target markets, namely: the Cypriot domestic market and export to the Egyptian market. At the same time, the Partnership is exploring options for combining the development of the reservoir with the development plans of nearby reservoirs located in the EEZ of Israel, including the Leviathan reservoir.

Optimization of infrastructures

The Partnership is focusing on promoting the plan for developing the Aphrodite reservoir, and to trade the gas on the target markets, namely: the Cypriot domestic market and export to the Egyptian market. At the same time, the Partnership is exploring options for combining the development of the reservoir with the development plans of nearby reservoirs located in the EEZ of Israel, including the Leviathan reservoir.

Oil and gas exploration

The Partnership is working to continue exploration of natural gas and/or oil in its oil asset fields and in new licenses.

Increasing the demand for natural gas

The Partnership is acting to increase demand for natural gas by promoting large-scale projects that utilize natural gas in the transport sector, to convert coal-fired power plants to natural gas and to encourage the use of natural gas for housing and in other industries.

1.20.4. Improving the financial position

Delek Group intends to continue to work to reduce its financial debt and improve liquidity by disposing of non-core assets, and to promote other significant measures and transactions, such as refinancing against unencumbered assets and an equity transaction with Ithaca, as stated above

1.20.5. Contribution to the community in Israel and corporate governance

The Company contributes, independently and through its subsidiaries, in a wide range of community activities. As a leading business group, the Group is committed to the principles of corporate responsibility in social and environmental aspects. The Group's community activities are managed primarily through the Delek Science, Education and Culture Foundation Ltd.

1.21. Financial information concerning geographic regions

As at December 31, 2020, the Group operates primarily in Israel and in the North Sea region. For further information, see Note 33 to the Financial Statements.

1.22. Discussion of Risk Factors

The Company operates in the energy sector in Israel and abroad, as well as in the fuels sector and other operating sectors, and therefore the principal risk factors of the Company stem from the sector-specific risks of each of its operating segments (as described in sections 1.7 through 1.9 above). Aside from the risks described for each of those segments, below are details of additional key risks to which the Group companies are exposed:

1.22.1 Transfer of the interests in the Tamar and Dalit Leases and compliance with the conditions of the Gas Framework

As set out in section 1.7.26(2), above, under the terms of the Gas Framework, the Partnership is required to transfer by December 2021 its entire interests in the Tamar and Dalit Leases to a third party. unrelated to the Partnership or the controlling shareholders of the Leviathan Reservoir or of the Karish and Tanin Reservoirs, subject to the approval of the Petroleum Commissioner (in this section below the “Effective Date”). For further information concerning the Gas Framework and the consequences of failure to comply with its conditions by the Effective Date, see section 1.7.26, above.

1.22.2 The Covid-19 pandemic: The outbreak of the Covid-19 pandemic at the beginning of 2020 caused a significant decline in the demand for natural gas throughout 2020. As at the date of approval of the Report, the uncertainty regarding the development of the Covid-19 crisis and its outcome on global and local economic activities is continuing. If the crisis continues, it could cause, inter alia, the imposition of restrictions on movement and impair economic activities, as well as a decrease in demand and prices of energy products in general and of natural gas in particular. If the Covid-19 crisis continues, or if it intensifies, it could adversely and materially affect the Company and its major investees, their businesses, their assets and their financial stability. It could materially impair the ability of the Group companies to meet their financial liabilities to various creditors and the ability of these companies to obtain the additional financing they require or their ability to refinance existing debt. In the wake of the Covid-19 crisis and the economic slowdown, the financial robustness of the customers of the Group companies may be impaired; the companies’ revenues could be harmed due to the continued falling of energy product prices and reduced demand for such products, etc. For further information concerning the effect of the Covid-19 crisis on the company and the Group companies to date, see section 1.6.6 above, and Note 1 to the Financial Statements as at December 31, 2020 (Chapter C of this Report). For the discussion on the Covid-19 coronavirus crisis as a risk factor in the Company’s operating segments, the energy sectors in Israel and abroad and the fuel segment in Israel, see sections 1.7.2(G), 1.8.3(K) and 1.9.2(D), above.

1.22.3 Development of the Group's gas operations: The growth and success of the Group's gas operations is dependent on various factors, part of which are out of the Company's control, such as changes in power production prices and/or the US CPI and/or other energy sources and/or global fuel prices; competition in gas supply; export restrictions; difficulties in obtaining finance; the security and political situation; dependence on the integrity of the national pipeline system; operating risks; exploration operation risks. Failure of any of these factors to materialize could have material adverse impact on the Group's operations. Also see the description of the risk factors in the energy sector in Israel in section 1.7.33 above, and overseas in section 1.8.26 above.

1.22.4 Oil and gas prices: The Group is materially affected by the oil and gas prices, which are set according to supply and demand and affected by economic and political parameters. Market prices of oil and gas are volatile and if prices fall significantly, the financial viability of the projects in which the Group has holdings may be adversely affected, which could cause the feasibility of investments to decrease and the oil and gas reserves to decline. Furthermore, the decline in energy prices could cause the Group and/or its partners in the oil assets to decide not to participate in the development plans. All these parameters may lead to a decrease in the Group's production volume abroad. A significant decline in oil and gas prices could limit or reduce Ithaca's ability to withdraw its credit line. Ithaca conducts hedging transactions on oil and gas prices using various instruments and at hedging rates that vary between years, therefore, if oil and gas prices rise, the impact on Ithaca’s cash flows is limited and affected by the type of instrument used for hedging and the scope of unhedged output, as well as a decline in prices.

1.22.5 Antitrust and Increased Competition the Group is subject to competition restrictions that deal with, inter alia, restrictions on the scope of operations, prohibited practices and manner of pricing products and services. Under certain circumstances, the Group's companies are liable to be restricted in their operations because of the provisions of the Antitrust laws in various countries, in a way that may restrict the expansion of their operations or even require them to downsize and change their operations. The Partnerships, together with their partners in the Tamar Project, were declared a monopoly in the supply of natural gas to Israel. Subsequent to this declaration, restrictions could be imposed on the operations of the Partnerships, including prohibiting them from refusing, under unreasonable reasons, to supply natural gas and barring the exploitation of their market power in a manner that could reduce business competition or cause public harm. The restrictions on the Partnerships due to their status as a monopoly in the supply of natural gas in Israel could have adverse effect on their ability to expand their operations in Israel. Furthermore, in certain cases, the Group and its investees may be subject to approval of transactions by the Commissioner of Competition in Israel, which is liable to restrict and even prevent such transactions being carried out, or to require acting in accordance with the terms and conditions contained in merger permits which are granted or may be granted by him. Failure to comply with competition laws or claims of failure to comply with these laws, could lead to civil and criminal sanctions and the imposition of various restrictions on the Group's operations. Competition laws are, from time to time, subject to changes and interpretation, including being made more stringent.

In this regard, the Market Concentration Law and its implications on the Group's structure should be noted, for details on this matter see sections 1.17.11.17.1, above.

1.22.6 Changes in foreign currency exchange rates The Company and its investees are affected by changes in foreign currency exchange rates, from several aspects: (a) from time to time the Company and some of its investees take loans denominated in foreign currencies, (primarily USD); (b) the exchange rates may affect the business results of some of the investees whose expenses and investments and/or that receive proceeds from sales in foreign currencies that are not their operating currency; (c) changes in exchange rates could affect the value of the Company's investments in the share capital of overseas companies and the foreign currency loans it received, and could also expose the Company to risks from translation of exchange rates, if the operating currencies of its subsidiaries, according to which they prepare their financial statements, are foreign currencies. The Company is specifically exposed to USD and GBP exchange rate changes, which impact the values in the Company's financial statements.

Though the Company and its investees try, from time to time, to neutralize such currency risks by using various financial instruments, it is uncertain that they will succeed, and they may even undertake under such transactions to make various payments for hedging.

1.22.7 Change in interest rates: The Group and/or its subsidiaries have loans at variable interest and therefore it is exposed to interest rate fluctuations, which could affect the Group's business results.

1.22.8 Economic slowdown and changes in the Group's markets: Changes in the markets in which it operates and an economic slowdown in those markets (particularly in the Israeli market) could have an adverse effect on the operations of the Company and its investees, as well as on the value and liquidity of their assets, the demand for their products and their revenues.

1.22.9 Capital markets: Deterioration in the global capital markets could adversely affect the Group's operations. Changes in the prices of marketable securities held by the Group expose it to risks deriving, inter alia, from capital market volatility and will affect its ability to generate capital gains from the realization of its investments. Deterioration of the capital market in Israel and worldwide could have material impact on the operations of the Company and the foreign securities that it holds, also with regard to its ability to raise capital and debt.

1.22.10 Financing, credit restrictions and compliance with financial covenants: The Company and the Group companies have substantial financial liabilities, and a constant need for refinancing their operations when such liabilities reach repayment date. The amendment to the deeds of trust for the debenture holders requires the Group to comply with financial criteria and other undertakings which could restrict the Group's operations and those of its investees (such as investments, restrictions on distribution of dividends, issuing of shares, providing collateral, mergers and disposal of assets), require the Group to set aside substantial provisions from its cash flows to cover debts, limit its ability to borrow additional moneys and could lead to a demand for immediate repayment of the liabilities and exercise of collateral in the event that they are not met. The absence of the ability of the Group and/or its investees to obtain financing in the future by receiving loans or debt and capital raising, under good terms, may lead to failure to comply with the terms of the amendment to the deed of trust and even lead to repayment of the debentures, prevent the expansion of the Group's operations, harm its current operations and lead to non-payment of dividends and even non-compliance with obligations towards third parties. The availability and terms of financing sources are dependent on various factors, including the operating status, financial position, capital market conditions and the ability and limitations of key financing bodies. In this regard, it is noted that regulatory changes that may in the future impose new restrictions, which could, among other things, adversely affect the Company's ability to raise further debt, at favorable terms. The Group is required to invest in the developing and production costs of its oil and gas reservoirs in the North Sea and in the acquisition of additional North Sea oil and gas assets. Its ability to finance the liabilities and to participate in future development plans (focusing on the development of Ithaca's North Sea reservoirs) and its general ability to continue developing additional assets depend mainly on (a) the cash flows generated from the on-production assets; (b) access to credit facilities. Cash flow depends on a combination of several parameters, including the performance of the reservoirs and production costs, together with parameters that are not in the Group's control, such as the price of oil and gas and changes in the capital markets.

1.22.11 Security and political situation: Deterioration in the security and political situation (domestic and international) in Israel could adversely affect the Group's operations. Since a major part of the Group's operations are in Israel, it is exposed to the implications of armed conflicts, terror acts and political and security instability in Israel. Such conflicts or acts are liable to harm the operations of the Group and its investees in Israel in a number of ways, including cause an Israeli economic slowdown which could adversely impact the scope of its operations and results; declines in the Israeli capital market which could adversely impact the Group's capital and debt raising ability, realization of its holdings and the value of its marketable holdings; harm the Group's employees in Israel and cause direct damage to the Group's installations, including its gas exploration, production and conveyance facilities (Yam Tethys, Tamar, Leviathan, Ashkelon), which are situated relatively close to the Israeli border with the Gaza Strip, and the INGL pipeline installations, EMG pipeline and other infrastructures used for supplying gas to Egypt, may serve as a specific target for their purposes; and a decline in the presence of foreign investors and international companies will to invest in and engage with Israeli companies. Furthermore, the Group's ability to operate in various countries around the globe, particularly in Middle East countries, which do not recognize Israel is already, by nature, restrictive. Calls and actions to boycott Israeli companies (in enemy countries as well as in friendly countries) may also adversely affect the Group's operations in Israel and abroad. Similar to the foregoing, the Group is exposed to armed conflict, hostile acts and political instability in all the countries in which it operates.

1.22.12 Changes in legislation and standards: Special laws apply to significant parts of the Group's operations. The Group's financial results could be affected by changes in legislation and standards in various areas, including competition laws, laws governing the obligation to issue tenders, laws regulating areas such as fuel, gas, telecommunications, supervision of insurance business, control on prices of products and services, excise rates, consumer protection, etc. Furthermore, changes in the policy of the authorities operating by virtue of these laws is liable to affect the Group. Similarly, some of the Group's companies operate abroad and they are liable to be affected by changes in legislation, excise, regulatory proceedings and policy in the countries in which they operate.

A change in accounting regulations could affect the business results of the Group and its investees, and the ability of those investees to distribute dividends.

1.22.13 Supervision of banks: The Group and some of its investees are subject to the Proper Banking Practice directives issued by the Supervisor of Banks in Israel, which include, inter alia, restrictions on the volume of loans that Israeli banks may extend to a single borrower and the largest borrower group in the bank (as these terms are defined in the aforementioned directives). In view of the foregoing restrictions, the scope of the loans assumed by the Group and its controlling shareholder may, under certain circumstances, impact the Group's ability to borrow additional sums from Israeli banks, and on its ability to make investments which require bank credit, or investments in companies which have taken large volumes of credit from certain Israeli banks.

1.22.14 Licenses and concessions Some of the companies held by the Company operate on the basis of approvals, permits, licenses or concessions granted to them in Israel and abroad, in accordance with the law, by various authorities, inter alia the Ministry of National Infrastructures, Ministry of Telecommunications and Ministry of Transport. Failure to comply with the terms of these approvals, permits, licenses or concessions could lead to the imposition of sanctions, fines and even cancellation of the relevant approvals by the competent authorities. Such cancellation is liable to cause substantial harm to investees whose operations depend on these approvals. Some of these licenses and concessions have time limits and are renewable from time to time, all in accordance with the conditions and provision of the law and there is no certainty that these licenses or concessions will be renewed in the future. Non-renewal of such a license or concession may adversely impact the profitability of the company holding such a license or concession and consequently also on the Company's profitability. It is further noted that in view of the Concentration Law, it is possible that the applying company may encounter difficulties or may be unable to renew existing licenses or permits or may be able to renew them, subject to restrictions, and all as described in section 1.17.1, above.

1.22.15 Environment: Some of the Company's investees, particularly those in the oil and fuels sector, are exposed to various requirements laid down by the authorities in the matter of environmental protection in Israel and abroad. The other costs and resources necessary for complying with the environmental requirements are large. A change in legislation in this area or a change in the policy of the supervisory authorities may impact the profitability of these companies, and consequently also the Company's profitability and failure to comply with them may expose the Company to various sanctions, legal proceedings and loss of licenses. For information concerning the motion for certification of a class action that was filed with respect to the quality of the environment regarding the Company's real estate in Akko, see Note 24A4(2) to the Financial Statements.

1.22.16 Raw materials, equipment and infrastructure: Some of the Company's investees are exposed to changes in the prices of raw materials, such as the fuel sector which is exposed to changes in fuel or crude prices. Changes in the prices of raw materials are liable to impact the profitability of investees and consequently also the Company's profitability. Moreover, the companies are dependent upon the proper conveyance and storage of the various raw materials (for example, proper operation of fuel pipelines and terminals) and access to various infrastructures. These may be affected as a result of various factors, such as labor strikes, security events, transport breakdowns, limited access to ports (particularly the two main ports in Israel) natural disasters, extreme climatic conditions, etc.

1.22.17 Legal proceedings: Lawsuits have been filed against the Company and some of its investees, including class actions, in substantial amounts. If these companies are found liable in these legal proceedings or in any possible future legal action brought against the Company or its investees, this could adversely impact the Company's business results. Furthermore, the large number of legal claims against Company officers leads to a significant increase in the tariffs for officers and directors insurance policies and difficulty in obtaining such policies. Failure to renew the officers' insurance policy or to renew on unsatisfactory terms may result in directors and senior officers resigning or refraining from serving in an existing position in the Company. In this context, it should be noted that the motion to certify a class action filed by a consumer of the IEC against Tamar partners in respect of the price set in the agreement with IEC, if the action is certified and a final judgment is handed against the Tamar partners as set out in Note 24 to the Consolidated Financial Statements, this may have an adverse effect on the revenues of the Partnership, the results of its operations, its ability to meet its obligations and the prices at which the Partnership will sell natural gas to their customers. For further information concerning legal proceedings, also see Note 24 to the Financial Statements with regard to contingent liabilities.

1.22.18 Salary and labor relations: Material changes in the minimum wage or other material changes in the labor laws are liable to affect the results of the Company's investees and consequently also the Group's business results. Furthermore, strikes and labor disputes in the investees are liable to adversely affect the business results of the Group.

1.22.19 Restrictions on disposal of holdings: The Company and some of its investees are bound by legal and contractual restrictions which could inhibit the ability of the Company and its investees to realize these holdings.

1.22.20 Reliance on the results of investees and their cash flows: The Company's operating results depend, among other things, on the results of its investees. The Company's key investee is a public company trading on the TASE, operates independently, and its interests are not necessarily the same as the interests of the Company. The Company's sources of capital include profits distributed as dividends, management fees and repayments of loans to the Company by the investees. Changes in the profit distribution policy of the Company's investees, changes in profitability (including those brought about by changes in accounting principles) and in the cash flows of these companies, and restrictions on the distribution of profits are liable to affect the Company's cash flows and its business operations, and therefore it is not at all certain that they will be able to make such payments in time when it is in need of the cash flows. Furthermore, the Company's ability to raise foreign finance relies, inter alia, on the value of its holdings in the Group's companies.

1.22.21 Loans and guarantees to investees as part of its operations, the Company provides, from time to time, loans to its investees in material amounts as well as guarantees and collateral for various purposes such as guaranteeing finance they received, projects they carried out, etc. A decline in the profitability and cash flow of these investees or liquidity difficulties is liable to have an adverse effect on their ability to comply with the terms of the loans, or alternatively, to bring about the exercise of the guarantees provided by the Company and thereby adversely affect its financial position.

1.22.22 Insurance: Notwithstanding the fact that various risks involved in their business operations are insured by the investees, they are unable to protect against the realization of all risks, including the risks specified above, and existing insurances are also limited in aspects such as scope of insurance, insurance exceptions, timing of insurance payments, and the ability of the insurance companies to meet their liabilities. Accordingly, it is possible that there will be no insurance cover, full of partial, for the realization of various risks, including risks to the Group's employees and its plants.

1.22.23 Goodwill and negative publicity the goodwill of the Group, its investees and part of their brands are attained over years and the success of the Group and its investees is dependent to some extent on its goodwill. Negative publicity regarding the Group, its investees and their brands may adversely affect their goodwill and the willingness of customers, suppliers, investors and others to engage with them. The Group's goodwill is liable to be adversely affected, inter alia, by negative events connected with environmental and health issues, legal proceedings and claims pertaining to unethical and illegal conduct and various publicity, even if these are untrue.

1.22.24 Competition: Each of the Group's investees are exposed to competition in the sectors in which they operate, which could lead to decreasing prices of the products and services sold in their operating sectors as well as loss of market share, and could have a material adverse effect the revenues and profitability of the Group companies.

1.22.25 Information systems: The Group relies on information systems for its various activities. Information system failures (including as a result of natural disasters, power cuts, unauthorized hacking of the information systems, acts of terror etc.) and inability to repair them quickly is liable to harm the Group's businesses. Such failures could, inter alia, cause loss of business information, loss of customers and suppliers, harm to goodwill and significant costs for restoring the information systems.

1.22.26 Failure to comply with the undertakings of third parties engaged with the Group: Failure to comply with undertakings of parties with which the Group is engaged or their failure to pay can expose the Group to losses.

1.22.27 Impairment of securities: The Company is exposed to price volatility of the tradable securities that it holds. Among other things, as lump in capital markets abroad and in Israel, decrease in the operating results of companies in which the Company holds shares and a drop in oil prices could have adverse effect on the prices of the tradable securities held by the Group and affect the financial and accounting results of the holdings in these securities. In addition, such impairment could impact the financial ratios set in the financial agreements and to the financial institutions demanding additional collateral and/or place the debt for immediate repayment.

Breakdown of the Company's assessment of the types of risk factors and the degree of their impact on the Company's foregoing risk factors:

	Impact of the Risk Factor		
	Major	**Moderate**	**Minor**
Macro risks			
The coronavirus crisis	X		
Changes in foreign currency exchange rates	X		
Interest rate fluctuations		X	
Economic slowdown and changes in the markets in which the Group operates:	X		
Capital markets:	X		
Security and political situation		X	
Changes in legislation and standards	X		
Supervision of banks		X	
Competition		X	
Impairment of available-for-sale securities	X		
Sector-specific Risks			
Financing, credit restrictions and compliance with financial covenants	X		
Environmental issues		X	
Raw materials, equipment and infrastructure			X
Company-specific risks			
Transfer of the interests in the Tamar and Dalit Leases and compliance with the conditions of the Gas Framework			
Licenses and concessions		X	
Development of the Group's gas operations	X		
Gas and oil prices	X		
Legal proceedings	X		
Salary and labor relations		X	
Antitrust and increased competition	X		
Restrictions on realization of holdings		X	
Reliance on the results of investees and their cash flows:	X		
Loans and guarantees to investees and related companies		X	
Insurance	X		
Goodwill and negative publicity			X
Information Systems		X	
Failure to comply with the undertakings of the parties engaged with the Group		X	

The information relating to risk factors and their effect on the Company is forward-looking information as defined in the Securities Law. This information relies, inter alia, on the Company's assessments based on past experience and familiarity with the relevant markets in its segments of operation and information regarding the relevant regulatory developments relating to the Company's operations. The Company is liable to be exposed in the future to other risk factors and the effect of each risk factor, if it materializes, could be different to the Company's assessment. As noted, forward-looking information is based on information available to the Company on reporting date. The actual results could be materially different from the results estimated or implied from this information.

Chapter

B

Board of Directors Report on the State of the Company's Affairs

March 30, 2021

Delek Group Ltd.

Board of Directors' report on the state of the Company's affairs
For the year ended December 31, 2020

The Board of Directors of the Delek Group Ltd. ("the Company" and/or "the Group"), hereby presents the Company's Board of Directors' Report for the year ended December 31, 2020.

A. The Board of Directors’ explanations on the state of the Company's affairs:

1. Description of the Company and its business environment

The Company operates mainly through investees engaged in oil and gas exploration and production in Israel and abroad. In this context, it is noted that in the fourth quarter of 2020, the Company sold its controlling shareholdings in Delek Israel, which markets fuel products in Israel. Furthermore, in the fourth quarter of 2019, the Company completed the sale of its Insurance and Finance in Israel operations (The Phoenix), and completed the acquisition of actively-producing oil and gas assets in the North Sea, as detailed below.

The Group's financial data and its operating results are affected, among other things, by the financial data and operating results of its investees, and by its sale or acquisition of holdings. The Company's cash flow is affected, among other things, by dividends received from its investees, by inflows from the disposal of its holdings therein, by its ability to raise financing in Israel and abroad which depends, among other things, on the value of its holdings, financial market conditions in Israel and abroad, and by the Group's investments.

In accordance to the Company's agreements with certain banks from June 2020, in the third quarter of 2020 and until the end of October 2020, the Company and the staff companies repaid all of their debts to said banks, to a total amount of NIS 840 million. Following such repayments, as of the financial statements' approval date, the Company and the staff companies do not have any debts to said banks. The Group performed several significant actions which served the Group, among other things, to repay said debts. These included selling the right to royalties from the Karish and Tanin leases, to the amount of NIS 318 million; selling the controlling shareholdings (70%) in Delek Israel, to the amount of NIS 525 million (of which NIS 450 million were received in cash; a further NIS 74 million were received in February and March 2021 after the buyer exercised their various options); securitization of overriding royalties from the Leviathan Reservoir, to the amount of USD 180 million (NIS 608 million)(before the safety buffers to guarantee interest payments and issuance costs); and receiving a dividend from Delek Israel, to the amount of NIS 150 million. In addition to the above, in November 2020, Ithaca distributed USD 100 million (NIS 340 million) in dividends. This amount, plus an additional amount of USD 30 million from the proceeds on the sale of Delek Israel, served to repay a bank debt. Following such repayment, the total debt of the Company and its staff companies to the banks totaled only USD 8 million. Furthermore, NIS 120 million in dividends were received from Delek Drilling in December 2020. In addition, in the reporting period the Company completed capital issuances (including warrant exercises) to a total amount of NIS 450 million. For more information, see Note 26 to the financial statements.

Subsequent to the financial position statement date, the Company received a loan from a third party, backed by a pledge on a Company-owned building in Herzliya, to the amount of NIS 104 million. For information concerning a convertible loan to the amount of USD 50 million, see Note 19 to the financial statements.

In December 2020, the Partnership announced that it would distribute earnings of NIS 117 million (Group's share - NIS 65 million). The dividend was distributed in January 2021.

Following on Note 1 to the financial statements, concerning the COVID-19 outbreak, in 2020 the virus spread to many countries around the world, and in March 2020 the World Health Organization declared the outbreak a global pandemic ("the COVID-19 Pandemic"). The outbreak caused, and continues to cause, illness and even death around the world. As the COVID-19 Pandemic spread, many countries implemented, and continue to implement, significant restrictions which included and/or include, among other things, isolation and social distancing, restrictions on movement and transportation (including flights), lockdowns and reduction of commercial activity, etc. The COVID-19 Pandemic and the ensuing restrictions caused a substantial slow-down in global commerce, and sharp drops and extreme volatility on the global money markets. This decrease in commercial activity led to a significant drop in demand for oil products. Furthermore, in March 2020, an 'oil price war' broke out between Saudi Arabia and Russia, which increased production while demand went down. These developments caused extremely sharp drops in oil prices in 2020 and, in some countries, in natural gas prices as well. However, several countries have recently reached agreements to reduce the daily output of oil production in the coming months. Furthermore, in the latter half of 2020, many countries began implementing exit strategies to roll back their restrictions and implement a controlled and gradual return to normal. From the end of 2020, several countries also began vaccinating their populations to eradicate and/or slow-down the pandemic. In this context, it is noted that in 2020 and up to immediately prior to the financial statements' approval date, oil prices were extremely volatile. On December 31, 2019, the price for a barrel of Brent oil stood at USD 65; at the lowest point in 2020, this price dropped to USD 16 a barrel; as of December 31, 2020, the price stood at USD 52 a barrel; and near the financial statements' approval date, after an additional market recovery, the price stood at USD 64 a barrel.

As of the financial statements' approval date, there is uncertainty as to when the pandemic will end and/or concerning its potential resurgence. There is also uncertainty concerning the continuation and/or exacerbation of the global economic crisis and concerning future oil and natural gas prices.

Since the bulk of the Group's operations are in the energy industry, oil and natural gas prices (as well as the USD-NIS exchange rate) have a material (positive or negative) impact on the Group's operating results, the value of its assets (both marketable and non-marketable), its equity, operating cash flows, and its ability to dispose of assets and the proceeds receivable on such disposals, and on the Group's ability to secure additional sources of financing and/or the cost of such sources.

For information regarding impairment testing of assets and subsequent write-downs (write-down reversals) and losses from disposals in 2020, see Notes 10, 12, and 14 to the consolidated financial statements. In this regard, it is noted that the estimates used by the Group in these tests may fluctuate, among other things, due to the aforesaid uncertainty and volatility. The Group will continue to review its estimates, and will update them in accordance with developments in the COVID-19 Pandemic, its impact on the global and local economy, and its impact on oil and natural gas prices.

It is further noted that, the economic crisis of 2020 led to extreme drops in the market value of the Company's shares and the shares of its investees (mainly participation units in Delek Drilling Limited Partnership ("Delek Drilling" or "the Partnership"). This had a major adverse effect on the Group's financial position and its liquid resources, mainly due to the fact that part of these shares served to secure credit facilities extended to the Group. In 2020, the Group repaid all of its credit facilities, which were mainly secured by participation units in Delek Drilling. For information concerning the Group's financial position, see Section C below. It is further noted that, from the start of 2021 and until the financial statements' approval date, a material increase was recorded in the market value of the Company's shares and of Delek Drilling's participation units. However, they have yet to regain their market value prior to the COVID-19 Pandemic.

Since the bulk of the Group's operations are in the energy industry, a sustained rise in oil and natural gas prices may have a positive impact on the Group's operating results, the value of its assets (both marketable and non-marketable), its equity, operating cash flows, and its ability to dispose of assets and the proceeds receivable on such disposals. A positive impact may also be seen in the Group's ability to secure additional sources of financing and/or the cost of such sources. On the other hand, continuation of the COVID-19 Pandemic and continued volatility in global energy prices may reduce domestic and global demand for the Group and its product, and undermine the financial strength of the Group's customers, partners, and suppliers.

In their opinion on the Company's financial statements as of December 31, 2020, the Company's auditors draw attention to the disclosure concerning the COVID-19 Pandemic, its effects, and the significant decrease in global oil and gas prices. For more information, see Notes 1A-1C to the financial statements. As aforesaid, the Company has worked and continues to work to implement its plans which include, as aforesaid, capital raising, disposing of significant volumes of assets and investments, raising asset-backed debt, and receiving dividends from investees in order to meet its various obligations. The Company believes there is a good chance that it will realize its plan. In this context it is noted, as aforesaid, that the significant and important actions which the Group has successfully completed over the past year in accordance with said plan have allowed the Company to make early repayments of significant volumes to the banks and to its debenture-holders, on time and in due order. However, since full implementation of the Company's plan is outside the Company's sole control and depends, as aforesaid, among other things, on several cumulative events, some of which must occur in relatively short time-frames and/or in significant amounts and in light of the financial covenants established with the debenture holders and additional creditors which may require their consent not to call for immediate repayment of the remaining debt (should the Company fail to comply with its financial covenants) - there is uncertainty concerning the actual materialization of said plans. These factors, together with additional factors as detailed above, raise significant doubts as to the Company's continued operation as a going concern.

2. Principal Operations

Oil and gas operations in and around Israel

- The Group's gas and oil operations in Israel are carried out mainly through Delek Drilling Limited Partnership ("Delek Drilling" or "the Partnership").
- As of the financial statements' approval date, the Partnership mainly deals in the exploration, development and production of natural gas, condensate and oil in Israel and Cyprus, and in promoting various natural gas-based projects, in order to increase natural gas sales from the Partnership's assets. The Partnership is also studying commercial opportunities for exploration, development, and production of natural gas and oil in the Mediterranean Basin. According to the Gas Framework (see Note 12O to the attached financial statements), the Partnership must transfer all of its rights in the I/12 Tamar and I/13 Dalit leases (jointly - "Tamar and Dalit") no later than December 2021. Therefore, as of the financial statements' approval date, in the coming period the Partnership plans to focus its efforts on finding an optimal solution to complying with the Gas Framework's requirements. As such, the Partnership mainly plans to pursue options for selling said rights to a third party. At the same time, the Partnership is working to pursue a possible framework for splitting its assets. Under this framework, all of the Partnership's assets, excluding its rights in the Tamar and Dalit leases and in the Yam-Tethys Project would be transferred to a new company in the UK ("the UK Company") against allocation of shares which would be distributed to the holders of participation units. The UK Company would subsequently issue shares to foreign investors and list its shares for trading on the London Stock Exchange and on the TASE. For more information, see Note 12 to the attached financial statements.
- On December 31, 2019, supply of natural gas started from the Leviathan Reservoir to the domestic market, and on January 1, 2020 and January 15, 2020 supply of natural gas began to Jordan and Egypt, respectively.
- In March 2020, Delek Energy sold 5% of Delek Drilling's capital (for more information, see Note 10I to the financial statements). Post-sale, the equity attributable to the Company's shareholders decreased by NIS 313 million (including attribution to capital reserves from transactions with non-controlling interests).
- In April 2020, the Company sold its investment in Cohen Gas and Oil Development Ltd. in consideration for NIS 207 million (for more information, see Note 10K to the financial statements). Following such sale, in the second quarter of 2020 the Company recognized a loss attributable to the Company's shareholders of NIS 235 million (post-tax).
- On July 8, 2020, a transaction was completed whereby the Company and Delek Energy Systems Ltd. ("Delek Energy") sold to a third party ("the Buyer") all of the Company's and Delek Energy's rights to overriding royalties from the Karish and Tanin leases (excluding the Partnership's royalty rights). Consideration for the sale totaled NIS 318 million. Following such sale, in the third quarter of 2020, the Company recognized a loss attributable to the Company's shareholders of NIS 44 million (post-tax).
- In July 2020, the Partnership made partial early repayment on the third series of Tamar Bond debentures, to an amount of USD 240 million. For more information, see Note 12K1 to the financial statements.
- Completion of Leviathan's refinancing

  In August 2020, a debenture issuance was completed by Delek Leviathan Bond Ltd., a wholly-owned SPC of the Partnership. This issuance included debentures to a total amount of USD 2.25 billion, issued under Rule 144A and Regulation S. The debentures were issued in 4 series, maturing in 2023, 2025, 2027, and 2030. The debentures are secured by a lien on Delek Drilling's rights in the Leviathan leases. The proceeds from this issuance served the Partnership, among other things, to repay USD 2 billion in bank loans. For more information, see Note 12K2 to the financial statements.
- Securitization of overriding royalties from Leviathan

  On October 28, 2020, an issuance was completed of USD 180 million in debentures to classified investors from Israel and abroad. The issuance was carried out by Delek Overriding Royalty Leviathan Ltd. ("the Issuer"), a wholly-owned subsidiary of Delek Energy, and was secured by a lien on rights to overriding royalties from the Leviathan Project which were transferred to the Issuer. On the completion date, all proceeds from the Issuance, including the Total Issuance Proceed, less a safety buffer guaranteeing the interest payments, and the Issuance and underwriting costs, were transferred directly to a designated escrow account held by the trustees for the Company's debenture-holders, to the amount of USD 147 million (NIS 498 million). This amount served to repay the Company's debenture holders, in accordance with the amended deed of trust. For more information, see Note 12L to the financial statements.

- In the second half of 2020, Delek Energy sold all of its holdings (39.3%) in Delek Royalties (2012) Ltd., for a total consideration of NIS 45 million. For more information, see Note 12C1(4) to the financial statements.
- In November 2020, the Partnership announced that it would distribute earnings of USD 65 million (Group's share - USD 36 million; NIS 120 million). The dividend was received in December 2020. Furthermore, in December the Partnership announced that it would distribute earnings of NIS 117 million (Group's share, received in January 2021 - NIS 65 million).
- In the fourth quarter of 2020, the Group included a provision for impairment of oil and gas assets in the Tamar Project to the amount of USD 186 million (NIS 599 million), pre-tax. The Company's share in said impairment totaled NIS 24 million, post-tax. The minority interest in said impairment totaled NIS 436 million.

  In light of this impairment, the Company attributed to the Tamar Project's cash-generating unit part of the goodwill attributable to oil and gas exploration and production in and around Israel. Overall, the impairment totaled NIS 80 million, where the Company's share totaled NIS 70 million, and the minority interest totaled NIS 10 million.

  The total impact of these impairments on the profit attributable to the Company's shareholders amounted to NIS 94 million, post-tax. For more information, see Note 12C(6) to the financial statements.

<u>Oil and gas operations in the North Sea</u>

- The Group's operations in this segment are carried out through Ithaca Energy Ltd. ("Ithaca"), an indirect wholly-owned Group subsidiary dealing in oil and gas exploration, production and sale in the North Sea, and holding the rights to oil assets located in the North Sea in territorial waters off the coast of England. Furthermore, Ithaca serves as the operator in some of its assets.
- On November 8, 2019, Ithaca completed a strategic transaction for acquiring 100% of the shares of Chevron North Sea Limited ("CNSL") from Chevron Products UK Limited ("the Seller"). CNSL holds various right interests in ten production oil and gas assets located in the North Sea offshore of England, drilling and exploration licenses, a pipeline and infrastructure, and skilled professional staff, all of which were included in the acquisition. CNSL serves as the operator for four of the acquired assets, accounting for 67% of all 2P reserves in the acquired assets. CNSL's acquired operations join Ithaca's existing development and production operations, which focus mainly on developing reservoirs in the Greater Stella Area ("GSA"). Production in the GSA is conducted from a central floating platform known as FPF-1.
- In the reporting period, Ithaca continued production from the Stella and Harrier reservoirs in the GSA, and from the reservoirs acquired from CNSL as aforesaid. Ithaca also continued developing the reservoir. The Vorlich reservoir came online on November 9, 2020. In the coming years, Ithaca plans to drill additional reservoirs in the Greater Stella Area, and to connect these reservoirs to FPF-1. Ithaca also plans to extend the polymers project in the Captain reservoir to additional areas to accelerate oil production.
- Ithaca has an agreement with BP to market and sell gas and oil produced from all Ithaca assets for a period of 3 years, with an option to extend the contract up to 5 years.
- Ithaca has enacted measures to allow operations under COVID-19 restrictions, mainly as concerns operations personnel and manning of facilities. Despite the COVID-19 restrictions, except for a delay in the Vorlich reservoir coming online, and a production delay in the Captain reservoir, production from the Company's other assets was not impacted. As aforesaid, the Vorlich reservoir came online in early November 2020.
- In the first quarter of 2020, the Group included a provision for impairment of oil and gas assets in the North Sea, to the amount of USD 751 million (NIS 2.6 billion), pre-tax (USD 451 million (NIS

1.6 billion), post-tax). This impairment was due, among other things, to the COVID-19 Pandemic, lower forecasts concerning oil and gas prices, corresponding updates to production rates, and changes in the discounting rate. In the first quarter of 2020, the Group also included a provision for impairment of goodwill attributable to energy operations in the North Sea, to the amount of USD 216 million (NIS 770 million).

- As of December 31, 2020, following a recovery in oil and gas prices and an increase in the reserves estimate, the Group, through an independent third-party appraiser, tested whether it should reverse the impairment recorded on oil and gas development and production assets in the North Sea. Following this review, the Group reversed a provision for impairment to a pre-tax amount of USD 452 million (NIS 1,453 million) (USD 271 million (NIS 871 million), post-tax).
- Overall, write-downs (post-tax) to gas and oil operations in the North Sea in 2020 totaled USD 396 million (NIS 1,397 million).

  It is noted that, in 2019, the Group included a provision for impairment of oil and gas assets in the North Sea (mainly in connection with the GSA Reservoir), to the amount of USD 199 million (NIS 688 million) (post-tax - USD 120 million (NIS 413 million)).

- The Group, through an independent third party appraiser, performed additional tests for impairment of goodwill attributable to the 'Oil and Gas Development and Production Assets in the North Sea' unit as whole. These tests were performed as of June 30, and December 31, 2020. The unit's recoverable amount was measured as the fair value of the investment in oil and gas production operations in the North Sea, net of selling costs. As of June 30, 2020, this amount was estimated at USD 1.2 billion; as of December 31, 2020, the amount was estimated at USD 1.9 billion. This value is higher than the carrying amount for the investment in this unit for each of the above date. The Company therefore is not required to recognize additional impairment on goodwill.
- For more information concerning a provision for impairment of oil and gas assets and goodwill in the North Sea, see Notes 12U6 and 14B3 to the financial statements.
- In 2020, Ithaca distributed a dividend of USD 120 million.
- Subsequent to the financial position statement date, on January 26, 2021, the Company's Board of Directors authorized the Company's management to study and pursue a plan to list Ithaca's shares for trading on the main London Stock Exchange, including through an exchange purchase offer whereby part of the Company's debentures would be exchanged for Ithaca shares, up to a total of 25% of Ithaca's shares, so that after such exchange, the Company would hold 75% of Ithaca's shares. Immediately following the listing of Ithaca's shares for trading on the London Stock Exchange, should such listing take place, the Company will work to also list Ithaca's shares for trading on the TASE, under dual-listing guidelines. The Company's Board of Directors estimates that the prospective plan may hold significant advantages for the Company and for the holders of its securities.

Fuel operations in Israel

- On July 7, 2020, a transaction was completed whereby Delek Israel sold to a third party all of its rights in Delek Pi Gliloth Limited Partnership ("Pi Gliloth") and in the land from which Pi Gliloth operates its fuel terminals in Haifa, Ashdod, Be'er Sheva, and Jerusalem. Consideration for the sale totaled NIS 720 million, paid to Delek Israel in full upon the transaction's completion. In the reporting period, based among other things on the price of this transaction, and the estimated capitalization fees due to the Israel Land Authority from Delek Israel under the agreement, Delek Israel recognized a provision for impairment of goodwill attributable to Pi Gliloth's operations to the amount of NIS 111 million (pre-tax). For more information, see Note 10J3 to the financial statements.
- In July 2020, Delek Israel paid the Group a dividend of NIS 150 million.
- On July 23, 2020, Delek Israel signed a detailed agreement to sell 100% of the shares in IPP Ashkelon Limited and IPP Sorek Ltd. (which operate the power plants in Ashkelon and Sorek), for a total consideration of NIS 367 million. According to the agreement, the consideration is payable in two installments. The first installment, of NIS 307 million, is payable upon completion, and the remaining NIS 60 million is payable one year after the completion date (deferred consideration). The transaction was completed subsequent to the financial position statement date, in February 2021. In the reporting period, Delek Israel recognized a NIS 191 million provision for the power plants' impairment. For more information, see Note 10J1 to the financial statements.

- On October 16, 2020, the Group sold 70% of Delek Israel's share capital, for a total consideration of NIS 525 million. Consideration for the sold shares will be paid as follows: Upon the transaction's completion, the buyer paid NIS 450 million in cash ("the Payment Upon Completion"), against the transfer of 60% of Delek Israel's share capital to the buyer. The remaining consideration of NIS 75 million ("the Deferred Consideration") will be transferred by the buyer by June 30, 2021, against 10% of Delek Israel's share capital ("the Additional Shares"). The Additional Shares were delivered to the parties' trustee by the date that the seller transfers consideration for said shares. Should the buyer fail to finalize payment of the Deferred Consideration, or any part thereof, by June 30, 2021, the parties' trustee will transfer to the buyer a prorated number of shares in accordance with that portion of the Deferred Consideration which was actually transferred by such date. The parties' trustee will transfer the remaining balance of the sold shares, held at that time by the parties' trustee, to the trustees for the Company's debenture-holders. Furthermore, the agreement grants the buyer an option to buy up to an additional 5% of Delek Israel's issued and paid-up share capital ("the Optional Shares") from the completion date and up to June 30, 2021. The share price for the Optional Shares is identical to the selling price subject to certain adjustments, reflecting an addition of NIS 37 million if the option is exercised in full. The option is exercisable until June 30, 2021. On the completion date, the cash consideration was received, and on October 27, 2020, all of the Company's and the staff companies' debts to the relevant banks were settled. Following such repayment, the Company does not have any debts outstanding to the relevant banks. Upon such repayment, all participation units in Delek Drilling pledged to said banks were transferred to a central escrow account for all the relevant banks ("the Banks' Escrow Account"), as stipulated in the letter of consent between the Company and the relevant banks. Under the Company's amended deeds of trust in effect since June 17, 2020 ("the Amended Deed"), the participation units were transferred from the Banks' Escrow Account to the account of the trustees for the Company's debentures. Following completion of such transfer and registration of the corresponding liens, 40% of all of the Partnerships' participation units were pledged to the debenture-holders. The remainder of the participation units remaining in the Banks' Escrow Account was released from any pledge.

  Subsequent to the financial position statement date, in February 2021, the buyer transferred to the Company one half of the deferred consideration, to the amount of NIS 37.5 million, against the transfer of 5% of Delek Israel's share capital. The buyer also exercised part of its option and bought 1.66% of Delek Israel's capital for a total consideration of NIS 12.5 million. Furthermore, in March 2021, the buyer exercised its remaining option and bought 3.34% of Delek Israel's issued and paid-up capital for a total consideration of NIS 25 million. Post-sale, as of the report's approval date, the Group holds 25% of Delek Israel's issued and paid-up capital. The remaining shares, accounting for 5% of Delek Israel's share capital, are held in escrow until payment of the deferred consideration.

- The gain to the Company's shareholders on the sale of control in Delek Israel totaled NIS 74 million. It is noted that, after selling control in Delek Israel as aforesaid, Delek Israel's operating results until the sale date (including gains on the sale), were presented in profit or loss under the 'Profit or loss from discontinued operations' item. As for the remaining investment in Delek Israel (40% of Delek Israel's capital as of December 31, 2020), presented as per the equity method - the Group has concluded that it does not meet the quantitative criteria set forth in IFRS 8 for classification as a reporting segment. Therefore, Delek Israel's results are presented under 'Additional operations'. In the fourth quarter of 2020, Delek Israel (40%) contributed NIS 2 million to the profit attributable to the Company's shareholders.

Other Operations

- Exercise of swap transactions on The Phoenix Holdings Ltd. ("The Phoenix") shares

  On April 27, 2020 and on May 10, 2020, the Company notified the banks with which it had undertaken swap contracts to sell 25,000,000 shares in The Phoenix, of the early completion of these swaps and the release to the Company of a net cash amount of NIS 143 million which had been pledged to the banks to secure the swaps, as common for such transactions. The shares were sold in an off-TASE transaction for a total consideration of NIS 413 million. For more information, see also Note 10E2 to the financial statements.

- Seller's loan for the sale of The Phoenix's shares

  As part of the sales agreement for The Phoenix's shares, the Company provided the buyer a subordinated debt whose balance as of December 31, 2020 totaled NIS 268 million ("the Seller's Loan").

The Seller's Loan, elements of the contingent considerations, and future adjustments (including as concerns the option) are measured in the financial statements at fair value through profit or loss. As of December 31, 2020, the net fair value of these instruments totaled NIS 143 million (as of December 31, 2019 - NIS 140 million). As such, and accounting for NIS 24 million in interest payments, the Company recognized a loss of NIS 23 million in the reporting period, presented under the 'Profit (loss) from discontinued operations, net' item. For more information, see Note 10E1 to the financial statements.

– Sale of IDE Holdings Ltd. ("IDE") shares

In March 2020, the Group sold its remaining holdings (20%) in IDE, for a total consideration of NIS 169 million. Thus, in the first quarter of 2020, the Group recognized net gains of NIS 20 million. For more information, see also Note 10H to the financial statements.

– Sale of investment property

In March 2020, the Company sold to Gadot Biochemicals Ltd. ("Gadot") its title to land in the Haifa Bay area, on which Gadot's facility is located. Consideration for the sale totaled NIS 33 million, which was approximately the asset's carrying value.

– Sale of land in Acre

Subsequent to the financial position statement date, in March 2021, the Group signed a detailed agreement to sell an investment-property asset in Acre, as-is, for a total consideration of NIS 200 million. Consideration will be paid as following: NIS 10 million were paid to the Company upon signing the memorandum of understanding; NIS 30 million are payable by the buyer near the agreement's signature date, will be kept in escrow for the Company, and will be transferred to the seller within one business day of the following conditions being met. The remaining consideration is payable against receipt of title to the property, registration of a pledge to the financing party, and approvals to transfer the rights registrations. The agreement includes termination conditions and failure to meet these conditions grants the buyer the right to terminate the agreement. For more information, see Note 11D to the financial statements.

Changes in the Company's equity

– In May 2020, the Company completed a capital raising (shares and warrants) with immediate proceeds of NIS 137 million.

– In August 2020, the Company completed an additional capital raising (shares and warrants) with immediate proceeds of NIS 176 million. For more information, see Note 26 to the financial statements.

– In November and December 2020, a total of 232,272 warrants (Series 8), 758,000 warrants (Series 9), 255,242 warrants (Series 11), and 5 warrants (Series 12) were exercised for 1,245,519 shares of NIS 1 par value in the Company, for a total consideration of NIS 99.7 million. After these exercises, the Company's issued and paid-up share capital totaled 16,798,717 shares of NIS 1 par value, each. Furthermore, in December 2020, the Company completed an additional capital raising of shares for a total consideration of NIS 39 million.

– On December 15, 2020, a total of 96,852 warrants (Series 8) expired.

– As of December 31, 2020, the Company's issued and paid-up share capital totaled 17,159,717 shares of NIS 1 par value, each. Warrants currently in circulation are as follows: 379,000 warrants (Series 10); 502,758 warrants (Series 11); and 378,995 warrants (Series 12).

– Subsequent to the financial position statement date and until immediately prior to the financial statements' approval date, a total of 193,359 warrants (Series 10) were exercised into 193,359 shares of NIS 1 par value each in the Company, for a total consideration of NIS 14.5 million. Furthermore, 29,625 warrants (Series 12) were exercised into 29,625 shares of NIS 1 par value each for a total consideration of NIS 2.3 million. After these exercises, the Company's issued and paid-up share capital totaled 17,382,701 shares of NIS 1 par value, each. Warrants currently in circulation are as follows: 185,641 warrants (Series 10); 502,758 warrants (Series 11); and 349,370 warrants (Series 12).

3. Results of Operations

A) The profit attributable to the Company's shareholders in the fourth quarter of 2020 amounted to NIS 1,069 million, as compared to a loss of NIS 311 million in the same quarter last year.

The loss attributable to the Company's shareholders for all of 2020 totaled NIS 1,874 million, as compared to a net profit of NIS 234 million in the same period last year.

Contribution to net profit (loss) attributable to Company shareholders from principal operations (NIS millions):

	Q1 2020	Q2 2020	Q3 2020	Q4 2020	2020		Q1 2019	Q2 2019	Q3 2019	Q4 2019	2019
Oil and gas exploration and production in and around Israel *)	136	11	158	21	326		117	58	99	110	384
Oil and gas exploration and production in the North Sea **)	37	102	55	181	375		57	27	2	199	285
Contribution of continuing operations before discontinued operations and capital and other gains	**173**	**113**	**213**	**202**	**701**		**174**	**85**	**101**	**309**	**669**
Impairment of gas and oil assets, goodwill, and other income (expenses) in oil and gas operations ***)	(2,358)	(220)	(24)	895	(1,707)		(13)	(1)	35	(739)	(718)
Finance, tax, and other income (expenses) ****)	(581)	(219)	(40)	(28)	(868)		129	106	(71)	119	283
Net profit (loss) attributable to Company shareholders	**(2,766)**	**(326)**	**149**	**1,069**	**(1,874)**		**290**	**190**	**65**	**(311)**	**234**

*) Excluding gains or losses on the sale of oil and gas assets, impairment recognized on the Tamar Reservoir, and revaluation of amounts receivable and a right to royalties from the Karish and Tanin leases and the Tamar and Dalit leases; and also excluding losses recognized in profit or loss from fair value adjustments to the balance of the investment in Tamar Petroleum, included under the 'Impairment of gas and oil assets, goodwill, and other income (expenses)' item in gas and oil operations.

**) Excluding impairment losses on oil and gas assets and goodwill of NIS 1,397 million, post-tax (USD 396 million)(in 2019 - NIS 413 million, post tax (USD 120 million)).

***) For more information on impairment testing for gas and oil assets and goodwill, see Notes 12 and 14 to the financial statements. In the reporting period, the item includes NIS 235 million (post-tax) in losses on the disposal of the investment in Cohen Development.

****) In the reporting period, the item includes a provision for impairment of power plant operations to the amount of NIS 191 million, erosion of the securities portfolio by NIS 194 million, and losses of NIS 23 million from fair value changes to the seller's loan to The Phoenix's buyers as aforesaid. Furthermore, Delek Israel's results were presented under the 'Profit (loss) from discontinued operations, net' item. Delek Israel's operations in the reporting period yielded a loss of NIS 131 million, as compared to a profit of NIS 91 million in the same period last year. The item includes gains on the sale of Delek Israel's shares and revaluation of the remaining investment to the amount of NIS 74 million.

B) Revenues from operating activities (NIS millions):

The Group's revenues in the reporting period totaled NIS 6.7 billion, as compared to NIS 3.4 billion in the same period last year, as detailed in the table below (NIS millions):

	2020	2019		10-12/2020	10-12/2019
Oil and gas exploration and production in and around Israel	2,667	1,332		685	320
Oil and gas asset development and production in the North Sea	4,052	2,062		946	1,100
Other segments including adjustments	(48)	(38)		3	(10)
Total revenues	**6,671**	**3,356**		**1,634**	**1,410**

See also Note 33 to the consolidated financial statements - Information Regarding Operating Segments.

C) Operating profit (loss) (NIS millions):

	2020	2019		10-12/2020	10-12/2019
Oil and gas exploration and production in and around Israel	705	649		(232)	194
Oil and gas asset development and production in the North Sea	(734)	(104)		1,774	(370)
Other segments including adjustments	(65)	(118)		(2)	(196)
Total operating profit (loss)	**(94)**	**427**		**1,540**	**(372)**

See also Note 33 to the consolidated financial statements - Information Regarding Operating Segments.

D) Highlights from the Company's consolidated income statements (NIS millions):

	2020	2019		10-12/2020	10-12/2019
Revenues	6,671	3,356		1,634	1,410
Cost of sales	3,536	1,901		807	845
Gross profit	**3,135**	**1,455**		**827**	**565**
General and administrative expenses	241	121		57	30
Group's share in losses of operating associates, net	(15)	(42)		(9)	(36)
Other income (expenses), net	(2,973)	(865)		779	(871)
Operating profit (loss)	**(94)**	**427**		**1,540**	**(372)**
Finance income	382	560		270	127
Finance expenses	(2,294)	(1,219)		(528)	(481)
Profit (loss) after finance expenses, net	**(2,006)**	**(232)**		**1,282**	**(726)**
Group's share in earnings (loss) of associates, net	5	19		2	14
Profit (loss) before income tax	(2,001)	(213)		1,284	(712)
Income tax (tax benefit)	(406)	(417)		520	(491)
Profit (loss) from continuing operations	**(1,595)**	**204**		**764**	**(221)**
Profit (loss) from discontinued operations, net	**(215)**	**582**		**118**	**23**
Net profit (loss)	**(1,810)**	**786**		**882**	**(198)**
Attributable to -					
Company shareholders	(1,874)	234		1,069	(311)
Non-controlling interests	64	552		(187)	113
	(1,810)	**786**		**882**	**(198)**

E) Movement in comprehensive income (loss) (in NIS millions):

	2020	2019		10-12/2020	10-12/2019
Net profit (loss)	**(1,810)**	**786**		**882**	**(198)**
Other comprehensive income (loss) from continuing operations (post-tax):					
Profit (loss) from investment in equity instruments measured at fair value through other comprehensive income	(101)	(167)		31	(18)
Gain (loss) on financial assets at fair value through other comprehensive income	20	-		19	-
Transfer to profit or loss from adjustments from translation of overseas operations	28	14		-	-
Gain (loss) from cash flow hedges	645	92		(247)	(119)
Transfer to profit or loss from cash flow hedges	(570)	(101)		(72)	(32)
Adjustments from translation of overseas operations (*)	(594)	(969)		(699)	(106)
Other comprehensive income (loss) attributable to associates, net	(2)	(4)		-	(5)
Total other comprehensive income (loss) from continuing operations	**(574)**	**(1,135)**		**(968)**	**(280)**
Total other comprehensive income from discontinued operations, net	**-**	**149**		**-**	**(80)**
Total comprehensive income (loss)	**(2,384)**	**(200)**		**(86)**	**(558)**
Attributable to:					
Company shareholders	**(2,155)**	**(501)**		**399**	**(644)**
Non-controlling interests	**(229)**	**301**		**(485)**	**86**
	(2,384)	**(200)**		**(86)**	**(558)**

(*) The Group has material investments in investee companies and an investee partnership whose functional currency is not NIS (USD). Thus, changes in currency exchange rates materially affect the Group's other comprehensive income or loss and the equity attributable to Company shareholders. In the reporting period, the USD lost 7% against the NIS, as compared to a decrease of 7.8% in the same period last year.

4. Financial Position

The Group's total assets as of December 31, 2020, amounted to NIS 34.3 billion, compared with NIS 47.0 billion as of December 31, 2019.

<u>Principal changes in assets and liabilities as included in the consolidated statements as of December 31, 2020, compared with December 31, 2019:</u>

<u>Cash and cash equivalents and short-term investments</u>

As of December 31, 2020, the Group had cash and short-term investment balances of NIS 961 million, composed mainly of NIS 657 million in Delek Drilling, and NIS 271 million in the Company and Delek Energy (of which NIS 92 million were in a deposit pledged to the trustee for the debentures).

<u>Current and non-current assets</u>

The Group's total current assets in its consolidated financial statements (excluding cash and short-term investments), excluding held-for-sale assets, as of December 31, 2020, amounted to NIS 1.4 billion, as compared to NIS 3.2 billion as of December 31, 2019. This decrease in current assets was mainly due to loss of control in Delek Israel in October 2020, with the remaining investment in Delek Israel's shares being presented as per the equity method.

As of December 31, 2020, the Group’s total non-current assets amounted to NIS 27.9 billion, compared to NIS 41.5 billion as of December 31, 2019, a decrease of NIS 13.6 billion. This decrease in non-current assets was mainly due to provisions for impairment of oil and gas assets and goodwill attributable to energy operations in in the North Sea, to the amount of USD 396 million (NIS 1.4 billion). The decrease was further affected by reclassification of NIS 3.9 billion in non-current assets (mainly oil and gas assets from the Tamar Project as held-for-sale assets, and the sale of some of the Group's investments.

<u>Short- and long-term liabilities</u>

Financial liabilities in the consolidated financial statements (to banks and others and to debenture-holders and holders of convertible debentures), as of December 31, 2020, amounted to NIS 18.1 billion, as compared to NIS 27.8 billion as of December 31, 2019. This decrease was due to repayment of NIS 12.7 billion in bank debt and debentures, re-classification of NIS 2 billion in debentures issued to finance the Tamar Project (Tamar Bonds) as liabilities associated with held-for-sale assets, and the sale of control in Delek Israel. On the other hand, in the reporting period, the Group raised debentures to finance the Leviathan Project (Leviathan Bonds) and conducted a securitization of overriding royalties from the Leviathan Project to a total amount of NIS 8.1 billion. Results were also affected by the re-classification of Delek Israel's financial debt as liabilities associated with held-for-sale assets.

<u>Contingent claims</u>

In their opinion on the financial statements, the Company's auditors draw attention to legal actions brought against Group companies. For details, see Note 24A to the financial statements.

<u>Additional information</u>

For additional information regarding repayments of principal and interest on the Company's and the staff companies' debts, see Appendix A to the Board of Directors' Report.

5. Sources of Finance and Liquidity

The net financial debt of the Company and the staff companies as of December 31, 2020:[(1)]

	NIS millions
Liabilities	
Debentures	(5,325)
Loan from subsidiary (*)	(242)
Bank and other loans	(300)
Other liabilities	(281)
Total liabilities	**(6,148)**
Assets	
Cash and deposits	159
Restricted deposits and investments in securities	206
Escrow deposit pledged to debenture trustee	92
Financial investments	24
Loans (**)	1,195
Other payables	70
Treasury shares (***)	59
Total assets	**1,805**
Financial debt, net	**(4,343)**

(*) In October 2020, a debenture issuance was completed to classified investors in Israel and abroad, to the amount of USD 180 million (before safety buffers securing interest payments and issuance costs) by Delek Overriding Royalty Leviathan Ltd. ("the Issuer"), a subsidiary (100%) of Delek Energy. The issuance was secured by a pledge of rights to overriding royalties from the Leviathan Project which were transferred to the Issuer. For more information, see Note 12L to the financial statements

(**) Composition of loans extended as of December 31, 2020:

Borrower	Loan balance (NIS millions)
Loans to Ithaca	881
Seller's loan, net - The Phoenix transaction	143
Others	171
Total	**1,195**

(***) As of December 31, 2020, and as of the financial statements' approval date, Delek Financial Investments (2012) Limited Partnership, a wholly-owned subsidiary partnership of the Delek Group, holds 586,422 shares of NIS 1 par value in the Delek Group. For more information, see Section (f) - Additional information below.

(1) Staff companies: Delek Group, Delek Petroleum, Delek Financial Investments (2012) Limited Partnership, Delek Power Plants Limited Partnership, DKL Energy, DKL Investments, Delek Infrastructure, Delek Hungary Holdings Limited, and Delek Energy.

Projected cash flows

According to Regulation 10(b)(14) of the Securities Regulations (Periodic and Immediate Reports), 1970 ("the Securities Regulations"), companies which, upon publication of their financial statements, have debt certificates in circulation, must test for warning signs as defined in the Securities Regulations. If one or more warning signs are found, companies must provide disclosure concerning their projected cash flows.

The financial statements as of December 31, 2020, include the following warning signs: (1) the auditors' opinion as of the reporting date drew attention to significant doubts concerning the Company's continued operation as a going concern; (2) a working capital deficit for a period of twelve months, and the Company's Board of Directors did not determine that such deficit does not indicate a problem with the Company's liquidity.

The Company's Management has presented to the Company's Board of Directors all sources received until immediately prior to the financial statements' approval date, and all forecast sources which may serve the Company and the staff companies to meet their obligations in the next two years including the Company's forecast inflows from earning and dividend distributions from investee partnerships and companies, the Company's cash balances and securities portfolios (liquid balances) which service operating activities and liability repayments, plans to raise significant funds, mainly by selling part of its holdings in its investees, disposing of other assets, financing backed by Delek Drilling participation units, and capital raising (as of the financial statements' approval date, the Company raised a total of NIS 450 million).

The Company's Board of Directors, having reviewed the forecast sources and uses report presented by Management, under different scenarios, believes, based on past experience, the Company's proven ability to raise funds in recent years and the Company's assets, that the assumptions underlying the report are reasonable. The Company's Board of Directors also believes that the Company will be able to secure the sources of financing indicated in the projected cash flows, required to settle the Company's liabilities. See also Note 1 to the consolidated financial statements concerning the COVID-19 Pandemic and its effects on the Company's business.

The forecast presented in this report refers to the Company and its wholly-owned staff companies, including Delek Energy Systems Ltd. ("Delek Energy"), and other wholly-owned staff companies such as: DKL Investments Limited, DKL Energy Limited, Delek Infrastructure Ltd., Delek Financial Investments (2012) Limited Partnership, Delek Petroleum Limited, and Delek Hungary Holdings Limited (jointly - "the Company and Its Staff Companies").

Projected cash flows for the Company and its wholly-owned Staff Companies:

	Assumptions	2021	2022
Opening balance - cash and liquid balances	**1**	**275**	**1,441**
Inflows			
Forecast earning distributions from Delek Drilling	2	65	290
Forecast dividend distributions from Ithaca	3	50	166
Dividend distributions from Delek Israel	4	56	19
Total dividends from investees		**171**	**475**
Cash consideration from the sale of Delek Israel shares (see Note 3E(4) to the consolidated financial statements)	5	75	-
Disposal of investees and other assets	5	264	-
Capital raising - Company shares / exercised warrants	6	50	-
Other inflows	7	48	8
Equity transaction in Ithaca (new partner/merger/pre-IPO/IPO)	8	1,326	-
Total other inflows		**1,763**	**8**
Financing against pledge of Delek Drilling participation units coupled with a capital-raising round	9	-	600
Financing against pledge of Ithaca shares	10	663	-
Refinancing - pledge of real estate asset		99	
Financing / disposal of remaining shares in Delek Israel	11	-	81
Total loans and additional raising		**762**	**681**
Total inflows		**2,696**	**1,164**
Outflows			
Principal payments on debentures	12	(915)	(1,778)
Interest payments on debentures	12	(261)	(187)
Payments made on BNP's loan	13	(25)	-
Payments on bank loans	14(a)	(100)	-
Interest payments on bank loans and other liabilities	14(b)	(50)	(103)
Total debt payments (principal and interest)		**(1,351)**	**(2,068)**
Other outflows	15	(179)	(97)
Total other outflows		**(179)**	**(97)**
Total outflows		**(1,530)**	**(2,165)**
Closing balance - cash and liquid balances		**1,441**	**440**

<u>Assumptions underlying forecast cash flows for January 1, 2021 to December 31, 2022</u>

<u>General assumptions</u>

- USD amounts were translated at an exchange rate of USD 1 = NIS 3.3.
- Debentures and loans are linked to the known CPI as of December 31, 2020.
- The following projected cash flows do not account for restricted cash balances and their projected release back to the Company (except for a NIS 92 million deposit pledged to the trustee for the debentures, which is included in the cash balance as of December 31, 2020). The Company's and the Staff Companies' pledged deposits and investments in marketable securities near the financial statements' approval date totaled NIS 195 million.
- **<u>Assumptions underlying specific projected cash flow items</u>**

1. <u>Cash and liquid balances</u>

   The item includes the following balances, as of December 31, 2020 (NIS millions):

	December 31, 2020
Cash balance	159
Escrow deposit pledged to debenture trustee	92
Financial investments (mainly marketable securities)	24
Total	**275**

2. <u>Forecast earning distributions from Delek Drilling</u>

   In December 2020, Delek Drilling announced an earnings distribution of NIS 117 million, paid out in January 2021 (Group's share - NIS 65 million). It is currently estimated that Delek Drilling will distribute USD 80 million for 2021, at the start of 2022, and an additional USD 80 million for 2022 will be distributed in December 2022. The projected cash flow accounts for the Company's share in these distributions (54.7%).

   Earning distributions from Delek Drilling are mainly based on expected cash flows from Delek Drilling's operating activities, and Delek Drilling's payout capacity.

   The assumption underlying this cash flow is that earning distributions by Delek Drilling receivable for Delek Drilling's pledged participation units will serve to repay the liabilities (debentures) for which the units are pledged.

3. <u>Forecast dividend distributions from Ithaca</u>

   The forecast is based on the assessment that Ithaca will distribute USD 15 million (NIS 50 million) in dividends in 2021 and USD 75 million (Company's share - NIS 166 million) in 2022. Dividend distributions from Ithaca are mainly based on expected cash flows from Ithaca's operating activities, and assessments by Ithaca's management.

4. <u>Forecast dividend distributions from Delek Israel</u>

   The forecast is based on the assessment that Delek Israel will distribute dividends from the sale of its power plant operations and from its current earnings (the Group's share - NIS 56 million in 2021, and NIS 19 million in 2022). This estimate is based mainly on a business forecast compiled by Delek Israel's management, Delek Israel's payout capacity, and the shareholders' agreement which sets a minimum dividend payout policy.

5. <u>Disposal of investees and other assets</u>

   A. Cash consideration received on the disposal of Delek Israel - In October 2020, the Company completed the sale of 70% of Delek Israel's share capital, at a value of NIS 750 million. On the completion date, a cash consideration was paid, to the amount of NIS 450 million, against 60% of Delek Israel's share capital. One half of the remaining consideration to the amount of NIS 37.5 million was transferred by the buyer in February 2021, against an additional 5% of Delek Israel's share capital. In February

2021, the buyers also exercised their option to buy an additional 1.66% of Delek Israel's share capital for a total consideration of NIS 12.5 million. Furthermore, in March 2021, a further consideration of NIS 25 million was received for the exercise of additional options.

B. Disposal of investees and other assets - Reflects expected considerations on the exercise of options granted to the buyers of Delek Israel's shares (see sub-section (a) above) and an expected cash consideration on the sale of a real estate property in Acre, sale of 2 Company-owned power plants, and a tax refund.

6. <u>Capital raising - Company shares and warrants to Company shares</u>

The Company's Board of Directors has decided to work to raise NIS 450 million in capital in 2020, and NIS 50 million in the first four months of 2021. In 2020, the Company raised NIS 450 million, and plans to raise NIS 50 million by April 2021 through warrant exercises and capital raising. Near the financial statements' approval date, a total of NIS 16 million were received through the exercise of warrants (Series 9). For more information concerning these capital raising rounds and the issue of warrants accompanying these raising rounds, see Note 26 to the financial statements.

7. <u>Other inflows</u>

Reflects repayments (principal and interest) on loans extended by the Company.

8. <u>Equity transactions in Ithaca</u>

The Company is working to find a partner and/or to sell part of Ithaca's shares (including selling as part of an initial public offering) and/or to raise funds through a pre-IPO mechanism for Ithaca shares and/or an offer for a voluntary exchange of Delek Group debentures for Ithaca shares as part of an IPO and/or the issuance of share capital and/or a combination of the above, to the amount of USD 400 million. To this end, the Company has hired IPO consultants, accountants, and attorneys, and has begun the necessary preparations for carrying out said IPO.

9. Financing against pledge of Delek Drilling participation units coupled with a capital-raising round

In accordance with the Company's amended deed of trust with its debenture-holders, the raising of debt backed by Delek Drilling's unencumbered participation units must be coupled with capital raising, so that the total debt and capital raised will be equal to the value of the pledged participation units, based on the mechanism set forth in the amended deed of trust. In its projected cash flow, the Company assumed that these actions will yield cash flows of NIS 600 million.

10. <u>Financing against pledge of Ithaca shares</u>

The Group is working to secure USD 200 million in financing against the pledge of Ithaca's shares. For information concerning a loan from a foreign bank secured by Ithaca's shares, see Section 14 below. The projected cash flows assumes that the principal of the new loan will be payable after three years, based on non-binding understandings with the financing entity.

11. <u>Financing / disposal of part of the remaining shares in Delek Israel</u>

Debt-raising and/or sale involving part of Delek Israel's shares held by the Group, based on Delek Israel's value as set in the sale of Delek Israel's shares in October 2020, with adjustments for assumed dividend payments.

12. <u>Principal and interest payments on debentures</u>

Based on the original amortization schedules for the Company's and Staff Companies' debentures.

For more information on agreements with debenture holders, see Note 19 to the financial statements.

13. Repayment of BNP's loan and future loan payments

    The balance of BNP's loan totals USD 8 million, and is expected to be settled in May 2021.

14. Loan payments to banks and others, net

    The above cash flows include repayment of a NIS 100 million loan received from a financial institution in January 2021, in accordance with the Company's commitment of June 2020.

    The item also includes interest payments on loans, as detailed in Sections 9, 10, and 11.

15. Other outflows

    The item includes fees and tax payments, general and administrative expenses, abandonment costs, and other payments.

16. The forecast does not account for options to dispose of additional assets (in lieu of or in addition to raising debt backed by such assets. These include: options to sell overriding royalties from Leviathan; options to sell Delek Drilling's unencumbered participation units; dispose of real estate assets; the seller's loan in The Phoenix transaction; debt restructuring on the open market which may become possible should the yield on the debentures continue to decrease, as seen in recent months following progress in implementing the Company's plans and recoveries in global energy prices; additional capital transactions in connection with Delek Israel shares and Ithaca shares; and more. The Company will consider such transactions based on market conditions and the materialization of the assumptions underlying the above cash flows.

Warning concerning forward-looking information - In the attached projected cash flow, the Company has included, both for its own operations and for the operations of its investees, forward-looking information as defined in the Securities Law, 1968. This information includes, among other things, the probability for the materialization of relevant business scenarios expected to yield inflows for the Company, the time frames for the materialization of such scenarios; results of operations; possible alternatives for securing sources to meet the liabilities of the Company and the staff Companies as they become due; the amounts and timing of debenture and loan repayments for the Company and the staff companies and other forecasts, assessments, assumptions, and other information concerning future events or matters, whose materialization is uncertain and outside the Company's or its investees' control, especially in light of the extreme uncertainty prevailing on the report's approval date due to the COVID-19 pandemic.

6. Analysis of Operations by Segment

A) <u>Oil and gas exploration and production in and around Israel</u>

As aforesaid, oil and gas exploration and production in and around Israel are carried out mainly through Delek Drilling.

<u>Results of oil and gas exploration and production in and around Israel, as included in the Group's results (NIS millions):</u>

	2020	2019		10-12/2020	10-12/2019
Revenues from gas sales net of royalties	**2,667**	**1,332**		**685**	**320**
Operating profit (adjusted for impairment and losses on disposal of oil and gas assets)	**1,619**	**652**		**390**	**197**
Loss on disposal of oil and gas assets and investment, post-tax	(235)	(3)		-	(3)
Impairment of oil and gas assets	**(679)**	**-**		**(622)**	**-**
EBITDA	**2,238**	**1,089**		**522**	**304**
Finance income (expenses), net	(576)	**217**		**41**	**75**
Net profit (loss) attributable to Group shareholders	**117**	**476**		**43**	**176**
Gas sales from Tamar, in BCM (*)	8.2	10.5		2.4	2.6
Gas sales from Leviathan, in BCM (*)	7.3	-		2	-
Gas sales in BCM (*)	**15.5**	**10.5**		**4.4**	**2.6**
Condensate sales - thousands of barrels (***)	**944**	**482**		**270**	**123**

(*) The data relate to sales of natural gas (100%) from the Tamar and Leviathan projects (previous year - Tamar and Yam Tethys), rounded to one tenth of one BCM.

(**) The data relate to condensate sales (100%) from the Tamar and Leviathan projects, rounded to thousands of barrels.

Analysis of the Oil and Gas Exploration and Production in and around Israel segment's results

In the reporting period, oil and gas exploration and production in and around Israel yielded a profit of NIS 117 million, as compared to a net profit of NIS 476 million in the same period last year. This decrease in profit in the reporting period was mainly due to NIS 235 million (post-tax) in losses on disposal of the investment in Cohen Development, as well as a NIS 94 million (share attributable to the Company's shareholders, post-tax) impairment in the Tamar Reservoir. It is further noted that, in the present period, the Partnership does not discount credit costs for the Leviathan Project, as gas production has come online. The profit attributable to the Group's shareholders adjusted for losses on the disposal of Cohen Development and impairment of the Tamar Reservoir as aforesaid totaled NIS 446 million in the reporting period. Furthermore, in the same period last year the Group recognized expenses of NIS 80 million from fair value adjustments to the investment in Tamar Petroleum.

In the fourth quarter of 2020, oil and gas exploration and production yielded a profit of NIS 43 million. This, compared with a profit of NIS 176 million in the same quarter last year. This decrease in net profit was mainly due to impairment of gas and oil assets attributable to the Tamar Project.

Revenues from gas sales net of royalties

In the reporting period, revenues from oil and gas sales, net of royalties, totaled NIS 2,667 million, compared with NIS 1,332 million in the same period last year. The increase was mainly attributable to the start of production in the Leviathan Reservoir, as aforesaid. This increase was partially offset by lower revenues from the Tamar Reservoir, mainly due to the COVID-19 Pandemic (see Note 1 to the financial statements) and the start of production from the Leviathan Reservoir.

The following table presents gas quantities (100%) sold in the reporting period, by reservoir and customer location:

	2020 (BCM)			
	Israel	**Jordan**	**Egypt**	**Total**
Tamar	7.7	0.2	0.3	8.2
Leviathan	3.5	1.9	1.9	7.3
Total	**11.2**	**2.1**	**2.2**	**15.5**

	20190 (BCM)			
	Israel	**Jordan**	**Egypt**	**Total**
Tamar	10.2	0.2	-	10.4
Yam Tethys	0.1	-	-	0.1
Leviathan	-	-	-	-
Total	**10.3**	**0.2**	**-**	**10.5**

In the fourth quarter of 2020, revenues from gas and oil sales net of royalties amounted to NIS 685 million, compared to NIS 320 million in the same quarter last year. The increase was mainly attributable to the start of production in the Leviathan Reservoir, as aforesaid.

Operating profit (excluding impairment of oil and gas assets and investment disposal losses)

Operating profit in the reporting period amounted to NIS 1,619 million, compared to NIS 652 million in the same period last year. This increase in operating profit was mainly due to the start of production in the Leviathan Reservoir. Furthermore, operating profit was lower in the corresponding period of last year due to a NIS 134 million fair value adjustment to the investment in Tamar Petroleum.

In the fourth quarter of 2020, operating profit totaled NIS 390 million, as compared to NIS 197 million in the same quarter last year. This increase in operating profit was mainly due to the start of production in the Leviathan Reservoir.

Finance income (expenses), net

In the reporting period, net finance expenses totaled NIS 576 million, as compared to net finance income of NIS 217 million in the same period last year. This year-on-year increase in finance expenses was mainly due to credit costs no longer being discounted for the Leviathan Project, as it reached the end of the development stage and began producing natural gas.

In the fourth quarter of 2020, net finance income amounted to NIS 41 million, compared with net finance income of NIS 75 million in the corresponding quarter last year. This decrease in net finance income was mainly due to credit costs no longer being discounted in the Leviathan Project, as its construction phase ended and gas production began. The decrease was further impacted by a reduction in raising cost balances for debts settled by early repayment, including LIBOR hedging costs.

It is further noted that finance income for the fourth quarter of the reporting period and last year includes income on the revaluation of royalties receivable from the Karish and Tanin leases, to the amount of NIS 218 million and NIS 91 million, respectively.

Impairment of gas and oil assets and goodwill

In the fourth quarter of 2020, the Group included a provision for impairment of oil and gas assets in the Tamar Project to the amount of USD 186 million (NIS 599 million), pre-tax. The Company's share in said impairment totaled NIS 24 million, post-tax. The minority interest in said impairment totaled NIS 436 million.

In light of this impairment, the Company attributed to the Tamar Project's cash-generating unit part of the goodwill attributable to oil and gas exploration and production in and around Israel. Overall, the impairment totaled NIS 80 million, where the Company's share totaled NIS 70 million, and the minority interest totaled NIS 10 million. For more information, see Note 12C(6) to the financial statements.

The valuation appraising the oil and gas assets in the Tamar Project as of December 31, 2020, is attached as Appendix C to this report.

	2020	2019		10-12/2020	10-12/2019
Net profit from Delek Drilling's statements	**1,256**	**802**		**476**	**277**
Indirect holdings (*)	54.7%	59.8%		54.7%	59.8%
Group's share	**702**	**480**		**260**	**166**
Income tax	(132)	(112)		(94)	(22)
Revenues from overriding royalties	32	37		6	12
Results of direct holdings in Yam Tethys (4.44%)	(4)	(9)		(1)	(3)
Amortization of excess acquisition costs **)	(47)	(15)		(11)	8
General and administrative expenses	(29)	(18)		(15)	(4)
Finance income (expenses), net	(76)	93		(8)	(1)
Other income (expenses)	(329)	20		(94)	20
Contribution to net profit from oil and gas exploration and production	**117**	**476**		**43**	**176**

*) In 2019, the Group's indirect holdings in Delek Drilling totaled 59.8%. It is noted that, in March 2020, the Company's indirect holdings in Delek Drilling went down to 54.7%.

(**) Current amortization of excess cost attributable to the Tamar and Leviathan projects (previously recognized as part of the Cohen Development transaction).

For more information about oil and gas exploration and production in and around Israel, see Notes 10I, 12C through 12T, 14, and 24A(1)to the financial statements and Part A of the Periodic Report - Description of the Company's Business.

B) **Oil and gas exploration and production in the North Sea**

Ithaca Energy ("Ithaca") is an independent oil and gas operator operating in the North Sea, holding both production and development oil and gas assets.

On November 8, 2019, Ithaca completed the purchase of 100% of CNSL's share capital from Chevron North Sea Limited ("CNSL"). CNSL owns ten actively-producing oil and gas assets and exploration licenses. CNSL's financial statements are consolidated in the Group's statements as of that date. For more information on this transaction, see Chapter 2 above, and Note 10F to the financial statements.

Ithaca's financial data as included in the financial statements (including attribution of excess acquisition costs incurred upon assuming control):

Statement of Financial Position

(USD millions)	December 31, 2020	December 31, 2019
Cash and cash equivalents	1	15
Other current assets	244	327
Investments in oil and gas exploration and production	2,513	2,903
Other assets, net (mainly deferred taxes)	665	589
Goodwill	767	982
Total assets	**4,190**	**4,816**
Current liabilities (trade and other payables)	335	419
Bank loans, RBL, and debentures	1,187	1,514
Loan from the Delek Group	271	261
Other long-term liabilities (mainly obligation to disassemble assets)	1,500	1,335
Equity attributable to Ithaca's shareholders	**897**	**1,287**
Total liabilities and equity	**4,190**	**4,816**

Income statement

(USD millions)	2020	2019		10-12/2020	10-12/2019
Revenues from oil and gas sales	1,176	582		285	315
Cost of sales (excluding depreciation and inventory turnover)	(421)	(205)		(116)	(106)
Depreciation expenses	(346)	(190)		(78)	(112)
Oil and gas inventory turnover	(2)	2		17	11
Gross profit	**407**	**189**		**108**	**108**
Reversal of impairment (impairment) of oil and gas assets and goodwill	(518)	(199)		452	(199)
Other expenses, net	(38)	(22)		(13)	(14)
Finance expenses, net	(221)	(155)		(47)	(93)
Profit (loss) before income tax	**(370)**	**(187)**		**500**	**(198)**
Tax benefit (tax expenses)	84	148		(174)	136
Net profit (loss) attributable to Ithaca's shareholders	**(286)**	**(39)**		**326**	**(62)**
Output in the reporting period (KBoe)	**24,250**	**10,435**		**5,596**	**5,718**
Average daily output (KBoed)	**66**	**29**		**61**	**62**

Cash flow from operating activities and adjustment to net profit

(USD millions)	2020	2019		10-12/2020	10-12/2019
Revenues, net (*)	**1,144**	**584**		**285**	**324**
Operating expenses	(389)	(198)		(98)	(103)
General, administrative, currency, and other expenses	(10)	(11)		12	(4)
Cash flows from operating activities	**745**	**375**		**199**	**217**
One-time costs, in cash	(21)	(17)		(21)	(17)
Depreciation and amortization	(346)	(190)		(78)	(112)
Reversal of impairment (impairment) of oil and gas assets and goodwill	(518)	(199)		452	(199)
Other non-cash income (expenses)	3	2		3	2
Net finance expenses, excluding results of hedges	(233)	(158)		(55)	(89)
Tax benefit (tax expenses)	84	148		(174)	136
Net profit (loss) attributable to Ithaca's shareholders	**(286)**	**(39)**		**326**	**(62)**

*) Net revenues plus (less) actual gains (losses) on hedges, inventory turnover, royalty expenses and oil tanker costs.

Additional data concerning Ithaca's results:

Overall, Ithaca's operating results yielded a loss of USD 286 million in 2020, as compared to a loss of USD 39 million in 2019. This decrease in Ithaca's results in the reporting period was mainly due to impairment recognized on oil and gas assets and goodwill due to the COVID-19 pandemic. These amounted to USD 518 million, pre-tax (USD 396 million, post-tax) in 2020. It is noted that, in 2019, the Group included a provision for impairment of oil and gas assets in the North Sea (mainly in connection with the GSA Reservoir), to the amount of USD 199 million (USD 120 million, post-tax).

Revenues

Ithaca's revenues in the reporting period totaled USD 1,176 million, as compared to revenues of USD 582 million in the same period last year. Revenue composition was as follows:

Sales revenues (USD millions)	2020	2019		10-12/2020	10-12/2019
Oil	585	334		129	200
Natural gas	172	127		69	60
NGL (natural gas liquids)	36	29		10	12
Other income	10	1		7	1
Gains on hedges	373	91		70	42
Total	**1,176**	**582**		**285**	**315**

The year-on-year increase in revenues in the reporting period was mainly due to increased volumes of oil and gas sales, mainly following the addition of new in-production oil assets through CNSL's acquisition. However, in the reporting period, the COVID-19 pandemic caused a drop in oil and gas prices, which adversely affected Ithaca's revenues.

Output in the reporting period totaled 24.3 mmbl (66 bbl/day on average), as compared to 10.4 mmbl in 2019. The average selling price for oil (before hedging) was down in the reporting period, reaching USD 44/bbl, as compared to USD 66/bbl in 2019. Furthermore, gas prices were down in the reporting period, from 32 pennies/therm in 2019, to 25 pennies/therm on average in the present period, following a decrease in gas prices in England. It is noted that the negative impact of these price drops was largely mitigated by Ithaca's hedges on gas and oil prices. These hedges are made as part of Ithaca's risk management policy. The effect of these hedges on Ithaca's revenues amounted to an additional USD 373 million in revenues in the reporting year.

Cost of sales

In the reporting year, cost of revenues (excluding depreciation costs and inventory turnover) totaled USD 421 million, as compared to USD 205 million in 2019. The bulk of this year-on-year increase was due to the acquisition of CNSL's assets, as aforesaid. Average production costs totaled USD 16 per barrel in the reporting period, as compared to USD 19 per barrel in 2019.

In the reporting period, depreciation and amortization costs totaled USD 346 million, as compared to USD 190 million in the same period last year. This increase in depreciation costs was mainly due to amortization of newly-acquired assets (CNSL's assets and increased rights in the GSA Project), which are depreciated in line with their output.

Impairment of gas and oil assets and goodwill

In the first quarter of 2020, the Group recognized a provision for impairment of oil and gas assets in the North Sea and a write-down of goodwill, to the amount of USD 667 million, post-tax (NIS 2.4 billion). This impairment was mostly due to the crisis on the global energy markets, caused by the COVID-19 Pandemic and the price war between Russia and Saudi Arabia, which lowered forecasts for oil and gas prices. The impairment was also partially driven by a decrease in reserves.

In the fourth quarter of 2020, following recoveries in oil and gas prices and an increase in reserve quantities, the Group reversed part of the impairment it recognized in the first quarter of

2020 on oil and gas assets, to the amount of USD 452 million pre-tax (USD 271 million, post-tax). Thus, the overall write-downs recognized in the reporting period on oil and gas operations in the North Sea totaled USD 396 million, post-tax.

Furthermore, the Group, through an independent third party appraiser, performed additional tests for impairment of goodwill attributable to the 'Oil and Gas Development and Production Assets in the North Sea' unit as whole. These tests were performed as of June 30, and December 31, 2020. The unit's recoverable amount was measured as the fair value of the investment in oil and gas production operations in the North Sea, net of selling costs. As of June 30, 2020, this amount was estimated at USD 1.2 billion; as of December 31, 2020, the amount was estimated at USD 1.9 billion. This value is higher than the carrying amount for the investment in this unit for each of the above date. The Group is therefore not required to recognize additional impairment on goodwill.

For more information, see Notes 12U and 14 to the financial statements.

The valuation appraising the oil and gas assets in the North Sea and goodwill as of December 31, 2020, is attached as Appendix C to this report.

In 2020, Ithaca paid USD 120 million in dividends.

Finance income (expenses) from hedges

As part of its risk management strategy, Ithaca hedges oil and gas prices, mainly through put options and swaps. As of December 31, 2020, Ithaca had open price hedges on 9 mmbl of oil, at an average hedged price of USD 43/bbl. Ithaca also had open price hedges on 497 million therms of gas, at an average hedged price of 45 pennies/therm. The value of these hedges as of December 31, 2020 reflects a liability of USD 73 million (NIS 235 million).

It is noted that, in light of the drop in oil prices, in the reporting period Ithaca exercised some of its hedges, and swapped them for hedges reflecting current oil price forecasts. These activities generated a cash flow of USD 156 million for Ithaca in the reporting period. For more information on these hedges, see Note 20A to the financial statements.

Other finance expenses, net

Net finance expenses (excluding effects from hedges) totaled USD 233 million in the reporting period, as compared to USD 158 million in the same period last year. Finance expenses were up mainly due to changes in loan terms and volumes in connection with CNSL's acquisition.

For more information concerning Ithaca's operations, see Notes 10F, 12U, 14, and 24A(3)(1) to the financial statements and Part A of the Periodic Report - Description of the Company’s Business.

C) Additional operations

Infrastructures

For information concerning the sale of the Group's holdings in power plants, see Note 10J12 to the consolidated financial statements.

For information concerning the sale of the Company's remaining holdings (20%) in IDE, see Note 10H to the financial statements.

B. Market Risk Exposure and Management

1. The following table details Israeli CPI data and exchange rates for the primary currencies used by the Group:

As of	USD representative exchange rate NIS	GBP representative exchange rate	Known CPI Points *)
December 31, 2020	3.215	4.391	100.08
December 31, 2019	3.456	4.559	100.68
Change during the year	**%**	**%**	**%**
2020	(6.97)	(3.69)	(0.60)
2019	(7.79)	(4.88)	0.30
2018	8.10	2.39	1.20

*) Base index - 2014 average.

C. Aspects of Corporate Governance

1. Corporate responsibility and philanthropy

As a leading commercial company, the Delek Group is committed to principles of corporate responsibility in both social and environmental matters. The Group's social responsibility activities are coordinated through the Delek Science, Education and Culture Foundation (PBC) ("the Delek Foundation"), a wholly-owned (100%) Group subsidiary.

The Delek Foundation promotes and supports the promotion of education, heritage (including projects promoting Jewish heritage), culture, social welfare, and science in Israel. This support is reflected in donations to institutions operating in these fields, and in scholarships awarded to students in academic institutions and in secondary schools. The Delek Foundation also donates to various charitable causes, mainly through organizations helping and supporting the less fortunate.

In 2018, 2019, and 2020, the Delek Foundation donated a total of NIS 8.6 million, NIS 3.1 million, and NIS 1.7 million, respectively.

In 2018, 2019, and 2020, a respective total of 84%, 55%, and 26% of the Delek Foundation’s funds were donated to heritage causes. Additional donations in these years went toward education, culture, and welfare, and toward other Delek Foundation causes.

The Group focuses its corporate responsibility activities on promoting education and supporting youths in Israel. The Delek Foundation works towards these ends through several channels:

A) Supporting the students of the "Ehad Meshelanu" pre-military program, which helps at-risk youths to enlist for their military service and volunteer for combat service. The "Ehad Meshelanu" program has achieved outstanding enlistment rates - 94% of program graduates enlisted for military service, 85% enlisted and volunteered for combat service;

B) Awarding scholarships to underprivileged students. As part of these efforts, in 2018, the Delek Foundation donated NIS 400 thousand to the Netanya Academic College. It is noted that Mr. Last, Chairman of the Company’s and the Delek Foundation’s boards, also serves as a member of the Netanya Academic College’s board of trustees and audit committee;

C) Adopting a Border Police division, to which an additional unit was added this year - the Mista'arvim Unit, as part of the Adopt a Combat Soldier organization which helps support combat soldiers' welfare.

2. Compliance plan

In November 2012, the Company adopted an internal securities compliance plan, based on the criteria issued by the Israel Securities Authority. This included the preparation and/or review of existing procedures, and appointment of an internal compliance officer and a compliance committee. In March 2016, the Company's Board of Directors approved an update to the internal compliance plan, based on an updated compliance survey conducted by the Company, and an update to the procedures based on legislative changes and the results of the said survey. In 2019, the Company conducted a new compliance survey to review and update its compliance plan.

3. Directors with accounting and financial expertise and independent directors

A) The Company's Board of Directors has determined that there shall be a minimum of two directors having accounting and financial expertise, as the Board of Directors believes the above minimum number allows the Board of Directors to fulfill its duties by law and pursuant to the Company's constituent documents in all matters pertaining to examination of the Company's financial position and the preparation and approval of its financial statements. In practice, as of the financial statements' approval date, the Company has 7 directors, of which 2 have accounting and financial expertise.

At the end of June 2020, Mr. Avi Harel and Mrs. Yehudit Titelman Zidnberg (outside director), both of whom have accounting and financial expertise, announced their resignation as of July 1, 2020. On June 29, 2020, Mr. Udi Erez was appointed as a Company director. Based on Mr. Udi Erez' declarations, the Company's Board of Directors has determined that he constitutes a director having accounting and financial expertise. On August 25, 2020, Mrs. Ruth Dahan-Portnoy was appointed an outside director in the Company, having accounting and financial expertise.

Furthermore, according to Company procedure, the Company's auditors are invited to attend all Board of Directors meetings in which the financial statements are discussed, and the auditors are at the Board of Directors' service to provide any explanation and clarification required in connection with the financial statements.

B) The following directors have accounting and financial expertise: Mrs. Ruth Dahan-Portnoy (outside director) and Mr. Udi Erez (ordinary director). For information concerning their relevant experience and education, see Regulation 26 in Chapter D of the periodic report.

C) Independent directors - Mr. Roni Milo is serving as an independent director. However, it is noted that the Company has not adopted the "provisions on the percentage of independent directors" as defined in Section 219(e) of the Companies Law.

4. Disclosure concerning the Company's internal auditor

A) **<u>The internal auditor as of the reporting date</u>**

1) Name of internal auditor: Gana Gali

2) Start of tenure: January 1, 2016

3) 3) Qualifications:

CPA, BA in business administration with a major in accounting, and MA in public administration and internal auditing, CISA, CIA, CRMA, CRISC.

4) The internal auditor complied with the conditions specified in Sections 3(a) and 8 to the Internal Auditing Law, 1992 ("the Internal Auditing Law") and Section 146(b) to the Companies Law, 1999 ("the Companies Law").

5) The internal auditor is not a Company employee, but rather provides it with internal auditing services as an outside service provider. In addition, the internal auditor provides the Company services to review the effectiveness of internal controls over the Company's financial reporting (ISOX). The internal auditor is a partner in Rosenblum Holtzman, CPAs.

6) The internal auditor does not perform any other function in the Company other than that of internal auditor.

7) The internal auditor also serves as internal auditor for Delek Drilling and the general partner in Delek Drilling (his tenure as internal auditor in these companies does not cause conflicts of interest with his duties as internal auditor for the Company). The internal auditor also serves as internal auditor for Cohen Development and Industrial Buildings Ltd., which was sold by the Delek Group in 2020.

8) The internal auditor is not an interested party in the Company, nor is he a relative of an interested party in the Company, nor is he the auditing accountant or any person acting on its behalf.

9) The internal auditor does not hold any securities issued by the Company or its related entities.

B) **Method of appointment**

Mr. Gana's appointment as internal auditor was approved by the Company's Board on November 26, 2015 following the recommendations of the Company's Audit Committee, after the latter found Mr. Gana to possess the necessary qualifications to perform his duties, among other things, in light of his expertise and vast experience in internal auditing, and after Mr. Gana declared that he meets all the qualification requirements required to perform his duties as internal auditor by law, and bearing in mind, among other things, the Company's profile, its size, and the scope and complexity of its operations.

C) **Internal auditor's superior**

The internal auditor reports directly to the chairman of the Company.

D) **Work plan for the reporting year**

The internal auditor in the Company follows an annual work-plan coordinated with the Chairman of the Board and the Company's CEO and with the Audit Committee's approval.

The work plan leaves the internal auditor room for discretion to deviate from the plan, subject to formal approval from the Audit Committee.

Considerations in determining the internal auditing work plan

The annual work plan was formulated, inter alia, based on the following: the risks underlying the Company's operations, previous experience, opportunities for streamlining and savings, regulation of Company operations, and review of the implementation of previous audit report recommendations.

The work plan is built, among other things, based on a risk survey prepared by the internal auditor and which was approved by the Audit Committee on November 28, 2017.

The work plan includes various regulatory matters which are examined every year, bearing in mind that the Company holds investees, and that its main investees employ separate internal auditors and maintain independent audit committees. The annual audit plan is proposed by the internal auditor. Special emphases are occasionally added by the Audit Committee.

Transactions listed under Section 270 of the Companies Law, which were carried out in the reporting year, are examined by the internal auditor as part of his annual work plan. Furthermore, the internal auditor reviews other material transactions as per the annual audit plan.

As the Company maintains holdings in investees, the audit plan is comprised of two main parts:

1) Audit of the Company's own operations (including, inter alia, compliance with procedures, cost control, management of Company funds, reporting procedures, statutory compliance and control over resolution performance).

2) Ongoing monitoring of internal auditing in investees, as detailed below:

E) **Auditing of material investees**

Internal auditing includes ongoing monitoring of adequate and proper internal auditing activities in all of the Company's investees.

All material investees employ internal auditors (as in-house employees or through outsourcing). Audit reports are discussed by the audit committees and/or by the boards of directors of these corporations, which include directors also serving as Company officers.

F) **Scope of employment**

In 2020, the annual number of hours worked by Gali Gana and other internal auditors outsourced or employed in-house by the Company and the Group companies amounted to 4,480 work hours.(***)

Hours invested in internal auditing activities:

Company	Hours	Notes
The Company(*)	600	By the Company's auditor
Delek Drilling	600	By the Company's auditor
Delek Israel(**)	1,150	By an outside auditor
Cohen Development(***)	30	By the Company's auditor
Ithaca Energy	2,100	By an outside auditor

(*) Including ongoing review of internal auditing activities in all direct and indirect Company investees.

(**) On October 26, 2020, the Company completed the sale of control in Delek Israel, by selling 70% of its share capital to a third party. As of December 31, 2020, the Company holds only 40% of Delek Israel's share capital. The above data represent all hours invested in internal auditing activities in Delek Israel in 2020.

(***) On April 19, 2020, the Company disposed of its investment in Cohen Development's shares. Data therefore reflect the proportional time worked by the internal audit in 2020 up to the sale.

The Company's Board of Directors believes that the internal auditor's work plan and the number of work hours allocated for its implementation, meet the Company's needs. The Company can expand the scope of internal auditing activities if necessary.

G) **The audit**

The internal audit is conducted according to generally accepted Israeli and international internal auditing standards, including standards established by the Institute of Internal Auditors in Israel (IIA) and in the US, and according to professional guidelines for internal auditing as prescribed in Section 4(b) to the Internal Auditing Law.

The Company's Board has been satisfied that the auditor complies with all the above requirements and conditions, considering the internal auditor's statement as submitted to the Board.

H) **Access to information**

The internal auditor has full, unrestricted, continuous and direct access to the Company's information systems, including financial data, for conducting internal audit activities under Section 9 to the Internal Audit Law.

I) **Internal audit report**

Internal audit reports are submitted in writing, circulated, and discussed by the Company's Audit Committee. Furthermore, specific meetings and discussions are held by the audit committees of investees, concerning audit findings. The audit reports were discussed by the Audit Committee in its meetings of June 8, 2020, and December 30, 2020.

J) **Board of Directors' assessment of the internal auditor's work**

The Company's Board of Directors believes that the scope of internal auditing in 2020, the nature and continuity of these activities and the Company's internal auditor's work plan are reasonable, and achieve the purposes of the internal auditing function.

K) **Compensation**

The internal auditor's employment terms are as follows:

1) Overall annual fee of NIS 115,000 (plus VAT).

2) The Board of Directors believes the internal auditor's remuneration does not affect or undermine the exercise of his professional judgment.

5. Auditors' Fees

	For the year ended December 31							
	2020				2019			
	Audit and tax services		Other services		Audit and tax services		Other services	
	Hours	NIS thousands	Hours	NIS thousands	Hours	NIS thousands	Hours	NIS thousands
The Company and wholly owned HQ companies								
Kost Forer Gabbay and Kasierer	7,154	1,893	-	-	9,010	2,728	700	564
Other consolidated companies								
Delek The Israel Fuel Corporation Ltd.*)								
Kost Forer Gabbay and Kasierer	5,135	1,121	146	48	6,143	1,498	-	-
Delek Drilling Limited Partnership								
Kost Forer Gabbay and Kasierer, and Ziv Haft serve as joint auditors for Delek Drilling Limited Partnership	8,812	2,078	5,859	2,974	11,218	2,056	3,037	1,485
Somekh Chaikin	185	22	-	-	302	30	-	-
Ithaca Energy Inc.								
PWC	-	-	-	-	547	499	2,347	2,138
EY UK	6,467	2,952	-	-	5,760	2,652	-	-

(*) On October 26, 2020, the Company sold its control in Delek Israel. As of that date, the Company's investment in Delek Israel is treated as per the equity method (associate company). Data in the above table represent 100% of the fees and hours invested in Delek Israel in 2020.

6. Disclosure on the financial statements' approval process

The Company's Board of Directors is the corporate organ charged with overall supervision and approval of the financial statements.

7. Classification of Negligible Transactions

On August 30, 2009, the Company’s Board of Directors resolved to adopt guidelines and principles for classifying a transaction as a negligible transaction in keeping with the Securities Regulations (Periodic and Immediate Reports), 1970 ("the Reporting Regulations"), both as regards transactions with interested parties listed in the financial statements, and as regards controlling shareholder transactions.

The Company’s Board of Directors has determined that a transaction will be deemed negligible if it meets all of the following conditions:

A) Its value does not exceed 0.1% of the Company’s equity net of non-controlling interest, as stated in the Company’s most recent annual financial statements.

B) It does not constitute an extraordinary transaction (as defined in the Companies Law).

C) The transaction is also qualitatively negligible.

D) In long-term transactions (e.g. - multi-year property leases), the negligibility of the transaction will be examined on an annual basis (for example - does the annual lease exceed the aforesaid amount).

E) In insurance transactions, the premium will be examined as representing the transaction's value, as opposed to the scope of the insurance coverage provided.

F) Each transaction will be examined individually, but the negligibility of related or contingent transactions will be examined in aggregate.

G) Where a question arises concerning the application of the above criteria, the Company will exercise judgment and will examine negligibility based on the aim of the reporting regulations and guidelines above.

On December 28, 2014, June 15, 2017, and May 29, 2019, the Company's Audit Committee decided to update the Company's negligible transactions procedure, and add the following:

Any transaction in which the Company signs joint agreements to receive consulting services from employees or third parties in various matters including, but without limitation: law, regulation, finance and/or investments, tax and media, will be considered negligible if it meets all the rules set forth in the Company's negligible transactions procedures, provided that expenses for the transaction do not exceed NIS 2 million, and the terms of the transaction for the Company are no different than its terms for the associate or the controlling shareholder, pro rata. For long-term transactions, compliance with negligible value will be tested on an annual basis (for each calendar year). For example, in a long-term contract, scope of employment will be measured using the annual consultancy fees/wages.

Each year, the Audit Committee will check that transactions specified in this report meet the above non-significance criteria.

D. Disclosure relating to the Company's financial reporting

1. Critical accounting estimates

For information about main accounting estimates, see Note 2B to the consolidated financial statements.

2. Events after the financial position statement date

For information on material events subsequent to the financial position statement date, see Chapter A to the Board of Directors' Report.

E. Dedicated disclosure for debenture holders

1. Data concerning the Company's debentures, including debentures held by a wholly-owned subsidiary partnership of the Company:

Series	Issue date (including expansions)	Par value Original	Par value balance as of Dec. 31, 2020	Nominal interest rate	Linkage	Carrying amount as of Dec. 31, 2020	Interest accrued in the books as of Dec. 31, 2020	Repayment dates (principal/ interest)	Stock exchange value as of December 31, 2020	Trustee
B13	3/2007	913	183	Until listing - +5.1%, after listing - 4.6%	Israeli CPI	222	3	Principal and interest payments on Mar. 29 and Sept. 29, 2021	190	Hermetic Trust (1975) Ltd. 113 Hayarkon St. Tel Aviv Tel: 03-5274867 - Dan Avnon
B18	11/2009 6/2010 7/2011	1,062	354	6.1%	Israeli CPI	385	4	Interest payments on Apr. 30 and Oct. 31 and principal payments on Oct. 31 in each of 2021-2022	263	Reznik Paz Nevo RPN Trusts 2007 Ltd., 14 Yad Harutzim St., Tel Aviv Tel: 03-6389200, Elad Sirkis
B19	11/2010	560	280	4.65%	Israeli CPI	297	2	Interest payments on May 10 and Nov. 10 and principal payments on Nov. 10 in each of 2021-2022	200	Hermetic Capital Ltd. 113 Hayarkon St. Tel Aviv Tel: 03-5544553 - Tzuri Galili
B22	6/2007	500	125	4.50%	Israeli CPI	151	-	Principal and interest payments on Jun. 30 and Dec. 31, 2021	117	Mishmeret - Trusts Services Company Ltd., 48 Menahem Begin St., Tel Aviv, Tel: 03-6374335/4, Atty. Rami Katzav, CPA.
B31	2/2015 6/2015 10/2015 2/2017	3,276	3,108	Until the rating downgrade (Mar. 22, 2020) - 4.3% From Mar. 23, 2020 - 5.3%	Un-linked	3,108	60	Interest payments on Aug. 20 and Feb. 20 and principal payments on Feb. 20 in each of 2021-2025	2,032	Hermetic Trust (1975) Ltd. 113 Hayarkon St. Tel Aviv Tel: 03-5274867 - Dan Avnon
B33	7/2016	705	705	Until the rating downgrade (Mar. 22, 2020) - 2.8% From Mar. 23, 2020 - 3.8%	Convertible and non-linked	705	13	Interest payments on Jul. 10 and Jan. 10 in each of 2021-2022; principal payment on Jan. 10, 2022	519	Hermetic Trust (1975) Ltd. 113 Hayarkon St. Tel Aviv Tel: 03-5274867 - Dan Avnon
B34	2/2018	521	480	Until the rating downgrade (Mar. 22, 2020) - 4.48% From Mar. 23, 2020 - 5.48%	Un-linked	480	-	Interest payments on Jun. 30 and Dec. 31 and principal payments on Dec. 31 (except Dec. 31, 2022) in each of 2021-2028	309	Hermetic Trust (1975) Ltd. 113 Hayarkon St. Tel Aviv Tel: 03-5274867 - Dan Avnon

2. Additional information on debentures convertible to Company shares

Series	Conversion to shares	Conversion ratio	Key conversion terms	Forced conversion
B33	Delek Group Ordinary shares 1084188	Conversion ratio in the period from July 11, 2019 to December 31, 2021 - 1,278.52907	The right to conversion into Company shares will stand on each day of trading until December 31, 2021, such that every NIS 1,278.52907 par value in Debentures (Series B33) may be converted to one ordinary share in the Company. Adjustments will be made following distribution of bonus shares, participation in rights issuances, and dividend distributions.	The Company is entitled to forced conversion if the closing price for the Company's shares on the TASE for 15 consecutive days of trading exceeds NIS 2,000 (starting July 11, 2019)

3. For more information on the debenture settlement plan, see Note 19 to the financial statements.

4. For a current rating report on the Company's Debentures (Series B13, B22, B31, B33, B34) (in this paragraph – "the Debentures"), see S&P Maalot's report, subsequent to the financial position statement date, of January 31, 2021, included herein by way of reference, adjusting the Debentures' rating from ilCCC-Developing to ilB-Developing. For more information, see the Company's immediate report of January 31, 2021 (ref. no. 2021-01-012097), included here by way of reference.

   It is noted that, in 2020, S&P Maalot updated its rating reports as follows: on September 30, 2020, S&P Maalot updated its rating for the debentures from ilCCC-Negative to ilCCC-Developing; on May 5, 2020, S&P Maalot announced that it would downgrade its rating for the Debentures from ilBBB-Negative to ilCCC-Negative; on April 1, 2020, S&P Maalot announced that it would downgrade its rating for the Debentures from ilA/Stable to ilBBB-Negative.

Financial covenants (debentures)

In June 2020, the Company signed an amendment to the deeds of trust between the Company and the holders of its various debenture series. The amended deeds of trust specified grounds for immediate repayment, as follows:

- In the period until May 31, 2021, the trustee and the debenture holders will not call for immediate repayment of the debentures on grounds based solely on the state of the Company's business as it was at the time of the amended deed's publication and/or on grounds concerning a low rating of the Company's debentures.
- Until the publication date of the first quarter statements in 2021, the grounds for immediate repayment specified in the deeds of trust concerning low equity - shall not apply. For statements from the second quarter of 2021 and until the annual statements for 2023, the holders will have grounds for immediate repayment if the equity after deducting additional equity arising from revaluations and equity as presented in the statements are lower than the levels specified in the amended deed for these purposes. From the statements for the first quarter of 2024 onwards, the debenture holders will have ground to call for immediate repayment if the equity presented in the Company's statements falls below NIS 2.6 billion.
- Until the publication date of the first quarter statements in 2021, the grounds for immediate repayment specified in the deeds of trust concerning the equity to balance sheet ratio - shall not apply. For statements from the second quarter of 2021 and until the annual statements for 2023, requirements have been specified for the equity to balance sheet ratio. Should the company fail to meet these requirements for two consecutive quarters, the holders will have grounds for immediate repayment. From the statements for the first quarter of 2024, the debenture holders will have grounds to call for immediate repayment should the equity to balance sheet ratio according to the Company's separate statements fall below 20% for two consecutive quarters.

The amended deed includes additional declarations and obligations for the Company, including: (a) concerning uses for proceeds from capital issuances and/or dividends and/or sales and/or pledges of certain assets; (b) an obligation not to deposit monies and/or securities with the creditor banks of the Company or companies under its control, except for certain permissible exceptions; (c) an obligation not to acquire assets and/or make investments and/or assume credit and/or assume fiscal liabilities toward financial creditors and/or change the terms of certain credit agreements, except for certain permissible exceptions; (d) in the Effective Period: the Company's general and administrative expenses will not exceed such amounts as specified, the Company will not make distributions, the Company and companies under its control will not undertake transactions in which the controlling shareholder has a personal interest (except for officers' insurance and existing contracts as disclosed in the statements), the Company and private companies under its control will neither sell nor buy Company debentures; (e) obligations to provide the trustees with various notices; (f) an obligation to cover the fees and expenses of the trustees and their agents. It was furthermore agreed that a violation of any of the Company's obligations under the amended deed would grant the trustees and the debenture holders grounds to call for immediate repayment, and a right to exercise all sureties provided to the trustees.

For more information, see also Notes 1C and 19 to the financial statements.

F. Additional information

1. Buyback of securities

On December 27, 2018, the Company's Board of Directors approved a buy-back plan (through the subsidiary partnership) of Company shares and/or debentures to a monetary amount of up to NIS 100 million, for the period of January 1, 2019 to December 31, 2019. Furthermore, on October 6, 2019, the Company's Board of Directors approved another buy-back plan (through the subsidiary partnership) of Company shares and/or debentures to a monetary amount of up to NIS 100 million, for the period of October 6, 2019 to October 7, 2020.

As part of these plans, in 2019 the subsidiary partnership bought an additional 207,821 shares in the Company, in consideration for NIS 111 million, as well as NIS 2 million in Company debentures.

Furthermore, in 2020, the subsidiary partnership bought an additional 135,662 shares in the Company in consideration for NIS 60 million. As of December 31, 2020 and the report's approval date, the subsidiary partnership held 586,422 Company shares. In 2020, the Company and the subsidiary partnership also bought NIS 26 million in Company debentures.

2. Company employees

The Board of Directors would like to thank the Company's management, the management of the Company's investees, and to all the employees for their dedicated work and their contribution to the advancement of the Company.

Sincerely

Gabriel Last	**Idan Wallace**
Chairman of the Board	CEO

Signature date: March 30, 2021

Appendix A to the Board of Directors' Report

Breakdown of principal and interest payments on the Company and the staff companies' debentures and bank and other loans as of December 31, 2020 (in NIS millions):

		2021	2022	2023	2024	2025	2026 onward	Total
Debentures	**Principal**	915	1,778	796	796	796	244	**5,325**
	Interest	260	188	119	77	35	26	**705**
Bank and other loans (*)	**Principal**	24	-	-	104	-	-	**128**
	Interest	8	7	7	-	-	-	**22**
Total		**1,207**	**1,973**	**922**	**977**	**831**	**270**	**6,180**

(*) Excluding a convertible liability.

Appendix B to the Board of Directors' Report

Following on Note 12 to the financial statements and following a tax authority decision received by Delek Overriding Royalty Leviathan Ltd. prior to a debenture issuance, the following financial data will be provided to Delek Overriding Royalty Leviathan Ltd.'s debenture-holders:

Statements of Financial Position (Dollars in thousand)

	Note	December 31 2020	December 31 2019
Current assets			
Cash and cash equivalents	3	3	-
Short-term investments	4	326	-
Royalties and other receivables	5	1,328	-
Total current assets		1,657	-
Non-current assets			
Long-term investments	4	19,613	-
Loan to controlling shareholder	7	76,334	-
Assets in respect of ORRI	1B	197,704	-
Deferred Taxes		888	-
Total non-current assets		294,539	-
		296,196	-
Current liabilities			
Other payables	8	877	-
Total current liabilities		877	-
Non-current liabilities			
Debentures	9	169,001	-
Total non-current assets		169,001	-
Equity			
Share capital		295	-
Share premium		127,275	-
Retained earnings		(1,252)	-
Total equity		126,318	-
		296,196	-

Statements of Comprehensive Income (Dollars in thousand)

	Note	For the year end		
		31.12.2020	31.12.2019	December 31, 2018
Revenue from overriding royalties	6	1,335	-	-
General and administrative expenses	10	203	-	-
Depletion		712	-	-
Operating profit		420	-	-
Financing expenses	11	2,883	-	-
Financing income	11	(1,067)		
Loss before income tax		(1,396)	-	-
Income tax	13	144	-	-
Loss and total comprehensive loss		(1,252)	-	-

*) The company's operations started at October 28 2020.

Statements of changes in shareholders equity (Dollars in thousand)

	Share capital	Share premium	Retained earnings	Total
Balance as at January 1, 2018	*	-	-	*
Total comprehensive income (loss)	-	-	-	-
Balance as at December 31, 2018	*	-	-	*

	Share capital	Share premium	Retained earnings	Total
Balance as at January 1, 2019	*	-	-	*
Total comprehensive income (loss)	-	-	-	-
Balance as at December 31, 2019	*	-	-	*

	Share capital	Share premium	Retained earnings	Total
Balance as at January 1, 2020	*	-	-	*
Total comprehensive income (loss) **	-	-	(1,252)	(1,252)
overriding royalties	295	127,275		127,570
Balance as at December 31, 2019	295	127,275	(1,252)	126,318

* Less 1 thousand dollars.

**) The company's operations started at October 28 2020.

Statements of Cash Flows (Dollars in thousand)

	For the year ended		
	31.12.2020	(*31.12.2019	(*31.12.2018
Cash Flows - Current Operations:			
Loss for the year	(1,252)	-	-
Adjustments for:			
Depletion and depreciation	1,252	-	-
Deferred Taxes	(888)	-	-
Changes in assets and liabilities items:			
Increase in trade and other receivables	(1,328)	-	-
Increase in trade and other payables	2,134	-	-
Net cash used for current operations	(82)	-	-
Cash Flows - Investment Activity:			
Investment in oil and gas assets	(70,815)	-	-
Loan granted to controlling shareholder	(80,037)	-	-
Repayment of loans to controlling shareholders	3,703	-	-
Long-term deposit in bank deposits	(20,900)	-	-
Short-term deposit in bank deposits	(326)	-	-
Net cash deriving from (used for) investment activity	(168,375)	-	-
Cash Flows - Financing Activity:			
Bond offering (net of issue costs)	168,460	-	-
Net cash deriving financing activity	168,460	-	-
Increase in cash and cash equivalents	3	-	-
Cash and cash equivalents balance at the beginning of the year	-	-	-
Cash and cash equivalents balance at the end of the year	3	-	-
Annex A - Finance and investment activity not involving cash flows:			
Investments in oil and gas assets against share premium	127,601	-	-
Annex B - Additional information on cash flows:			
Interest paid	2,328	-	-

*) The company’s operations started at October 28 2020.

Appendix C to the Board of Directors' Report

In accordance with Regulation 8B to the Securities Regulations, the following valuations are attached herewith:

A. Impairment testing for goodwill attributable to the cash-generating unit 'Oil and Gas Development and Production Assets in the North Sea', and testing for impairment of oil and gas assets in the North Sea.

Delek Group Ltd.

Impairment Testing Under IAS 36

March 23, 2021

March 23, 2021

Private and Confidential

Tamir Polikar
Chief Financial Officer
DKL Investments Limited
19 ABBA eBAN BLVD
P.O.B 2054
Herzliya 4612001
Israel

Valuation Services in Connection with the Impairment Testing of Ithaca Energy Ltd under IAS 36

Dear Mr. Polikar,

Pursuant to your request, Duff & Phelps Ltd ("Duff & Phelps" or "D&P") have been engaged by DKL Investments Limited ("DKL") to provide valuation services relating to the impairment test analysis (the "Services") of Delek Group Ltd.'s ("Delek") investment in Ithaca Energy Limited ("Ithaca" or the "Company") for financial reporting purposes.

The objective of our analysis was to provide recommendations of the recoverable amount ("Recoverable Amount") of Delek's investment in Ithaca and certain specific oil fields of Ithaca as of December 31, 2020 (the "Valuation Date"). We understand that the results of our analysis will be used solely for the purpose of assisting the Delek's management ("Management") in estimating the Recoverable Amount of Ithaca in accordance with International Accounting Standard 36: Impairment of Assets ("IAS36").

We are aware that you wish to use our valuation for the preparation of the financial statements of Delek and if necessary, also to attach it to the financial statements. The full details of the terms of our engagement are included in our engagement letter dated January 22, 2021.

We wish to note that we have no personal interest in the shares of the companies named in this report. In addition, the payment we receive for preparing it is not contingent upon the results of the valuation.

We have appreciated the opportunity to work with you on this engagement. Please call Mathias Schumacher on +44 20 7089 4720 if we can be of further assistance.

Yours sincerely,

DRAFT

Duff & Phelps Ltd.
By: Mathias Schumacher
Managing Director

Contents

Section 01

Introduction

Introduction to Duff & Phelps

Duff & Phelps is a valuation and corporate finance advisor with a global presence, with more than 3,500 employees across more than 28 countries worldwide. Founded in 1932, Duff & Phelps provides advisory services to more than 7,500 clients, including nearly 50.0 percent of the S&P 500. We offer a variety of diverse services, including valuation advisory, tax services, mergers and acquisitions advisory, and restructuring services among others. The Valuation Advisory Services team within Duff & Phelps comprises over 1,200 professionals and specialises in financial reporting advisory, including purchase price allocations, goodwill and intangible impairment testing, fresh start accounting and business valuations.

Scope of Services – IAS 36

Scope of Services

Duff & Phelps was retained by DKL Investments Limited to assist with the performance of certain procedures, as set out below, relating to the application of IAS 36: Impairment of Assets. The Services consisted solely of assisting Delek with performing the impairment test of its investment in Ithaca under IAS 36 for financial reporting purposes.

Ithaca acquired Chevron North Sea Limited ("CNSL") in November 2019, and the existing goodwill balance as of the Valuation Date largely results from this transaction. As part of our impairment testing analysis, we have estimated the Recoverable Amount, as defined below, of the investment in Ithaca in order to compare with the carrying amount ("Carrying Amount") to determine the potential risk of impairment. Our estimation of the Recoverable Amount of the investment in Ithaca reflects the operation of both the Ithaca and newly acquired CNSL assets. Further to our impairment testing of the investment in Ithaca, we have also assessed the Recoverable Amount(s) of other fields to assess possible impairment of individual fields.

Delek's acquisition of Ithaca

In October 2015, Delek acquired 19.9 percent of the equity of Ithaca. On February 6, 2017, Delek further announced that it had signed an agreement with Ithaca to purchase the remaining shares of the Company, then representing 80.8 percent of the total equity, through its subsidiary DKL Investments Ltd. This decision was made in support of Delek's greater strategy to expand its international energy operations. Delek's intention at the time of the transaction was to continue Ithaca's core operations, focusing on the development of the GSA assets.

Ithaca's acquisition of CNSL

Ithaca, as an indirectly wholly owned subsidiary of Delek, acquired the shares of CNSL for USD 1.7 billion in November 2019. The deal included ten producing fields (4 operated and 6 non-operated by CNSL) in the UK North Sea. The deal established Delek as the second largest independent oil and gas producer in the UK North Sea behind Chrysaor. Delek will continue to operate four of the ten fields (namely – Alba, Alder, Captain and Erksine). The transaction officially closed on November 08, 2019.

Company Profile(s)

Delek Group Ltd

Delek Group is an independent exploration and production company focused on the development of reserves in the Levant Basin off the coast of Israel, including Leviathan and Tamar among others. In addition, Delek has international operations, with a focus on high-potential opportunities in the North Sea through Ithaca, as well as in North America. Delek's shares are traded on the Tel Aviv Stock Exchange (TASE: DLEKG) and are part of the TA 35 Index.[1]

Ithaca Energy Ltd

Ithaca is an oil and gas operator with assets focused in the North Sea, with an asset base including both producing and exploratory oil and gas fields. Ithaca's primary focus is on the development of the Greater Stella Area ("GSA") licenses, located in the Central North Sea. Ithaca first became involved with the GSA assets in 2008, when it completed transactions with Shell, Esso, and Maersk to acquire an interest in the Stella and Harrier licenses.

The GSA assets are comprised of the Stella, Hurricane, Harrier, Vorlich, and Austen discoveries. These five fields are serviced from a central hub known as the FPF-1 floating production facility (the "FPF-1"). The FPF-1 was refurbished beginning in 2011 and work was completed in August 2016. Following the completion of FPF-1 updates, production began at the Stella field in February 2017. Ithaca currently operates the FPF-1 for extraction from six wells at the Stella field, with one well online at the Harrier field. The Hurricane, Vorlich and Courageous discoveries are at various maturities in the development stage, but eventually will also be serviced by the FPF-1.

Chevron North Sea Limited

Chevron North Sea Limited produces crude oil and natural gas from the United Kingdom North Sea. The company was incorporated in 1981 and is based in Aberdeen, United Kingdom.

[1] Delek-Group Company Website and S&P Capital IQ

World Oil & Gas Market

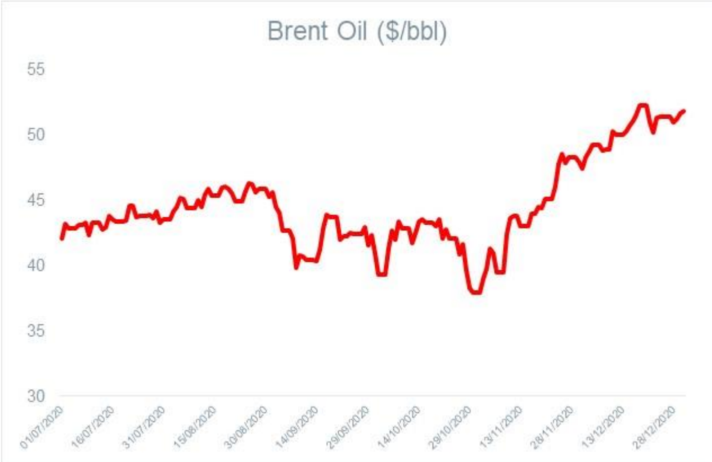
Starting in Q1 2020, the global markets have been severely impacted by COVID-19 pandemic. The country-wide lockdowns coupled with travel bans implemented by state authorities sent the oil & gas sector into turmoil. The global demand for crude reduced by as much as a third in April 2020 from pre-COVID levels. Russia and Saudi Arabia entered into a price war in March after delegates representing their nations' in the OPEC+ talks failed to reach an agreement on extending the production cuts. The price war between the two of the largest and most influential producers lasted 31 days. These 31 days had convinced oil majors and independent producers to cut their spending and delay projects across basins.

As at June end Brent Crude ("Brent") and West Texas Intermediate ("WTI") oil were trading at USD 41.3/bbl. and USD 39.3/bbl. respectively.[2] Towards first week of April, the two OPEC+ giants decided to end their price-war and made efforts to stabilize the oil markets. Russia and Saudi Arabia together with other members of the OPEC+ decided to reduce output in a combined effort to lift the markets from a pandemic driven collapse. The demand drop coincided with US production levels remaining robust despite oil storage tanks touching full capacity. The plunge in WTI price to below USD 0 on 20th April (first time in history) was in part result of the traders seeking to offload their obligations to take on physical product ahead of May contract's expiry.

2020 remained a challenging year for the energy sector. As the market turbulence halted towards the end of the year, there were signs of a nascent recovery. Price of crude stabilized towards the USD 50's range and some in the industry expect the oil cycle is turning in their favor. The IEA projects oil consumption will rise by approximately 6 million bpd in 2021 averaging c. 97 million bpd. This still is below the pre-pandemic demand levels of 100 million bpd in 2019. A reduction in air travel combined with less gasoline and gasoil demand is cited as the primary rationale for the projected lower 2021 demand. This coupled with uncertainty surrounding economic recovery further adds pressure to the projected demand for hydrocarbons.

On the supply side – the price collapse in 2020 did stifle investment in the hydrocarbon industry while social distancing measures on the rigs and platforms delayed drilling and other operational activities. According to the US EIA, US crude output (shale including) fell from over 12 mbpd in 2019 to c. 11 mbpd in 2020.

[2] S&P Capital IQ



Source: S&P Capital IQ

Though the unconventional sector did stabilize towards H2 2020, it is assumed that the robust-growth days for the shale sector are behind us. That said, one of the key variables for the oil sector will be how the operators respond if the crude price rises much above the USD 50/bbl mark. Globally, the IEA forecasts production sans Opec to increase by 0.5 mbpd in 2021 after witnessing a decline of c. 2.6 mbpd in 2020.

2021 could be viewed as a transition year and market rebalancing for supply and demand is expected to occur towards 2022. US produced oil will join Europe's pricing benchmark in the coming months, reflecting the changing shape of the global oil market. The move is designed to prop up a mechanism that is vulnerable to expected output declines in the North Sea, while the US shale boom has led to barrels of US oil flowing into Europe each month. Still, the 2021 (and beyond) outlook remains uncertain and cooperation amongst OPEC & Non-OPEC countries is essential in order to stabilize the global supply-demand dynamics. This along with the energy transition move gaining momentum, poses additional challenges for the hydrocarbon sector.

Definition of Recoverable Amount

IAS 36 defines the Recoverable Amount of an asset as the higher of its Fair Value less costs to sell (“Fair Value Less Cost to Sell” or “FVLCTS”) or its value in use (“Value in Use” or “VIU”), where FVLCTS is defined as *“the amount obtainable from the sale of an asset or cash generating unit in an arm’s length transaction between knowledgeable, willing parties, less the costs of disposal”* and VIU is defined as *“the present value of the future cash flows expected to be derived from an asset or cash generating unit”*. We note that IAS 36 does not require an analysis of both the FVLCTS and VIU as the Recoverable Amount is determined by the higher of both.

Under IAS 36, goodwill impairment is then tested by checking if the Recoverable Amount is greater than the Carrying Amount.

Section 02

Sources of Information and Procedures

Sources of Information

In the course of our valuation analysis, we relied upon financial and other information, including prospective financial information obtained from Management and from various public, financial, and industry sources. Our conclusion is dependent on such information being complete and accurate in all material respects. However, as is customary in the business valuation profession, the scope of our work will not enable us to accept responsibility for the accuracy and completeness of such provided information.

The principal sources of information used in performing our valuation include:

- Ithaca's Cashflow Valuation Model, including production and financial projections for the lifetime of each of Ithaca and CNSL's oil and gas fields;
- Production profile provided by Management. These forecasts are based on the draft reserve report prepared by Netherland, Sewell & Associates Inc. ("NSAI");
- NSAI's draft report summarizing their findings and projections;
- Brent price forecast – 31.12.2020 prepared by Chen Herzog, Chief economist & Partner, BDO;
- Brent oil price forecast used by Management;
- Carrying Amount of Ithaca and certain fields;
- Publicly available financial statements and other information for comparable companies; and
- Other available information relevant to the valuation of the Subject Assets.

We also used selected third-party databases for financial information, including:

- Standard and Poor's Capital IQ database;
- Duff & Phelps 2020 Valuation Handbook: Guide to Cost of Capital;
- Bloomberg LP; and

In addition, we held meetings, in person or via telephone conference, with the following people:

- Tamir Polikar, CFO, Delek Group
- Gilad Myerson, CEO, DKL Investments
- David Crawford, CFO, Ithaca Energy; and
- James McPetrie, Corporate Finance Manager, Ithaca Energy

Procedures

In general, our procedures have included, but were not limited to the following:

- Analysis of general market data, including economic, governmental, and environmental forces which could affect the Recoverable Amount of the investment;
- Analysis of comparable companies for estimating an appropriate WACC for Ithaca;
- Discussions with Management concerning the history and future operations of Ithaca, the market environment, and the projections prepared for the business;
- Analysis of historical and projected operating and financial results including revenues, operating margins and capital expenditures;
- Estimation of the Recoverable Amount of Ithaca through the application of the Income Approach; and
- Comparison of the Recoverable Amounts of Ithaca to the respective Carrying Amount in order to test for impairment as of the Valuation Date.

Section 03

Ithaca Impairment Test – IAS 36

Valuation Approach

In performing the goodwill impairment test under IAS 36, we first estimated the Recoverable Amount of the Investment in Ithaca, as described below. Having determined the Recoverable Amount, we compared it to the Carrying Amount. As described under Financial Reporting Requirements, impairment is indicated if the Carrying Amount exceeds the Recoverable Amount.

In estimating the Recoverable Amount, we relied primarily on a discounted cash flow ("Discounted Cash Flow" or "DCF") valuation under the Income Approach as an indication of Ithaca's FVLCTS. The Income Approach is a valuation technique that provides an estimation of the value of a business based on the cash flows that the business can be expected to generate in the future. The Income Approach is generally an important indicator of value to the owner and to a prospective purchaser of a business because it permits a comparison to be made with alternative investment opportunities. It is not unusual for a prospective purchaser to evaluate the reasonableness of the purchase price of a business by estimating the present value of the projected net cash flows in the future. Ithaca management provided us with a financial model containing production and cash flow projections for the Company and this formed the basis of our analysis under the Income Approach. We compared the FVLCTS indicated by the Income Approach to the Carrying Amount of the investment in Ithaca to determine whether an impairment was indicated at the Valuation Date.

Ithaca Operations

In estimating the Recoverable Amount of the investment in Ithaca, we have considered the Company's financial forecasts. These include forecasts from Ithaca's fields and the acquired CNSL fields. We have detailed the fields and Ithaca's working interest in each field ("WI") in the table below:

Ithaca		CNSL	
Field	**Working Interest**	**Field**	**Working Interest**
Stella	100%	Captain	85%
Hurricane	100%	Alba	23%
Harrier	100%	Erskine	50%
Don SW	40%	Britannia	32%
Ythan	40%	Brodgar	6%
W Don	21%	Enochdhu	50%
Cook	61%	Callanish	17%
Athena	40%	Alder	74%
Causeway	65%	Elgin-Franklin	4%
Fionn	100%	Jade	20%
Jacky	100%	Fortriu	22%
Courageous	55%	Fotla	60%
Topaz	35%	Marigold	100%
Anglia	30%	Macallan	50%
Broom	8%		
Vorlich	34%		
Austen	100%		
Isabella	10%		
Pierce	7%		

Source: Management provided financial model

Financial Projections

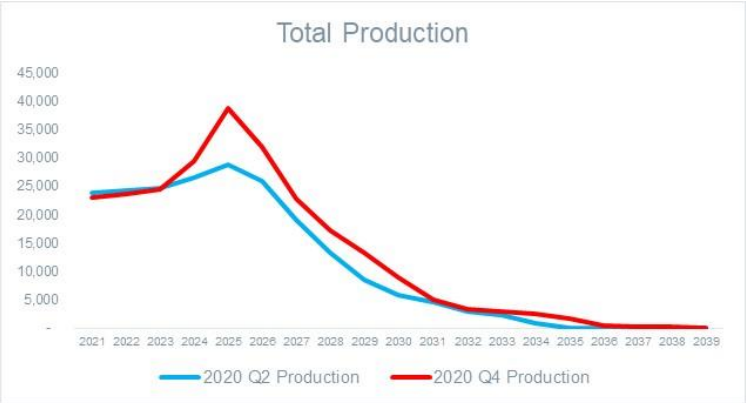
Management have provided us with their updated financial model with forecasts for the lifetime of each of Ithaca's and CNSL's fields'. The production forecasts are based on NSAI's reserve estimates. As at the Valuation Date, Ithaca has five producing fields. The fields acquired as part of the CNSL transaction include four fields (Captain, Alba, Erskine, and Alder) that are operated by Ithaca. Additionally, Isabella (10% WI) and Marigold (100% WI) have been added to the Ithaca & CNSL portfolio's, respectively.

These projections included production forecasts as well as estimates of operating and central costs ("Opex"), capital expenditures ("Capex"), and key assumptions around pricing and inflation. Management have revised their production profile based on technical reports and appraisals conducted for the reserves by Ithaca's consultant, NSAI as at December 2020, as well as the opinion and expertise of the Company's technical staff and Management. Furthermore, we note that these projections include certain assumptions for key inputs such as inflation and commodity prices. We further note that the 2P reserves are un-risked whilst a success rate of 35.0 to 70.0 percent is applied to the 2C reserves. We further note that 2020 production performance has also influenced the risk factors applied to the 2C reserves by Management in their updated production profile.

The financial projections, which we relied upon for the purposes of our analysis were based on the following assumptions:

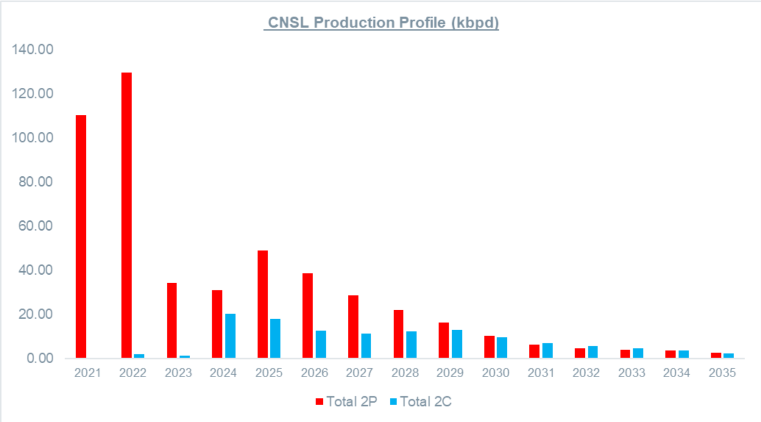
Production

Extraction of hydrocarbons is the primary driver for Ithaca's business profile. The raw reserve data for each field is based on NSAI's estimates. Management, based on their experience of operating these fields, apply a risking (or success factor) on each field. We note that the total net production has increased by c. 38 Mmbls from Q2 2020 production forecasts. The updated production forecast also includes the reserve estimates for Isabella & Marigold, which were not included in the production forecast in Q2 2020.

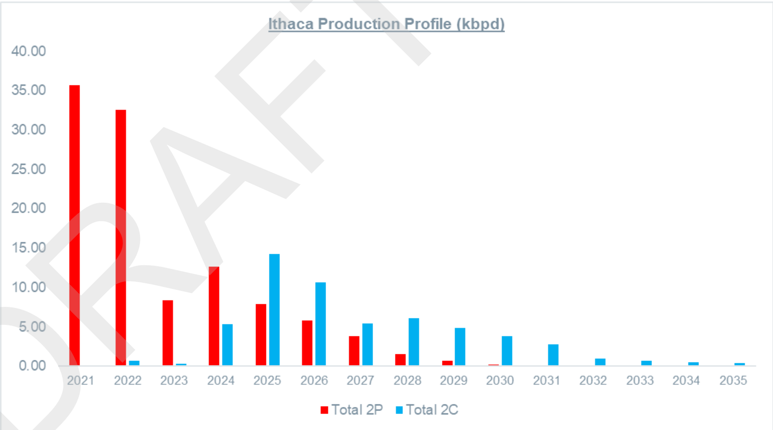


Source: Management provided forecasts (Q2 & Q4 2020)

We have also analysed 2P and 2C reserves for major fields under the CNSL and Ithaca portfolio's after considering for the Company's working interest in each field. The graph(s) below illustrate the un-risked reserves (kbpd):



CNSL Fields



Ithaca Fields

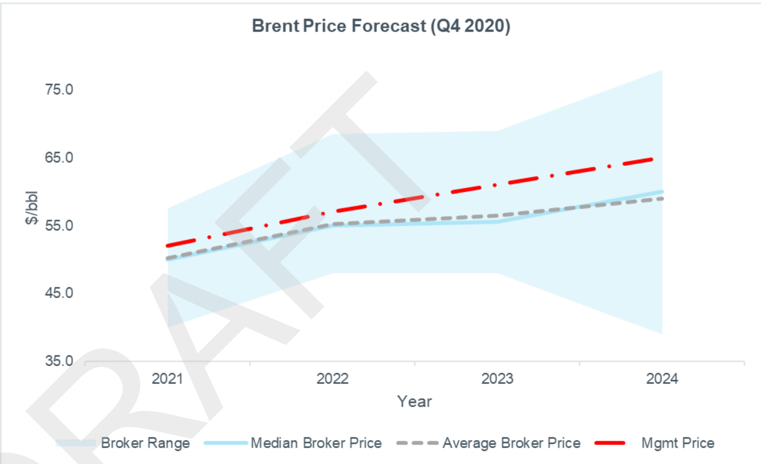
Revenues

Revenue for Ithaca (including CNSL fields) is derived through the extraction and sale of the oil, gas, and natural gas liquids ("NGL") reserves associated with each of the fields'. Revenue is estimated for each field based on the respective field's production profile and price forecasts for the underlying commodity over the life of the field.

Price Forecasts

Management have provided us with their price forecasts for Brent oil until the projected life of the fields. Management base their Brent oil price forecast on estimates provided by BDO. The Brent oil price in the BDO report is based on estimates by independent entities such as IHS Global Insights, WoodMac, DoE & the World Bank.

We have compared Management's concluded (nominal) Brent oil price forecast against the forecasts provided by independent market participants and brokers. The graph below compares Management's concluded Brent oil price (nominal) against other market participants' views. Management's Brent oil price forecast lies within a reasonable range from a market participants' view. In our analysis, we have relied on Management's concluded nominal price.



Source: Bloomberg, D&P Analysis

Additionally, we note that there is a price-differential applied to each field. The commodity price differential is applied to compensate for the "quality of the hydrocarbon being produced" or the "distance from mouth", which reflects the logistics of bring the hydrocarbon to the market. Please refer to Exhibit 17.0 for detailed analysis on the Brent oil price comparison.

Inflation

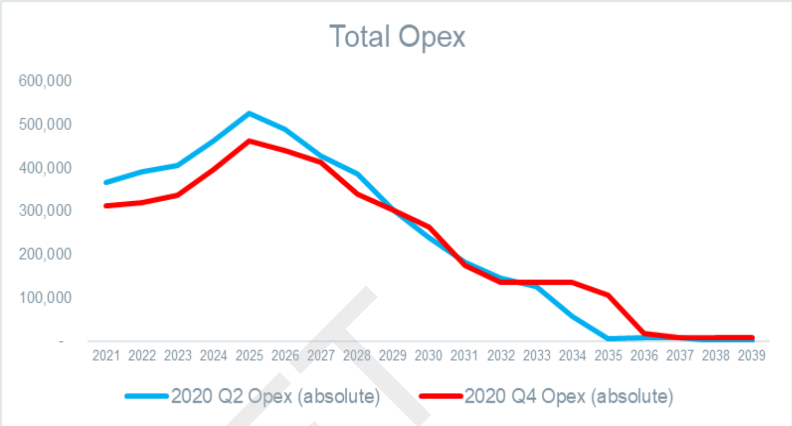
Management relied upon an inflation assumption of 2.0 percent annually in their projections. To validate this assumption, we compared it to the inflation forecast from IHS Markit's latest data as of December 2020 for long-term inflation expectations. We note that while revenues for Ithaca are forecast in USD, most of the Company's costs are incurred in GBP, and we therefore considered inflation expectations for both the United States and United Kingdom.

We also note that due to COVID-19, developed and developing economies are undergoing economic slowdown. State governments and global organisations such as the IMF have provided financial benefits/bailout packages to revive the economic activity. However, there remains immense uncertainty around speed and magnitude of the economic recovery. Certain sectors such as aviation, commercial real estate, apparel retail and hospitality & tourism have been adversely impacted more than other sectors. Given the uncertainty around inflation forecast, assumption of long-term inflation factor of 2.0 percent seems appropriate given the current economic environment. The comparison for inflation forecast is illustrated in the following graph:

Source: IHS Markit Inflation Forecast, December 2020

Operating Expenses and Central Costs

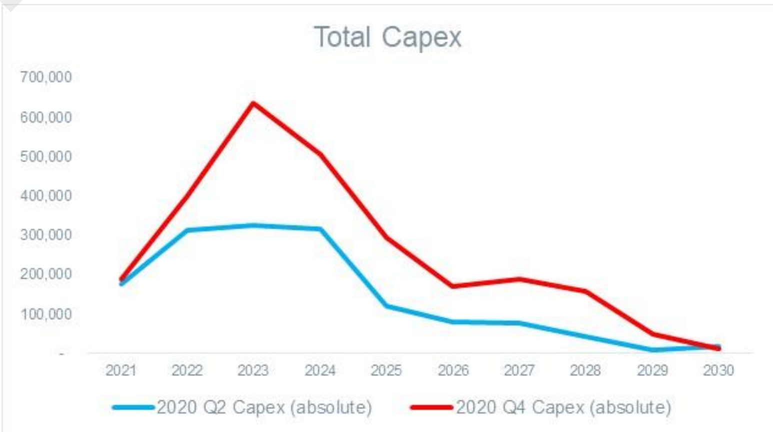
Management have provided us with estimates of the cash operating costs required for the daily operations of the extraction activities. In addition, Ithaca will incur some central costs, such as administrative expenses and hedging costs. NSAI has estimated these costs over the life of the assets. During 2020, Management were successful in optimizing their cost structure and thus, have been able to reduce their costs as compared to Q2 2020 levels.



Source: Management provided financial model

Capital Expenditures

The Capex reflected in Management's forecast includes investments in wells and the costs incurred to bring these wells to a producing stage. We note that under UK regulations, capital expenditures in the oil and gas industry are immediately depreciable and are thus treated as expenses in our projections.



Source: Management provided financial model

We note that Capex projections have increased by over USD 1 billion since Q2 2020 projections. This increase in the Capex projections comprises of costs associated with Marigold and Isabella coming onstream. As stated before, both these fields were not part of the portfolio in Q2 2020.

Additionally, there is increased production assumed for the other fields in the CNSL portfolio as well. Furthermore, for Captain, part of the polymer costs which were previously placed under Opex have been transferred to Capex.

Decommissioning Costs

At the end of the life of each oil and gas field, Ithaca will incur certain abandonment costs for the operating basins/fields. These costs are associated with decommissioning the equipment and facilities and are mandated for an exploration company to meet its requirements for and environmental clean-up required once production at the respective field has ceased. Management has provided us with an estimation of future decommissioning costs expectations.

Taxes

We note that in the course of acquiring and developing its assets, Ithaca has accrued significant net operating losses (“NOLs”), which reduce the future taxes payable for the Company. Going forward, profits from CNSL assets can be offset by Ithaca’s existing NOLs along with the tax relief which Ithaca will receive as part of the decommissioning costs. As a result, Ithaca is expected to offset all taxable profits and will begin paying taxes in 2025.

Discount Rate Determination

When applying the Income approach, the cash flows expected to be generated by a business or asset are discounted to their present value equivalent using a rate of return that reflects the relative risk of the investment, as well as the time value of money. In determining the appropriate discount rate to be applied to the forecasted cash flows, we considered the weighted average cost of capital ("WACC").

Weighted Average Cost of Capital

The WACC is calculated by weighting the required returns on interest-bearing debt and common equity capital in proportion to their estimated percentages in an expected industry capital structure.

The general formula for calculating the WACC is:

$$WACC = \frac{E}{E+D}k_e + \frac{D}{E+D}k_d(1-t)$$

Where:

k_d	=	Pre-tax rate of return on debt capital;
k_e	=	Rate of return on equity capital; and
D	=	Debt capital;
E	=	Equity capital;
t	=	Applicable tax rate.

Required Return on Equity

We used the Capital Asset Pricing Model ("CAPM") to estimate the required return on equity. The CAPM is described in the following sections.

Capital Asset Pricing Model

CAPM has been empirically tested and is widely accepted for the purpose of estimating a company's required return on equity capital. In applying the CAPM, the rate of return on equity is estimated as the sum of the current risk-free rate of return, plus a Market Equity Risk Premium expected over the risk-free rate of return, multiplied by the "beta" for the stock, plus a size premium (where applicable). Beta is defined as a risk measure that reflects the sensitivity of a company's stock price to the movements of the stock market as a whole.

The CAPM rate of return on equity capital is calculated using the following formula:

$$k_e = R_f + \beta(R_M - R_f) + SSP$$

Where:

k_e	=	Rate of return on equity capital;
R_f	=	Risk free rate of return;
β	=	Beta or systematic risk for this type of equity investment;
R_M - R_f	=	Market Equity Risk Premium (the expected return on a broad portfolio of stocks in the market (R_M) less the risk-free rate (R_f)); and
SSP	=	Small Stock Premium.

Risk-free Rate of Return

For the risk-free rate of return, we used a yield on 20-year US government bonds as of the Valuation Date. Research indicates that the low yields observed currently represent an aberration, overly influenced by a “flight to quality.” Indications are that these low yields may not be sustainable. As a result, we applied a longer-term normalised yield of 2.5 percent instead of the spot yield. These yields are “risk-free” only in nominal terms (i.e., if they are held to maturity, default risk is assumed to be negligible).

Beta

Beta (β) is a statistical measure of the volatility of the price of a specific stock relative to the movement of a general group. Generally, beta is considered to be indicative of the market’s perception of the relative risk of the specific stock. For unlisted firms, practical application of the CAPM is dependent upon the ability to identify publicly traded companies that have similar risk characteristics as the subject company/assets in order to derive meaningful measures of beta.

Market Equity Risk Premium

Due to the increased risk of holding equity securities as compared to holding debt securities, investors demand a risk premium as part of their return on equity capital. This risk premium is defined as the difference between the market return on equity and the risk-free rate of return. Since the expectations of the average investor are not directly observable, the Market Equity Risk Premium must be inferred. Based on a review of historical and forward-looking market risk premium data, we applied a 5.5 percent premium.

Small Stock Premium

The CAPM rate of return is adjusted by a premium that reflects the extra risk of an investment in a small company. This premium is derived from differences in historical returns between small and large company stocks. Using the Duff & Phelps 2020 Valuation Handbook as reference, we consider that the appropriate small stock premium for a company of Ithaca's size is 1.42 percent.

Cost of Debt Capital

The rate of return on debt capital is the rate a prudent debt investor would require on interest-bearing debt. We have utilised a corporate US BB rated bond index rate to determine the pre-tax cost of debt as of the Valuation Date. This rate was then adjusted to account for the normalised risk-free rate, resulting in a yield of 4.4 percent. This yield is an indication of the pre-tax cost of U.S. based debt capital.

$$\boldsymbol{k_d = (k)(1 - t)}$$

Where:

k_d	=	After-tax rate of return on debt capital;
k	=	Pre-tax rate of return on debt capital; and
t	=	Applicable tax rate (30.0 percent).

Tax Rate

We note that a tax rate of 30.0 percent is applied in our WACC calculations. Whilst the marginal tax rate for UK North Sea operators is 40.0 percent, 10.0 percent of this total which reflects supplementary charges is not deductible for finance costs, hence, does not provide a tax-shield for the cash flows.

Weighted Average Cost of Capital Conclusion

The resulting post-tax WACC was calculated as 9.75 percent. Please refer to Exhibit 16.0 for our detailed WACC calculations.

Recoverable Amount

Present Value of Projected Cash Flows

Based on the assumptions described above, we estimated the total present value of future cash flows on an Enterprise Value basis to be USD 3.10 billion (including working capital adjustment). We have detailed out our calculations in Exhibit 2.0.

Recoverable Amount

We have estimated the Adjusted Enterprise Value of the Company to be approximately USD 3.10 billion. This includes a net working capital surplus of c. USD 28 million as at the Valuation Date. We have made further adjustments for Gross Debt of USD 1.49 billion. We further note that Delek's Shareholder Loan to Ithaca of USD 272.0 million is a part of the Gross Debt. We have therefore, added this back in our calculations to arrive at the Net Equity Value including Shareholder Loans. The table below illustrates our calculations to derive the Equity Value.

Equity Value (USD 000s)	
Adjusted Enterprise Value	3,096,563
Less: Gross Debt	(1,492,000)
Add: Cash	1,000
Add: Shareholder Loan	272,000
Equity Value	**1,877,563**
Equity Value (rounded)	**1,878,000**

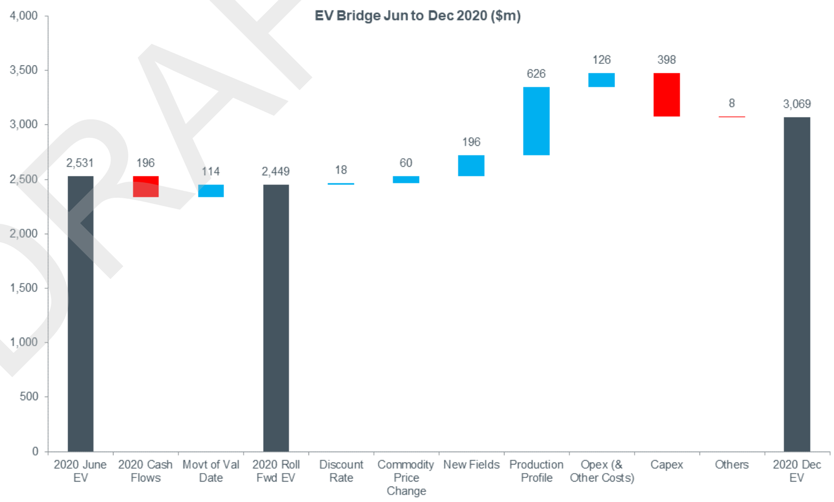
Enterprise Value Movement (Q2-Q4 2020)

Enterprise Value Bridge

H1 2020 was marred by the pandemic and the impact on the global oil & gas sector was severe. Oil majors and IOCs wrote down asset values, revisited their FID calculations and corrected their long-term price forecasts. Global oil & gas sector did witness some stability towards Q4 2020, and the market sentiment was relatively positive.

Management, in conjunction with NSAI, have subsequently revised their production forecasts and the associated investments needed accordingly. As stated earlier, the net production for Q4 2020 is c. 38 Mmbls higher than the Q2 2020 forecast. To achieve this production level, additional Capex has also been accounted for in the latest projections.

As part of our analysis, we have assessed the impact of certain key inputs and presented the findings in an enterprise value bridge. This value bridge illustrates the rationale behind an increase in enterprise value from June to December 2020. Please note our June and December 2020 EVs are without the working capital adjustments.



Source: D&P Analysis

Commentary on the enterprise value bridge:

- We have utilized our June 2020 concluded value of USD 2.5 billion as the starting point.
- After removing the cash flow impact for 2020 and the time period factor, we arrive at the 2020 Roll-Forward enterprise value of USD 2.45 billion.
- Our calculated discount rate has slightly reduced from 10.0 percent in June 2020 to 9.75 percent in December 2020. Additionally,

Management have revised their Brent Oil price assumptions, upwards. Both these factors result in an increase in the value.

- Marigold and Isabella are additions to the combined portfolio. Ithaca holds a 100.0 percent and 10.0 percent working interest in Marigold and Isabella, respectively. The addition of these fields results in an increase of c. USD 200 million.
- We also note that the expected production profile in the CNSL portfolio has increased since June 2020 levels. The increased production leads to an increase of c. USD 600 million.
- Cost optimizations lead to a reduction in the Opex. Part of this reduction also relates to shift of polymer costs (for Captain field only) from Opex to Capex.
- In order to achieve higher production and bringing new fields onstream, additional Capex has also been projected. This leads to a reduction in value of c. 400 million.
- After incorporating the above-mentioned changes, we arrive at an enterprise value of c. USD 3.07 billion for December 2020.

Calculation of Carrying Amount

Management have provided us with the Carrying Amount of the investment in Ithaca as per Delek's records. In estimating the Carrying Amount we understand that financial assets (cash) and financial liabilities (long-term and short-term debt, provisions for liabilities and obligations under finance leases) were excluded. We note however that Delek has extended a shareholder loan to Ithaca which has been included in the Carrying Amount. As of the Valuation Date the balance of the loan including accrued interest was USD 272.0 million. As stated above, we have included this in our calculations.

As provided to us by Management, the estimated Carrying Amount of the investment in Ithaca amounts to USD 1.17 billion.

Conclusion – Ithaca Impairment Testing

As illustrated in the table below, the Recoverable Amount as of the Valuation Date is above the Carrying Amount of the investment in Ithaca, thus, *indicating no Goodwill Impairment as of the Valuation Date.*

IAS 36 Impairment Conclusion (USD 000s)	
Estimated Recoverable Amount	1,878,000
Carrying Amount at Valuation Date	1,169,000
Indicated Excess / (Impairment)	**709,000**

Section 04

Field-by-Field Impairment Test

Individual Fields

Background

The Ithaca-operated GSA is located in the heart of the Central Graben area of the Central North Sea, on the UK Continental Shelf. Ithaca owns licenses to six fields in the GSA which are all supported by the FPF-1 floating production facility. The GSA licences contain the Stella and Harrier fields, both of which are in production as at the Valuation Date, and the Vorlich field, which is currently in the process of being developed. Ithaca also owns operated interests in several satellite fields that are planned for development via the hub infrastructure, being the Hurricane and Courageous discoveries. Ithaca's focus on the GSA is driven by monetisation of the currently identified reserves as well as the generation of additional value via the wider opportunities provided by the range of undeveloped discoveries surrounding the production hub.

As part of our analysis, we have looked at cash flows for certain individual oil fields. Additionally, there are oil fields which are grouped together and are illustrated in the table below:

GSA	Britsats
Stella	Britannia
Harrier	Callanish
Hurricane	Alder
Vorlich	Brodgar
Courageous	Enochdhu

Impairment Testing

As described previously, we have completed impairment testing at the level of Delek's total investment in Ithaca as held on Delek's books. In addition, we have estimated the Recoverable Amount of certain oil fields or group of oil fields. Please refer to Exhibit 3.0 for further details on filed - specific impairment(s).

Methodology

We have utilised the same methodology in calculating the field values of these assets as utilised in calculating the Recoverable Amount for the investment in Ithaca. We have relied on the production and other forecasts provided by Management. While the Ithaca-level cash flows were assessed on a consolidated level, for the purposes of the field-by-field impairment testing, we have considered the cash flows for the fields separately.

There are several minor differences between the approach used in the Ithaca-level impairment test and field-specific impairment test:

- We have not included the decommissioning costs or hedging costs in the field-level cash flows. We understand that in Delek's consolidated accounts, these assets and liabilities are recognised separately, and we have therefore excluded them when estimating the NPV of an individual field in order to avoid double-counting.

- We have not included a separate line of cash flows related to the general and administrative ("SG&A") costs for individual fields. We understand that the majority of administrative expenses relating to the fields are onshore support costs. Management have advised us that the costs which are specific to each field have already been allocated and are captured in each field's operating expenses.

- The additional SG&A costs which we reflect at the total Ithaca level relate to central costs which are not attributable to any individual field. Therefore, we have not included these cost items at the field-specific level.

- We have performed our field-level analysis on a pre-tax basis, and field values have been converted into post-tax values subsequently utilising a tax rate of 40.0 percent.

Please refer to Exhibits 4.0 – 15.0 for field-level cash flows.

The following table illustrates the Carrying Amount and the Recoverable Amount for individual fields:

Field	Net Book Value (1)	Recoverable Amount (2)	Possible Impairment
GSA Fields	353,489	350,628	(2,861)
Britsats Fields	147,938	253,234	-
Cook	130,194	174,207	-
Pierce	34,665	58,804	-
Austen	72,116	110,370	-
Isabella	-	24,523	-
Captain	1,079,315	1,423,555	-
Alba	34,841	31,086	(3,755)
Erskine	70,389	140,597	-
Elgin Franklin & W Franklin	97,778	163,613	-
Jade	24,937	61,770	-
Marigold/ Yeoman	6,341	175,342	-

(1) Provided by Management
(2) Calculated using a discont rate of 9.75%

Section 05

Limiting Conditions

Limiting Conditions

This document has been prepared solely for the Management and directors of Delek for the purposes stated herein and should not be relied upon for any other purpose. Unless required by law, this report shall not be provided to any third party (with the exception of the appropriate tax and regulatory authorities and Delek's auditors and legal and tax advisors) without our prior written consent. In no event, regardless of whether consent has been provided, shall we assume any responsibility to any third party to which the report is disclosed or otherwise made available.

Our procedures did not include investigation of, and we assume no responsibility for, the titles to, or any liens against, the assets of Delek or Ithaca. Furthermore, we assume there are no hidden, unapparent, or unexpected conditions that could affect the value of the business and accept no responsibility for discovering such conditions.

While our work has involved an analysis of financial information and accounting records, our engagement does not include an audit in accordance with generally accepted auditing standards of Delek's existing business records. Accordingly, we assume no responsibility and make no representations with respect to the accuracy or completeness of any information provided by and on behalf of Delek or Ithaca. Budgets, projections, and forecasts relate to future events and are based on assumptions that may not remain valid for the whole of the relevant period. Consequently, this information cannot be relied upon to the same extent as that derived from audited accounts for completed accounting periods. The outbreak of COVID-19 was declared a pandemic by the World Health Organization on March 11, 2020 and has severely impacted global economy, including the energy sector. We express no opinion as to how closely the actual results will correspond to those projected or forecast by Delek or Ithaca.

We determined Recoverable Amount assuming the ongoing use of the assets in the existing business. Accordingly, the conclusions reached in this valuation are meaningful only for the specific purpose of this engagement as stated above.

In the course of our valuation, we used financial and other information, including prospective financial information, provided to us by Delek or Ithaca management or obtained from public sources we believe to be reliable; the more significant sources of this information are identified in this report. Our conclusions are dependent on such information being complete and accurate in all material respects; however, we have not examined such information and, accordingly, do not express an opinion or any other form of assurance thereon.

In accordance with our agreement, this report is limited to estimating the Recoverable Amount of the investment in Ithaca and the individual fields for impairment testing purposes. Additional issues may exist that could affect the local jurisdiction tax treatment of the Company with respect to which we have prepared this report. This report does not consider or provide a conclusion with respect to any of those issues. With respect to any significant local jurisdiction tax issue outside the scope of this report, this report was not written, and cannot be used, by anyone for the purpose of avoiding local jurisdiction tax penalties.

Section 06

Exhibits

Delek Group Ltd.

Exhibit 1.0

Ithaca Energy Ltd. Impairment Testing

Valuation Date: December 31, 2020

Ithaca Summary of Values

Currency in USD Thousands (Unless otherwise noted)

DRAFT - For Discussion Purposes Only

Total Enterprise Value (Adj)	(1)	3,096,563
Less: Gross Debt		(1,492,000)
Add: Cash		1,000
Add: Shareholder Loan		272,000
Equity Value (Rounded)	(2)	**1,878,000**
Carrying Amount	(3)	1,169,000
Indicated Excess / (Impairment)		**709,000**

DRAFT

Notes:

(1) Please see Exhibit 2.0 for detailed calculations.

(2) Please see Exhibit 2.0 for detailed calculations.

(3) Provided by Management.

Delek Group Ltd.

Ithaca Energy Ltd. Impairment Testing

Valuation Date: December 31, 2020

Ithaca Discounted Cash Flow Analysis

Currency in USD Thousands (Unless otherwise noted)

Exhibit 2.0

Page 1/2

DRAFT - For Discussion Purposes Only

	01/01/2021	01/01/2022	01/01/2023	01/01/2024	01/01/2025	01/01/2026	01/01/2027	01/01/2028	01/01/2029	01/01/2030	01/01/2031	01/01/2032
	02/07/2021	02/07/2022	02/07/2023	01/07/2024	02/07/2025	02/07/2026	02/07/2027	01/07/2028	02/07/2029	02/07/2030	02/07/2031	01/07/2032
	31/12/2021	31/12/2022	31/12/2023	31/12/2024	31/12/2025	31/12/2026	31/12/2027	31/12/2028	31/12/2029	31/12/2030	31/12/2031	31/12/2032
	2021	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Net Production (1)												
Ithaca	6,482	6,387	7,164	9,898	13,776	10,565	6,545	4,321	2,853	1,836	941	227
CNSL	16,618	17,163	17,300	19,440	24,936	21,416	16,163	12,951	10,518	7,017	4,139	3,180
Total Net Production (Mboe)	**23,100**	**23,550**	**24,464**	**29,338**	**38,712**	**31,982**	**22,707**	**17,273**	**13,371**	**8,853**	**5,080**	**3,406**
Net Revenue												
Ithaca	276,130	282,357	344,275	492,821	710,542	542,314	336,453	227,081	153,935	103,731	60,163	17,905
CNSL	777,297	857,124	928,642	1,124,905	1,574,611	1,408,346	1,104,130	940,702	788,014	548,440	347,252	270,666
Total Net Revenue	**1,053,427**	**1,139,481**	**1,272,917**	**1,617,726**	**2,285,152**	**1,950,660**	**1,440,583**	**1,167,783**	**941,949**	**652,171**	**407,416**	**288,571**
% growth		*8.2%*	*11.7%*	*27.1%*	*41.3%*	*(14.6%)*	*(26.1%)*	*(18.9%)*	*(19.3%)*	*(30.8%)*	*(37.5%)*	*(29.2%)*
Operating Costs												
Ithaca	(73,730)	(84,476)	(98,533)	(132,292)	(180,544)	(159,453)	(139,827)	(105,868)	(79,580)	(58,890)	(36,047)	(3,419)
CNSL	(238,443)	(235,907)	(239,205)	(265,008)	(281,275)	(281,096)	(274,142)	(234,244)	(224,842)	(206,205)	(139,810)	(133,227)
Total Operating Costs	**(312,173)**	**(320,383)**	**(337,738)**	**(397,300)**	**(461,819)**	**(440,549)**	**(413,968)**	**(340,112)**	**(304,422)**	**(265,096)**	**(175,857)**	**(136,646)**
EBITDA	**741,254**	**819,098**	**935,178**	**1,220,426**	**1,823,333**	**1,510,110**	**1,026,615**	**827,670**	**637,527**	**387,076**	**231,559**	**151,925**
		10.5%	*14.2%*	*30.5%*	*49.4%*	*(17.2%)*	*(32.0%)*	*(19.4%)*	*(23.0%)*	*(39.3%)*	*(40.2%)*	*(34.4%)*
Other Income (Costs) - G&A and Hedging												
Ithaca	(119,713)	(103,630)	(25,910)	(21,650)	(22,083)	(22,524)	(22,975)	(23,436)	(14,343)	(14,630)	(14,922)	(12,684)
CNSL												
Total Other Income (Costs) - G&A and Hedging	(119,713)	(103,630)	(25,910)	(21,650)	(22,083)	(22,524)	(22,975)	(23,436)	(14,343)	(14,630)	(14,922)	(12,684)
Net Capex												
Ithaca	(35,349)	(97,395)	(174,959)	(224,512)	(25,853)	(17,118)	(10,195)	(8,701)	(4,734)	-	-	-
CNSL	(152,010)	(300,850)	(459,297)	(281,882)	(266,624)	(151,050)	(178,926)	(147,308)	(43,824)	(11,520)	(732)	-
Total Net Capex	**(187,359)**	**(398,245)**	**(634,256)**	**(506,394)**	**(292,477)**	**(168,168)**	**(189,121)**	**(156,009)**	**(48,558)**	**(11,520)**	**(732)**	**-**
DSA Postings												
Ithaca	(1,074)	(890)	(750)	(1,125)	(1,379)	(1,353)	(1,451)	(1,686)	(1,745)	(2,037)	(2,037)	-
CNSL	(2,429)	(2,197)	(2,730)	(3,443)	(4,629)	(5,474)	(6,161)	(6,685)	(6,378)	(8,465)	(7,999)	(7,662)
Total DSA Postings	(3,503)	(3,087)	(3,481)	(4,568)	(6,009)	(6,827)	(7,612)	(8,371)	(8,123)	(10,502)	(10,036)	(7,662)
Decommissioning Costs												
Ithaca	(19,980)	(21,088)	(16,562)	(22,672)	(18,309)	(63,820)	(10,398)	(1,304)	(13,804)	(27,036)	-	(185,549)
CNSL	-	-	-	-	-	-	-	-	(54,211)	-	(191,035)	(86,083)
Total Decommissioning Costs (2)	(19,980)	(21,088)	(16,562)	(22,672)	(18,309)	(63,820)	(10,398)	(1,304)	(68,015)	(27,036)	(191,035)	(271,632)
Pre-Tax Income	**410,699**	**293,047**	**254,970**	**665,142**	**1,484,455**	**1,248,770**	**796,508**	**638,551**	**498,488**	**323,387**	**14,834**	**(140,053)**
Margin	*39.0%*	*25.7%*	*20.0%*	*41.1%*	*65.0%*	*64.0%*	*55.3%*	*54.7%*	*52.9%*	*49.6%*	*3.6%*	*(48.5%)*
Total Tax Payable	**-**	**-**	**-**	**-**	**(389,914)**	**(464,680)**	**(306,783)**	**(245,670)**	**(196,360)**	**(128,635)**	**(5,888)**	**56,021**
Free Cash Flow	**410,699**	**293,047**	**254,970**	**665,142**	**1,094,541**	**784,091**	**489,725**	**392,881**	**302,128**	**194,752**	**8,946**	**(84,032)**
Partial Period	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Mid-Year Adjustment	0.50	1.50	2.50	3.50	4.50	5.50	6.50	7.50	8.50	9.50	10.50	11.50
PV Factor @ 9.75%	0.9545	0.8697	0.7925	0.7221	0.6579	0.5995	0.5462	0.4977	0.4535	0.4132	0.3765	0.3430
PV of Free Cash Flow to Firm	**392,032**	**254,877**	**202,059**	**480,284**	**720,131**	**470,047**	**267,499**	**195,536**	**137,010**	**80,471**	**3,368**	**(28,827)**

Preliminary Enterprise Value	3,068,563
Add: Working Capital Surplus (3)	28,000
Adjusted Enterprise Value	**3,096,563**
Less: Gross Debt (4)	(1,492,000)
Add: Cash (5)	1,000
Add: Shareholder Loan (6)	272,000
Equity Value	**1,877,563**
Equity Value (Rounded)	**1,878,000**

WACC Sensitivity

9.50%	**9.75%**	10.00%
1,904,173	**1,877,563**	1,851,230

DRAFT

Notes:

(1) Production forecasts have been provided by Management.

(2) Decommissioning cost estimates have been provided by Management.

(3) Working Capital surplus ($28 mn) as at Valuation Date, provided by Management.

(4) Gross Debt includes the RBL facility, Bonds and the SH Loan.

(5) Provided by Management.

(6) Includes principal loan amount of USD 250 mn and accrued interest of USD 13 mn

Delek Group Ltd. **Exhibit 2.0**

Ithaca Energy Ltd. Impairment Testing Page 2/2

Valuation Date: December 31, 2020

Ithaca Discounted Cash Flow Analysis

Currency in USD Thousands (Unless otherwise noted) DRAFT - For Discussion Purposes Only

	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
	01/01/2033	01/01/2034	01/01/2035	01/01/2036	01/01/2037	01/01/2038	01/01/2039	01/01/2040	01/01/2041	01/01/2042	01/01/2043	01/01/2044
	02/07/2033	02/07/2034	02/07/2035	01/07/2036	02/07/2037	02/07/2038	02/07/2039	01/07/2040	02/07/2041	02/07/2042	02/07/2043	01/07/2044
	31/12/2033	31/12/2034	31/12/2035	31/12/2036	31/12/2037	31/12/2038	31/12/2039	31/12/2040	31/12/2041	31/12/2042	31/12/2043	31/12/2044
Net Production (1)												
Ithaca	166	124	94	72	56	45	36	29	23	19	6	-
CNSL	2,708	2,341	1,631	340	153	138	125	63	-	-	-	-
Total Net Production (Mboe)	**2,874**	**2,465**	**1,725**	**413**	**209**	**182**	**161**	**91**	**23**	**19**	**6**	**-**
Net Revenue												
Ithaca	13,532	10,406	8,056	6,379	5,114	4,146	3,369	2,784	2,308	1,929	576	-
CNSL	237,394	212,058	147,541	20,772	10,318	9,537	8,844	4,553	-	-	-	-
Total Net Revenue	**250,926**	**222,464**	**155,597**	**27,151**	**15,432**	**13,683**	**12,212**	**7,337**	**2,308**	**1,929**	**576**	**-**
% growth	*(13.0%)*	*(11.3%)*	*(30.1%)*	*(82.6%)*	*(43.2%)*	*(11.3%)*						
Operating Costs												
Ithaca	(2,760)	(2,298)	(1,970)	(1,733)	(1,560)	(1,433)	(1,339)	(1,271)	(1,221)	(1,185)	(391)	-
CNSL	(133,763)	(134,524)	(103,945)	(16,277)	(6,807)	(6,859)	(6,931)	(4,059)	-	-	-	-
Total Operating Costs	**(136,522)**	**(136,822)**	**(105,915)**	**(18,010)**	**(8,366)**	**(8,292)**	**(8,270)**	**(5,330)**	**(1,221)**	**(1,185)**	**(391)**	**-**
EBITDA	**114,404**	**85,642**	**49,682**	**9,142**	**7,065**	**5,391**	**3,942**	**2,008**	**1,088**	**744**	**184**	**-**
	(24.7%)	*(25.1%)*	*(42.0%)*	*(81.6%)*	*(22.7%)*	*(23.7%)*						
Other Income (Costs) - G&A and Hedging												
Ithaca	(7,763)	(7,918)	(673)	(687)	(700)	(714)	(729)	(743)	(758)	(773)	(789)	-
CNSL												
Total Other Income (Costs) - G&A and Hedging	(7,763)	(7,918)	(673)	(687)	(700)	(714)	(729)	(743)	(758)	(773)	(789)	-
Net Capex												
Ithaca	-	-	-	-	-	-	-	-	-	-	-	-
CNSL	-	-	-	-	-	-	-	-	-	-	-	-
Total Net Capex	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
DSA Postings												
Ithaca	-	-	-	-	-	-	-	-	-	-	-	-
CNSL	(7,152)	(6,978)	(7,122)	(5,382)	(3,460)	(2,132)	(731)	(737)	(557)	(375)	(189)	-
Total DSA Postings	(7,152)	(6,978)	(7,122)	(5,382)	(3,460)	(2,132)	(731)	(737)	(557)	(375)	(189)	-
Decommissioning Costs												
Ithaca	-	-	-	-	-	-	-	-	-	-	-	(9,252)
CNSL	(87,805)	(89,561)	(36,061)	(228,689)	(227,728)	(173,233)	(176,698)	-	(16,406)	(16,734)	(17,069)	(17,411)
Total Decommissioning Costs (2)	(87,805)	(89,561)	(36,061)	(228,689)	(227,728)	(173,233)	(176,698)	-	(16,406)	(16,734)	(17,069)	(26,663)
Pre-Tax Income	**11,684**	**(18,814)**	**5,826**	**(225,616)**	**(224,822)**	**(170,689)**	**(174,216)**	**527**	**(16,634)**	**(17,138)**	**(17,863)**	**(26,663)**
Margin	*4.7%*	*(8.5%)*	*3.7%*	*(831.0%)*	*(1,456.9%)*	*(1,247.5%)*	*(1,426.6%)*	*7.2%*	*(720.7%)*	*(888.4%)*	*(3,101.7%)*	-
Total Tax Payable	**(4,674)**	**7,526**	**(2,330)**	**90,246**	**89,929**	**68,275**	**69,686**	**(211)**	**6,653**	**6,855**	**7,145**	**10,665**
Free Cash Flow	**7,010**	**(11,289)**	**3,496**	**(135,370)**	**(134,893)**	**(102,413)**	**(104,529)**	**316**	**(9,980)**	**(10,283)**	**(10,718)**	**(15,998)**
Partial Period	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Mid-Year Adjustment	12.50	13.50	14.50	15.50	16.50	17.50	18.50	19.50	20.50	21.50	22.50	23.50
PV Factor @ 9.75%	0.3126	0.2848	0.2595	0.2364	0.2154	0.1963	0.1789	0.1630	0.1485	0.1353	0.1233	0.1123
PV of Free Cash Flow to Firm	**2,191**	**(3,215)**	**907**	**(32,007)**	**(29,061)**	**(20,104)**	**(18,696)**	**52**	**(1,482)**	**(1,391)**	**(1,321)**	**(1,797)**

Preliminary Enterprise Value	3,068,563
Add: Working Capital Surplus (3)	28,000
Adjusted Enterprise Value	**3,096,563**
Less: Gross Debt (4)	(1,492,000)
Add: Cash (5)	1,000
Add: Shareholder Loan (6)	272,000
Equity Value	**1,877,563**
Equity Value (Rounded)	**1,878,000**

Notes:

(1) Production forecasts have been provided by Management.

(2) Decommissioning cost estimates have been provided by Management.

(3) Working Capital surplus ($28 mn) as at Valuation Date, provided by Management.

(4) Gross Debt includes the RBL facility, Bonds and the SH Loan.

(5) Provided by Management.

(6) Includes principal loan amount of USD 250 mn and accrued interest of USD 13 mn

Delek Group Ltd. **Exhibit 3.0**

Ithaca Energy Ltd. Impairment Testing

Valuation Date: December 31, 2020

Field Values

Currency in USD Thousands (Unless otherwise noted) DRAFT - For Discussion Purposes Only

Field	Net Book Value (1)	Recoverable Amount (2)	Possible Impairment
GSA Fields	353,489	350,628	(2,861)
Britsats Fields	147,938	253,234	-
Cook	130,194	174,207	-
Pierce	34,665	58,804	-
Austen	72,116	110,370	-
Isabella	-	24,523	-
Captain	1,079,315	1,423,555	-
Alba	34,841	31,086	(3,755)
Erskine	70,389	140,597	-
Elgin Franklin & W Franklin	97,778	163,613	-
Jade	24,937	61,770	-
Marigold/ Yeoman	6,341	175,342	-

Notes:

(1) Provided by Management.

(2) Please refer to the individual Exhibits for detailed calculations.

Delek Group Ltd. **Exhibit 4.0**

Ithaca Energy Ltd. Impairment Testing

Valuation Date: December 31, 2020

GSA Fields Summary of Values

Currency in USD Thousands (Unless otherwise noted) DRAFT - For Discussion Purposes Only

Field Name	Post Tax Field NPV
Stella	34,698
Harrier	114,577
Hurricane	39,771
Vorlich	134,467
Courageous	27,115
Total	**350,628**

Delek Group Ltd.

Ithaca Energy Ltd. Impairment Testing

Exhibit 4.1

Valuation Date: December 31, 2020

GSA Field Cash Flows: Stella

Currency in USD Thousands (Unless otherwise noted)

DRAFT - For Discussion Purposes Only

Stella	Notes:	01/01/2021 31/03/2021 **Q1 2021**	01/04/2021 30/06/2021 **Q2 2021**	01/07/2021 30/09/2021 **Q3 2021**	01/10/2021 31/12/2021 **Q4 2021**	01/01/2022 31/03/2022 **Q1 2022**	01/04/2022 30/06/2022 **Q2 2022**	01/07/2022 30/09/2022 **Q3 2022**	01/10/2022 31/12/2022 **Q4 2022**	01/01/2023 31/12/2023 **2023**	01/01/2024 31/12/2024 **2024**	01/01/2025 31/12/2025 **2025**	01/01/2026 31/12/2026 **2026**	01/01/2027 31/12/2027 **2027**	01/01/2028 31/12/2028 **2028**
Net Production															
Oil (mbbl)		50	50	50	50	28	28	28	28	61	42	30	22	16	12
NGL (mbbl)		27	27	27	27	16	16	16	16	40	27	19	14	10	7
Gas (mboe)		148	148	148	148	86	86	86	86	219	150	106	76	56	41
Total Net Production (mboe)	(1)	226	226	226	226	130	130	130	130	320	219	154	111	82	60
Net Revenue	(1)	8,691	8,687	8,684	8,681	4,920	4,918	4,916	4,914	12,116	8,562	6,229	4,628	3,529	2,682
Net Opex	(1)	(296)	(296)	(296)	(296)	(1,621)	(1,621)	(1,621)	(1,621)	(4,607)	(4,426)	(2,528)	(2,115)	(2,283)	(2,340)
Net Capex	(1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Net Field Cash Flows		8,395	8,392	8,388	8,385	3,299	3,297	3,295	3,293	7,510	4,136	3,701	2,513	1,246	342
Discount Period		0.12	0.37	0.62	0.87	1.12	1.37	1.62	1.87	2.50	3.50	4.50	5.50	6.50	7.50
Present Value of Net Field Cash Flows @ 9.75%		8,299	8,199	8,008	7,819	3,006	2,935	2,866	2,798	6,019	3,021	2,462	1,523	688	172

	Notes:	01/01/2029 31/12/2029 **2029**	01/01/2030 31/12/2030 **2030**	01/01/2031 31/12/2031 **2031**	01/01/2032 31/12/2032 **2032**	01/01/2033 31/12/2033 **2033**	01/01/2034 31/12/2034 **2034**	01/01/2035 31/12/2035 **2035**	01/01/2036 31/12/2036 **2036**	01/01/2037 31/12/2037 **2037**	01/01/2038 31/12/2038 **2038**	01/01/2039 31/12/2039 **2039**	01/01/2040 31/12/2040 **2040**	01/01/2041 31/12/2041 **2041**	01/01/2042 31/12/2042 **2042**
Net Production															
Oil (mbbl)		6	3	-	-	-	-	-	-	-	-	-	-	-	-
NGL (mbbl)		4	2	-	-	-	-	-	-	-	-	-	-	-	-
Gas (mboe)		20	10	-	-	-	-	-	-	-	-	-	-	-	-
Total Net Production (mboe)	(1)	30	15	-	-	-	-	-	-	-	-	-	-	-	-
Net Revenue	(1)	1,382	691	-	-	-	-	-	-	-	-	-	-	-	-
Net Opex	(1)	(1,337)	(708)	(0)	-	-	-	-	-	-	-	-	-	-	-
Net Capex	(1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Net Field Cash Flows		45	(17)	(0)	-	-	-	-	-	-	-	-	-	-	-
Discount Period		8.50	9.50	10.50	11.50	12.50	13.50	14.50	15.50	16.50	17.50	18.50	19.50	20.50	21.50
Present Value of Net Field Cash Flows @ 9.75%		21	(7)	(0)	-	-	-	-	-	-	-	-	-	-	-

Pre-Tax Field NPV		57,830
Tax Rate:	(2)	40.0%
Post-Tax Field NPV		**34,698**

Notes:

(1) Forecasts as per Management

(2) Taxes include a corporate tax of 30.0% and a supplementary tax of 10.0%

Delek Group Ltd.

Ithaca Energy Ltd. Impairment Testing

Exhibit 4.2

Valuation Date: December 31, 2020
GSA Field Cash Flows: Harrier
Currency in USD Thousands (Unless otherwise noted)

DRAFT - For Discussion Purposes Only

Harrier	Notes:	01/01/2021 31/03/2021 **Q1 2021**	01/04/2021 30/06/2021 **Q2 2021**	01/07/2021 30/09/2021 **Q3 2021**	01/10/2021 31/12/2021 **Q4 2021**	01/01/2022 31/03/2022 **Q1 2022**	01/04/2022 30/06/2022 **Q2 2022**	01/07/2022 30/09/2022 **Q3 2022**	01/10/2022 31/12/2022 **Q4 2022**	01/01/2023 31/12/2023 **2023**	01/01/2024 31/12/2024 **2024**	01/01/2025 31/12/2025 **2025**	01/01/2026 31/12/2026 **2026**	01/01/2027 31/12/2027 **2027**	01/01/2028 31/12/2028 **2028**
Net Production															
Oil (mbbl)		23	23	23	23	18	18	18	18	61	327	318	187	151	128
NGL (mbbl)		42	42	42	42	34	34	34	34	113	301	332	233	189	161
Gas (mboe)		230	230	230	230	185	185	185	185	620	1,653	1,827	1,279	1,041	886
Total Net Production (mboe)	(1)	295	295	295	295	237	237	237	237	794	2,281	2,478	1,698	1,381	1,176
Net Revenue	(1)	10,857	10,852	10,847	10,842	8,375	8,371	8,367	8,362	28,023	86,219	95,516	66,380	55,627	48,870
Net Opex	(1)	(197)	(197)	(197)	(197)	(2,595)	(2,595)	(2,595)	(2,595)	(9,857)	(29,987)	(27,372)	(19,391)	(23,839)	(28,910)
Net Capex	(1)	-	-	-	-	-	-	-	-	-	(51,379)	-	-	-	-
Total Net Field Cash Flows		10,660	10,655	10,650	10,645	5,780	5,776	5,772	5,768	18,166	4,853	68,144	46,989	31,788	19,960
Discount Period		0.12	0.37	0.62	0.87	1.12	1.37	1.62	1.87	2.50	3.50	4.50	5.50	6.50	7.50
Present Value of Net Field Cash Flows @ 9.75%		10,539	10,411	10,167	9,927	5,267	5,142	5,021	4,901	14,560	3,544	45,334	28,483	17,557	10,045

	Notes:	01/01/2029 31/12/2029 **2029**	01/01/2030 31/12/2030 **2030**	01/01/2031 31/12/2031 **2031**	01/01/2032 31/12/2032 **2032**	01/01/2033 31/12/2033 **2033**	01/01/2034 31/12/2034 **2034**	01/01/2035 31/12/2035 **2035**	01/01/2036 31/12/2036 **2036**	01/01/2037 31/12/2037 **2037**	01/01/2038 31/12/2038 **2038**	01/01/2039 31/12/2039 **2039**	01/01/2040 31/12/2040 **2040**	01/01/2041 31/12/2041 **2041**	01/01/2042 31/12/2042 **2042**
Net Production															
Oil (mbbl)		107	65	38	-	-	-	-	-	-	-	-	-	-	-
NGL (mbbl)		135	83	49	-	-	-	-	-	-	-	-	-	-	-
Gas (mboe)		742	456	267	-	-	-	-	-	-	-	-	-	-	-
Total Net Production (mboe)	(1)	984	604	354	-	-	-	-	-	-	-	-	-	-	-
Net Revenue	(1)	41,993	26,559	15,951	-	-	-	-	-	-	-	-	-	-	-
Net Opex	(1)	(29,585)	(18,299)	(13,514)	-	-	-	-	-	-	-	-	-	-	-
Net Capex	(1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Net Field Cash Flows		12,407	8,261	2,437	-	-	-	-	-	-	-	-	-	-	-
Discount Period		8.50	9.50	10.50	11.50	12.50	13.50	14.50	15.50	16.50	17.50	18.50	19.50	20.50	21.50
Present Value of Net Field Cash Flows @ 9.75%		5,688	3,450	928	-	-	-	-	-	-	-	-	-	-	-

Pre-Tax Field NPV		190,962
Tax Rate:	(2)	40.0%
Post-Tax Field NPV		**114,577**

Notes:
(1) Forecasts as per Management
(2) Taxes include a corporate tax of 30.0% and a supplementary tax of 10.0%

Delek Group Ltd. **Exhibit 4.3**

Ithaca Energy Ltd. Impairment Testing

Valuation Date: December 31, 2020

GSA Field Cash Flows: Hurricane

Currency in USD Thousands (Unless otherwise noted)

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Hurricane	Notes:	01/01/2021 31/03/2021 **Q1 2021**	01/04/2021 30/06/2021 **Q2 2021**	01/07/2021 30/09/2021 **Q3 2021**	01/10/2021 31/12/2021 **Q4 2021**	01/01/2022 31/03/2022 **Q1 2022**	01/04/2022 30/06/2022 **Q2 2022**	01/07/2022 30/09/2022 **Q3 2022**	01/10/2022 31/12/2022 **Q4 2022**	01/01/2023 31/12/2023 **2023**	01/01/2024 31/12/2024 **2024**	01/01/2025 31/12/2025 **2025**	01/01/2026 31/12/2026 **2026**	01/01/2027 31/12/2027 **2027**	01/01/2028 31/12/2028 **2028**
Net Production															
Oil (mbbl)		-	-	-	-	166	166	166	166	1,614	557	685	367	195	108
NGL (mbbl)		-	-	-	-	7	7	7	7	64	27	115	64	34	17
Gas (mboe)		-	-	-	-	37	37	37	37	351	150	632	355	184	96
Total Net Production (mboe)	(1)	-	-	-	-	211	211	211	211	2,030	735	1,431	786	413	222
Net Revenue	(1)	-	-	-	-	10,491	10,488	10,485	10,481	107,512	40,571	70,902	40,076	22,100	12,534
Net Opex	(1)	(0)	(0)	(0)	(0)	(1,568)	(1,568)	(1,568)	(1,568)	(22,317)	(11,581)	(15,901)	(9,548)	(8,032)	(6,632)
Net Capex	(1)	(6,524)	(6,524)	(6,524)	(6,524)	(22,034)	(22,034)	(22,034)	(22,034)	-	(26,267)	-	-	-	-
Total Net Field Cash Flows		(6,524)	(6,524)	(6,524)	(6,524)	(13,110)	(13,114)	(13,117)	(13,120)	85,195	2,723	55,001	30,528	14,067	5,902
Discount Period		0.12	0.37	0.62	0.87	1.12	1.37	1.62	1.87	2.50	3.50	4.50	5.50	6.50	7.50
Present Value of Net Field Cash Flows @ 9.75%		(6,449)	(6,374)	(6,228)	(6,084)	(11,946)	(11,675)	(11,410)	(11,148)	68,286	1,988	36,590	18,505	7,769	2,970

	Notes:	01/01/2029 31/12/2029 **2029**	01/01/2030 31/12/2030 **2030**	01/01/2031 31/12/2031 **2031**	01/01/2032 31/12/2032 **2032**	01/01/2033 31/12/2033 **2033**	01/01/2034 31/12/2034 **2034**	01/01/2035 31/12/2035 **2035**	01/01/2036 31/12/2036 **2036**	01/01/2037 31/12/2037 **2037**	01/01/2038 31/12/2038 **2038**	01/01/2039 31/12/2039 **2039**	01/01/2040 31/12/2040 **2040**	01/01/2041 31/12/2041 **2041**	01/01/2042 31/12/2042 **2042**
Net Production															
Oil (mbbl)		62	28	11	-	-	-	-	-	-	-	-	-	-	-
NGL (mbbl)		9	4	1	-	-	-	-	-	-	-	-	-	-	-
Gas (mboe)		50	21	6	-	-	-	-	-	-	-	-	-	-	-
Total Net Production (mboe)	(1)	121	53	18	-	-	-	-	-	-	-	-	-	-	-
Net Revenue	(1)	7,186	3,323	1,216	-	-	-	-	-	-	-	-	-	-	-
Net Opex	(1)	(4,967)	(2,365)	(1,025)	-	-	-	-	-	-	-	-	-	-	-
Net Capex	(1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Net Field Cash Flows		2,219	957	192	-	-	-	-	-	-	-	-	-	-	-
Discount Period		8.50	9.50	10.50	11.50	12.50	13.50	14.50	15.50	16.50	17.50	18.50	19.50	20.50	21.50
Present Value of Net Field Cash Flows @ 9.75%		1,017	400	73	-	-	-	-	-	-	-	-	-	-	-

Pre-Tax Field NPV		66,285
Tax Rate:	(2)	40.0%
Post-Tax Field NPV		**39,771**

Notes:

(1) Forecasts as per Management

(2) Taxes include a corporate tax of 30.0% and a supplementary tax of 10.0%

Delek Group Ltd.

Ithaca Energy Ltd. Impairment Testing

Exhibit 4.4

Valuation Date: December 31, 2020

GSA Field Cash Flows: Vorlich

Currency in USD Thousands (Unless otherwise noted)

DRAFT - For Discussion Purposes Only

Vorlich	Notes:	01/01/2021 31/03/2021 Q1 2021	01/04/2021 30/06/2021 Q2 2021	01/07/2021 30/09/2021 Q3 2021	01/10/2021 31/12/2021 Q4 2021	01/01/2022 31/03/2022 Q1 2022	01/04/2022 30/06/2022 Q2 2022	01/07/2022 30/09/2022 Q3 2022	01/10/2022 31/12/2022 Q4 2022	01/01/2023 31/12/2023 2023	01/01/2024 31/12/2024 2024	01/01/2025 31/12/2025 2025	01/01/2026 31/12/2026 2026	01/01/2027 31/12/2027 2027	01/01/2028 31/12/2028 2028
Net Production															
Oil (mbbl)		416	416	416	416	185	185	185	185	359	195	115	72	48	33
NGL (mbbl)		62	62	62	62	58	58	58	58	215	185	143	110	85	65
Gas (mboe)		203	203	203	203	189	189	189	189	704	607	468	360	277	214
Total Net Production (mboe)	(1)	680	680	680	680	432	432	432	432	1,278	988	726	542	410	311
Net Revenue	(1)	29,988	29,979	29,969	29,960	18,586	18,580	18,575	18,569	52,904	40,389	29,901	22,617	17,458	13,614
Net Opex	(1)	(7,175)	(7,175)	(7,175)	(7,175)	(4,834)	(4,834)	(4,834)	(4,834)	(14,748)	(11,973)	(8,605)	(5,811)	(6,600)	(7,092)
Net Capex	(1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Net Field Cash Flows		22,812	22,803	22,794	22,785	13,752	13,746	13,740	13,735	38,156	28,416	21,296	16,806	10,858	6,522
Discount Period		0.12	0.37	0.62	0.87	1.12	1.37	1.62	1.87	2.50	3.50	4.50	5.50	6.50	7.50
Present Value of Net Field Cash Flows @ 9.75%		22,552	22,280	21,761	21,248	12,530	12,238	11,952	11,670	30,583	20,753	14,168	10,187	5,997	3,282

	Notes:	01/01/2029 31/12/2029 2029	01/01/2030 31/12/2030 2030	01/01/2031 31/12/2031 2031	01/01/2032 31/12/2032 2032	01/01/2033 31/12/2033 2033	01/01/2034 31/12/2034 2034	01/01/2035 31/12/2035 2035	01/01/2036 31/12/2036 2036	01/01/2037 31/12/2037 2037	01/01/2038 31/12/2038 2038	01/01/2039 31/12/2039 2039	01/01/2040 31/12/2040 2040	01/01/2041 31/12/2041 2041	01/01/2042 31/12/2042 2042
Net Production															
Oil (mbbl)		23	15	5	-	-	-	-	-	-	-	-	-	-	-
NGL (mbbl)		50	34	12	-	-	-	-	-	-	-	-	-	-	-
Gas (mboe)		164	112	41	-	-	-	-	-	-	-	-	-	-	-
Total Net Production (mboe)	(1)	238	161	58	-	-	-	-	-	-	-	-	-	-	-
Net Revenue	(1)	10,623	7,399	2,743	-	-	-	-	-	-	-	-	-	-	-
Net Opex	(1)	(6,804)	(5,197)	(2,112)	-	-	-	-	-	-	-	-	-	-	-
Net Capex	(1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Net Field Cash Flows		3,819	2,203	632	-	-	-	-	-	-	-	-	-	-	-
Discount Period		8.50	9.50	10.50	11.50	12.50	13.50	14.50	15.50	16.50	17.50	18.50	19.50	20.50	21.50
Present Value of Net Field Cash Flows @ 9.75%		1,751	920	240	-	-	-	-	-	-	-	-	-	-	-

Pre-Tax Field NPV		224,112
Tax Rate:	(2)	40.0%
Post-Tax Field NPV		**134,467**

Notes:

(1) Forecasts as per Management

(2) Taxes include a corporate tax of 30.0% and a supplementary tax of 10.0%

Delek Group Ltd. **Exhibit 4.5**
Ithaca Energy Ltd. Impairment Testing

Valuation Date: December 31, 2020
GSA Field Cash Flows: Courageous
Currency in USD Thousands (Unless otherwise noted) DRAFT - For Discussion Purposes Only

Courageous	Notes:	01/01/2021 31/03/2021 **Q1 2021**	01/04/2021 30/06/2021 **Q2 2021**	01/07/2021 30/09/2021 **Q3 2021**	01/10/2021 31/12/2021 **Q4 2021**	01/01/2022 31/03/2022 **Q1 2022**	01/04/2022 30/06/2022 **Q2 2022**	01/07/2022 30/09/2022 **Q3 2022**	01/10/2022 31/12/2022 **Q4 2022**	01/01/2023 31/12/2023 **2023**	01/01/2024 31/12/2024 **2024**	01/01/2025 31/12/2025 **2025**	01/01/2026 31/12/2026 **2026**	01/01/2027 31/12/2027 **2027**	01/01/2028 31/12/2028 **2028**
Net Production															
Oil (mbbl)		-	-	-	-	-	-	-	-	-	-	528	1,052	486	172
NGL (mbbl)		-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas (mboe)		-	-	-	-	-	-	-	-	-	-	282	723	663	518
Total Net Production (mboe)	(1)	-	-	-	-	-	-	-	-	-	-	810	1,775	1,149	691
Net Revenue	(1)	-	-	-	-	-	-	-	-	-	-	44,050	96,925	58,862	32,242
Net Opex	(1)	-	-	-	-	-	-	-	-	-	(0)	(10,559)	(23,947)	(17,393)	(11,983)
Net Capex	(1)	-	-	-	-	-	-	-	-	(24,513)	(40,173)	(15,472)	-	-	-
Total Net Field Cash Flows		-	-	-	-	-	-	-	-	(24,513)	(40,173)	18,019	72,978	41,469	20,260
Discount Period		0.12	0.37	0.62	0.87	1.12	1.37	1.62	1.87	2.50	3.50	4.50	5.50	6.50	7.50
Present Value of Net Field Cash Flows @ 9.75%		-	-	-	-	-	-	-	-	(19,647)	(29,339)	11,987	44,237	22,904	10,196

	Notes:	01/01/2029 31/12/2029 **2029**	01/01/2030 31/12/2030 **2030**	01/01/2031 31/12/2031 **2031**	01/01/2032 31/12/2032 **2032**	01/01/2033 31/12/2033 **2033**	01/01/2034 31/12/2034 **2034**	01/01/2035 31/12/2035 **2035**	01/01/2036 31/12/2036 **2036**	01/01/2037 31/12/2037 **2037**	01/01/2038 31/12/2038 **2038**	01/01/2039 31/12/2039 **2039**	01/01/2040 31/12/2040 **2040**	01/01/2041 31/12/2041 **2041**	01/01/2042 31/12/2042 **2042**
Net Production															
Oil (mbbl)		62	22	1	-	-	-	-	-	-	-	-	-	-	-
NGL (mbbl)		-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas (mboe)		406	318	23	-	-	-	-	-	-	-	-	-	-	-
Total Net Production (mboe)	(1)	467	340	24	-	-	-	-	-	-	-	-	-	-	-
Net Revenue	(1)	20,215	14,116	1,000	-	-	-	-	-	-	-	-	-	-	-
Net Opex	(1)	(11,283)	(12,293)	(1,003)	-	-	-	-	-	-	-	-	-	-	-
Net Capex	(1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Net Field Cash Flows		8,932	1,823	(4)	-	-	-	-	-	-	-	-	-	-	-
Discount Period		8.50	9.50	10.50	11.50	12.50	13.50	14.50	15.50	16.50	17.50	18.50	19.50	20.50	21.50
Present Value of Net Field Cash Flows @ 9.75%		4,095	761	(1)	-	-	-	-	-	-	-	-	-	-	-

Pre-Tax Field NPV		45,191
Tax Rate:	(2)	40.0%
Post-Tax Field NPV		**27,115**

Notes:
(1) Forecasts as per Management
(2) Taxes include a corporate tax of 30.0% and a supplementary tax of 10.0%

Delek Group Ltd.

Exhibit 5.0

Ithaca Energy Ltd. Impairment Testing

Valuation Date: December 31, 2020

Britsats Fields Summary of Values

Currency in USD Thousands (Unless otherwise noted)

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Field Name	Post Tax Field NPV
Britannia	148,895
Callanish	43,584
Alder	29,908
Brodgar	6,184
Enochdhu	24,663
Total	**253,234**

Delek Group Ltd.

Exhibit 5.1

Ithaca Energy Ltd. Impairment Testing

Valuation Date: December 31, 2020

Britsats Field Cash Flows: Britannia

Currency in USD Thousands (Unless otherwise noted)

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		01/01/2021	01/04/2021	01/07/2021	01/10/2021	01/01/2022	01/04/2022	01/07/2022	01/10/2022	01/01/2023	01/01/2024	01/01/2025	01/01/2026	01/01/2027	01/01/2028
		31/03/2021	30/06/2021	30/09/2021	31/12/2021	31/03/2022	30/06/2022	30/09/2022	31/12/2022	31/12/2023	31/12/2024	31/12/2025	31/12/2026	31/12/2027	31/12/2028
Britannia	Notes:	**Q1 2021**	**Q2 2021**	**Q3 2021**	**Q4 2021**	**Q1 2022**	**Q2 2022**	**Q3 2022**	**Q4 2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
Net Production															
Oil (mbbl)		78	79	80	80	80	81	82	82	288	262	238	218	196	177
NGL (mbbl)		40	40	41	41	42	42	43	43	152	138	125	115	103	93
Gas (mboe)		516	521	527	527	528	534	540	540	1,905	1,728	1,572	1,439	1,292	1,169
Total Net Production (mboe)	(1)	633	640	647	647	650	657	664	664	2,345	2,127	1,935	1,772	1,591	1,439
Net Revenue	(1)	24,862	25,128	25,394	25,386	24,414	24,676	24,938	24,929	87,963	81,536	76,258	71,613	66,110	61,626
Net Opex	(1)	(9,138)	(9,138)	(9,138)	(9,138)	(8,612)	(8,612)	(8,612)	(8,612)	(35,594)	(43,545)	(43,257)	(46,206)	(46,961)	(47,198)
Net Capex	(1)	(330)	(330)	(330)	(330)	-	-	-	-	-	-	-	-	-	-
Total Net Field Cash Flows		15,393	15,659	15,925	15,917	15,802	16,064	16,326	16,317	52,370	37,991	33,001	25,406	19,149	14,428
Discount Period		0.12	0.37	0.62	0.87	1.12	1.37	1.62	1.87	2.50	3.50	4.50	5.50	6.50	7.50
Present Value of Net Field Cash Flows @ 9.75%		15,218	15,300	15,204	14,843	14,398	14,301	14,201	13,864	41,975	27,746	21,955	15,400	10,576	7,261

		01/01/2029	01/01/2030	01/01/2031	01/01/2032	01/01/2033	01/01/2034	01/01/2035	01/01/2036	01/01/2037	01/01/2038	01/01/2039	01/01/2040	01/01/2041	01/01/2042
		31/12/2029	31/12/2030	31/12/2031	31/12/2032	31/12/2033	31/12/2034	31/12/2035	31/12/2036	31/12/2037	31/12/2038	31/12/2039	31/12/2040	31/12/2041	31/12/2042
	Notes:	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**
Net Production															
Oil (mbbl)		161	96	-	-	-	-	-	-	-	-	-	-	-	-
NGL (mbbl)		85	51	-	-	-	-	-	-	-	-	-	-	-	-
Gas (mboe)		1,063	636	-	-	-	-	-	-	-	-	-	-	-	-
Total Net Production (mboe)	(1)	1,310	783	-	-	-	-	-	-	-	-	-	-	-	-
Net Revenue	(1)	57,521	35,375	-	-	-	-	-	-	-	-	-	-	-	-
Net Opex	(1)	(46,091)	(33,761)	-	-	-	-	-	-	-	-	-	-	-	-
Net Capex	(1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Net Field Cash Flows		11,430	1,614	-	-	-	-	-	-	-	-	-	-	-	-
Discount Period		8.50	9.50	10.50	11.50	12.50	13.50	14.50	15.50	16.50	17.50	18.50	19.50	20.50	21.50
Present Value of Net Field Cash Flows @ 9.75%		5,240	674	-	-	-	-	-	-	-	-	-	-	-	-
Pre-Tax Field NPV		248,158													
Tax Rate:	(2)	40.0%													
Post-Tax Field NPV		**148,895**													

Notes:

(1) Forecasts as per Management

(2) Taxes include a corporate tax of 30.0% and a supplementary tax of 10.0%

Delek Group Ltd. **Exhibit 5.2**

Ithaca Energy Ltd. Impairment Testing

Valuation Date: December 31, 2020

Britsats Field Cash Flows: Callanish

Currency in USD Thousands (Unless otherwise noted)

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Callanish	Notes:	01/01/2021 31/03/2021 **Q1 2021**	01/04/2021 30/06/2021 **Q2 2021**	01/07/2021 30/09/2021 **Q3 2021**	01/10/2021 31/12/2021 **Q4 2021**	01/01/2022 31/03/2022 **Q1 2022**	01/04/2022 30/06/2022 **Q2 2022**	01/07/2022 30/09/2022 **Q3 2022**	01/10/2022 31/12/2022 **Q4 2022**	01/01/2023 31/12/2023 **2023**	01/01/2024 31/12/2024 **2024**	01/01/2025 31/12/2025 **2025**	01/01/2026 31/12/2026 **2026**	01/01/2027 31/12/2027 **2027**	01/01/2028 31/12/2028 **2028**
Net Production															
Oil (mbbl)		75	76	77	77	72	73	74	74	295	228	174	135	107	86
NGL (mbbl)		19	19	19	19	18	18	18	18	64	48	36	27	21	16
Gas (mboe)		14	14	14	14	13	13	13	13	47	35	26	20	15	12
Total Net Production (mboe)	(1)	108	109	111	111	103	104	105	105	406	311	236	182	143	115
Net Revenue	(1)	5,203	5,261	5,318	5,318	5,331	5,390	5,449	5,449	22,645	18,443	14,628	11,812	9,811	8,281
Net Opex	(1)	(866)	(866)	(866)	(866)	(798)	(798)	(798)	(798)	(3,146)	(3,393)	(3,225)	(3,210)	(3,153)	(3,087)
Net Capex	(1)	(404)	(404)	(404)	(404)	(2,037)	(2,037)	(2,037)	(2,037)	-	-	-	-	-	-
Total Net Field Cash Flows		3,933	3,991	4,048	4,048	2,496	2,555	2,614	2,614	19,499	15,050	11,402	8,602	6,658	5,193
Discount Period		0.12	0.37	0.62	0.87	1.12	1.37	1.62	1.87	2.50	3.50	4.50	5.50	6.50	7.50
Present Value of Net Field Cash Flows @ 9.75%		3,888	3,899	3,865	3,775	2,274	2,274	2,274	2,221	15,629	10,991	7,586	5,214	3,677	2,614

	Notes:	01/01/2029 31/12/2029 **2029**	01/01/2030 31/12/2030 **2030**	01/01/2031 31/12/2031 **2031**	01/01/2032 31/12/2032 **2032**	01/01/2033 31/12/2033 **2033**	01/01/2034 31/12/2034 **2034**	01/01/2035 31/12/2035 **2035**	01/01/2036 31/12/2036 **2036**	01/01/2037 31/12/2037 **2037**	01/01/2038 31/12/2038 **2038**	01/01/2039 31/12/2039 **2039**	01/01/2040 31/12/2040 **2040**	01/01/2041 31/12/2041 **2041**	01/01/2042 31/12/2042 **2042**
Net Production															
Oil (mbbl)		70	38	-	-	-	-	-	-	-	-	-	-	-	-
NGL (mbbl)		13	0	-	-	-	-	-	-	-	-	-	-	-	-
Gas (mboe)		10	5	-	-	-	-	-	-	-	-	-	-	-	-
Total Net Production (mboe)	(1)	93	44	-	-	-	-	-	-	-	-	-	-	-	-
Net Revenue	(1)	6,959	3,545	-	-	-	-	-	-	-	-	-	-	-	-
Net Opex	(1)	(2,980)	(2,023)	-	-	-	-	-	-	-	-	-	-	-	-
Net Capex	(1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Net Field Cash Flows		3,980	1,521	-	-	-	-	-	-	-	-	-	-	-	-
Discount Period		8.50	9.50	10.50	11.50	12.50	13.50	14.50	15.50	16.50	17.50	18.50	19.50	20.50	21.50
Present Value of Net Field Cash Flows @ 9.75%		1,824	635	-	-	-	-	-	-	-	-	-	-	-	-

Pre-Tax Field NPV		72,641
Tax Rate:	(2)	40.0%
Post-Tax Field NPV		**43,584**

Notes:

(1) Forecasts as per Management

(2) Taxes include a corporate tax of 30.0% and a supplementary tax of 10.0%

Delek Group Ltd.

Exhibit 5.3

Ithaca Energy Ltd. Impairment Testing

Valuation Date: December 31, 2020

Britsats Field Cash Flows: Alder

Currency in USD Thousands (Unless otherwise noted)

DRAFT - For Discussion Purposes Only

Alder	Notes:	01/01/2021 31/03/2021 Q1 2021	01/04/2021 30/06/2021 Q2 2021	01/07/2021 30/09/2021 Q3 2021	01/10/2021 31/12/2021 Q4 2021	01/01/2022 31/03/2022 Q1 2022	01/04/2022 30/06/2022 Q2 2022	01/07/2022 30/09/2022 Q3 2022	01/10/2022 31/12/2022 Q4 2022	01/01/2023 31/12/2023 2023	01/01/2024 31/12/2024 2024	01/01/2025 31/12/2025 2025	01/01/2026 31/12/2026 2026	01/01/2027 31/12/2027 2027	01/01/2028 31/12/2028 2028
Net Production															
Oil (mbbl)		43	44	44	44	31	31	32	32	79	56	6	-	-	-
NGL (mbbl)		18	18	18	18	13	13	13	13	32	23	3	-	-	-
Gas (mboe)		143	144	146	146	101	103	104	104	259	184	20	-	-	-
Total Net Production (mboe)	(1)	204	206	208	208	145	147	148	148	370	264	29	-	-	-
Net Revenue	(1)	8,099	8,186	8,272	8,268	5,646	5,706	5,766	5,763	14,580	10,714	1,213	-	-	-
Net Opex	(1)	(2,223)	(2,223)	(2,223)	(2,223)	(1,625)	(1,625)	(1,625)	(1,625)	(5,060)	(4,744)	(620)	-	-	-
Net Capex	(1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Net Field Cash Flows		5,876	5,963	6,049	6,045	4,021	4,081	4,141	4,138	9,520	5,970	593	-	-	-
Discount Period		0.12	0.37	0.62	0.87	1.12	1.37	1.62	1.87	2.50	3.50	4.50	5.50	6.50	7.50
Present Value of Net Field Cash Flows @ 9.75%		5,809	5,826	5,775	5,638	3,663	3,633	3,602	3,516	7,630	4,360	394	-	-	-

	Notes:	01/01/2029 31/12/2029 2029	01/01/2030 31/12/2030 2030	01/01/2031 31/12/2031 2031	01/01/2032 31/12/2032 2032	01/01/2033 31/12/2033 2033	01/01/2034 31/12/2034 2034	01/01/2035 31/12/2035 2035	01/01/2036 31/12/2036 2036	01/01/2037 31/12/2037 2037	01/01/2038 31/12/2038 2038	01/01/2039 31/12/2039 2039	01/01/2040 31/12/2040 2040	01/01/2041 31/12/2041 2041	01/01/2042 31/12/2042 2042
Net Production															
Oil (mbbl)		-	-	-	-	-	-	-	-	-	-	-	-	-	-
NGL (mbbl)		-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas (mboe)		-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Net Production (mboe)	(1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Revenue	(1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Opex	(1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Capex	(1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Net Field Cash Flows		-	-	-	-	-	-	-	-	-	-	-	-	-	-
Discount Period		8.50	9.50	10.50	11.50	12.50	13.50	14.50	15.50	16.50	17.50	18.50	19.50	20.50	21.50
Present Value of Net Field Cash Flows @ 9.75%		-	-	-	-	-	-	-	-	-	-	-	-	-	-

Pre-Tax Field NPV		49,847
Tax Rate:	(2)	40.0%
Post-Tax Field NPV		**29,908**

Notes:

(1) Forecasts as per Management

(2) Taxes include a corporate tax of 30.0% and a supplementary tax of 10.0%

Delek Group Ltd.

Exhibit 5.4

Ithaca Energy Ltd. Impairment Testing

Valuation Date: December 31, 2020

Britsats Field Cash Flows: Brodgar

Currency in USD Thousands (Unless otherwise noted)

DRAFT - For Discussion Purposes Only

Brodgar	Notes:	01/01/2021 31/03/2021 Q1 2021	01/04/2021 30/06/2021 Q2 2021	01/07/2021 30/09/2021 Q3 2021	01/10/2021 31/12/2021 Q4 2021	01/01/2022 31/03/2022 Q1 2022	01/04/2022 30/06/2022 Q2 2022	01/07/2022 30/09/2022 Q3 2022	01/10/2022 31/12/2022 Q4 2022	01/01/2023 31/12/2023 2023	01/01/2024 31/12/2024 2024	01/01/2025 31/12/2025 2025	01/01/2026 31/12/2026 2026	01/01/2027 31/12/2027 2027	01/01/2028 31/12/2028 2028
Net Production															
Oil (mbbl)		18	18	18	18	0	0	0	0	-	-	-	-	-	-
NGL (mbbl)		7	7	7	7	0	0	0	0	-	-	-	-	-	-
Gas (mboe)		64	65	66	66	1	1	1	1	-	-	-	-	-	-
Total Net Production (mboe)	(1)	89	90	91	91	1	1	1	1	-	-	-	-	-	-
Net Revenue	(1)	3,426	3,462	3,498	3,497	35	35	36	36	-	-	-	-	-	-
Net Opex	(1)	(806)	(806)	(806)	(806)	(24)	(24)	(24)	(24)	-	-	-	-	-	-
Net Capex	(1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Net Field Cash Flows		2,620	2,656	2,693	2,691	11	12	12	12	-	-	-	-	-	-
Discount Period		0.12	0.37	0.62	0.87	1.12	1.37	1.62	1.87	2.50	3.50	4.50	5.50	6.50	7.50
Present Value of Net Field Cash Flows @ 9.75%		2,590	2,596	2,571	2,510	10	10	10	10	-	-	-	-	-	-

	Notes:	01/01/2029 31/12/2029 2029	01/01/2030 31/12/2030 2030	01/01/2031 31/12/2031 2031	01/01/2032 31/12/2032 2032	01/01/2033 31/12/2033 2033	01/01/2034 31/12/2034 2034	01/01/2035 31/12/2035 2035	01/01/2036 31/12/2036 2036	01/01/2037 31/12/2037 2037	01/01/2038 31/12/2038 2038	01/01/2039 31/12/2039 2039	01/01/2040 31/12/2040 2040	01/01/2041 31/12/2041 2041	01/01/2042 31/12/2042 2042
Net Production															
Oil (mbbl)		-	-	-	-	-	-	-	-	-	-	-	-	-	-
NGL (mbbl)		-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas (mboe)		-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Net Production (mboe)	(1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Revenue	(1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Opex	(1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Capex	(1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Net Field Cash Flows		-	-	-	-	-	-	-	-	-	-	-	-	-	-
Discount Period		8.50	9.50	10.50	11.50	12.50	13.50	14.50	15.50	16.50	17.50	18.50	19.50	20.50	21.50
Present Value of Net Field Cash Flows @ 9.75%		-	-	-	-	-	-	-	-	-	-	-	-	-	-

Pre-Tax Field NPV		10,307
Tax Rate:	(2)	40.0%
Post-Tax Field NPV		**6,184**

Notes:

(1) Forecasts as per Management

(2) Taxes include a corporate tax of 30.0% and a supplementary tax of 10.0%

Delek Group Ltd.

Exhibit 5.5

Ithaca Energy Ltd. Impairment Testing

Valuation Date: December 31, 2020
Britsats Field Cash Flows: Enochdhu
Currency in USD Thousands (Unless otherwise noted)

DRAFT - For Discussion Purposes Only

Enochdhu	Notes:	01/01/2021 31/03/2021 Q1 2021	01/04/2021 30/06/2021 Q2 2021	01/07/2021 30/09/2021 Q3 2021	01/10/2021 31/12/2021 Q4 2021	01/01/2022 31/03/2022 Q1 2022	01/04/2022 30/06/2022 Q2 2022	01/07/2022 30/09/2022 Q3 2022	01/10/2022 31/12/2022 Q4 2022	01/01/2023 31/12/2023 2023	01/01/2024 31/12/2024 2024	01/01/2025 31/12/2025 2025	01/01/2026 31/12/2026 2026	01/01/2027 31/12/2027 2027	01/01/2028 31/12/2028 2028
Net Production															
Oil (mbbl)		59	60	61	61	53	54	54	54	173	144	122	105	92	81
NGL (mbbl)		9	9	9	9	8	8	8	8	27	22	19	16	14	13
Gas (mboe)		9	9	9	9	8	8	8	8	25	21	18	15	13	12
Total Net Production (mboe)	(1)	77	78	79	79	69	70	70	70	225	187	158	136	119	106
Net Revenue	(1)	3,798	3,840	3,883	3,883	3,669	3,710	3,751	3,751	12,737	11,231	9,907	8,899	8,195	7,638
Net Opex	(1)	(1,216)	(1,216)	(1,216)	(1,216)	(1,142)	(1,142)	(1,142)	(1,142)	(4,514)	(4,753)	(4,713)	(4,804)	(4,865)	(4,917)
Net Capex	(1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Net Field Cash Flows		2,582	2,624	2,667	2,667	2,527	2,568	2,609	2,609	8,223	6,477	5,194	4,095	3,330	2,721
Discount Period		0.12	0.37	0.62	0.87	1.12	1.37	1.62	1.87	2.50	3.50	4.50	5.50	6.50	7.50
Present Value of Net Field Cash Flows @ 9.75%		2,553	2,564	2,546	2,487	2,303	2,286	2,269	2,217	6,591	4,731	3,455	2,483	1,839	1,369

	Notes:	01/01/2029 31/12/2029 2029	01/01/2030 31/12/2030 2030	01/01/2031 31/12/2031 2031	01/01/2032 31/12/2032 2032	01/01/2033 31/12/2033 2033	01/01/2034 31/12/2034 2034	01/01/2035 31/12/2035 2035	01/01/2036 31/12/2036 2036	01/01/2037 31/12/2037 2037	01/01/2038 31/12/2038 2038	01/01/2039 31/12/2039 2039	01/01/2040 31/12/2040 2040	01/01/2041 31/12/2041 2041	01/01/2042 31/12/2042 2042
Net Production															
Oil (mbbl)		72	44	-	-	-	-	-	-	-	-	-	-	-	-
NGL (mbbl)		11	7	-	-	-	-	-	-	-	-	-	-	-	-
Gas (mboe)		10	6	-	-	-	-	-	-	-	-	-	-	-	-
Total Net Production (mboe)	(1)	94	57	-	-	-	-	-	-	-	-	-	-	-	-
Net Revenue	(1)	7,052	4,506	-	-	-	-	-	-	-	-	-	-	-	-
Net Opex	(1)	(4,921)	(3,462)	-	-	-	-	-	-	-	-	-	-	-	-
Net Capex	(1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Net Field Cash Flows		2,131	1,044	-	-	-	-	-	-	-	-	-	-	-	-
Discount Period		8.50	9.50	10.50	11.50	12.50	13.50	14.50	15.50	16.50	17.50	18.50	19.50	20.50	21.50
Present Value of Net Field Cash Flows @ 9.75%		977	436	-	-	-	-	-	-	-	-	-	-	-	-

Pre-Tax Field NPV		41,105
Tax Rate:	(2)	40.0%
Post-Tax Field NPV		**24,663**

Notes:
(1) Forecasts as per Management
(2) Taxes include a corporate tax of 30.0% and a supplementary tax of 10.0%

Delek Group Ltd. **Exhibit 6.0**

Ithaca Energy Ltd. Impairment Testing

Valuation Date: December 31, 2020

Field Cash Flows: Cook

Currency in USD Thousands (Unless otherwise noted) DRAFT - For Discussion Purposes Only

		01/01/2021	01/04/2021	01/07/2021	01/10/2021	01/01/2022	01/04/2022	01/07/2022	01/10/2022	01/01/2023	01/01/2024	01/01/2025	01/01/2026	01/01/2027	01/01/2028
		31/03/2021	30/06/2021	30/09/2021	31/12/2021	31/03/2022	30/06/2022	30/09/2022	31/12/2022	31/12/2023	31/12/2024	31/12/2025	31/12/2026	31/12/2027	31/12/2028
Cook	Notes:	**Q1 2021**	**Q2 2021**	**Q3 2021**	**Q4 2021**	**Q1 2022**	**Q2 2022**	**Q3 2022**	**Q4 2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
Net Production															
Oil (mbbl)		237	239	242	242	312	315	319	319	1,692	2,257	1,795	1,222	840	360
NGL (mbbl)		-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas (mboe)		29	30	30	30	13	14	14	14	73	97	78	53	37	16
Total Net Production (mboe)	(1)	266	269	272	272	325	329	333	333	1,765	2,354	1,873	1,275	877	376
Net Revenue	(1)	12,812	12,954	13,096	13,981	18,301	18,504	18,706	18,706	105,961	150,398	125,074	88,849	64,515	29,096
Net Opex	(1)	(8,435)	(8,435)	(8,435)	(8,435)	(7,703)	(7,703)	(7,703)	(7,703)	(35,707)	(34,372)	(36,875)	(36,836)	(42,918)	(21,423)
Net Capex	(1)	(417)	(417)	(417)	(417)	-	-	-	-	-	(22,280)	-	-	-	-
Total Net Field Cash Flows		3,960	4,102	4,244	5,130	10,598	10,801	11,004	11,003	70,254	93,746	88,199	52,013	21,597	7,672
Discount Period		0.12	0.37	0.62	0.87	1.12	1.37	1.62	1.87	2.50	3.50	4.50	5.50	6.50	7.50
Present Value of Net Field Cash Flows @ 9.75%		3,915	4,008	4,052	4,784	9,656	9,616	9,572	9,349	56,310	68,464	58,676	31,528	11,929	3,861

		01/01/2029	01/01/2030	01/01/2031	01/01/2032	01/01/2033	01/01/2034	01/01/2035	01/01/2036	01/01/2037	01/01/2038	01/01/2039	01/01/2040	01/01/2041	01/01/2042
		31/12/2029	31/12/2030	31/12/2031	31/12/2032	31/12/2033	31/12/2034	31/12/2035	31/12/2036	31/12/2037	31/12/2038	31/12/2039	31/12/2040	31/12/2041	31/12/2042
	Notes:	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**
Net Production															
Oil (mbbl)		241	204	163	-	-	-	-	-	-	-	-	-	-	-
NGL (mbbl)		-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas (mboe)		11	9	7	-	-	-	-	-	-	-	-	-	-	-
Total Net Production (mboe)	(1)	252	213	171	-	-	-	-	-	-	-	-	-	-	-
Net Revenue	(1)	20,243	17,953	14,854	-	-	-	-	-	-	-	-	-	-	-
Net Opex	(1)	(14,259)	(14,210)	(14,013)	-	-	-	-	-	-	-	-	-	-	-
Net Capex	(1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Net Field Cash Flows		5,983	3,743	841	-	-	-	-	-	-	-	-	-	-	-
Discount Period		8.50	9.50	10.50	11.50	12.50	13.50	14.50	15.50	16.50	17.50	18.50	19.50	20.50	21.50
Present Value of Net Field Cash Flows @ 9.75%		2,743	1,563	320	-	-	-	-	-	-	-	-	-	-	-

Pre-Tax Field NPV		290,345
Tax Rate:	(2)	40.0%
Post-Tax Field NPV		**174,207**

Notes:

(1) Forecasts as per Management

(2) Taxes include a corporate tax of 30.0% and a supplementary tax of 10.0%

Delek Group Ltd. **Exhibit 7.0**

Ithaca Energy Ltd. Impairment Testing

Valuation Date: December 31, 2020

Field Cash Flows: Pierce

Currency in USD Thousands (Unless otherwise noted)

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		01/01/2021	01/04/2021	01/07/2021	01/10/2021	01/01/2022	01/04/2022	01/07/2022	01/10/2022	01/01/2023	01/01/2024	01/01/2025	01/01/2026	01/01/2027	01/01/2028
		31/03/2021	30/06/2021	30/09/2021	31/12/2021	31/03/2022	30/06/2022	30/09/2022	31/12/2022	31/12/2023	31/12/2024	31/12/2025	31/12/2026	31/12/2027	31/12/2028
Pierce	Notes:	**Q1 2021**	**Q2 2021**	**Q3 2021**	**Q4 2021**	**Q1 2022**	**Q2 2022**	**Q3 2022**	**Q4 2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
Net Production															
Oil (mbbl)		84	85	86	86	75	76	77	77	276	235	185	157	126	109
NGL (mbbl)		24	25	25	25	73	74	74	74	285	253	190	156	117	98
Gas (mboe)		40	40	41	41	106	107	108	108	416	368	276	227	171	143
Total Net Production (mboe)	(1)	148	150	152	152	254	257	260	260	977	856	651	541	414	349
Net Revenue	(1)	6,228	6,296	6,364	6,362	9,561	9,662	9,762	9,760	37,759	34,429	27,379	23,707	19,196	16,999
Net Opex	(1)	(2,330)	(2,330)	(2,330)	(2,330)	(2,798)	(2,798)	(2,798)	(2,798)	(11,298)	(11,168)	(10,570)	(10,403)	(10,048)	(9,993)
Net Capex	(1)	(1,780)	(1,780)	(1,780)	(1,780)	(468)	(468)	(468)	(468)	-	-	-	-	-	-
Total Net Field Cash Flows		2,118	2,186	2,254	2,253	6,294	6,395	6,495	6,493	26,461	23,261	16,808	13,305	9,148	7,007
Discount Period		0.12	0.37	0.62	0.87	1.12	1.37	1.62	1.87	2.50	3.50	4.50	5.50	6.50	7.50
Present Value of Net Field Cash Flows @ 9.75%		2,094	2,136	2,152	2,101	5,735	5,693	5,650	5,517	21,209	16,988	11,182	8,065	5,053	3,526

		01/01/2029	01/01/2030	01/01/2031	01/01/2032	01/01/2033	01/01/2034	01/01/2035	01/01/2036	01/01/2037	01/01/2038	01/01/2039	01/01/2040	01/01/2041	01/01/2042
		31/12/2029	31/12/2030	31/12/2031	31/12/2032	31/12/2033	31/12/2034	31/12/2035	31/12/2036	31/12/2037	31/12/2038	31/12/2039	31/12/2040	31/12/2041	31/12/2042
	Notes:	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**
Net Production															
Oil (mbbl)		33	-	-	-	-	-	-	-	-	-	-	-	-	-
NGL (mbbl)		30	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas (mboe)		43	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Net Production (mboe)	(1)	106	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Revenue	(1)	5,339	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Opex	(1)	(3,361)	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Capex	(1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Net Field Cash Flows		1,978	-	-	-	-	-	-	-	-	-	-	-	-	-
Discount Period		8.50	9.50	10.50	11.50	12.50	13.50	14.50	15.50	16.50	17.50	18.50	19.50	20.50	21.50
Present Value of Net Field Cash Flows @ 9.75%		907	-	-	-	-	-	-	-	-	-	-	-	-	-

Pre-Tax Field NPV		98,007
Tax Rate:	(2)	40.0%
Post-Tax Field NPV		**58,804**

Notes:

(1) Forecasts as per Management

(2) Taxes include a corporate tax of 30.0% and a supplementary tax of 10.0%

Delek Group Ltd.
Ithaca Energy Ltd. Impairment Testing

Exhibit 8.0

Valuation Date: December 31, 2020
Field Cash Flows: Austen
Currency in USD Thousands (Unless otherwise noted)

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		01/01/2021 31/03/2021	01/04/2021 30/06/2021	01/07/2021 30/09/2021	01/10/2021 31/12/2021	01/01/2022 31/03/2022	01/04/2022 30/06/2022	01/07/2022 30/09/2022	01/10/2022 31/12/2022	01/01/2023 31/12/2023	01/01/2024 31/12/2024	01/01/2025 31/12/2025	01/01/2026 31/12/2026	01/01/2027 31/12/2027	01/01/2028 31/12/2028
Austen	Notes:	**Q1 2021**	**Q2 2021**	**Q3 2021**	**Q4 2021**	**Q1 2022**	**Q2 2022**	**Q3 2022**	**Q4 2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
Net Production															
Oil (mbbl)		-	-	-	-	-	-	-	-	-	1,292	2,845	1,236	327	57
NGL (mbbl)		-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas (mboe)		-	-	-	-	-	-	-	-	-	1,173	2,807	2,600	1,243	331
Total Net Production (mboe)	(1)	-	-	-	-	-	-	-	-	-	2,465	5,652	3,837	1,569	388
Net Revenue	(1)	-	-	-	-	-	-	-	-	-	132,252	311,491	199,131	78,704	19,270
Net Opex	(1)	-	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(28,785)	(68,133)	(51,401)	(25,825)	(8,658)
Net Capex	(1)	-	-	-	-	-	-	-	-	(146,105)	(82,842)	-	-	-	-
Total Net Field Cash Flows		-	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(146,105)	20,625	243,358	147,730	52,879	10,612
Discount Period		0.12	0.37	0.62	0.87	1.12	1.37	1.62	1.87	2.50	3.50	4.50	5.50	6.50	7.50
Present Value of Net Field Cash Flows @ 9.75%		-	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(117,106)	15,063	161,897	89,549	29,206	5,341

		01/01/2029 31/12/2029	01/01/2030 31/12/2030	01/01/2031 31/12/2031	01/01/2032 31/12/2032	01/01/2033 31/12/2033	01/01/2034 31/12/2034	01/01/2035 31/12/2035	01/01/2036 31/12/2036	01/01/2037 31/12/2037	01/01/2038 31/12/2038	01/01/2039 31/12/2039	01/01/2040 31/12/2040	01/01/2041 31/12/2041	01/01/2042 31/12/2042
	Notes:	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**
Net Production															
Oil (mbbl)		-	-	-	-	-	-	-	-	-	-	-	-	-	-
NGL (mbbl)		-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas (mboe)		-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Net Production (mboe)	(1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Revenue	(1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Opex	(1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Capex	(1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Net Field Cash Flows		-	-	-	-	-	-	-	-	-	-	-	-	-	-
Discount Period		8.50	9.50	10.50	11.50	12.50	13.50	14.50	15.50	16.50	17.50	18.50	19.50	20.50	21.50
Present Value of Net Field Cash Flows @ 9.75%		-	-	-	-	-	-	-	-	-	-	-	-	-	-

Pre-Tax Field NPV		183,950
Tax Rate:	(2)	40.0%
Post-Tax Field NPV		**110,370**

Notes:
(1) Forecasts as per Management
(2) Taxes include a corporate tax of 30.0% and a supplementary tax of 10.0%

Delek Group Ltd.

Exhibit 9.0

Ithaca Energy Ltd. Impairment Testing

Valuation Date: December 31, 2020
Field Cash Flows: Isabella
Currency in USD Thousands (Unless otherwise noted)

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Isabella	Notes:	01/01/2021 31/03/2021 **Q1 2021**	01/04/2021 30/06/2021 **Q2 2021**	01/07/2021 30/09/2021 **Q3 2021**	01/10/2021 31/12/2021 **Q4 2021**	01/01/2022 31/03/2022 **Q1 2022**	01/04/2022 30/06/2022 **Q2 2022**	01/07/2022 30/09/2022 **Q3 2022**	01/10/2022 31/12/2022 **Q4 2022**	01/01/2023 31/12/2023 **2023**	01/01/2024 31/12/2024 **2024**	01/01/2025 31/12/2025 **2025**	01/01/2026 31/12/2026 **2026**	01/01/2027 31/12/2027 **2027**	01/01/2028 31/12/2028 **2028**
Net Production															
Oil (mbbl)		-	-	-	-	-	-	-	-	-	-	-	-	185	556
NGL (mbbl)		-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas (mboe)		-	-	-	-	-	-	-	-	-	-	-	-	64	192
Total Net Production (mboe)	(1)	-	-	-	-	-	-	-	-	-	-	-	-	249	748
Net Revenue	(1)	-	-	-	-	-	-	-	-	-	-	-	-	16,462	51,772
Net Opex	(1)	-	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(2,888)	(8,838)
Net Capex	(1)	(116)	(116)	(116)	(116)	(1,847)	(1,847)	(1,847)	(1,847)	(4,341)	(1,570)	(10,381)	(17,118)	(10,195)	(8,701)
Total Net Field Cash Flows		(116)	(116)	(116)	(116)	(1,847)	(1,847)	(1,847)	(1,847)	(4,341)	(1,570)	(10,381)	(17,118)	3,378	34,234
Discount Period		0.12	0.37	0.62	0.87	1.12	1.37	1.62	1.87	2.50	3.50	4.50	5.50	6.50	7.50
Present Value of Net Field Cash Flows @ 9.75%		(115)	(114)	(111)	(109)	(1,683)	(1,644)	(1,606)	(1,569)	(3,480)	(1,146)	(6,906)	(10,376)	1,866	17,228

	Notes:	01/01/2029 31/12/2029 **2029**	01/01/2030 31/12/2030 **2030**	01/01/2031 31/12/2031 **2031**	01/01/2032 31/12/2032 **2032**	01/01/2033 31/12/2033 **2033**	01/01/2034 31/12/2034 **2034**	01/01/2035 31/12/2035 **2035**	01/01/2036 31/12/2036 **2036**	01/01/2037 31/12/2037 **2037**	01/01/2038 31/12/2038 **2038**	01/01/2039 31/12/2039 **2039**	01/01/2040 31/12/2040 **2040**	01/01/2041 31/12/2041 **2041**	01/01/2042 31/12/2042 **2042**	01/01/2043 31/12/2043 **2043**
Net Production																
Oil (mbbl)		487	335	235	169	124	92	70	54	42	33	26	21	17	14	4
NGL (mbbl)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas (mboe)		168	115	81	58	43	32	24	19	14	11	9	7	6	5	1
Total Net Production (mboe)	(1)	655	450	316	227	166	124	94	72	56	45	36	29	23	19	6
Net Revenue	(1)	46,954	33,690	24,398	17,905	13,532	10,406	8,056	6,379	5,114	4,146	3,369	2,784	2,308	1,929	576
Net Opex	(1)	(7,983)	(5,818)	(4,381)	(3,419)	(2,760)	(2,298)	(1,970)	(1,733)	(1,560)	(1,433)	(1,339)	(1,271)	(1,221)	(1,185)	(391)
Net Capex	(1)	(4,734)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Net Field Cash Flows		34,237	27,872	20,018	14,486	10,772	8,108	6,086	4,647	3,555	2,713	2,029	1,514	1,088	744	184
Discount Period		8.50	9.50	10.50	11.50	12.50	13.50	14.50	15.50	16.50	17.50	18.50	19.50	20.50	21.50	22.50
Present Value of Net Field Cash Flows @ 9.75%		15,695	11,642	7,619	5,024	3,403	2,334	1,596	1,110	774	538	367	249	163	102	23

Pre-Tax Field NPV		40,872
Tax Rate:	(2)	40.0%
Post-Tax Field NPV		**24,523**

Notes:
(1) Forecasts as per Management
(2) Taxes include a corporate tax of 30.0% and a supplementary tax of 10.0%

Delek Group Ltd.

Exhibit 10.0

Ithaca Energy Ltd. Impairment Testing

Valuation Date: December 31, 2020
Field Cash Flows: Captain
Currency in USD Thousands (Unless otherwise noted)

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Captain	Notes:	01/01/2021 31/03/2021 Q1 2021	01/04/2021 30/06/2021 Q2 2021	01/07/2021 30/09/2021 Q3 2021	01/10/2021 31/12/2021 Q4 2021	01/01/2022 31/03/2022 Q1 2022	01/04/2022 30/06/2022 Q2 2022	01/07/2022 30/09/2022 Q3 2022	01/10/2022 31/12/2022 Q4 2022	01/01/2023 31/12/2023 2023	01/01/2024 31/12/2024 2024	01/01/2025 31/12/2025 2025	01/01/2026 31/12/2026 2026	01/01/2027 31/12/2027 2027	01/01/2028 31/12/2028 2028
Net Production															
Oil (mbbl)		1,682	1,682	1,682	1,682	2,000	2,000	2,000	2,000	8,871	8,148	15,171	13,702	9,860	8,556
NGL (mbbl)		-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas (mboe)		-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Net Production (mboe)	(1)	1,682	1,682	1,682	1,682	2,000	2,000	2,000	2,000	8,871	8,148	15,171	13,702	9,860	8,556
Net Revenue	(1)	88,862	88,869	88,876	88,884	115,723	115,731	115,740	115,748	548,945	536,919	1,045,553	985,679	748,920	684,228
Net Opex	(1)	(24,832)	(24,832)	(24,832)	(24,832)	(25,807)	(25,807)	(25,807)	(25,807)	(105,255)	(107,178)	(121,906)	(121,830)	(116,040)	(113,479)
Net Capex	(1)	(30,247)	(30,247)	(30,247)	(30,247)	(51,657)	(51,657)	(51,657)	(51,657)	(282,949)	(175,314)	(260,912)	(146,212)	(172,212)	(140,524)
Total Net Field Cash Flows		33,784	33,791	33,798	33,805	38,259	38,267	38,276	38,284	160,740	254,428	662,735	717,636	460,668	430,225
Discount Period		0.12	0.37	0.62	0.87	1.12	1.37	1.62	1.87	2.50	3.50	4.50	5.50	6.50	7.50
Present Value of Net Field Cash Flows @ 9.75%		33,398	33,016	32,266	31,524	34,860	34,068	33,294	32,530	128,837	185,812	440,894	435,006	254,433	216,510

	Notes:	01/01/2029 31/12/2029 2029	01/01/2030 31/12/2030 2030	01/01/2031 31/12/2031 2031	01/01/2032 31/12/2032 2032	01/01/2033 31/12/2033 2033	01/01/2034 31/12/2034 2034	01/01/2035 31/12/2035 2035	01/01/2036 31/12/2036 2036	01/01/2037 31/12/2037 2037	01/01/2038 31/12/2038 2038	01/01/2039 31/12/2039 2039	01/01/2040 31/12/2040 2040	01/01/2041 31/12/2041 2041	01/01/2042 31/12/2042 2042
Net Production															
Oil (mbbl)		6,869	4,366	2,979	2,277	1,940	1,701	1,152	-	-	-	-	-	-	-
NGL (mbbl)		-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas (mboe)		-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Net Production (mboe)	(1)	6,869	4,366	2,979	2,277	1,940	1,701	1,152	-	-	-	-	-	-	-
Net Revenue	(1)	570,073	379,934	268,215	209,574	184,454	166,885	115,329	-	-	-	-	-	-	-
Net Opex	(1)	(112,132)	(109,378)	(108,172)	(107,414)	(108,320)	(109,390)	(83,013)	-	-	-	-	-	-	-
Net Capex	(1)	(38,039)	(10,761)	(732)	-	-	-	-	-	-	-	-	-	-	-
Total Net Field Cash Flows		419,902	259,796	159,311	102,160	76,134	57,495	32,316	-	-	-	-	-	-	-
Discount Period		8.50	9.50	10.50	11.50	12.50	13.50	14.50	15.50	16.50	17.50	18.50	19.50	20.50	21.50
Present Value of Net Field Cash Flows @ 9.75%		192,493	108,516	60,632	35,427	24,050	16,549	8,475	-	-	-	-	-	-	-

Pre-Tax Field NPV		2,372,591
Tax Rate:	(2)	40.0%
Post-Tax Field NPV		**1,423,555**

Notes:
(1) Forecasts as per Management
(2) Taxes include a corporate tax of 30.0% and a supplementary tax of 10.0%

Delek Group Ltd.

Exhibit 11.0

Ithaca Energy Ltd. Impairment Testing

Valuation Date: December 31, 2020
Field Cash Flows: Alba
Currency in USD Thousands (Unless otherwise noted)

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Alba	Notes:	01/01/2021 31/03/2021 Q1 2021	01/04/2021 30/06/2021 Q2 2021	01/07/2021 30/09/2021 Q3 2021	01/10/2021 31/12/2021 Q4 2021	01/01/2022 31/03/2022 Q1 2022	01/04/2022 30/06/2022 Q2 2022	01/07/2022 30/09/2022 Q3 2022	01/10/2022 31/12/2022 Q4 2022	01/01/2023 31/12/2023 2023	01/01/2024 31/12/2024 2024	01/01/2025 31/12/2025 2025	01/01/2026 31/12/2026 2026	01/01/2027 31/12/2027 2027	01/01/2028 31/12/2028 2028
Net Production															
Oil (mbbl)		149	151	153	153	151	153	155	155	927	938	781	679	624	587
NGL (mbbl)		-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas (mboe)		-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Net Production (mboe)	(1)	149	151	153	153	151	153	155	155	927	938	781	679	624	587
Net Revenue	(1)	7,616	7,700	7,784	7,783	8,473	8,566	8,659	8,659	55,566	59,977	52,246	47,454	46,066	45,671
Net Opex	(1)	(6,200)	(6,200)	(6,200)	(6,200)	(6,348)	(6,348)	(6,348)	(6,348)	(26,854)	(27,614)	(27,781)	(28,176)	(28,667)	(29,223)
Net Capex	(1)	(345)	(345)	(345)	(345)	(4,659)	(4,659)	(4,659)	(4,659)	(28,955)	(11,847)	(5,126)	(4,838)	(6,714)	(6,784)
Total Net Field Cash Flows		1,072	1,156	1,240	1,239	(2,534)	(2,440)	(2,347)	(2,348)	(243)	20,516	19,339	14,440	10,686	9,663
Discount Period		0.12	0.37	0.62	0.87	1.12	1.37	1.62	1.87	2.50	3.50	4.50	5.50	6.50	7.50
Present Value of Net Field Cash Flows @ 9.75%		1,060	1,129	1,183	1,155	(2,309)	(2,173)	(2,042)	(1,995)	(195)	14,983	12,865	8,753	5,902	4,863

	Notes:	01/01/2029 31/12/2029 2029	01/01/2030 31/12/2030 2030	01/01/2031 31/12/2031 2031	01/01/2032 31/12/2032 2032	01/01/2033 31/12/2033 2033	01/01/2034 31/12/2034 2034	01/01/2035 31/12/2035 2035	01/01/2036 31/12/2036 2036	01/01/2037 31/12/2037 2037	01/01/2038 31/12/2038 2038	01/01/2039 31/12/2039 2039	01/01/2040 31/12/2040 2040	01/01/2041 31/12/2041 2041	01/01/2042 31/12/2042 2042
Net Production															
Oil (mbbl)		554	477	72	-	-	-	-	-	-	-	-	-	-	-
NGL (mbbl)		-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas (mboe)		-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Net Production (mboe)	(1)	554	477	72	-	-	-	-	-	-	-	-	-	-	-
Net Revenue	(1)	44,786	40,448	6,319	-	-	-	-	-	-	-	-	-	-	-
Net Opex	(1)	(29,809)	(30,216)	(5,114)	-	-	-	-	-	-	-	-	-	-	-
Net Capex	(1)	(5,786)	(760)	-	-	-	-	-	-	-	-	-	-	-	-
Total Net Field Cash Flows		9,191	9,472	1,206	-	-	-	-	-	-	-	-	-	-	-
Discount Period		8.50	9.50	10.50	11.50	12.50	13.50	14.50	15.50	16.50	17.50	18.50	19.50	20.50	21.50
Present Value of Net Field Cash Flows @ 9.75%		4,213	3,956	459	-	-	-	-	-	-	-	-	-	-	-

Pre-Tax Field NPV		51,810
Tax Rate:	(2)	40.0%
Post-Tax Field NPV		**31,086**

Notes:
(1) Forecasts as per Management
(2) Taxes include a corporate tax of 30.0% and a supplementary tax of 10.0%

Delek Group Ltd. **Exhibit 12.0**

Ithaca Energy Ltd. Impairment Testing

Valuation Date: December 31, 2020

Field Cash Flows: Erksine

Currency in USD Thousands (Unless otherwise noted) DRAFT - For Discussion Purposes Only

Erskine	Notes:	01/01/2021 31/03/2021 **Q1 2021**	01/04/2021 30/06/2021 **Q2 2021**	01/07/2021 30/09/2021 **Q3 2021**	01/10/2021 31/12/2021 **Q4 2021**	01/01/2022 31/03/2022 **Q1 2022**	01/04/2022 30/06/2022 **Q2 2022**	01/07/2022 30/09/2022 **Q3 2022**	01/10/2022 31/12/2022 **Q4 2022**	01/01/2023 31/12/2023 **2023**	01/01/2024 31/12/2024 **2024**	01/01/2025 31/12/2025 **2025**	01/01/2026 31/12/2026 **2026**	01/01/2027 31/12/2027 **2027**	01/01/2028 31/12/2028 **2028**
Net Production															
Oil (mbbl)		230	233	235	235	215	218	220	220	813	750	701	594	502	48
NGL (mbbl)		32	33	33	33	30	31	31	31	115	98	84	70	57	5
Gas (mboe)		307	311	314	314	290	293	296	296	1,099	1,018	955	804	674	64
Total Net Production (mboe)	(1)	570	576	583	583	536	541	547	547	2,028	1,867	1,739	1,467	1,234	117
Net Revenue	(1)	25,771	26,057	26,344	26,343	24,535	24,807	25,080	25,079	95,649	91,644	88,439	77,182	67,656	6,654
Net Opex	(1)	(9,870)	(9,870)	(9,870)	(9,870)	(10,034)	(10,034)	(10,034)	(10,034)	(40,787)	(41,515)	(42,366)	(42,439)	(42,425)	(5,140)
Net Capex	(1)	-	-	-	-	(7,330)	(7,330)	(7,330)	(7,330)	-	(2,345)	-	-	-	-
Total Net Field Cash Flows		15,901	16,187	16,474	16,473	7,170	7,443	7,715	7,715	54,862	47,784	46,073	34,742	25,230	1,514
Discount Period		0.12	0.37	0.62	0.87	1.12	1.37	1.62	1.87	2.50	3.50	4.50	5.50	6.50	7.50
Present Value of Net Field Cash Flows @ 9.75%		15,720	15,816	15,727	15,362	6,533	6,626	6,711	6,556	43,973	34,898	30,651	21,059	13,935	762

	Notes:	01/01/2029 31/12/2029 **2029**	01/01/2030 31/12/2030 **2030**	01/01/2031 31/12/2031 **2031**	01/01/2032 31/12/2032 **2032**	01/01/2033 31/12/2033 **2033**	01/01/2034 31/12/2034 **2034**	01/01/2035 31/12/2035 **2035**	01/01/2036 31/12/2036 **2036**	01/01/2037 31/12/2037 **2037**	01/01/2038 31/12/2038 **2038**	01/01/2039 31/12/2039 **2039**	01/01/2040 31/12/2040 **2040**	01/01/2041 31/12/2041 **2041**	01/01/2042 31/12/2042 **2042**
Net Production															
Oil (mbbl)		-	-	-	-	-	-	-	-	-	-	-	-	-	-
NGL (mbbl)		-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas (mboe)		-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Net Production (mboe)	(1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Revenue	(1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Opex	(1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Capex	(1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Net Field Cash Flows		-	-	-	-	-	-	-	-	-	-	-	-	-	-
Discount Period		8.50	9.50	10.50	11.50	12.50	13.50	14.50	15.50	16.50	17.50	18.50	19.50	20.50	21.50
Present Value of Net Field Cash Flows @ 9.75%		-	-	-	-	-	-	-	-	-	-	-	-	-	-

Pre-Tax Field NPV		234,329
Tax Rate:	(2)	40.0%
Post-Tax Field NPV		**140,597**

Notes:

(1) Forecasts as per Management

(2) Taxes include a corporate tax of 30.0% and a supplementary tax of 10.0%

Delek Group Ltd.

Exhibit 13.0

Ithaca Energy Ltd. Impairment Testing

Valuation Date: December 31, 2020
Field Cash Flows: Elgin Franklin & W Franklin
Currency in USD Thousands (Unless otherwise noted)

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		01/01/2021	01/04/2021	01/07/2021	01/10/2021	01/01/2022	01/04/2022	01/07/2022	01/10/2022	01/01/2023	01/01/2024	01/01/2025	01/01/2026	01/01/2027	01/01/2028
		31/03/2021	30/06/2021	30/09/2021	31/12/2021	31/03/2022	30/06/2022	30/09/2022	31/12/2022	31/12/2023	31/12/2024	31/12/2025	31/12/2026	31/12/2027	31/12/2028
Elgin Franklin & W Franklin	Notes:	**Q1 2021**	**Q2 2021**	**Q3 2021**	**Q4 2021**	**Q1 2022**	**Q2 2022**	**Q3 2022**	**Q4 2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
Net Production															
Oil (mbbl)		137	139	140	140	118	120	121	121	381	313	264	242	203	175
NGL (mbbl)		52	53	53	53	47	48	48	48	156	126	108	100	84	72
Gas (mboe)		245	248	250	250	219	222	224	224	718	598	515	476	399	341
Total Net Production (mboe)	(1)	434	439	444	444	385	389	394	394	1,255	1,037	887	819	686	588
Net Revenue	(1)	18,554	18,758	18,963	18,961	16,528	16,708	16,888	16,887	55,159	47,273	41,746	39,749	34,612	30,887
Net Opex	(1)	(2,234)	(2,234)	(2,234)	(2,234)	(2,183)	(2,183)	(2,183)	(2,183)	(8,272)	(7,925)	(7,750)	(7,728)	(7,441)	(7,297)
Net Capex	(1)	(1,246)	(1,246)	(1,246)	(1,246)	(550)	(550)	(550)	(550)	(1,428)	(1,214)	(586)	-	-	-
Total Net Field Cash Flows		15,073	15,278	15,483	15,481	13,794	13,975	14,155	14,153	45,459	38,134	33,410	32,021	27,171	23,590
Discount Period		0.12	0.37	0.62	0.87	1.12	1.37	1.62	1.87	2.50	3.50	4.50	5.50	6.50	7.50
Present Value of Net Field Cash Flows @ 9.75%		14,902	14,928	14,781	14,437	12,569	12,441	12,313	12,026	36,436	27,850	22,227	19,410	15,007	11,872

		01/01/2029	01/01/2030	01/01/2031	01/01/2032	01/01/2033	01/01/2034	01/01/2035	01/01/2036	01/01/2037	01/01/2038	01/01/2039	01/01/2040	01/01/2041	01/01/2042
		31/12/2029	31/12/2030	31/12/2031	31/12/2032	31/12/2033	31/12/2034	31/12/2035	31/12/2036	31/12/2037	31/12/2038	31/12/2039	31/12/2040	31/12/2041	31/12/2042
	Notes:	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**
Net Production															
Oil (mbbl)		138	115	103	94	78	59	54	51	47	43	39	20	-	-
NGL (mbbl)		56	46	42	37	31	24	22	20	19	17	15	8	-	-
Gas (mboe)		265	218	194	171	145	110	100	93	87	78	71	35	-	-
Total Net Production (mboe)	(1)	459	379	339	302	254	193	176	164	153	138	125	63	-	-
Net Revenue	(1)	24,879	21,373	19,642	18,045	15,521	12,134	11,276	10,782	10,318	9,537	8,844	4,553	-	-
Net Opex	(1)	(6,919)	(6,745)	(6,749)	(6,738)	(6,684)	(6,540)	(6,610)	(6,706)	(6,807)	(6,859)	(6,931)	(4,059)	-	-
Net Capex	(1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Net Field Cash Flows		17,960	14,628	12,893	11,306	8,837	5,594	4,667	4,076	3,511	2,678	1,913	494	-	-
Discount Period		8.50	9.50	10.50	11.50	12.50	13.50	14.50	15.50	16.50	17.50	18.50	19.50	20.50	21.50
Present Value of Net Field Cash Flows @ 9.75%		8,233	6,110	4,907	3,921	2,791	1,610	1,224	974	764	531	346	81	-	-

Pre-Tax Field NPV		272,689
Tax Rate:	(2)	40.0%
Post-Tax Field NPV		**163,613**

Notes:
(1) Forecasts as per Management
(2) Taxes include a corporate tax of 30.0% and a supplementary tax of 10.0%

Delek Group Ltd.

Exhibit 14.0

Ithaca Energy Ltd. Impairment Testing

Valuation Date: December 31, 2020
Field Cash Flows: Jade
Currency in USD Thousands (Unless otherwise noted)

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Jade	Notes:	01/01/2021 31/03/2021 Q1 2021	01/04/2021 30/06/2021 Q2 2021	01/07/2021 30/09/2021 Q3 2021	01/10/2021 31/12/2021 Q4 2021	01/01/2022 31/03/2022 Q1 2022	01/04/2022 30/06/2022 Q2 2022	01/07/2022 30/09/2022 Q3 2022	01/10/2022 31/12/2022 Q4 2022	01/01/2023 31/12/2023 2023	01/01/2024 31/12/2024 2024	01/01/2025 31/12/2025 2025	01/01/2026 31/12/2026 2026	01/01/2027 31/12/2027 2027	01/01/2028 31/12/2028 2028
Net Production															
Oil (mbbl)		32	32	32	32	52	52	52	52	221	188	159	138	120	105
NGL (mbbl)		29	29	29	29	34	34	34	34	129	113	98	88	78	70
Gas (mboe)		116	116	116	116	137	137	137	137	522	457	398	354	314	281
Total Net Production (mboe)	(1)	177	177	177	177	223	223	223	223	873	758	655	580	512	455
Net Revenue	(1)	6,801	6,798	6,796	6,794	8,713	8,710	8,707	8,704	35,399	31,792	28,315	25,787	23,569	21,721
Net Opex	(1)	(2,226)	(2,226)	(2,226)	(2,226)	(2,403)	(2,403)	(2,403)	(2,403)	(9,723)	(9,567)	(9,402)	(9,372)	(9,278)	(9,258)
Net Capex	(1)	(4,580)	(4,580)	(4,580)	(4,580)	(2,004)	(2,004)	(2,004)	(2,004)	-	-	-	-	-	-
Total Net Field Cash Flows		(6)	(8)	(11)	(13)	4,305	4,303	4,300	4,297	25,676	22,226	18,913	16,415	14,291	12,463
Discount Period		0.12	0.37	0.62	0.87	1.12	1.37	1.62	1.87	2.50	3.50	4.50	5.50	6.50	7.50
Present Value of Net Field Cash Flows @ 9.75%		(6)	(8)	(10)	(12)	3,923	3,830	3,740	3,651	20,580	16,232	12,582	9,950	7,893	6,272

	Notes:	01/01/2029 31/12/2029 2029	01/01/2030 31/12/2030 2030	01/01/2031 31/12/2031 2031	01/01/2032 31/12/2032 2032	01/01/2033 31/12/2033 2033	01/01/2034 31/12/2034 2034	01/01/2035 31/12/2035 2035	01/01/2036 31/12/2036 2036	01/01/2037 31/12/2037 2037	01/01/2038 31/12/2038 2038	01/01/2039 31/12/2039 2039	01/01/2040 31/12/2040 2040	01/01/2041 31/12/2041 2041	01/01/2042 31/12/2042 2042
Net Production															
Oil (mbbl)		92	80	70	47	42	39	35	33	`	-	-	-	-	-
NGL (mbbl)		63	54	48	40	37	34	31	29	-	-	-	-	-	-
Gas (mboe)		253	218	194	162	148	136	126	115	-	-	-	-	-	-
Total Net Production (mboe)	(1)	408	351	312	250	227	209	192	177	-	-	-	-	-	-
Net Revenue	(1)	19,994	17,841	16,234	12,862	11,989	11,304	10,600	9,990	-	-	-	-	-	-
Net Opex	(1)	(9,296)	(9,205)	(9,222)	(9,113)	(9,208)	(9,322)	(9,443)	(9,571)	-	-	-	-	-	-
Net Capex	(1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Net Field Cash Flows		10,698	8,637	7,012	3,749	2,781	1,982	1,156	419	-	-	-	-	-	-
Discount Period		8.50	9.50	10.50	11.50	12.50	13.50	14.50	15.50	16.50	17.50	18.50	19.50	20.50	21.50
Present Value of Net Field Cash Flows @ 9.75%		4,904	3,608	2,669	1,300	879	570	303	100	-	-	-	-	-	-

Pre-Tax Field NPV		102,950
Tax Rate:	(2)	40.0%
Post-Tax Field NPV		**61,770**

Notes:
(1) Forecasts as per Management
(2) Taxes include a corporate tax of 30.0% and a supplementary tax of 10.0%

Delek Group Ltd. | **Exhibit 15.0**

Ithaca Energy Ltd. Impairment Testing

Valuation Date: December 31, 2020

Field Cash Flows: Marigold

Currency in USD Thousands (Unless otherwise noted)

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Marigold/ Yeoman	Notes:	01/01/2021 31/03/2021 **Q1 2021**	01/04/2021 30/06/2021 **Q2 2021**	01/07/2021 30/09/2021 **Q3 2021**	01/10/2021 31/12/2021 **Q4 2021**	01/01/2022 31/03/2022 **Q1 2022**	01/04/2022 30/06/2022 **Q2 2022**	01/07/2022 30/09/2022 **Q3 2022**	01/10/2022 31/12/2022 **Q4 2022**	01/01/2023 31/12/2023 **2023**	01/01/2024 31/12/2024 **2024**	01/01/2025 31/12/2025 **2025**	01/01/2026 31/12/2026 **2026**	01/01/2027 31/12/2027 **2027**	01/01/2028 31/12/2028 **2028**
Net Production															
Oil (mbbl)		-	-	-	-	-	-	-	-	-	3,463	3,045	1,892	1,269	900
NGL (mbbl)		-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas (mboe)		-	-	-	-	-	-	-	-	-	341	300	187	125	89
Total Net Production (mboe)	(1)	-	-	-	-	-	-	-	-	-	3,804	3,345	2,078	1,394	989
Net Revenue	(1)	-	-	-	-	-	-	-	-	-	235,375	216,306	140,169	99,190	73,996
Net Opex	(1)	-	-	-	-	-	-	-	-	-	(14,775)	(20,254)	(17,329)	(15,311)	(14,644)
Net Capex	(1)	(850)	(850)	(850)	(850)	(6,976)	(6,976)	(6,976)	(6,976)	(145,965)	(91,162)	-	-	-	-
Total Net Field Cash Flows		(850)	(850)	(850)	(850)	(6,976)	(6,976)	(6,976)	(6,976)	(145,965)	129,438	196,052	122,840	83,879	59,352
Discount Period		0.12	0.37	0.62	0.87	1.12	1.37	1.62	1.87	2.50	3.50	4.50	5.50	6.50	7.50
Present Value of Net Field Cash Flows @ 9.75%		(840)	(830)	(811)	(793)	(6,356)	(6,210)	(6,068)	(5,927)	(116,994)	94,531	130,427	74,461	46,327	29,869

	Notes:	01/01/2029 31/12/2029 **2029**	01/01/2030 31/12/2030 **2030**	01/01/2031 31/12/2031 **2031**	01/01/2032 31/12/2032 **2032**	01/01/2033 31/12/2033 **2033**	01/01/2034 31/12/2034 **2034**	01/01/2035 31/12/2035 **2035**	01/01/2036 31/12/2036 **2036**	01/01/2037 31/12/2037 **2037**	01/01/2038 31/12/2038 **2038**	01/01/2039 31/12/2039 **2039**	01/01/2040 31/12/2040 **2040**	01/01/2041 31/12/2041 **2041**	01/01/2042 31/12/2042 **2042**
Net Production															
Oil (mbbl)		665	508	399	319	261	216	101	-	-	-	-	-	-	-
NGL (mbbl)		-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas (mboe)		66	50	39	32	26	21	10	-	-	-	-	-	-	-
Total Net Production (mboe)	(1)	731	558	438	351	286	237	111	-	-	-	-	-	-	-
Net Revenue	(1)	56,750	45,419	36,842	30,185	25,431	21,735	10,336	-	-	-	-	-	-	-
Net Opex	(1)	(12,694)	(11,416)	(10,554)	(9,961)	(9,552)	(9,271)	(4,879)	-	-	-	-	-	-	-
Net Capex	(1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Net Field Cash Flows		44,056	34,003	26,289	20,224	15,879	12,463	5,457	-	-	-	-	-	-	-
Discount Period		8.50	9.50	10.50	11.50	12.50	13.50	14.50	15.50	16.50	17.50	18.50	19.50	20.50	21.50
Present Value of Net Field Cash Flows @ 9.75%		20,196	14,203	10,005	7,013	5,016	3,587	1,431	-	-	-	-	-	-	-

Pre-Tax Field NPV		292,237
Tax Rate:	(2)	40.0%
Post-Tax Field NPV		**175,342**

Notes:

(1) Forecasts as per Management

(2) Taxes include a corporate tax of 30.0% and a supplementary tax of 10.0%

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GIZA SINGER EVEN

Delek Group Ltd.

Impairment Assessment of the Oil and Gas Asset

As at December 31, 2020

****

March 2021

Contents

1. Introduction and Limit of Liability

1.1 General

This report was prepared by GSE Financial Advisory Ltd ("GSE") for Delek Group Ltd ("Delek Group" and/or "the Group") to assess impairment of the Group's invest in the oil and gas assets in the Tamar lease ("the Assets" and/or the Oil and Gas Assets") as part of application of IAS 36: Impairment of Assets ("the Report" and/or "the Opinion") as at December 31, 2020 ("Date of the Report").

We are aware that the Report is intended to be used by the Company, among other things, for preparation of its financial statements, and we, therefore, agreed to have it mentioned and/or included (including by way of reference) in any report published pursuant to the Securities Law, 1968 ("the Securities Law") and its regulations, as well as in a shelf prospectus and/or shelf offering memorandum published by the Company (including by way of reference).

In preparation of the Report, we relied on the information set out in section 1.2 below. GSE assumes that this information is reliable and does not examine it independently and therefore, the Opinion does not verify the correctness, completeness and accuracy thereof. However, it should be noted that nothing has come to our attention that could indicate that the information is unreasonable.

This Opinion includes a description of the methodology and main points of the assumptions and the analyses used to determine the recoverable amount of the Oil and Gas Asset. Nonetheless, it does not purport to be a full and detailed depiction of all the procedures that were applied in the formulating the Opinion.

This Report does not constitute and is not a substitute for due diligence. Furthermore, the Report is not intended to determine the value of the asset for a specific investor and does not contain any legal advice or opinion.

The Report does not include an accounting audit regarding compliance with accounting principles. GSE is not responsible for the manner of accounting presentation of the Company's financial statements, in terms of accuracy and completeness of the data and the implications of such accounting presentation, if any.

If the information and data on which GSE relied is incomplete, inaccurate or unreliable, the results of this Report may vary. We reserve the right to revise the Report in view of any new data not presented to us before. For the avoidance of any doubt, this Report is valid solely as at its signing date.

An economic valuation is meant to reflect reasonably and fairly a given situation at a given time, based on known data and taking into account basic assumptions, estimates and forecasts. **It is emphasized that the information set out in this Report regarding assumptions relating to quantities, production rate, projected price, investments and production costs for natural gas and condensate, constitutes forward-looking information as defined in Section 32A of the Securities Law, 1968, and there is no certainty that it will materialize, in whole or in part, in the foregoing manner or in any other manner. The foregoing information might materialize in a substantially different manner, due to various factors including changes in estimates of quantities and costs, increased competition, regulation, operational malfunctions, etc.**

We hereby confirm that we have no personal interest in and/or dependence on the Group, other than the fact that we receive fees for this Report. We also confirm that our fee is not conditional on the results of the assessment. GSE received an indemnity undertaking from the Group for any amount or liability or expense charged in excess of the fees paid in respect of this Report multiplied by three, incurred directly or indirectly due or related to preparation of this Report. The indemnity undertaking does not apply if it is determined that we act with malicious intent or negligence in connection with preparation of this Report.

GSE and any company directly and/or indirectly controlled by it, as well as any controlling shareholder, officer and employee of any of them, is not responsible for any damages, loss or expense of any kind, whether direct and/or indirect, that may be caused to anyone relying on the content of this Report, in whole or in part, provided that we have not acted with malicious intent or negligence that is not exempt by law or in bad faith.

1.2 Sources of information

<u>The main sources of information used in preparing the opinion are listed below:</u>

- The Group's periodic and quarterly reports for 2019-2020.
- Draft financial report of the Group for 2020.
- Current reserves report and discounted cash flow data of the Tamar lease published by Delek Drilling Limited Partnership ("Delek Drilling" and/or 'the Partnership") on March 17, 2021.
- Public information published on websites, in newspaper articles or other public sources.
- GSE's internal sources and databases.
- Meetings and/or telephone conversations with officers in the Company.

1.3 Details of the valuation company

GSE Financial Advisory Ltd. is a subsidiary of Giza Singer Even Ltd., a leading financing and investment banking advisory firm in Israel. The firm has gained vast experience in serving large-scale companies, high profile privatizations and significant transactions in Israel, over twenty-five years of operation. Giza Singer Even operates in three sectors, through autonomous and independent business divisions: financial advisory; investment banking; and analytical and corporate governance research.

The Report was prepared by a team headed by CPA Eitan Cohen, a partner OF Giza Singer Even and the head of its Economics Department, with more than 13 years of experience in the economic and business consulting and in valuation of companies and financial instruments. In the past, he served as director of the financial department of an entrepreneurial company in the infrastructure sector as well as director of the financial department of KPMG (Somekh Chaikin). Eitan is a Certified Public Accountant and holds a B.Com in Economics and Business Administration from Ben Gurion University and a master's in financial mathematics from Bar Ilan University.

Sincerely,

GSE Financial Advisory Ltd.
March X, 2021

2. Description of the Company

2.1 Background

Delek Group is a public company listed on the Tel Aviv Stock Exchange. The Group invests in and manages companies operating primarily in oil and gas exploration and production in the Mediterranean region and the North Sea. The Company is also active in the fuel sector and operation of gas stations and convenience stores in Israel.

The Group operates in the energy sector in Israel through its holdings of 100% of the share capital of Delek Energy Systems Ltd. ("Delek Energy"), which directly and indirectly holds Delek Drilling Limited Partnership ("Delek Drilling" and/or 'the Partnership"), which holds rights in oil assets, including the Leviathan reservoir (the Ratio Yam joint venture that is a joint venture for exploration, development and production of oil and gas within the I/15 Leviathan North and I/14 Leviathan South leases the "Leviathan Project"), the Tamar reservoir (a Michal Matan joint venture that is an oil and gas exploration, development and production project within the Tamar and Dalit Leases - below ("the Tamar Project") and the Aphrodite reservoir in Cyprus, As well as its direct and indirect holdings and royalty rights in the Partnership's oil assets. As at the date of the Report (December 31, 2020), the Group holds 100% of the share capital of the general partner in the Partnership and 54.7% of the participating unit capital issued by the limited partner in the Partnership.

2.2 Tamar project

The Tamar oil asset, consisting of the Tamar and Tamar SW (South West) natural gas fields, is an offshore oil asset located 90 kilometers west of Haifa covering 250 square kilometers. The Tamar and Tamar SW gas fields were discovered in 2009 and 2013, respectively. The reservoir is a high-quality reservoir by global standards with high levels of porosity and permeability as well as high connectivity between the parts of the reservoir, containing dry gas consisting of 99% methane. On March 31, 2013, the supply of natural gas to consumers commenced, with a production capacity of 1.1 BCF per day.

Below are estimated quantities of gas and condensate in the Tamar reservoir as at the end of 2020, as published in the Partnership's reserves report dated March 17, 2021:

Category of the Reserve	Total (100% of the Oil Asset						Total (Tamar and Tamar SW) Attributable to the Company's Equity Holders (Net)	
	Tamar Reservoir		Tamar SW Reservoir		Total (Tamar + Tamar SW Reservoirs)			
	Natural Gas BCF	Condensate Million Barrels	Natural Gas BCF	Condensate Million Barrels	Natural Gas BCF	Condensate Million Barrels	Natural Gas BCF	Condensate Million Barrels
P1 Proved Reserves	6,929.8	9.0	796.4	1.0	7,726.2	10.0	1,318.7	1.7
Probable Reserves	2,595.9	3.4	159.1	0.2	2,755.0	3.6	470.2	0.6
Total P2 Proved + Probable Reserves	9,525.7	12.4	955.6	1.2	10,481.2	13.6	1,788.9	2.3
Possible Reserves	2,366.0	3.1	102.2	0.1	2,468.3	3.2	421.3	0.5
Total P3 Proved + Probable + Possible Reserves	11,891.7	15.5	1,057.8	1.4	12,949.5	16.8	2,210.2	2.9

According to information received from the Group, in 2020, 8.25 BCM were produced from the Tamar reservoir and sold to customers.

Below is the structure of holdings in the Tamar project as at the date of the Report:

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

3. Description of the Business Environment

3.1 General

The natural gas sector in Israel began to develop with the discovery of the Noa and Mary B natural gas reservoirs in 1999-2000. These discoveries enabled Israeli companies, especially the Israel Electric Company ("IEC" or "the Electric Company") to shift to more extensive use of natural gas and to reduce the use of polluting and costlier fuels, such as coal, diesel fuel and fuel oil. The development of the sector accelerated with the discovery of the Tamar and Leviathan reservoirs in 2009 and 2010, respectively. These discoveries have a significant impact on Israel's energy independence and on the development and expansion of natural gas uses in the market in Israel.

Due to such development, there have been significant changes in the natural gas sector in Israel (including regulatory, economic and, environmental changes). Within a few years, natural gas in the Israeli market has become the main component in fuel for electricity production and a material source of energy for industry. The natural gas reserves that were discovered in Israel are capable of supplying all the gas requirements of the domestic market for the next few decades, and most of its energy requirements, thereby significantly reducing Israel's dependence on foreign energy sources.

The economic viability of investments in exploration and development of natural gas reservoirs is heavily dependent by global oil and gas prices, the demand for natural gas in local, regional, and international markets and on the export potential of natural gas requires, inter alia, significant gas reserves and a long-term agreements for the sale of significant volumes of natural gas , which would justify the high costs involved in establishing such infrastructure.

The use of natural gas has many benefits for the Israeli economy, including:

- **Energy cost savings in industry and electricity production** - The low price of natural gas as compared with alternative fuels that are widely used today, such as fuel oil and diesel fuel, leads to significant savings in production costs and consequently also to a decrease in the prices of final products whose main production costs are electricity. Most of the power plants constructed in recent years in Israel operate using natural gas driven turbines, with low construction costs[1], shorter construction time, reduced need for land[2] and many operational benefits. In addition to the relatively low price, natural gas is a more efficient energy source than other fuels, and it allows power plants and factories to achieve a high level of energy efficiency which is also ultimately reflected in cost savings[3]. According to estimates by the Natural Gas Authority[4] the total savings in the Israeli market in 2004-2019 due to the switch to using natural gas are estimated at NIS 71.3 billion. Most of the savings are from the electricity sector (NIS 55.7 billion), where total consumption in 2019 amounted to BCM 8.8, constituting 78% of the natural gas demand. The remaining savings from a shift to natural gas use is mainly attributed to

[1] Half of the cost of a coal-fired station, a third of the cost of a nuclear power station and 15% of a station powered by wind energy.

[2] Natural gas is transported via an underground pipeline and unlike other fuels, does not require storage space

[3] A combined-cycle power station that combines a gas turbine and a steam turbine is a more efficient and uses 55% of the energy. Cogeneration stations that use the thermal energy generated in the production process achieve an efficiency level of 80%.

[4] https://www.gov.il/BlobFolder/reports/ng_2019/he/ng_2019.pdf

industrial plants (NIS 15.6 billion), whose overall consumption in 2019 amounted to 2.4 BCM.

- **Clean energy** - The main substances emitted from the combustion of natural gas are carbon dioxide and steam. Since coal and oil are complex fuels, with a higher proportion of carbon and nitrogen- and sulfur-containing compounds, their combustion releases many more pollutants, including ash particles of substances that do not burn, but are found in the atmosphere and add to air pollution. By contrast, natural gas combustion releases a relatively low amount of pollutants, reducing air pollution and maintaining a cleaner, healthier environment.

- **Energy independence** - The geopolitical characteristics of Israel make it an energy island that for many years was unable to import fuels from neighboring countries, forcing it to rely on expensive fuel imports from Europe. Israel's energy isolation weakened slightly in 2008-2012 with the start of natural gas supplied from Egypt, but the sudden cut-off of supply demonstrated the importance of developing local energy sources. The development of Israel's natural gas sector will provide Israeli industry with long-term energy security, which will reduce its dependence on international energy sources.

- **Natural gas as a source of government revenue through taxation** - The Israeli natural gas sector is also expected to directly benefit the local economy through government revenue from corporate taxation and VAT from selling to the final consumer. Moreover, the Israeli economy has some unique taxation systems that apply to the natural gas market, and like all other fuel products, natural gas is also subject to excise taxes. In addition, under the Petroleum Law, the state collects royalties at a rate of 12.5% from total natural gas sales at the wellhead. Furthermore, due to the conclusions of the Sheshinski Committee, the state is entitled to an oil and gas profit levy pursuant to the Taxation of Profits from Natural Resources Law, 2011 ("the Levy" and "the Taxation of Profits from Natural Resources Law", respectively) at a rate of 20%-50% (depending on the corporate tax rate) on revenues of the holders of the oil rights less royalties, operating costs and development costs.

3.2 Customers

The natural gas market in Israel is made up of several categories of consumers that differ from one another according to the nature of their operations and the characteristics of their natural gas consumption:

- **Israel Electric Corporation (IEC)** - IEC is a highly important anchor customer for the Tamar project partners. IEC is a government company overseen by the Electricity Authority, among other things, with regard to the costs of electricity production outputs, particularly natural gas costs. In 2018, IEC purchased 4.66 BCM, in 2019, 4.2 BCM and in 2020, 2.56 BCM natural gas from the Tamar Partnership. The rate of electricity generated by IEC using natural gas and liquefied gas was estimated in 2018 and 2019 at 56.5% and 53.1%, respectively[5]. In this context, it is noted that the Ministry of Energy recently decided to terminate the agreement with gasification vessel used by IEC for receiving and re-gasification of imported LNG, by the end of 2022.

- **Independent power producers ("IPPs")** - are divided into several types, according to production technology used: conventional IPPs, cogeneration facilities, pumped storage,

[5] Source: IEC's financial statements for 2019.

renewable energy IPPs, and large plants that have set up their own power plants and for which they receive a self-production license. Section 93 of the Natural Gas Sector Law provides that natural gas sold to an IPP is a controlled product under the Control of Prices of Goods and Services, 1996. In 2019, the consumption of IPPs amounted to 3.6 BCM[6], which constitutes 32% of the natural gas consumption in 2019[7].

- **Major industrial consumers** - This category of consumers includes of a number of significant consumers, which are essential for the development of the Israeli gas sector. These are consumers with significant power and reputation in the Israeli economy, and that have extensive experience and knowledge regarding the activities of Israeli industry in general and of the natural gas economy in Israel in particular. Most of the major industrial plants in the country have signed agreements to purchase natural gas, as part of the construction of independent power plants in their yards, to provide their own power needs, which is only part of the production capacity of such power plant, and to sell the surplus power produced to external consumers. Accordingly, the natural gas purchase agreements signed by most of the major industrial consumers to date are also characteristic of the agreements with IPPs. Total natural gas consumption in the industry sector in 2019 amounted to 2.4 BCM, an increase of 20% compared to 2018. Most of the increase is due to new consumers that were connected to the distribution network[8].

- **Medium and small consumers** - The chain consumer sector, which is mainly made up of small and medium-sized enterprises and businesses such as laundries and bakeries, is a relatively new sector in the natural gas market that began to sign purchase agreements and agreements for converting infrastructures in recent years. These consumers consume low-pressure gas of relatively small and non-continuous volume throughout the day, some of which are not yet connected to underground pipeline or distribution systems, and therefore they consume condensed natural gas (CNG) - a temporary and not optimal solution, as the cost of such consumption can be double the cost of natural gas pumped via the distribution pipeline.

3.3 Regulatory environment

The production and sale of natural gas from reservoirs in reservoirs in the exclusive economic zone of Israel are subject to regulatory restrictions on the quantity of gas produced, on exports of gas out of Israel and on gas prices. In addition, the production and sale of natural gas from the Tamar, Leviathan, Karish and Tanin reservoirs and/or another reservoir are subject to further regulatory restrictions as follows:

- **Royalties to the State of Israel** - Pursuant to the Petroleum Law, a leaseholder is required to pay a royalty of 12.5% of the quantity of natural gas or oil produced in the lease, and should pay the state the market value of the royalty at wellhead. In 2019 and 2020, the Tamar project partners paid advances on account of 11.3% royalties on the Tamar project's revenues and in 2017 and 2018 at a rate of 11.65%. In February 2020, the Natural Administration at the Ministry of Energy issued draft guidelines for public comment on the method of calculating the value of the royalty value at the wellhead for offshore oil rights, and in June 2020, it issued the final version of these guidelines. In

6 It is noted that the classification of the customers in the Company's periodic report is different to that in the Ministry of Energy's report. Industrial customers that consume natural gas for electricity generation are classified by the Company as IPPs, whereas in the Ministry of Energy's report, as industrial customers.

7 Source: Review of the developments in the natural gas market. Link: https://www.gov.il/BlobFolder/reports/ng_2019/he/ng_2019.pdf.

8 See footnotes 5 and 6 above.

addition, In September 2020, the Natural Administration at the Ministry of Energy published specific provisions on the method of calculating the value of the royalty at the wellhead in the Tamar project, setting out the rate of recognized expenses to be deducted in the calculation of the value of the royalties at wellhead from the Tamar reservoir.

- **Taxation of Profits from Natural Resources Law** - The Taxation of Profits from Natural Resources Law set out the levy on oil and gas profits based on an R-factor mechanism, which is calculated according to the ratio between the net cumulative revenues from the project and the cumulative investments as defined in the law (“the Levy Coefficient”). A maximum Levy, at a rate of 20%, will be collected when the Levy Coefficient reaches 1.5 and will increase gradually up to 50% (the maximum rate varies for each tax years based on changes in the corporate tax rate) when the Levy Coefficient reaches 2.3.

  The law includes transitional provisions for reservoirs that commenced commercial production up to January 1, 2014 stipulating, among other things, that the Levy Coefficient will between 2 to 2.8 instead of 1.5 to 2.3. The Tamar reservoir falls within the scope of the transitional provisions.

  It is noted that from the last quarter of 2020, the Tamar reservoir partners started paying the Levy.

- **Antitrust and exemption from the provisions of the Antitrust Law** - In August 2015, the government adopted a resolution regarding the framework for regulation of the natural gas market in Israel, including in respect of the Partnership’s rights in the Tamar, Leviathan, Karish, and Tanin natural gas reservoirs, which came into effect on December 17, 2015, with an exemption from a number of provisions of the Antitrust Law, 1988 ("the Gas Framework").

  The Gas Framework grants exemption to Delek Drilling, Noble and Ratio Oil Exploration (1992) - Limited Partnership (jointly: “the Parties”) from the restrictive arrangement in connection with the Leviathan reservoir. It also grants exemption with respect to certain powers of the Commissioner (authority to regulate actions of a monopoly through provisions, authority to order monopoly owners regarding the sale of an asset, and the authority to order separation of a monopoly) in connection with Delek Drilling and Noble as monopolies by virtue of the Commissioner’s declaration in 2012 ("the Exemption")[9]. Granting of the foregoing Exemption is contingent on fulfillment of the following conditions:

  - Sale of the rights of Delek Drilling and Noble in the Karish and Tanin reservoirs to a third party that is not affiliated with the Parties or any of them, within 14 months of the date of granting the Exemption or the date of publication of the new draft regulations by the Commissioner of Petroleum Affairs concerning the qualifying conditions for the operator, whichever is later. On August 16, 2016, an agreement was signed between Delek Drilling and Energean for the sale of all rights in the Karish and Tanin leases.

[9] Declaration of monopolies pursuant to Section 26(A) of the Antitrust Law, 1988: Delek Drilling Limited Partnership together with Avner Oil and Gas Exploration Limited Partnership, Noble Energy Mediterranean Ltd, Isramco Negev 2 Limited Partnership and Dor Gas Exploration Limited Partnership as monopolies in the supply of natural gas in Israel since the second half of 2013 (November 13, 2012) Antitrust 500249.

- Sale of all rights of Delek Drilling in the Tamar reservoir to a third party that is not affiliated with any of the rights holders in the Leviathan, Karish and Tanin reservoirs and restriction of Noble's rights in the Tamar reservoir to maximum of 25%, within 72 months.

  In January 2018, Noble sold 7.5% of its rights in the Tamar and Dalit leases to the Company for a cash consideration and shares. In October 2018, Noble sold all its shares in the Company, and as of this date, its stake in the Tamar reservoir decreased to 25% (directly and indirectly).

- Imposition of a restrictions on new agreements signed for the gas supply from the Tamar and Leviathan reservoirs, such as a prohibition against restrictions on purchasing from other suppliers, in certain cases granting of the right to consumers to unilaterally determine the agreement period and granting of a unilateral possibility to consumers to change the supply quantity in an agreement. Some of these restrictions are limited to a period of four years from approval of the transfer of rights in Karish and Tanin.

- **Stable regulatory environment** - In the original Gas Framework, the Israeli government undertook to maintain "regulatory stability" with respect to natural gas exploration and production for a period of 10 years. Following a petition filed with the High Court of Justice against the foregoing stability clause, in March 2016 the High Court ruled that the issue of regulatory stability in the Gas Framework in the present wording is illegal. In May 2016, the government readopted its decision on the Gas Framework, providing an alternative arrangement for a "stable regulatory environment", to ensure a regulatory environment that encourages investments in the natural gas exploration and production segment.

- **Price control** - In the period from entry into force of the Gas Framework to the date of full compliance with the Exemption conditions, price controls in the natural gas sector pursuant to the Antitrust Law will be limited to imposition of reporting requirements on profits and the gas price, provided that during this period, the holders of rights in Tamar and Leviathan offer potential consumers a price based on the weighted average price of the prices in the existing agreement in respect of reservoirs or on prices in the export agreements, in several the price and linkage alternatives published within Government Resolution 476 from August 16, 2015. As of the third quarter of 2016, once every quarter the Natural Gas Authority publishes the weighted natural gas price and the price of natural gas for independent power producers.

3.4 Risk factors

Exploration and development of oil and natural gas reservoirs involve substantial costs under uncertain conditions and as a result, the financial risk level is extremely high. Below is a breakdown of the risk factors with a material impact on the operations of companies in the sector:

- **Changes in the electricity production tariff, price indices, prices of alternative energy sources** - The prices paid by consumers for natural gas derive, inter alia, from the electricity production tariff, the US consumer price index and the prices fuel alternatives to gas, such as fuel oil, diesel fuel and Brent oil. Furthermore, significant developments in alternative energy sources may lead to a change in the IEC's usage model such that preference will be given to power stations operated by means of alternative energy alternatives to gas.

- **Geopolitical risk** - The security and economic situation in Israel and the political situation in the Middle East could affect the willingness of countries and foreign entities, including in the Middle East, to engage in business with Israeli organizations and/or with international organizations operating in Israel. Consequently, any deterioration in the geopolitical situation in the Middle East and/or in the relationship between Israel and its neighbors for security and/or political and/or economic reasons, may impair the ability of companies operating in the gas and oil sector in Israel to promote their businesses with such countries and entities, and to export gas to neighboring countries.

- **Competition in the supply of gas** - In recent years, several significant gas reservoirs have been discovered in the exclusive economic zone of Israel in volumes that substantially exceed previous estimates in respect of the needs of the local economy. Currently in addition to the producing Tamar and Leviathan reservoirs, there are two other reservoirs under development in Israel: The Karish and Tanin reservoirs, which are expected to be additional significant suppliers of natural gas to the local economy. In addition, Israel held several tenders for additional offshore exploration blocks that might lead to further discoveries (and even granting of licenses later on). In addition, in 2015 a substantial natural gas reservoir was discovered in Egypt ("Zohar"), and in 2018 a natural gas reservoir was discovered in Block 6 in Cyprus. These reservoirs may have a negative impact on the ability to export natural gas from Israel. Additional discoveries may be made in the future, both Israel and in other countries in the eastern Mediterranean basin, the development of which could lead to entry of additional competitors and increased competition in the supply pf natural gas to the domestic market and to neighboring countries.

- **Export restrictions** - Restrictions on the quantity of gas that may be exported could increase excess supply in the domestic market, reducing local gas prices. In this context, it should be noted that based on the recommendations of the Adiri Committee from December 2018, the gas export quotas set in Government Decision 442 will remain unchanged. Nonetheless, based on the Committee's recommendations, the formula for calculating the export quota will be changed so that it will be greater compared to the formula set in Government Decision 442, with respect to gas reserves that have not yet been discovered.

- **Dependence on the integrity of the national pipeline in Israel, Egypt and Jordan** - The ability to supply the gas that will be produced from the reservoirs to potential consumers depends, among other things, on the integrity of the national gas supply pipeline and regional distribution networks. Furthermore, the supply capacity depends on the integrity of the pipeline systems to Egypt and to Jordan, as well as the internal pipelines in these countries.

- **Dependence on contractors and suppliers of professional equipment and services** - As at the date of this Report, there are no contractors in Israel who can carry out most of the operations required for the construction and operation of natural gas and oil reservoirs, and therefore the companies operating in the sector are dependent on contractors from abroad for performance of such work. Consequently, these operations could involve high costs and/or significant delays in schedules set for carrying out such work and for supplying the gas to the customers..

- **Operational risks and insufficient insurance coverage** - Oil and gas exploration and production are exposed to various risk, such as uncontrolled gushing of liquids and gas from well, explosion, collapse of wells and other events that could harm the functioning of the production and transmission systems, each of which could result in damage to or destruction of the oil or gas wells, the production and transmission facilities, exploration equipment, etc. Furthermore, there is risk of liability for pollution damage due to gushing and/or leaking of oil and/or gas. Notwithstanding the insurance policies available in the market, not all possible risks are covered or coverable.

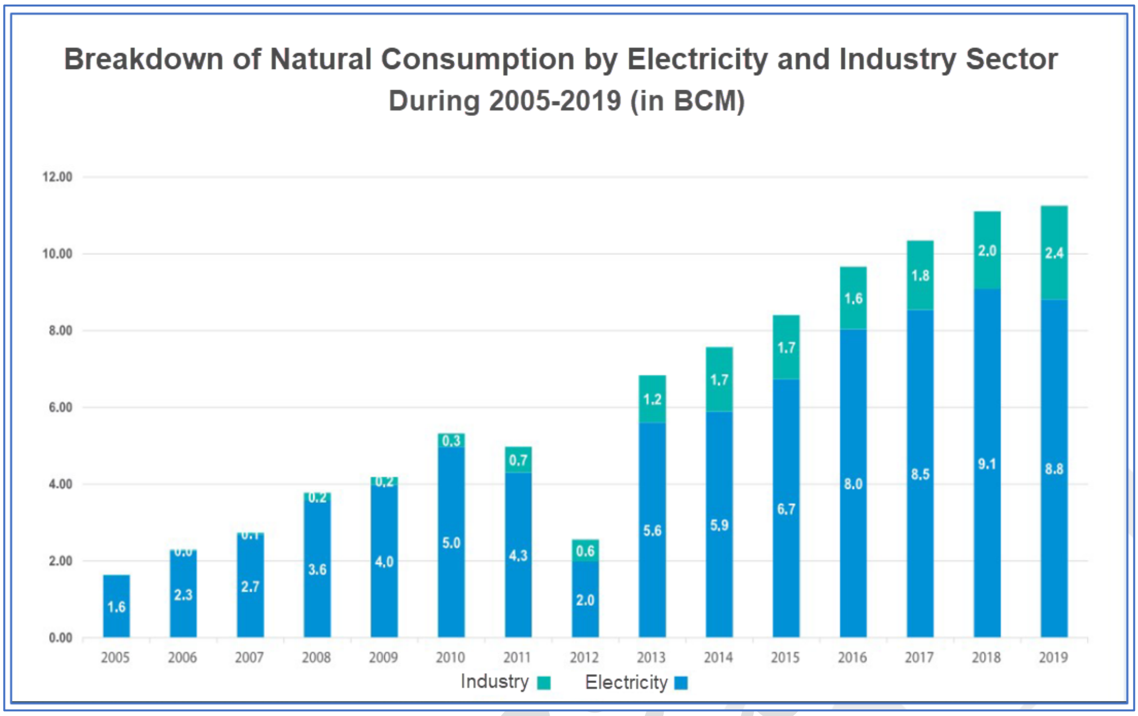
- **Regulatory changes** - The Partnership's operations in Israel require multiple regulatory permits, primarily from competent authorities pursuant to the Petroleum Law and the Natural Gas Sector Law, as well as permits from state institutions (including the Ministry of Defense, Ministry of the Environment, Tax Authority and planning authorities). In recent years, a number of proposals have been made to amend the relevant laws and/or regulations and/or guidelines applicable for these operations and a number of decisions, laws and guidelines have been published which if implemented could have a negative impact on the companies operating in the sector.

- **Subordination to environmental regulation** - Companies operating in the natural gas sector are subject to various laws, regulations and guidelines relating to environmental protection, which refer to diverse issues such as: oil or natural gas spilling into the marine environment, discharge of pollutants and various of types wastes (sewage, residue from drilling equipment, sludge, cement, etc.) and chemical substances used in the various stages of the work into the sea, emission of air pollutants, lighting and noise hazards, and construction of pipeline infrastructure on the seabed and related facilities. Furthermore, these companies are required, through the Project Operator, to obtain approvals from agencies authorized under the Petroleum Law, the Natural Gas Industry Law and other laws (such as environmental protection laws) for the purpose of their operations.

- **Other risk factors** - There are other risk factors that affect the operating segment, including difficulties in obtaining financing, information security risks, dependence on key customers, dependence on weather and sea conditions, revocation or expiration of rights and oil assets, etc.

3.5 Demand

Chart 1 - Natural Gas Consumption in Israel in 2005-2019[10]:



Natural gas consumption in the Israeli market in 2019 amounted to 11.25 BCM, 93% of which was supplied from the Tamar reservoir and the remainder from import of liquefied natural gas via the buoy[11]. According to the assessment of a professional advisor of the Partnership, the natural gas consumption in the Israeli economy in 2020 amounted to 12 BCM, of which 7.7 BCM was supplied by the Tamar reservoir, 3.5 BCM by the Leviathan reservoir and the remainder from the buoy.

Breakdown of the main factors that are expected to drive growth in the demand for natural gas:

3.5.1 The electricity economy

Recent years have seen a downtrend in the use of oil distillates and coal in the generation of electricity and conversion to using natural gas and renewable energies. This trend is being led by the Ministry of Energy and government resolutions setting targets to reduce the use of polluting fuels, among other things, by shutting down of IEC power stations and converting them to generation by natural gas. Below is a breakdown of government resolutions adopted on the subject in recent years:

- In August 2016, the Minister of Energy announced his decision to shut down four IEC coal-fired production units with the connection of three gas reservoirs to the shore, and construction of new natural gas-powered power stations within six years. Furthermore, in September 2016 the IEC received emission permits under the Clean Air Law, 2008 with regard to its coal-fired power plants, which set out, inter alia, the obligation to continue

[10] Source: Ministry of Energy http://online.fliphtml5.com/dldee/idah/
[11] Natural Gas Authority at the Ministry of Energy http://fs.knesset.gov.il/23/Committees/23_cs_bg_582204.pdf

installation of emissions reduction means and cessation of operation of units 1-4 at the coal-fired Orot Rabin power plant, no later than by June 1, 2022.

- In November 2017, the Minister of Energy decided on policy principles for minimal operation of coal-fired generation units, according to which priority will be given at all times for power generation using natural gas over coal, while the coal generation units will operate at the minimum load that allows for flexibility and reliability of supply to the market.

- In March 2018, the Knesset Finance Committee and subsequently the Knesset plenum approved orders providing, inter alia, that as of March 15, 2019, the excise tax on coal would increase by 125%, in view of the government's policy to gross up external costs of fuels and to encourage expansion of the use of natural gas. It was further decided that as of January 1, 2024, the excise tax on compressed natural gas (CNG) will gradually increase, subject to the existence of no less than 25 CNG filling stations that will receive all the required approvals for operating. It was also determined that as of May 1, 2018, the excise tax on diesel fuel, which is used mainly for transportation purposes, will gradually be abolished. On February 20, 2019, the Minister of Finance signed an order deferring the expected increase in excise tax on coal from March 2019 to January 2021.

- In October 2018, the Minister of Energy presented a plan aimed at bringing about a reduction in the use of polluting energy, the principal purpose being to cut down the use of polluting fuel products by 2030. Under the plan, targets were set in the following sectors:

  A. Electricity - 80% of power generation using natural gas and 20% by renewable energies as of 2030, with the coal-fired plants in Hadera and Ashkelon being finally shut down in 2028.

  B. Industry - Generation of 95% of the energy and steam required for industry using natural gas starting from 2030.

  C. Transportation - A gradual transition to electric cars and natural gas driven trucks, and with a total ban on the import of vehicles that run on polluting fuels as of 2030.

- In November 2019, the Minister of Energy announced that it would be possible to shorten the schedules for converting coal-fired power stations in Hadera and Ashkelon to natural gas by 2025. Consequently, the era of using coal in the State of Israel is expected to end in that year. This decision shortens the previous schedules by four years.

- On June 8, 2020, a joint announcement was issued to the Ministry of Energy and the Ministry of Environmental Protection[12], concerning the decision by the ministers to order the IEC to extend its planned shutdowns of the polluting coal-fired units 1-4 at the Orot Rabin site in Hadera, from the second half of 2020 until their complete shutdown in 2022, thus bringing about a further significant reduction in pollutant emissions into the air.

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[12] Ministry of Energy website, notice of the spokesperson's office dated June 8, 2020 https://www.gov.il/he/departments/news/press_080620

- On June 24, 2020, the Minister of Energy[13] announced his decision to reduce the use of coal in the IEC's power plants by a further 20% compared to 2019. Therefore, the use of coal in 2020 will not exceed 24.9% (compared to 30% in 2019).

- According to the Electricity Authority's current forecast indicated in its annual report for 2019[14], as published at the end of June 2020, electricity generation from natural gas is expected to increase significantly to 83% in 2025.

- On October 25, 2020, the government adopted a resolution on promoting renewable energy in the Israeli economy, a resolution based partly on the principles of the policy established by the Minister of Energy in July 2020 according to which electricity generation from renewable energy in 2030 will be 30% of the total electricity consumption, and electricity generation from natural gas will be 70% of the total electricity consumption. An update to the interim target was also set, so as to be 20% of the electricity generation from renewable energy by the end of 2025. Implementation of this policy may affect the demand for natural gas on the local market.

- On February 8, 2021, an announcement was made that the Minister of Energy instructed IEC to reduce the use of coal to 22.5% in 2021, as part of the policy to end the coal era in Israel by 2025[15].

3.5.2 Switch to the use of natural gas in industry

- Natural gas is a key component in industrial energy consumption (37.5% of the total use of fuels in industry in Israel in 2019[16]). The plants are linked to the natural gas via transmission and distribution pipelines and the transmission and distribution costs are monitored by the Natural Gas Authority.

- According to the report summarizing the activity of the Natural Gas Authority at the Ministry of Energy for 2019, to date 508 kilometers of distribution network has been installed nationwide (of which 158 kilometers in 2019) and 737 kilometers of transmission pipelines (of which 37 kilometers in 2019). Expansion of deployment of the natural gas distribution network may enable hundreds of potential industrial consumers to be connected to the network by 2030, whose consumption is expected to amount to 0.72 BCM per year, accounting for 80% of the potential light industrial consumption.

- According to Ministry of Energy assessments, without further policy measures, 150 consumers are expected to join the distribution grid by 2025, with a total consumption of 0.45 BCM, constituting half of potential connection of light industrial consumers. Additional potential consumption of 0.27 BCM deriving from connection of another 300 smaller plants, is expected to materialize following implementation of further policy measures (such as budgetary support for the deployment of the distribution network, encouragement of consumers to use natural gas, etc.).

- According to the Electricity Authority's forecast from 2018, in 2030 the total natural gas demand in the industrial sector is expected to exceed 3 BCM, of which 2.25 BCM from the natural gas consumption of customers connected to the distribution network and 0.84

[13] Ministry of Energy website, notice of the spokesperson's office dated June 24, 2020 https://www.gov.il/he/departments/news/press_240620

[14] https://www.gov.il/he/departments/general/dochmeshek

[15] https://www.calcalist.co.il/local/articles/0,7340,L-3892470,00.html

[16] Source: Review of the Energy Economy in Israel - Ministry of Energy https://www.gov.il/BlobFolder/reports/energy_sector_2019/he/energy_sector_review_2019.pdf

BCM from natural gas consumption to consumers connected to the distribution network[17].

- On July 10, 2020, the Ministry of Energy published a memorandum of law to amend the Natural Gas Sector Law, as part of which the Minister of Energy may grant a license to set up a specific distribution network to Israel Natural Gas Lines Ltd. (“INGL”) if he sees an urgent need thereof, and there is no party from the private sector that seeks and is able to establish the network. The purpose of this memorandum of law is to enable connection of industrial plants to the natural gas infrastructure to accelerate.

3.5.3 Export

Recently, there has a perceptible improvement in relations with several neighboring countries with whom business ties are strategic for the State of Israel in general, and for gas companies in particular. These improved relations have led to the signing of agreements for the export natural gas from Israel to its neighbors, as set out below:

- The Tamar partners signed agreements with NBL Eastern Mediterranean Marketing Limited ("NBL") for the export of natural gas to consumers in Jordan. In parallel, NBL signed an agreement with two Jordanian companies, Arab Potash Company and Jordan Bromine Company, whereby they would purchase natural gas from NBL to be used in their plants on the eastern bank of the Dead Sea in Jordan. These agreements are for 15-year periods and the total volume of natural gas in these agreements is 3 BCM.

- On September 26, 2016, an agreement was signed between Leviathan partners and the Jordanian electricity company (NEPCO) for the supply of up to 45 BCM natural gas for a period of 15 years. According to Delek Drilling's public report of December 31, 2019, natural gas started to be supplied from the Leviathan reservoir to customers with whom gas agreements were signed, including to the Jordanian electricity company.

- On February 19, 2018, Delek Drilling and Noble signed an agreement with the Egyptian company Dolphinus, which were assigned to the Tamar partners and Leviathan partners on September 26, 2018. On September 26, 2019, revised agreements were signed for the export of natural gas from the Tamar and Leviathan reservoirs in quantities of BCM 25.3 and BCM 60, respectively, for a period of 15 years. Further to the Leviathan Partnership’s report at the end of December 2019 concerning commencement of transmission of natural gas from the Leviathan Reservoir to various customers, on January 15, 2020, the Leviathan partners reported the start of natural gas transmission to Egypt. According to Tamar partners’ reports, in July 2020 the transmission of natural gas from the Tamar reservoir under export agreements to Egypt commenced.

- On November 6, 2019, a transaction was finalized for the purchase of 39% of EMG, the owner of the offshore gas transmission pipeline between Israel and Egypt, to EMED (a company held by Delek Drilling (25%), Noble Energy (25%) and East Gas (50%)) under which the capacity and operation rights in connection with the EMG pipeline were transferred to the buyer (EMED) in order to perform the foregoing agreements with Dolphinus.

- On March 26, 2020, the Natural Gas Authority Council issued an addendum to its decision of September 7, 2014, with regard to the financing of export projects through the national pipeline and division of the construction costs of the Ashdod-Ashkelon

[17] https://www.gov.il/BlobFolder/reports/periodic_examination/he/pua_2018_2042.pdf

combined section. According to the addendum to the decision, among other things, the offshore section of the pipeline to be constructed in the future, will be financed by the transmission license holder (43.5%) and the exporter (56.5%) according to milestones set out in the transmission agreement. The exporter's share of the foregoing cost will be paid by the Leviathan partners and Tamar partners, based on the future streaming rates from each of the reservoirs via the foregoing infrastructure and in compliance with the conditions set out in the agreement signed in this regard.

- On February 15, 2021, the partners of the Tamar and Leviathan reservoirs announced that preconditions in the transmission agreement for exporting gas to Egypt have been fulfilled in a manner that enables supply on a firm basis and increase the sale quantities to Egypt according to the supply conditions in the gas sale agreements of the different Partnerships.

3.5.4 Consequences of the Covid-19 Crisis:

- In the first quarter of 2020, there were sharp fluctuations and extremely sharp declines in the prices of oil and natural gas in international markets. According to market estimates, the volatility can be attributed to the Covid-19 pandemic, as well as to other causes and factors that impact demand and supply of energy products. After the production rate of crude oil was corrected in markets, trading of future crude oil contracts was restored at a price of around USD 60 per barrel (as at March 17, 2021).
- According to Bank of Israel data, from March to June 2020, there was a decrease in electricity consumption of between 5% and 10%, while in July-September there was a certain recovery in electricity consumption that slowed down in October 2020, partly as a result of the two lockdowns imposed on the local economy[18]. However, the total electricity generation in 2020 did not decrease and even rose slightly compared to 2019.
- If the Covid-19 pandemic and the global economic slowdown continue, they are expected to have a further adverse effect on the demand for energy products and their prices.

3.5.5 Demand forecast in the local market

- According to a local market demand forecast by an internal consultant of the Partnership shortly before the Report, local demand for natural gas in 2021 is expected to amount to 13.1 BCM and increase gradually to 17.9 BCM by 2025. The growth in local demand is expected to stem from termination of the use of coal for electricity generation, a natural rise in electricity demand due to population growth and improved standards of living, and completion of the connection of industrial plants and small consumers to the natural gas distribution and transmission network.

3.6 Market developments

- **Tamar and Leviathan leases** - On December 31, 2019, the Leviathan partners reported on the start of natural gas transmission from the Leviathan reservoir to customers under natural gas supply agreements signed with them, including the sale of natural gas to Jordan. Subsequently, on January 15, 2020 it was reported that the transmission of gas from the Leviathan reservoir to Egypt has begun.
- On October 2, 2020, Noble, who has holdings in the Tamar and Leviathan reservoirs and is the operator of these reservoirs, reported that the general meeting of shareholders

[18] https://www.boi.org.il/he/Pages/Indicators.aspx

officially approved the transaction for acquisition of the company by the US company Chevron for a consideration of USD 5 billion. This deal is an expression of trust in the local gas market and the economic potential inherent in these assets.

- On August 30, 2020, some of the Tamar project partners (jointly in this section: "the Sellers") report on the signing of agreements for the supply of natural gas from the Tamar reservoir to the Oil Refineries Ltd (in this section: ("Bazan") and ICL Group Ltd (in this section: ("ICL"). In the Sellers' estimation, cumulative revenues from the sale of natural gas to Bazan are expected to amount to USD 150 million, assuming that Bazan consumes natural gas according to the supply agreement until the end of 2021. The cumulative revenues from natural gas sales to ICL are expected to amount to 60% of the expected revenues under the Bazan agreement. On October 4, 2020, it was reported that the agreements with Bazan and ICL have been signed by all parties, including Delek Drilling.

- On September 23, 2020, Delek Drilling reported that the Partnership in the Leviathan project signed an agreement to supply natural gas to Ramat Hovav Partnership in a total volume of 1.3 BCM for a period of 30 months or the date of commercial operation of the Karish and Tanin reservoirs, whichever is earlier.

- On January 31, 2021, the Partnership in the Tamar project signed a compromise agreement ("Tamar Compromise Agreement") regulating the disputes in respect of an addendum to the gas supply agreement to IEC from 2012 (as revised from time to time ("The Addendum and "the IEC-Tamar Agreement, respectively) signed by IEC, the Company, Isramco Negev 2 Limited Partnership, Dor Gas Exploration Limited Partnership and Everest Infrastructures, Limited Partnership on October 4, 2020. According to the Tamar Compromise Agreement, the addendum will be canceled and replaced by the compromise agreement, according to which until June 30, 2021, IEC may purchase a quantity of 1.25 BCM from the Tamar reservoir, at a lower price than that of the IEC-Tamar Agreement, 0.81 BCM of which was already supplied in 2020, and additional quantities of gas if not supplied by the Leviathan Partnership.

- On February 23, 2021, the Company reported that further to a memorandum of understanding dated January 31, 2021, the Tamar Project Partnership signed a balance agreement for separate sale from the Tamar reservoir aimed at setting detailed rules and mechanisms in connection with participation of each of the Tamar partners in the gas output under the joint operating agreement, as well as balance arrangements that will apply between the partners in the event that the gas is not marketed according to the partners' proportionate share of the output. The agreement includes various arrangements and mechanisms that enable a partner to market, subject to certain conditions.

3.6.1 Karish and Tanin Leases

- On November 27, 2019, Energean, which is developing the Karish and Tanin reservoirs, reported the start of manufacture in China of a floating platform (FPSO) that intended for treatment of natural gas produced in the reservoirs. The natural gas production and treatment process will be carried out at the wellhead, at a distance of 90 kilometers from the shore.

- On March 4, 2019, Energean reported the start of implementation of the drilling plan in Israel, which includes drilling three production wells in the Karish reservoir and an exploratory drill in the Karish North reservoir, which is intended to verify the presence of 1.3 TCF of natural gas, with a 69% chance of success. On February 20, 2020, Energean reported that drilling of the three production wells in the Karish reservoir has been completed.

- On November 4, 2019, Energean reported that the exploratory drill in Karish North was completed. According to the report, 25 BCM of natural gas and 34 million barrels of liquid hydrocarbons (light oil/condensate) have been discovered in the reservoir, at a best estimate. On April 9, 2020, Energean reported on completion of an updated reserves report for the Karish and Tanin reservoirs. According to his report, the total resources in Karish North amount to 33.7 BCM of natural gas and 39.5 million barrels of liquid hydrocarbons.

- On September 16, 2020, Energean report on signing of two natural gas sale agreements on the local market in a cumulative quantity of 1.4 BCM per year and cumulative revenues of USD 2.5 billion. Most of the quantity is attributed to an agreement with Ramat Hovav Partnership (that was declared the winner of an IEC tender for the sale of the Ramat Hovav power station) for a period of up to 20 years. Energean indicated in the report that to date, contracts have been signed for an amount of 7 BCM per year of a production capacity of 8 BCM per year.

- On December 17, 2020, Energean reported that it has signed another agreement with Rapac Energy Ltd for the supply of natural gas in an average annual quantity of 0.4 BCM for a period of between 6 and 15 years, in addition to the existing signed agreements between them.

- On January 14, 2021, Energean reported on an FID in the Karish North reservoir in an amount of USD 150 million. Energean estimates that the project will provide an internal rate of return (IRR) of 40% and that natural gas will be produced from this reservoir for the first time in the second half of 2023.

- On February 11, 2021, Energean published a resources and reserves report as at December 31, 2020, prepared by the consulting firm DeGolyer MacNaughton, according to which the Karish, Karish North and Tanin reservoirs contain natural gas and liquid hydrocarbon reserves (P2) in quantities of 98.4 BCM and 99.6 million barrels, respectively[19].. The resources report also includes forecasts on the production rate of natural gas and liquid hydrocarbons, the volume of capital investments, operating expenses, royalties, taxes and levies for each of the reservoirs. According to the information published by Energean, as at December 31, 2020, 93% of the FPSO construction works, 90% of the shore works, 76% of the subsea works and 100% of the drilling works have been completed. It was also noted that the workforce of TechnipFMC, which is managing the construction of the FSO in Singapore, must be increased to meet the expected date of commencement of production at the end of 2021. However, if the workforce remains at the present level, this is likely to delay the expected date of commencement of production from the Karish reservoir to 2022.

[19] https://www.energean.com/media/4751/energean-israel-2020-cpr.pdf

4. Methodology

4.1 Impairment of Assets

Section 9 of IAS 36: Impairment of Assets ("IAS 36") stipulates that "An entity is required to assess at the end of each reporting period if there is an indication of impairment of an asset. Where there is an indication of impairment, the entity is required to estimate the recoverable amount of the asset."

The purpose of IAS 36 is to establish procedures which the entity is required to apply in order to ensure that its assets are not presented at a higher amount than their recoverable amount (as set out below). When the carrying amount of an asset is higher than its recoverable amount, the asset is impaired and IAS 36 requires the entity to recognize an impairment loss.

4.2 Recoverable Amount

Section 18 of IAS 36 defines the recoverable amount as "the higher of the fair value less costs to sell of an asset of cash-generating unit and its value in use," where:

- **Fair value less cost of disposal** is the price that would be received to sell an asset or paid to transfer a liability in an ordinary transaction between market participants at the measurement date, less costs of disposal (incremental costs directly attributable to the disposal of an asset or cash-generating unit, except for financing costs and income tax expenses).

- **Value in use** of an asset is the present value of the estimated future cash flows expected to be derived from continued use of an asset and from its disposal at the end of its useful life. In determining the value in use of an asset, IAS 36 requires an entity to use, among other things, cash flow forecasts based on reasonable and supportable assumptions that reflect the current condition of the asset and represent the management's best estimate of the range of economic conditions that will exist over its remaining useful life.

  The estimate of future cash flows may not include cash inflows or outflows that are expected to arise from a future restructuring to which the entity is not yet committed (including a reduction in manpower costs), or from improving or enhancing the asset's performance.

  The net present value will be calculated using a pre-tax discount rate reflecting current market assessments of the time value of the money and the risks specific to the asset. The discount rate may not reflect risks for which the future cash flows have already been adjusted. However, Section 85 of the Basis for Conclusions on IAS 36 states that: "In theory, discounting post-tax cash flows at a post-tax discount rate and discounting pre-tax cash flows at a pre-tax discount rate should give the same result, as long as the pre-tax discount rate is the post-tax discount rate adjusted to reflect the specific amount and timing of the future tax cash flows." Accordingly, the cash flows were used in this Report after tax and were discounted at a post-tax discount rate.

  According to Section 19 of IAS 36, it is unnecessary to determine both the fair value less costs to sell of an asset and its value in use. If one of these amounts is higher than the asset's carrying amount, there is no impairment of the asset and no need to estimate the other amount.

4.3 Testing for Impairment Indications

According to Section 12 of IAS 36, to assess whether there is any indication of impairment of an asset, an entity must consider external and internal indicators, such as Significant changes in the business environment in which the entity operates or in the market for which the asset is intended; an increase in market interest rates or rates of return used to discount the expected cash flows from the asset; a negative difference between the market capitalization and net carrying amount of the asset; obsolescence of or physical damage to the asset; plans to discontinue or restructure the activity to which the asset belongs, etc.

In view of Delek Group's need to dispose of its holdings in the Tamar project by the end of 2021, we were requested to assess the recoverable amount of the asset.

5. Estimate of the Recoverable Amount of Oil and Gas Assets

5.1 Cash Flow Forecast

On March 17, 2021, the Partnership reported a discounted cash flow ("the Tamar Project Partnership's Forecast") in its "Report on Reserves and Updated Discounted Cash Flow Figures for the Tamar Lease ("the Tamar Reserves Report")[20]. The main assumptions are as follows:

- Volume of natural gas sales of 8.6, 9.2, 9.1, 9.5 and 10.4 BCM in the years 2021 through 2025, respectively. A gradual increase to 11.65 BCM in 2030 and stabilization of this quantity until 2041. From 2042, a gradual decline in production quantities until exhaustion of the reservoir reserves.
- Average Brent oil price forecast (in USD)[21] of USD 52, USD 57, USD 61, USD 65, USD 68 and USD 71 per barrel in the years 2021 through 2026, respectively. A gradual increase up to a price of USD 86 in 2030 and stabilization at this price until the end of the forecast period.
- We assessed the present value of the cash flows based on a cash flow forecast in the P2 (Proved + Probable Reserves) category published in the reserves report, when the depreciation expenses were adjusted for tax purposes according to the recoverable amount of the asset.

5.2 Discount rate

The weighted average cost of capital (WACC) used in calculating the present value of the cash flows was estimated at 9.3% based on the parameters in the following table:

Parameter	Value	Note
Risk-free interest rate	0.84%	1
Beta	1.31	2
Market premium	5.4%	3
Specific risk premium	8.2%	4
Cost of equity of the Company	**16.1%**	
Cost of debt	6.2%	5
Tax rate	23.0%	6
Leverage ratio	60%	7
Weighted cost of capital (rounded)	**9.3%**	

20 https://mayafiles.tase.co.il/rpdf/1358001-1359000/P1358201-00.pdf

21 Based on the average of forecasted oil prices of third parties supplying a long-term price forecast of the NYMEX ICE Brent Crude price published shortly before the date of the Report, as follows: United States Department of Energy, World Bank, IHS Global Insights and Wood Mackenzie.

Notes to the table:

1. The yield on US government bonds for the cash flow duration (9 years).
2. Based on the unlevered beta of a sample of similar companies, as set out in the following table:

Company	Unlevered beta
Isramco Negev 2 Limited Partnership	0.63
Ratio Oil Exploration 1992 LP	0.91
Tamar Petroleum Ltd.	0.21
Delek Royalties (2012) Ltd.	0.41
Delek Drilling LP	0.87
Average for sample companies	0.61

The levered beta is estimated based on the average beta for the above sample companies, the normative leverage ratio (note 7 below) and the statutory tax rate in Israel.

3. Market risk premium in Israel (Damodaran, April 2021[22]).
4. The specific risk premium includes the following components:
   - Size premium of 0.7% (based on a value of USD 5-6 billion for the Tamar reservoir)[23].
   - Plus a 7.5% risk premium for the intrinsic risk level of the forecasts and the uncertainty regarding the consequences of the Covid-19 crisis, the increasing competition from the start of production from the Leviathan project and progress of development of the Karish reservoir.
5. The debt price is estimated in line with the leverage rate. For this purpose, we estimated the trendline yields to maturity of the marketable debentures of the sample countries (for details, see Appendix A).
6. According to the statutory tax rate in Israel.
7. The average leverage ratio of the sample companies (in the table in note 2 above) as of December 31, 2020 was estimated at 66% and was affected by the decrease in the market capitalization of the companies. We estimated the long-term normative leverage ratio of the Asset at 60%.

5.2.1 Findings

Based on the above methodology and assumptions, the present value of the expected cash flows for Delek Drilling's share in the Tamar Project (22%) was estimated at USD 1,381 million. However, since the Group is required to dispose of its holdings in the Tamar project by the end of 2021 under the Gas Framework, in order to estimate the recoverable amount we adjusted the present value using a 20% discount rate, which we believe reflects the difference between the above present value and the Group's expected net consideration (less disposal

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22 http://pages.stern.nyu.edu/~adamodar
23 Source: Duff & Phelps International Valuation Handbook 2021.

costs) from the sale of the Asset under current market conditions. Accordingly, the recoverable amount of the Asset was estimated at USD 1,104 million.

As an indication to the discount rate, we examined the difference between the market capitalization of the assets of the public companies that hold Tamar assets and the estimated value of their holdings in the Tamar assets, according to the same methodology and assumptions that we used when calculating their present value above,, and based on transactions with similar assets. In this context, we should note that in view of the volume of the transaction and timetables, as set out above, it is possible that the market expects the assets related to the Tamar project will be sold “under duress” and at a significant discount compared to their fair value. Therefore, we believe that the expected transaction has a negative impact on the market capitalization of the securities linked to the Tamar project, in light of excess supply in relation to demand in the capital market.

Below is a sensitivity analysis of the recoverable amount when subjected to a changes in the discount rate and the gas and condensate price curve (in relation to the base scenario):

		Discount Rate (WACC)						
		7.8%	**8.3%**	**8.8%**	**9.3%**	**9.8%**	**10.3%**	**10.8%**
Percentage of change in prices	-15.0%	1,062	1,013	967	924	884	848	813
	-10.0%	1,132	1,079	1,030	984	942	903	866
	-5.0%	1,201	1,145	1,093	1,044	999	958	919
	0.0%	1,271	1,211	1,156	1,104	1,057	1,013	972
	5.0%	1,340	1,277	1,218	1,164	1,114	1,068	1,024
	10.0%	1,409	1,343	1,281	1,224	1,172	1,123	1,077
	15.0%	1,479	1,409	1,344	1,284	1,229	1,177	1,130

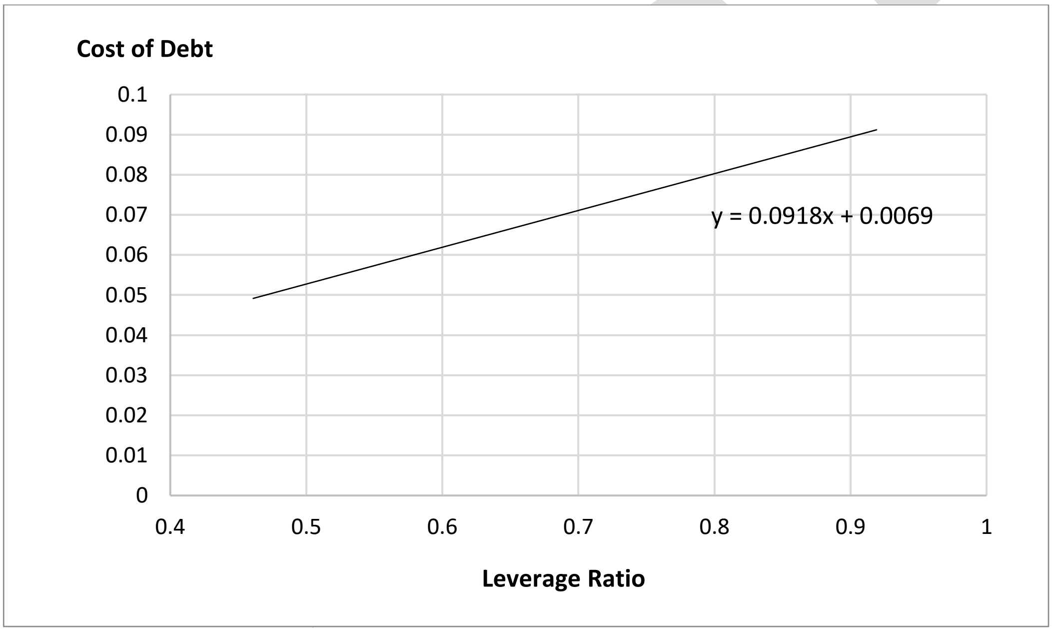
6. Appendices

Appendix A - Normative Debt Price

As stated in Section 5.2 above, the debt price was estimated in line with the normative leverage rate (60%). For this purpose, we estimated the trendline yields to maturity of the marketable debentures of the sample countries as at December 31, 2020, as shown in the following table:

Company	Tamar Petroleum	Tamar Petroleum	Delek Royalties	Delek Drilling	Isramco	Ratio
Leverage	91.9%	91.9%	61.1%	68.0%	46.1%	63.5%
Debentures	Series A	Series B	Series A	Series A	Series A	Series C
Rating	A1	A1	Aa3	A2	AA	
Yield	8.1%	8.1%	6.1%	5.6%	3.8%	7.1%
Duration	4.54	4.76	4.07	0.99	2.38	1.57
Yield adjusted to project duration (9)	8.8%	8.7%	6.8%	6.8%	4.8%	8.2%

The trendline was estimated based on the above yields, as described in the following chart:



Appendix B – Cash Flow Forecast

Year	Total Average	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Quantity of natural gas sales (BCM) (100% of the Asset)	**296.8**	8.60	9.16	9.13	9.49	10.35	10.62	10.91	11.00	11.46	11.65	11.65	11.65	11.65	11.65	11.65	11.65
Quantity of condensate sales (thousands of barrels) (100% of the Asset)	**13,625.7**	395	421	419	436	475	488	501	505	526	535	535	535	535	535	535	535
Post-tax cash flow (USD thousands)	**3,664,148.5**	121,081	136,699	129,251	128,023	88,284	112,021	146,653	150,272	158,588	162,743	162,825	162,115	162,011	161,948	153,495	134,452

Year	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053
Production rate of natural gas (BCM) (100% of the Asset)	11.65	11.65	11.65	11.65	11.65	11.19	9.71	8.38	7.24	6.25	5.39	4.66	4.02	3.47	3.00	2.59	0.38
Quantity of condensate sales (thousands of barrels) (100% of the Asset)	535	535	535	535	535	514	446	385	332	287	247	214	185	159	138	119	17
Post-tax cash flow (USD thousands)	136,932	121,900	148,767	120,301	147,829	141,193	121,484	103,793	88,619	75,249	63,009	52,755	43,693	36,369	16,804	10,140	(35,152)

Chapter C

Financial Statements

Delek Group Ltd.

Consolidated Financial Statements

December 31, 2020

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Consolidated Balance Sheets

	Note	December 31 2020	December 31 2019
		NIS millions	
Current assets			
Cash and cash equivalents	3	402	1,517
Short-term investments	4	559	786
Trade receivables	5	820	1,894
Other receivables	6	191	514
Current tax assets		40	83
Financial derivatives	10F	93	213
Inventory	7	306	477
		2,411	5,484
Assets held for sale	10	3,927	-
		6,338	5,484
Non-current assets			
Long-term loans, deposits, and receivables	8	3,176	3,667
Other financial assets	9	21	675
Investments in associates	10	573	492
Investment property	11	331	432
Right-of-use assets	22	22	910
Financial derivatives	10F	9	182
Investments in exploration and production of oil and gas assets, net	12	19,654	27,687
Fixed assets, net	13	77	2,129
Goodwill	14	2,798	4,174
Other intangible assets, net	14	-	7
Deferred taxes	31E	1,278	1,124
		27,939	41,479
		34,277	46,963

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The accompanying notes and the appendix are an integral part of the consolidated financial statements

Consolidated Balance Sheets

	Note	December 31 2020	December 31 2019
		NIS millions	
Current liabilities			
Borrowings and current maturities from banks and others	15	138	3,008
Debentures including current maturities of debentures	19	6,668	1,998
Trade payables	16	317	1,246
Other payables	17	1,107	1,439
Current maturities of lease liabilities		20	147
Current tax liabilities		75	497
Financial derivatives	10F	264	202
		8,589	8,537
Liabilities attributable to assets held for sale	10	2,230	-
		10,819	8,537
Non-current liabilities			
Loans from banks and others	18	2,247	12,091
Debentures	19	9,248	9,821
Convertible debentures and liabilities	19	-	865
Liabilities for employee benefits	21	-	11
Lease liability	22	3	771
Financial derivatives	10F	76	35
Provisions and other liabilities	23	5,265	5,333
Deferred taxes	31E	1,433	1,922
		18,272	30,849
Capital	26		
Share capital		18	13
Share premium		2,341	1,919
Proceeds for options and conversion option		38	18
Retained earnings		1,532	3,382
Foreign currency translation differences for foreign operations		(933)	(653)
Capital reserve from transactions with non-controlling interests		(677)	(289)
Other reserves		17	(3)
Treasury shares		(314)	(254)
Total equity attributable to shareholders of the Company		2,022	4,133
Non-controlling interests		3,164	3,444
Total capital		5,186	7,577
		34,277	46,963

March 30, 2021			
Date of approval of the financial statements	Gabriel Last Chairman of the Board of Directors	Idan Wallace CEO	Tamir Polikar Executive VP and CFO

The accompanying notes and the appendix are an integral part of the consolidated financial statements

Consolidated Statement of Income

	Note	Year ended December 31 2020	2019*)	2018*)
		NIS millions (Other net earnings (loss) per share)		
Revenue	33B	6,671	3,356	2,598
Cost of revenues	27	3,536	1,901	1,156
Gross profit		3,135	1,455	1,442
General and administrative expenses	28	241	121	119
Group share in profits (losses) of operational associates, net		(15)	(42)	89
Other revenues (expenses), net	29	(2,973)	(865)	49
Operating profit (loss)		(94)	427	1,461
Financing income	30	382	560	553
Financing expenses	30	(2,294)	(1,219)	(1,213)
		(2,006)	(232)	801
Group share in profits of associates, net		5	19	22
Profit (loss) before taxes on income		(2,001)	(213)	823
Tax benefit	31F	(406)	(417)	(57)
Profit (loss) from continuing operations		(1,595)	204	880
Profit (loss) from discontinued operations, net	10	(215)	582	400
Net profit (loss)		(1,810)	786	1,280
Attributable to:				
Shareholders of the Company		(1,874)	234	517
Non-controlling interests		64	552	763
		(1,810)	786	1,280
Net earnings (loss) per share attributable to shareholders of the Company (NIS)	32			
Basic earnings (loss) from continuing operations		(125.0)	(9.7)	42.5
Basic earnings (loss) from discontinued operations		(16.2)	29.8	3.3
Basic earnings (loss)		(141.2)	20.1	45.8
Diluted earnings (loss) from continuing operations		(125.0)	(9.7)	42.0
Diluted earnings (loss) from discontinued operations		(16.2)	29.8	3.3
Diluted earnings (loss)		(141.2)	20.1	45.3

*) Restated, see Note 10J.

The accompanying notes and the appendix are an integral part of the consolidated financial statements

Consolidated Statement of Comprehensive Income

	Year ended December 31		
	2020	**2019*)**	**2018*)**
	NIS millions		
Net profit (loss)	(1,810)	786	1,280
Other comprehensive income (loss) (net of tax effect):			
Amounts not reclassified to profit or loss:			
Loss from investment in equity instruments measured at fair value through other comprehensive income	(101)	(167)	-
Revaluation for transfer from fixed assets to investment property	20	-	24
Total	(81)	(167)	24
Amounts classified or reclassified to profit or loss under specific conditions:			
Profit for financial assets at fair value through other comprehensive income	-	-	1
Profit for cash flow hedges	645	92	158
Transfer to profit or loss for cash flow hedges	(570)	(101)	(67)
Foreign currency translation differences for foreign operations	(594)	(969)	817
Transfer to statement of income for foreign currency translation differences for foreign operations	28	14	18
Other comprehensive income (loss) attributable to associates, net	(2)	(4)	7
Total	(493)	(968)	934
Total other comprehensive income (loss) from continuing operations	(574)	(1,135)	958
Total other comprehensive income (loss) from discontinued operations, net	-	149	(135)
Total other comprehensive income (loss)	(574)	(986)	823
Total comprehensive income (loss)	(2,384)	(200)	2,103
Attributable to:			
Shareholders of the Company	(2,155)	(501)	1,129
Non-controlling interests	(229)	301	974
	(2,384)	(200)	2,103

*) Restated, see Note 10J.

The accompanying notes and the appendix are an integral part of the consolidated financial statements

Consolidated Statement of Changes in Equity

	Attributable to shareholders of the Company										
	Share capital	Share premium	Proceeds for options and conversion options	Retained earnings	Foreign currency translation differences for foreign operations	Reserve for transactions with holders of non-controlling interests	Other reserves *)	Treasury shares	Total	Non-controlling interests	Total capital
	NIS millions										
Balance as at December 31, 2019	13	1,919	18	3,382	(653)	(289)	(3)	(254)	4,133	3,444	7,577
Net profit (loss)	-	-	-	(1,874)	-	-	-	-	(1,874)	64	(1,810)
Other comprehensive income (loss)	-	-	-	-	(310)	-	29	-	(281)	(293)	(574)
Total comprehensive income (loss)	-	-	-	(1,874)	(310)	-	29	-	(2,155)	(229) *)	(2,384)
Issue of shares and options, net	4	301	42	-	-	-	-	-	347	-	347
Exercise of options for shares	1	114	(15)	-	-	-	-	-	100	-	100
Expired options	-	7	(7)	-	-	-	-	-	-	-	-
Disposal of revaluation fund due to disposal of an asset	-	-	-	24	-	-	(24)	-	-	-	-
Acquisition of treasury shares	-	-	-	-	-	-	-	(60)	(60)	-	(60)
Acquisition of shares from non-controlling interests	-	-	-	-	-	(7)	-	-	(7)	(5)	(12)
Deconsolidation	-	-	-	-	-	-	-	-	-	(221)	(221)
Sale of shares to non-controlling interests	-	-	-	-	30	(381)	15	-	(336)	407	71
Dividend to non-controlling interests	-	-	-	-	-	-	-	-	-	(232)	(232)
Balance as at December 31, 2020	18	2,341	38	1,532	(933)	(677)	17	(314)	2,022	3,164	5,186

*) Composition of comprehensive loss of non-controlling interests:

Net profit attributable to non-controlling interests	64
Loss for financial assets at fair value through other comprehensive income, net	(41)
Profit from cash flow hedges	6
Foreign currency translation differences for foreign operations	(258)
Total comprehensive loss attributable to non-controlling interests	(229)

The accompanying notes and the appendix are an integral part of the consolidated financial statements

Consolidated Statement of Changes in Equity

	Attributable to shareholders of the Company										
	Share capital	Share premium	Proceeds for conversion options	Retained earnings	Foreign currency translation differences for foreign operations	Reserve for transactions with holders of non-controlling interests	Other reserves *)	Treasury shares	Total	Non-controlling interests	Total capital
	NIS millions										
Balance as at December 31, 2018	13	1,910	27	3,403	(20)	(324)	99	(143)	4,965	7,305	12,270
Cumulative effect of initial adoption of IFRS 16 as at January 1, 2019	-	-	-	(1)	-	-	-	-	(1)	-	(1)
Balance as at January 1, 2019	13	1,910	27	3,402	(20)	(324)	99	(143)	4,964	7,305	12,269
Net profit	-	-	-	234	-	-	-	-	234	552	786
Other comprehensive loss	-	-	-	-	(633)	-	(102)	-	(735)	(251)	(986)
Total comprehensive income (loss)	-	-	-	234	(633)	-	(102)	-	(501)	301 **)	(200)
Acquisition of treasury shares	-	-	-	-	-	-	-	(111)	(111)	-	(111)
Deconsolidation (see Note 10E)	-	-	-	-	-	-	-	-	-	(3,539)	(3,539)
Expiry of conversion option	-	9	(9)	-	-	-	-	-	-	-	-
Transactions with non-controlling interests	-	-	-	-	-	35	-	-	35	-	35
Dividends	-	-	-	(254)	-	-	-	-	(254)	-	(254)
Dividend to non-controlling interests	-	-	-	-	-	-	-	-	-	(623)	(623)
Balance as at December 31, 2019	13	1,919	18	3,382	(653)	(289)	(3)	(254)	4,133	3,444	7,577

*) As at December 31, 2019, includes mainly capital reserve (negative) for financial assets at fair value through other comprehensive income in the amount of NIS 106 million and credit balance for cash flow hedging transactions in the amount of NIS 92 million

**) Composition of comprehensive income of non-controlling interests:

Net profit attributable to non-controlling interests	552
Profit for financial assets at fair value through other comprehensive income, net	71
Loss from cash flow hedges	(8)
Foreign currency translation differences for foreign operations	(314)
Total comprehensive income attributable to non-controlling interests	301

The accompanying notes and the appendix are an integral part of the consolidated financial statements

Consolidated Statement of Changes in Equity

	Attributable to shareholders of the Company										
	Share capital	Share premium	Proceeds for conversion options	Retained earnings	Foreign currency translation differences for foreign operations	Reserve for transactions with holders of non-controlling interests	Other reserves *)	Treasury shares	Total	Non-controlling interests	Total capital
	NIS million										
Balance as at December 31, 2017	13	1,924	27	3,122	(576)	15	199	(469)	4,255	6,480	10,735
Cumulative effect of adoption for the first time of IFRS 9 as at January 1, 2018	-	-	-	231	-	-	(148)	-	83	4	87
Balance as at January 1, 2018	13	1,924	27	3,353	(576)	15	51	(469)	4,338	6,484	10,822
Net profit	-	-	-	517	-	-	-	-	517	763	1,280
Other comprehensive income	-	-	-	-	564	-	48	-	612	211	823
Total comprehensive income	-	-	-	517	564	-	48	-	1,129	974 **)	2,103
Acquisition of treasury shares	-	-	-	-	-	-	-	(39)	(39)	-	(39)
Treasury shares held by Teudot Sal	-	1	-	-	-	-	-	30	31	-	31
Issuance of treasury shares by way of a tender offer	-	(15)	-	-	-	-	-	335	320	-	320
Transactions with non-controlling interests under an exchange tender offer	-	-	-	-	(8)	(464)	-	-	(472)	(236)	(708)
Transactions with non-controlling interests	-	-	-	-	-	125	-	-	125	251	376
Dividends	-	-	-	(467)	-	-	-	-	(467)	-	(467)
Dividend to non-controlling interests	-	-	-	-	-	-	-	-	-	(168)	(168)
Balance as at December 31, 2018	13	1,910	27	3,403	(20)	(324)	99	(143)	4,965	7,305	12,270

*) Mainly capital reserve for financial assets at fair value through other comprehensive income As at December 31, 2018, including a credit balance of NIS 12 million for investments held for sale.

**) Composition of comprehensive income of non-controlling interests:

Net profit attributable to non-controlling interests	763
Loss for financial assets measured at fair value through other comprehensive income, net	83
Loss from cash flow hedges	(5)
Foreign currency translation differences for foreign operations	299
Total comprehensive income attributable to non-controlling interests	974

The accompanying notes and the appendix are an integral part of the consolidated financial statements

Consolidated Statement of Cash Flows

	Year ended December 31		
	2020	2019	2018
	NIS millions		
Cash flows from operating activities			
Net profit (loss)	(1,810)	786	1,280
Adjustments to reconcile cash flows from operating activities (a)	4,977	4,037	(1,416)
Net cash from (used for) operating activities	3,167	4,823	(136)
Cash flows from investing activities			
Purchase of fixed assets, investment property and intangible assets	(53)	(330)	(399)
Proceeds from sale of fixed assets and investment property	35	93	25
Proceeds from sale of oil and gas assets	-	160	664
Proceeds from sale of financial assets, net	440	113	423
Repayment of loans to associates, net	3	-	84
Short-term investments, net	(284)	237	578
Investment in long-term bank deposits, net	16	(188)	(85)
Investments in oil and gas exploration and assets	(1,170)	(3,621)	(3,295)
Insurance proceeds	65	-	-
Cash added from disposal of investments in previously consolidated subsidiaries (B)	1,263	1,320	63
Cash flows used for acquisition of control in companies and operations (C)	(7)	(6,086)	(414)
Proceeds from sale of investments in associates	169	750	10
Tax paid for the sale of and investment in corporate company	-	(21)	-
Investments in associates	(1)	(427)	(78)
Repayment of loans to others, net	92	321	128
Net cash from (used for) investing activities	568	(7,679)	(2,296)

The accompanying notes and the appendix are an integral part of the consolidated financial statements

Consolidated Statement of Cash Flows (contd.)

	Year ended December 31		
	2020	2019	2018
	NIS millions		
Cash flow from financing activities			
Short-term loans from banks and others, net	(1,161)	(9)	274
Transactions with non-controlling interests	(137)	-	(152)
Receipt of long-term loans	113	6,848	5,461
Repayment of long-term loans	(9,585)	(1,966)	(716)
Dividend paid	-	(254)	(467)
Dividend paid to non-controlling interests	(190)	(498)	(209)
Acquisition of treasury shares by a subsidiary partnership	(60)	(111)	(39)
Issue of shares (net of issuance costs)	347	-	-
Issue of options (net of selling costs)	100	-	-
Repayment of liability for a lease	(123)	(174)	-
Payment for a put option and other contingent considerations	(200)	(35)	(22)
Issue of debentures and convertible debentures into shares (net of issuance costs)	8,145	2,561	1,282
Repayment of debentures	(2,043)	(1,131)	(3,396)
Net cash from (used for) financing activities	(4,794)	5,231	2,016
Exchange differences on cash balances of foreign operations	(35)	(32)	59
Change in cash and cash equivalents attributable to operations held for sale	(21)	(2,312)	486
Increase (decrease) in cash and cash equivalents	(1,115)	31	129
Cash and cash equivalents at the beginning of the year	1,517	1,486	1,357
Cash and cash equivalents at the end of the year:	402	1,517	1,486

Consolidated Statement of Cash Flows (contd.)

	Year ended December 31		
	2020	2019	2018
	NIS millions		
(A) Adjustments to reconcile cash flows from operating activities:			
Adjustments to profit or loss			
Depreciation, depletion, amortization, and impairment of assets	5,004	2,386	1,332
Deferred taxes, net	(613)	(442)	21
Increase (decrease) in employee benefit liabilities, net	(3)	3	4
Decrease (increase) of loans granted, net	(26)	33	(26)
Loss (profit) from the sale of fixed assets, real estate and investments, net	277	(262)	(3)
Group's share of results of associates, net (1)	14	28	233
Loss (profit) from the sale of oil and gas assets	-	3	(96)
Profit from a bargain acquisition	-	-	(105)
Change in fair value of financial assets and financial derivatives, net	184	(411)	211
Increase (decrease) in long-term liabilities, net	133	(8)	147
Increase in deferred acquisition costs	-	(52)	(73)
Cost of share-based payment	(5)	2	(1)
Proceeds received for hedging transactions swap	547	-	-
Change in financial investments of insurance companies, net	-	(5,803)	103
Investments net of proceeds from the sale of financial assets at fair value through other comprehensive income in insurance companies, net	-	(4,376)	(7,179)
Increase in reserves and other provisions in insurance companies	-	12,601	5,624
Acquisition of investment property for performance-based contracts and other investment property in insurance companies	-	(199)	(47)
Increase in reinsurance assets	-	(218)	(441)
Change in value of investment property, net	(3)	(47)	(107)
Changes in operating assets and liabilities:			
Decrease (increase) in trade receivables	(50)	211	121
Decrease in other receivables	152	169	166
Decrease (increase) in inventory	22	15	(68)
Decrease (increase) in other assets, net	(19)	15	(396)
Increase (decrease) in trade payables	(105)	164	(488)
Increase (decrease) in other payables	(532)	225	(348)
	4,977	4,037	(1,416)
(1) Net of dividends and earnings received	-	181	180

The accompanying notes and the appendix are an integral part of the consolidated financial statements

Consolidated Statement of Cash Flows (contd.)

		Year ended December 31		
		2020	2019	2018
		NIS millions		
(B)	Cash added from disposal of investments in consolidated companies			
	Working capital (excluding cash and cash equivalents), net	(424)	-	10
	Investments in oil and gas exploration and production assets	550	-	-
	Long-term assets	1,143	-	13
	Intangible assets	331	-	-
	Long-term liabilities	(1,045)	-	(3)
	Loan to the buyers for the acquisition	-	(152)	(11)
	Assets held for sale	853	103,607	36
	Other long-term assets	1,294	-	-
	Liabilities attributable to assets held for sale	(516)	(97,967)	-
	Deferred taxes	(145)	-	-
	Investment in an associate company	(300)	-	-
	Movement in capital reserves, net	15	(30)	17
	Profit (loss) on disposal of an investment	(272)	66	1
	Non-controlling interests	(221)	(3,539)	-
	Investment in a financial asset at fair value through profit or loss	-	(665)	-
		1,263	1,320	63
(C)	Investment derecognized for acquisition of control in companies and operations			
	Working capital (excluding cash and cash equivalents), net	2	(2)	(55)
	Investments in exploration and production of oil and gas assets	-	(7,554)	(1,022)
	Fixed assets, net	(9)	(39)	-
	Other long-term assets	-	(705)	-
	Deferred tax reserve (deferred tax asset)	-	1,731	(19)
	Goodwill	-	(2,837)	-
	Non-current liabilities	-	3,358	205
	Profit from a bargain acquisition	-	-	105
	Derecognition of investment in an associate	-	-	295
	Contingent consideration	-	-	77
	Assets held for sale, net	-	(38)	-
		(7)	(6,086)	(414)
(D)	Significant non-cash activities			
	Purchase of fixed assets, investment property and intangible assets	9	9	34
	Investment in oil and gas assets against liability	177	567	584
	Dividend to non-controlling interests	53	46	53
	Exercise of rights for royalties against investment in shares	-	-	83
	Exercise of rights for royalties against receivables	-	27	-
	Acquisition of non-controlling interests against reissuance of treasury shares	-	-	320
	Acquisition of shares in a subsidiary against the sale of the Partnership's units	-	-	343
	Distribution of shares of an associate as a dividend in kind for non-controlling interests	-	147	-
	Sale of investment property against loan provided	-	39	-
	Repayment of a loan against the sale of participating units	207	-	-
	Repayment of a liability to a bank against the sale of shares in swap transactions	-	132	-

The accompanying notes and the appendix are an integral part of the consolidated financial statements

Consolidated Statement of Cash Flows (contd.)

	Year ended December 31		
	2020	2019	2018
	NIS millions		
(E) Additional information on cash flows			
Cash paid during the year for:			
Interest	1,673	1,381	1,016
Taxes	311	263	679
Cash received during the year for:			
Interest	9	547	639
Dividends	-	113	170
Taxes	1	509	328

(F) For information about cash flows from discontinued operations, see Notes 10E and 10J.

NOTE 1 – GENERAL

A. Delek Group Ltd. ("the Company") invests in and manages companies and partnerships operating primarily in oil and gas exploration and production in Israel and other countries (in the North Sea), after the Group disposed of a number of leases and operations in recent years. For information about the Company's operating segments see Note 33. For information about assets used for significant activities that were discontinued see Note 10. The controlling shareholder of the Company is Yitzhak (Sharon) Tshuva, who, shortly before the approval date of the financial statements, holds 48.64% of the Company's capital and 50.34% of the voting rights (full dilution of 46.72% of the Company's capital and 48.12% of the voting rights), through his wholly owned companies.

B. Covid-19 crisis and decline in oil and gas prices

In December 2019, the Covid-19 pandemic broke out in China. In 2020, the virus spread to many countries around the world and in March 2020, it was declared a pandemic by the World Health Organization ("the Covid-19 Crisis"). The spread of Covid-19 has caused widespread morbidity and mortality in many countries. Due to the Covid-19 Crisis, many countries have imposed and are continuing to impose significant restrictions that included and/or include, among other things, self-isolation, restrictions on traffic and transportation (including flights), and closure and reduction of business activity. The crisis and the associated restrictions have caused a significant slowdown in global economic activity, and sharp declines and extreme fluctuations in capital markets around the world. Following the decline in business activity, there was a slump in demand for oil products. Moreover, in March 2020, the Russia-Saudi Arabia oil price war was reflected in an increase in oil production compared with the decline in demand. These events resulted in plummeting oil and natural gas prices in 2020 in some countries. However, agreements have recently been reached between countries to reduce the volume of daily oil production in the coming months. In addition, in the second half of 2020, many countries began to adopt a strategy of lifting restrictions and a controlled and gradual return to routine, and starting from the end of 2020, some countries began to vaccinate their populations to eradicate and/or slow down the pandemic. In this context, it should be noted that in 2020 and shortly before the approval date of the financial statements, oil prices were extremely volatile: as at December 31, 2019, the Brent oil price was USD 65 per barrel, and at its lowest point in 2020, the Brent oil price was USD 16 per barrel. As at December 31, 2020, the price was USD 52 per barrel, and shortly before the approval date of the financial statements, after further recovery in the markets, the price reached USD 64 per barrel.

As at the approval date of the financial statements, there is uncertainty regarding when the pandemic will be contained and/or will break out again and regarding the continuation and/or deepening of the global economic crisis, and future oil and natural gas prices.
Since the Group's main activity is in the energy sector, oil and natural gas prices (as well as the USD-NIS exchange rate) have a material effect (positive or negative) on the Group's operating results, on the value of its assets (marketable and non-marketable), capital, cash flows from its operating activity, as well as on its ability to dispose of assets and on the expected considerations from the disposals, and on its ability to raise additional sources of financing and/or financing costs.

For information about the assessments for impairment and amortization (reversal of amortization) and disposals in 2020, see Notes 10, 12C1(6), and 15 below. In this context, it should be noted that the estimates used by the Group for the assessments may be volatile, among other things, due to the aforesaid uncertainty. The Group will continue to review its estimates and update them according to developments in connection with the crisis, its effect on the economy in Israel and globally, and its effect on prices of oil and natural gas.

In addition, it should be noted that due to the economic crisis in 2020, there was a very significant decline in the trading value of the shares of the Company and its investees (mainly the participating units of Delek Drilling - Limited Partnership ("Delek Drilling" or "the Partnership"), which resulted in significant impairment of the Group's financial position and its liquid resources, mainly due to the fact that some of these shares served as collateral for the credit facilities provided to the Group. In 2020, the Group has repaid the full amount of credit facilities provided, which were secured mainly by the participating units of Delek Drilling. For information about the Group's financial position, see section C below. It is further noted that from the beginning of 2021 until the approval date of the financial statements, there was a significant increase in the marketable value of the Company's shares and Delek Drilling's participating units, although the marketable value did not reach its value prior to the outbreak of Covid-19.

NOTE 1 – GENERAL (CONTD.)

C. Financial position of the Group

1. General

- As at December 31, 2020, the Company (separate) has a working capital deficit of NIS 5.2 billion, and the Group (consolidated) has a working capital deficit of NIS 4.5 billion, mainly due to classification of debentures (over and above current maturities) in the amount of NIS 4.4 billion to short term. This classification is mainly because some of the waiver items in the amended deed of trust of the debentures series in June 2020 (see Note 19) are for less than twelve months from the date of the financial statements and because of non-compliance with the provisions in the amended the deed of trust regarding the limit of general and administrative expenses in 2020 (see also Note 19).

- It should be noted that, in addition to the aforesaid regarding the liabilities of the Company (separate), the Company provided certain guarantees to banks and other institutions for loans and credit taken out by certain subsidiaries (“the Staff Companies"). For information about the Company's obligations in the credit support document provided to the buyers of They Phoenix, see Note 10E(1).

  According to the original repayment schedules, in 2021, the Company and the Staff Companies have repayments (of principal and interest) amounting to NIS 1.3 billion and in 2022, another NIS 2 billion.

- As at December 31, 2020, liabilities (short- and long-term) to financing entities (mainly to debenture holders and banks and other institutions) of the Company and the Staff Companies amount to NIS 5.9 billion, against cash, marketable securities, and deposits pledged in favor of the debenture holders of the Company and the Staff Companies as at that date in the amount of NIS 275 million.

- Shortly before the approval date of the financial statements, the liabilities amount to NIS 5.6 billion, against financial assets amounting to NIS 70 million. For information about the updated collateral for these liabilities (taking into consideration agreements with debenture holder, and others as described above), see Notes 18 and 19 below.

- As set out in section B above, in the reporting period, the Covid-19 Crisis broke out (and it is still ongoing), which resulted in a significant slowdown in the local and global economy and a significant drop in oil and gas prices over a long period (which had an adverse effect on the Group's main activity).

NOTE 1 – GENERAL (CONTD.)

C. Financial position of the Group (contd.)

2) Decrease in oil and gas prices and implications on the Group

As set out in section B above, in the reporting period, the Covid-19 Crisis broke out (and it is still ongoing), which resulted in a significant slowdown in the local and global economy and a significant drop in oil and gas prices over a long period (which had an adverse effect on the Group's main activity).

- It should be noted that, as a result of the above, from the beginning of 2020 until the approval date of the financial statements, the following main events occurred:
  - There was a significant decrease in the TASE value of the shares of the Company and its investees (mainly Delek Drilling).
  - In 2020, there was a significant increase in returns on the Company's debentures, although following the economic recovery and the actions taken by the Group, the returns on the debentures decreased significantly (shortly before the approval date of the financial statements, the returns on the different debenture series were between 11% and 17%), which may make it difficult to refinance/raise additional debt and debentures.
  - There was a significant decrease in capital attributable to the Company's shareholders, which amounted to NIS 2 billion as at December 31, 2020 (as at December 31, 2019, NIS 4.1 billion). As set out in Note 19, in accordance with the provisions of the revised deed of trust, the capital attributable to the Company's shareholders as at June 30, 2021, should amount to a minimum amount of NIS 1.6 billion and as at March 31, 2022, NIS 2 billion. It should be noted that the continuation of the Covid-19 pandemic and declines in oil prices and/or in the USD exchange rate and/or the sale of assets in a quick disposal may adversely affect the balance of capital attributable to the Company's shareholders. On the other hand, future capital raising, an increase in oil prices, and continued improvement in the results of the investees will lead to an increase in capital attributable to the Company's shareholders.
  - As at the approval date of the financial statements, the Company and the Staff Companies repaid the full amount of the bank and other debts, other than the debt to a foreign bank amounting to USD 8 million. In addition, the Company has a loan of NIS 100 million, which the Company pledged in favor of the building in Herzliya that it owns, and a convertible loan of USD 50 million. For further information, see Notes 18 and 19.
- Following the spread of Covid-19, which led to sharp volatility in the capital markets in Israel and the world and plummeting oil and gas prices (in some of the period), there was an impairment in market value of the collateral (mainly Delek Drilling participating units) provided by the Company and its subsidiary Delek Energy Systems Ltd. ("Delek Energy") in favor of the credit providers. Under the provisions of the financing agreements, the impairment in the collateral against the balance of the debt to the credit providers fell below the rates set out in the various loan agreements, and as a result, at certain periods in 2020, the Company and Delek Energy were required to provide (pledge) additional collateral and/or to deposit cash (under the provisions of any agreement) in favor of the credit providers to meet the requirements of the agreements and/or to attempt to avoid a call for immediate repayment of the debt. It should also be noted that in the fourth quarter of 2020, the Group repaid the balance of the bank debts in full. In this context, it is noted that:

NOTE 1 – GENERAL (CONTD.)

C. Financial position of the Group (contd.)

2) Decrease in oil and gas prices and implications on the Group (contd.)

1) For a specific loan provided to Delek Energy by a foreign bank in 2013, with a balance of USD 57 million in March 2020, secured at that time by a lien on participating units representing 15% of the capital of Delek Drilling in favor of the foreign bank, in March 2020, the foreign bank claimed that in view of the exceptional decline in the price of Delek Drilling units, it (allegedly) has grounds to call for immediate repayment of the debt. Accordingly, on March 15, 2020, the foreign bank entered into an agreement with a third party for the sale of 12% of the participating units of Delek Drilling. Under the settlement arrangement between Delek Energy, the foreign bank, and a third party, which was completed on March 26, 2020, Delek Energy acquired 7% of the participating units of Delek Drilling (out of the 12%) for a consideration of USD 35.8 million. The remaining 3% of the participating units of Delek Drilling were released back to Delek Energy.

   After the completion of the aforesaid, the Group holds 55% of the capital of Delek Drilling. Following the aforesaid (net disposal of 5% of the capital of Delek Drilling), the capital attributable to the Company's shareholders decreased by NIS 313 million. For further information, see Note 10K to the financial statements.

2) For the loan of NIS 100 million backed by Delek Drilling's participating units, provided by an Israeli bank ("the Bank") to Delek Energy and guaranteed by the Company, on March 31, 2020, the Bank informed Delek Energy and the Company that the participating units that had been pledged in its favor had fallen below the value set in the agreement and since additional participating units had not been pledged to it in accordance with the terms of the loan, it seeks to call for immediate repayment of the loan and to immediately exercise the collateral provided in its favor.

   In discussions between the Company and Delek Energy with the Bank, the Bank sent an update letter stating the terms and requirements for postponing the exercise of the collateral. To avoid a situation in which the Bank exercises the participating units that were pledged to it, Delek Energy pledged additional participating units in favor of the Bank (at a lower rate than that stipulated in the loan terms), even though Company and Delek Energy believe that under the special circumstances, partially due to the Covid-19 Crisis, the Bank does not have the right to demand additional collateral and/or immediate repayment of the loan. Following the addition, the participating units pledged in favor of the Bank represent 5.7% of the capital of Delek Drilling (compared with 4.4% of the capital of Delek Drilling prior to the increment).

   The Bank gave Delek Energy until April 30, 2020 to fulfill the requirements in the letter of suspension of exercise, and on this date, if the requirements have been fulfilled, the financing facility will be provided again. As at April 30, 2020, the Company was unable to reach agreements with the Bank, on that date, that would ensure the non-exercise of the pledged participating units. Accordingly, on April 30, 2020, Delek Energy filed a motion for a temporary injunction ordering the Bank to refrain in any way from exercising the participation units pledged in its favor (among other things, in view of the Company's position that it has no grounds to call for immediate repayment). Following the court hearings, in May 2020, Delek Energy repaid its debt to the bank.

NOTE 1 – GENERAL (CONTD.)

C. Financial position of the Group (contd.)

2) Decrease in oil and gas prices and implications on the Group (contd.)

3) For the loan of USD 200 million taken by a wholly-owned foreign subsidiary (DKL Energy), as set out in Note 10F, and in view of the fact that the loan is not backed by marketable assets (other than 51% of the share capital of Delek North Sea Limited ("DNSL") and the entire share capital of Ithaca, which are not a traded company), the loan agreement set out margin call events that included a decrease of 20% in the index of benchmark companies (as defined in the loan agreement) or in the FTSE-100 Index, where in such event, the borrower will be required to deposit cash in the amount of the decrease in value as defined in the agreement. Grounds for early repayment under the loan agreement included a 50% decrease in the index of benchmark companies, a decrease of 50% in the FTSE-100 Index, a decrease of 50% in Company's shares, and a downgrade in Maalot's rating of the Company to BBB (plus) or below, represent grounds for repayment of half of the loan amount. The loan was provided under limited recourse terms and the Company provided the lender a guarantee for the borrower's obligation to unpaid accrued interest, the first margin call, and exceptional violation events.

In 2020, DKL Energy failed to comply with some of the financial covenants in connection with the loan that conferred on the Bank the right to call for immediate repayment of part/or of its debt. On April 7, 2020, the Bank signed an amendment to an agreement according to which the cash deposit amounting to USD 43.3 million was used for partial repayment of the loan and extension of the cure period for the call for immediate repayment.

On August 27, 2020, wholly owned foreign subsidiaries of the Group, DKL Energy and Delek North Sea Limited ("DNSL" and jointly "the Foreign Subsidiaries") signed an amendment and addition to the agreement with a foreign bank in connection with the loan ("the Amended Agreements"), which came into effect after completing registration of the collateral in October 2020. Under the Amended Agreements, a waiver was received from the foreign bank for failure to comply with financial covenants (for which, up to October 2020, a waiver was granted for fixed periods that were extended from time to time). There was no change in the original repayment dates of the principle. There will be a 2% increase in the interest rate on the loan up to November 2020, followed by an increase of another 2%. The existing collateral remained, and collateral of the balance of DNSL shares was added, such that 100% of the shares of DNSL, the parent company (100%) of Ithaca were pledged, and a loan and capital note between DKL Energy and DNSL will be pledged. Under the Amended Agreements, there was no change in events underlying the Company's guarantee. In addition, a negative pledge was provided on 6% of the total participating units of Delek Drilling.

In May and November 2020, an amount of USD 120 million was repaid from the balance of the loan in view of dividends received from Ithaca, and in November 2020, an additional USD 32 million was repaid (as at December 31, 2020, the balance of the loan amounts to USD 8 million).

<u>Liabilities, financial covenants, and grounds for immediate repayment</u>

The Amended Agreements eliminated the margin call events that were set out in the original agreement and removed criteria relating to ratings and the Company's share price and various indexes described above.
Under the Amended Agreements, the undertaking to comply with financial covenants remained unchanged, according to which the ratio of total net debt to net profit before taxes and financing, net of depreciation and amortization and net of appraisal and exploration expenses (EBITDAX) does not exceed 2.5. A review of this ratio is required at each calculation date (March 31, June 30, September 30, and December 31 of each year). As at December 31, 2020, this ratio was 1.6.

NOTE 1 – GENERAL (CONTD.)

C. Financial position of the Group (contd.)

2) Decrease in oil and gas prices and implications on the Group (contd.)

3) (contd.)

Liabilities, financial covenants, and grounds for immediate repayment (contd.)

Under the Amended Agreements, the lender has the right to call for immediate repayment of the loan (after the cure period), among other things, in the event of failure to pay on time, non-compliance with the dividend obligations set out above, non-compliance with the financial covenants set out above, changes in inter-company loans in the foreign subsidiaries, non-compliance with undertakings according to the agreement, events of change in control of assets, events of insolvency and liquidation in Delek Group companies, and impairment in the closing value of the S&P Global Oil Index below the level set in the agreement. The right to call for immediate repayment was also determined in the event of cross default in the borrower group (DKL Energy and subsidiaries and its investees) and in the event of the materialization of this right.

- On March 23, 2020, Midroog Ltd. ("Midroog") downgraded the rating of the Company's debentures from A2.il to Ca.il (down 14 ratings), due to Midroog's assessment of a high probability of default. The Company disputed the rating report of Midroog and its result. In this context, it should be noted that on April 13, 2020, the Company announced the termination of its relations with Midroog and that Midroog will cease to serve as the Company's rating company from that date. The Company's series of debentures will continue to be rated by Maalot. On April 1, 2020, Maalot downgraded the Company's debentures from ilA to ilBBB (a downgrade of four ratings), keeping it on CreditWatch with negative outlook, due to weak liquidity reflected in a material gap between short-term sources and uses. Following the downgrade, the annual interest rate of some of the debenture series increased by 1%. It is further noted that on May 5, 2020, Maalot downgraded the Company's debenture rating to ilCCC (a downgrade of another five ratings) with negative outlook due to the increased risk of default. On September 30, 2020, Maalot revised the rating to ilCCC with developing outlook and on January 31, 2021, partly due to actions taken by the Company to reduce the debt and improve its resources, Maalot upgraded the rating of the Group's debentures to ilB with developing outlook.

  A downgrade in the debenture rating such that the rating falls below BBB- of Maalot or an equivalent rating for more than 21 business days represented grounds to call for immediate repayment of the debentures.

- Further to the above, regarding the impairment of the various collaterals, the rating downgrade, the deterioration in the ratios of Company's debt to asset value, and the going concern remark in the financial statements, in the reporting period, there were events that are considered or that may be considered to be events of default for some of the liabilities of the Company and the Staff Companies towards the financial institutions and the debenture holders. For information about the agreements and the amendment to the deeds of trust that were approved on June 17, 2020 with the Company's debenture holders, and the standstill agreement with some of the banks, under which the grounds for calling for immediate payment were revised and/or frozen, see section 3 and Note 19 below.

NOTE 1: GENERAL (CONTD.)

C. Financial position of the Group (contd.)

3) Discussions and agreements with representatives of the debenture holders and with banks on the outline for reinforcing capital and collateral

In March 2020, the general meeting of the Company's debenture holders approved the establishment of a joint representation on their behalf and joint legal and economic advisors for all debenture series, with the aim of assisting the debenture holders and trustees and to act as their representative in the assessment of the Company's financial position, the alternatives, and the actions available to the debenture holders to protect their rights and in negotiations and proceedings with the Company and/or its controlling shareholder. The Company and the representation held discussions, with the aim of regulating the terms of the debentures and the Company's obligations to them. In addition, in April-June 2020, the Company and certain banks held negotiations, due to the breach of the covenants, with the aim of arranging the terms of the loans that were provided and the Company's obligations to them. In June 2020, amendments to the deeds of trust with the debenture holders and an agreement with the banks were approved. Under the agreements, the Company undertook to raise capital, dispose of assets, pledge assets and investments in favor of the debenture holders and the banks, and comply with various financial covenants, some of which were revised in the agreements. The agreements set out events and covenants, which, if breached, will allow the debenture holders and the banks to call for immediate repayment of the Company's obligations to them. In this context, it was determined, among other things, that as from June 1, 2021, the rating of the Company's debentures will be at least (BBB-) and the Company is required to meet the minimum equity and equity to balance sheet ratios according to the various parameters that gradually increase over the years. For 2021, it was determined that as from the financial statements for the second quarter of 2021 and up to and including the annual financial statements for 2021, the Company requires minimum equity of NIS 1.6 billion and equity to balance sheet ratio (separate statement) of at least 12.5%, and for 2022, it was determined that as from the financial statements for the first quarter of 2022 and up to and including the annual financial statements for 2022, the Company requires minimum equity of NIS 2 billion and equity ratio to balance sheet ratio (separate statement) of at least 15% . For further information see Note 19.

It was further determined that general and administrative expenses in 2020, including those of the Staff Companies, will not exceed those in 2019, based on the Company's financial statements (including the costs of the amendment to the deed of trust). In 2021, they will not exceed NIS 45 million; in 2022, NIS 40 million; and from 2023, NIS 35 million. For further information see Note 19.

It should be noted that in 2020, the Company's administrative and general expenses, including those of the Staff Companies (including the costs of the amendment to the deed), exceeded those of 2019 by NIS 5.4 million and the Company did not meet the aforesaid undertaking. However, following discussions that began in 2020 between DKL (a staff company) and Ithaca, subsequent to the balance sheet date, in March 2021, it was agreed that Ithaca will participate in DKL's management expenses for 2020. Accordingly, in March 2021, Ithaca transferred an additional amount of USD 1.7 million (NIS 5.7 million) over and above the amount of USD 0.7 million that has already been transferred by Ithaca for these expenses. The additional amount transferred subsequent to the balance sheet date exceeds the deviation attributed to 2020. Therefore, the Company's believes, based also on a legal opinion that it received, that as at the approval date of the financial statements, the above non-compliance has been amended.

It should be emphasized that the right to call for immediate repayment to the debenture holders also establishes a similar right for other lenders, including a convertible loan and credit provided to the Group in the amount of USD 58 million (NIS 190 million). These credit amounts are classified in the financial statements as a short-term liability.

If the Company estimates that it will not meet other financial criteria at the dates set out above, it intends to act in advance to obtain a waiver and/or extension and/or to amend the relevant covenants, and it believes that it will be able to reach understandings with the debenture holders on this matter.

NOTE 1: GENERAL (CONTD.)

C. Financial position of the Group (contd.)

4) Disposal of assets and investments and raising capital and debt

- In March 2020, the Group disposed of the balance of its holding (20%) in the shares of IDE Holdings Ltd. ("IDE") for NIS 169 million (see Note 10H) and an investment property for NIS 33 million. In addition, in April 2020, the Company disposed on the balance of its holdings in the shares of Cohen Development for NIS 207 million (see Note 10H).
- In April and May 2020, the Company informed the banks of early termination of all the swap transactions in connection with The Phoenix shares. The swap shares (25,000,000 shares) were sold by the banks in off-floor transactions for an amount of NIS 413 million. On completion of the transactions, a cash amount of NIS 143 million, which was pledged to the banks to secure the transactions, as is standard in this type of transaction, was released in favor of the Company. For further information, see Note 10E2.
- In July 2020, the transaction was completed for the sale of the rights of the Company and Delek Energy to overriding royalties in the Karish and Tanin reservoirs for a consideration of NIS 318 million. For further information see Note 12H.
- In July 2020, Delek - the Israeli Fuel Company Ltd. ("Delek Israel") completed a transaction for the sale of its holdings in the Pi Glilot terminals for a consideration of NIS 720 million, and a binding agreement was signed for the sale of Delek Israel's holdings in IPP Delek Ashkelon Ltd. and IPP Delek Sorek Ltd., which own power plants for electricity generation, (subsequent to the balance sheet date, in February 2021, the transaction for the sale of the power plants was completed). In July 2020, Delek Israel distributed a dividend to the Group in the amount of NIS 150 million. For further information see Note 10J(3).
- In October 2020, the Group sold 70% of the share capital of Delek Israel for NIS 525 million. On the closing date of the transaction, the buyer paid an amount of NIS 450 million in cash against the transfer of 60% of Delek Israel's share capital to the buyer and it was agreed that the buyer will transfer the balance of the consideration of up to NIS 75 million by June 30, 2021 against up to 10% of Delek Israel's share capital and an option was granted to purchase an additional 5% of Delek Israel's share capital. Subsequent to the balance sheet date, in February 2021, the buyer sold half of the additional shares and 1.67% of the option for a total consideration of NIS 50 million. In addition, in March 2021, the buyer exercised the balance of the option granted to it for 3.34% of Delek Israel's issued and paid-up capital for NIS 25 million. The remaining shares, representing 5%, are deposited in trust until June 30, 2021. For further information, see Note 10J4.
- In May, August and December 2020, as required by the amended deed of trust for the debenture series, the Group raised debt (shares and options) in the amount of NIS 137 million, NIS 176 million and NIS 140 million (NIS 100 million from exercising options), respectively. For further information, see Note 26. Furthermore, the Company is required or may be required to raise additional capital in accordance with the revised deed of trust for the debenture series, for further information, see Note 19. In this context, it should be noted that by April 8, 2021, the Company is required to raise capital in the amount of NIS 50 million (up to the approval date of the financial statements, options have been exercised for the Company's shares in the amount of NIS 17 million).

NOTE 1: GENERAL (CONTD.)

C. Financial position of the Group (contd.)

4) Disposal of assets and investments and raising capital and debt (contd.)

- On October 28, 2020, Delek Leviathan Overriding Royalty Ltd. ("the Issuer"), a special purpose company of Delek Energy, completed the issuance of debentures to foreign and Israeli classified investors in the amount of USD 180 million (gross), which was secured by a lien on the rights to overriding royalties from the Leviathan project that were transferred to the Issuer. The net amount transferred to the Company amounted to USD 147 million. For further information, see Note 12L.
- In October 2020, the Company signed a loan agreement with a third party for a loan against a lien on a building in Herzliya that it owns. Subsequent to the balance sheet date, in January 2021, the loan of NIS 104 million was received, linked to the CPI and bearing interest at a rate of 7%. The loan is payable in January 2024. The proceeds of the loan were mainly used to repay a previous loan taken in connection with the property.
- Subsequent to the balance sheet date, in March 2021, the Group signed a detailed agreement for the sale of investment property in Acre for NIS 200 million as is. The consideration will be paid as follows: NIS 10 million was paid to the Group when the memorandum of understanding was signed, NIS 30 million will be paid by the buyer shortly before signing the agreement and this amount will be held in escrow for the Group and transferred to the seller within one business day after fulfillment of the conditions defined below. The balance of the consideration will be paid on receipt of possession, registration of a lien in favor of the party providing the finance, and confirmations of the transfer for registration of the rights. The agreement sets out terminating conditions, which, if they are not fulfilled within a defined period, the buyer will have the right to cancel the agreement. For further information see Note 11D.
- In addition, the Group is assessing the disposal of additional assets (including partial disposal of the Group's investment in Ithaca) and the receipt of loans and/or the partial exchange of the debentures.

5) Repayments to debenture holders and banks and pledge of assets

In 2020 and shortly before the approval date of the financial statements, the Company and its Staff Companies repaid the full amount of their liabilities to the debenture holders and the banks and financial institutions under the agreements with them, including in connection with the agreements set out in section 3 above, amounting to a total of NIS 3.5 billion. For further information, see Note 19.

NOTE 1: GENERAL (CONTD.)

C. Financial position of the Group (contd.)

6) Conclusion

Under the agreements with the debenture holders and the financial institutions, and for the Company and the Staff Companies to meet repayment of their liabilities, the Company was and is required to raise a substantial amount of capital, dispose of assets and investments on a substantial scale, raise debt based on assets, and receive dividends from investees. The amounts of these sources are required to repay the Company's obligations, which are very substantial (in 2021, the Company and the Staff Companies are required to repay the obligations to debenture holders, financial institutions, and others in an amount of NIS 1.3 billion and in 2022, NIS 2 billion).

As aforesaid, repayment of the liabilities of the Company and the Staff Companies at their due date is subject to their ability to dispose of assets and investments on a significant scale; raise debt and capital on a significant scale, some of which is required in the near future and is greatly affected by oil and natural gas prices; and receive dividends from investees and partnerships.

It should be noted that the Company's ability to receive a substantial amount of dividend from investees refers mainly to the receipt of dividends from Delek Drilling and Ithaca. The ability of these companies to distribute dividends is subject, among other things, to their compliance with the financial covenants and obtaining the approval of financing entities and/or their ability to generate significant available cash flows, which is also dependent on the demand for oil and natural gas and prices of oil and natural gas. In 2020, as set out above, Ithaca distributed a dividend of USD 120 million and in addition, Delek Drilling distributed and/or announced a dividend of USD 100 million (the Group's share is USD 185 million).

In addition, as set out above, the Company is required to comply with the terms of the agreements and covenants with the debenture holders (and with the financial institutions) and/or to reach understandings with them, so that there will not be grounds to call for immediate repayment of the obligations of the Company and the Staff Companies (in particular raising the ratio of the debenture debts until May 31, 2021, compliance with general and administrative amounts, and the minimum thresholds and equity ratios as set out in section 3 above). The Company's management believes that if required, it will be able to reach agreements with the debentures holders regarding the financial covenants.

As aforesaid, the Company worked and is working to realize its plans, including the raising of capital, disposal of substantial assets and investments, raising of debt based on assets and receipt of dividends from investees, in order to meet its various obligations. The Company believes that it is highly likely that its plans will be realized, and in this context, it should be noted that, as set out above, the significant and important actions that the Group was able to complete during the past year in accordance with the outline enabled it to make early repayments to the banks in substantial amounts and to the debenture holders on time and as required. However, since completion of the Company's plans is not under its sole control and depends, as described above, among other things, on third parties and/or the materialization of several incremental events, some of which must occur within relatively short periods and/or in a significant scope, and in view of the financial covenants that were determined with the debenture holders and other lenders that may require their consent not be call for immediate repayment (in the event of non-compliance with the covenants), there is uncertainty as to the actual materialization of these plans. These factors, together with the other factors described above, raise substantial doubt about the Company's ability to continue as a going concern. The financial statements do not include adjustments for the values of assets and liabilities and their classification, which might be required if the Company is unable to continue as a going concern.

NOTE 1: GENERAL (CONTD.)

D. Financial positions of subsidiaries

1) Delek Drilling

- In August 2020, Delek Drilling (through a special purpose company) issued debentures in an amount of USD 2.25 billion ("Leviathan Bond", for further information, see Note 12L), used primarily to repay short-term loans of USD 2 billion.
- With respect to the Covid-19 Crisis, it should be noted that in the first half of 2020, and in particular in the second quarter, there was stagnation in local demand for natural gas compared with the corresponding period last year, mainly due to the effect of the Covid-19 Crisis on demand for electricity in this market, resulting from lockdowns and restrictions on economic activity. It should be noted that, notwithstanding the continuation of the Covid-19 Crisis, there was an increase in demand for natural gas in the second half of 2020 compared with the corresponding period last year.

As at the approval date of the financial statements, it is difficult to estimate how the Covid-19 Crisis will continue and develop in the coming years, the extent of its effect on the global economy, and its effect on demand and sales from the Leviathan and Tamar reservoirs in the coming years. Under these circumstances, the Covid-19 Crisis is a global macroeconomic risk creating uncertainty regarding future global economic activity and its expected effect on financial markets, interest margins, exchange rates, and commodity prices in the energy sector and it may harm many industries including the energy sector in which the Partnership operates. As part of the strategy for addressing the Covid-19 Crisis, the Tamar partners, Leviathan partners and Block 12 partners in Cyprus took steps to streamline and reduce operating budgets for 2020 and to postpone planned investment budgets for later years, and accordingly, the partners in these projects approved revised budgets for 2020. The Partnership continues to work, together with its other partners in these projects, to expand its streamlining plans in the coming years as well.

It is further noted that Noble, which is the operator in the Tamar and Leviathan projects, has prepared a plan with the relevant parties for addressing the Covid-19 Crisis, with the aim of ensuring, to the extent possible, access to the various facilities and the continuation of essential operations in these facilities.

2) Ithaca

As at December 31, 2020, Ithaca has a working capital deficit of USD 110 million (NIS 353 million).

The Covid-19 Crisis and the decrease in oil and gas prices had a significant effect on the results of Ithaca's operations. The management of Ithaca is closely following the crisis and the market developments and is taking steps and formulating plans to minimize the implications. As set out above, the recent positive developments in the markets and in oil and gas prices have a positive effect on Ithaca's results and the value of its assets.

Ithaca implemented, among other things, measures to isolate and separate work teams to the minimum required level, reduce capital investment in 2020, and reduce operating and production costs in substantial amounts. It is further noted that Ithaca has hedge transactions on oil and gas prices for 2021-2022 in a material scope (see Note 20A). For further information about Ithaca, see Notes 10F and 12U.

In May 2020, Ithaca distributed a dividend in the amount of USD 20 million (NIS 70 million). In addition, in November 2020, Ithaca distributed another dividend amounting to USD 100 million (NIS 340 million).

NOTE 1: GENERAL (CONTD.)

E. Definitions

In these financial statements -

The Company	-	Delek Group Ltd.
The Group	-	The Company and its subsidiaries and partnerships which are consolidated in the consolidated financial statements
Subsidiaries	-	Companies and partnerships controlled by the Company (as defined in IFRS 10) and their financial statements are consolidated with the financial statements of the Company
Associates	-	Companies and partnerships over which the Company has significant influence or has a contractual arrangement for joint control and the Group investment in these companies is accounted for using the equity method
Investees	-	Subsidiaries or associates and associate partnerships See also the appendix to the financial statements listing the principle partnerships and investees
Interested parties and controlling shareholder	-	As defined in the Israel Securities Regulations (Annual Financial Statements), 2010
Related parties	-	As defined in IAS 24 (Revised)
CPI	-	The Consumer Price Index published by the Central Bureau of Statistics in Israel
USD	-	US dollar

NOTE 2: SIGNIFICANT ACCOUNTING POLICIES

A. Basis of presentation

The financial statements of the Company have been prepared on a cost basis, except for investment property, financial investments, derivatives (including embedded derivatives) and certain financial instruments and liabilities for share-based payments, which are measured at fair value in each reporting period, and with the exception of investments accounted for using the equity method and deferred taxes.

The Company has elected to present the statement of income using the function of expense method.

Basis of preparation of the financial statements

These financial statements have been prepared in accordance with International Financial Reporting Standards (IFRS).

Furthermore, the financial statements have been prepared in accordance with the provisions of the Israeli Securities Regulations (Annual Financial Statements), 2010, insofar as these regulations are applicable to consolidated insurance companies.

Consistent accounting policy

The accounting policies applied in the consolidated financial statements have been applied consistently to all the periods presented, unless otherwise stated.

B. Estimates, assumptions and judgments

Below is a description of the key estimates and assumptions made in the financial statements concerning uncertainties at the end of the reporting period and the critical estimates computed by the Group that may result in a material adjustment to the carrying amounts of assets and liabilities within the next financial year are discussed below:

– Impairment of non-financial assets

The Group evaluates the need to record an impairment of the carrying amount of non-financial assets, including fixed assets, oil and gas assets, intangible assets with a defined useful life, and investments accounted for according to the equity method, whenever events or changes in circumstances indicate that the carrying amount is not recoverable. See section S below. In addition, the Group reviews goodwill for impairment at least once a year.

This requires management to assess the expected future cash flows from continued use of the cash-generating units and also to select a suitable discounted rate for these cash flows. For further information, see section S below.
As from the acquisition date, goodwill is allocated to a cash-generating unit or a group of cash-generating units which are expected to generate benefits from the synergy of the combination.

In particular, it should be noted that measurement of the recoverable amount of oil and gas assets (and the assessment of goodwill impairment attributable to operation in this sector) requires management to make assumptions regarding expected costs and investments, the probability of the existence of development plans, quantities of resources in the reservoir (mainly estimated proven and probable oil reserves), expected selling prices (in particular, the expectation for future oil and gas prices), implications of the Petroleum Profits Tax Law, and discount rates, to evaluate the future cash flows from the assets.

The changes in estimates that were taken into account may significantly change the results of the assessment.

NOTE 2: SIGNIFICANT ACCOUNTING POLICIES (CONTD.)

B. Estimates, assumptions and judgments (contd.)

– Estimate of proven and prospective oil and gas reserves and future costs

The estimate of the proven and prospective oil and gas reserves are used, among other things, to determine the amortization rate of the assets used in the operations over the reporting period. Depreciation of investments (also taking into account expected future costs for production of the proven and prospective resources) associated with discovery and production of proven and prospective oil and gas reserves is based on the depletion method. According to this method, in each accounting period the assets are depreciated at a rate determined by the number of units of oil and gas actually produced, divided by the proven and prospective oil and gas reserves remaining according to estimates. The estimated oil and gas reserves in the producing reservoirs in the reporting period, and the future anticipated costs are calculated each year based partially on assessments of oil and gas reserves by external experts. The estimated proven and prospective reserves and the future anticipated costs according to these principles is subjective, based on different assumptions and the estimates of experts and might sometimes differ significantly. Given the significant amounts of the Group's depreciation expenses, the changes in estimates can have a material effect on the operating results and the financial position of the Group (including in respect of assessing impairment of oil and gas assets). See also section T below.

– Determining fair value of an unquoted financial instrument

The fair value of an unquoted financial asset classified at level 3 on the fair value hierarchy is determined on the basis of valuation techniques, usually the projected future cash flows discounted at the current discount rates applicable for items with similar terms and risk characteristics. Changes in the estimated future cash flows and discount rates taking into account the risk assessment, such as liquidity risk, credit risk and volatility may affect the fair value of these assets.

– Discount rate of a lease liability

Since the interest rate implicit in the Group's leases is not readily determinable, the incremental borrowing rate of the Group companies is used. The incremental borrowing rate constitutes the rate of interest that the relevant company would have to pay to borrow over a similar term, and with a similar security, the funds necessary to obtain an asset of a similar value to the right-of-use asset in a similar economic environment. Where there are no financing transactions which the Group can use as a basis, it determines the incremental borrowing rate in accordance with the financing risk attributable to the lessee company, the lease term, and other economic variables arising from the terms and conditions in the lease. The Group uses an outside valuator to determine the incremental interest rate.

– Deferred tax assets

A deferred tax asset is recognized for unused carryforward tax losses and temporary differences to the extent that it is probable that future taxable profits will be available against which the losses can be utilized according to the tax rate that is expected to apply to this taxable income. Management judgment is required to calculate the amount of the deferred tax asset that can be recognized based on the timing, future taxable income and tax planning strategy. Further to the above regarding the impairment testing of oil and gas assets, in determining the expected taxable income from operations in these assets, estimates of future oil and gas prices, future disposal development costs, quantity of reserves in reservoirs, and other factors are taken into consideration. Changes in these estimates may result in a material change in the balance of deferred taxes. For further information, see section U below and Note 31E.

NOTE 2: SIGNIFICANT ACCOUNTING POLICIES (CONTD.)

B. Estimates, assumptions and judgments (contd.)

- Obligation for disposal of assets

  The timing and amount of the financial resources required to settle the obligation are based on the assessment of the managements of the Partnership and the subsidiary, based, among other things, on estimates of professional advisors and periodic assessments of the adequacy of these estimates.

- Legal claims

  When assessing the possible outcomes of legal claims that were filed against the Company and its investees, the Group companies relied on the opinions of their legal counsel. These opinions are based on the best of their professional judgment, and take into consideration the current stage of the proceedings and the legal precedents for various matters. Since the outcomes of the claims will ultimately be determined in the courts, these outcomes could differ from the assessments.

  In addition to these claims, the Company is exposed to unasserted legal claims, among other things, where there is any doubt as to the interpretation of the agreement and/or the provisions of the law and/or their implementation. This exposure is brought to the attention of the Company and its investees in several ways, including through customer applications to Group entities, in particular to the Group's public complaints officer, through customer complaints to the public inquiries unit in the supervisor's office, and through claims (other than class action suits) filed at the court.

  These issues are brought to the attention of the Group's management insofar as the relevant entities identify that the claims could have widespread implications. When assessing the risk arising from these unasserted allegations/claims, the Group companies rely on internal assessments of the relevant parties and the management, which assess the prospects of a claim being filed and the chances for its success, if filed. The assessment is based on experience gained with respect to filing claims and the analysis of each claim. By their nature, in view of the preliminary stage of the clarification of the legal claim, the actual outcome could be different from the assessment made before the claim was filed.
  For further information, see Note 24A.

NOTE 2: SIGNIFICANT ACCOUNTING POLICIES (CONTD.)

C. Consolidated financial statements

The consolidated financial statements include the statements of companies that are controlled by the Company (subsidiaries). Control exists when the Company has the power to affect the investee, is exposed, or has rights, to variable returns from its involvement with the investing entity, and it has the ability to affect those returns arising from the investee. When assessing the existence of control, all potential voting rights are taken into account only if they are exercisable. The financial statements are consolidated from the date that control is obtained and ends when such control ceases.

Significant intragroup balances and transactions and profits or losses arising from transactions between the Group companies have been eliminated in full in the consolidated financial statements.

Non-controlling interests for subsidiaries represent the capital of the subsidiaries that cannot be attributed, directly or indirectly, to the parent company They are presented in equity separately from the equity attributable to the parent. Profit or loss and any part of other comprehensive income are attributed to the Company and the non-controlling interests. Equity instruments such as preferred stock and similar instruments issued by subsidiaries are recognized under non-controlling interests. The attribution of the profit or loss of a subsidiary takes into account arrangements for distribution of profits such as dividends for cumulative preferred shares. Losses are attributed to non-controlling interests even if the result is a negative balance of non-controlling interests in the consolidated statement of financial position.

The acquisition of non-controlling interests by the Group is recognized as an increase or decrease in equity (when non-controlling interests also include a share of other comprehensive income the Company re-attributes the accumulated amounts that were recognized in other comprehensive income to the owners of the Company and the non-controlling interests).
Upon the disposal of an interest in a subsidiary that does not result in a loss of control, an increase or decrease is recognized in equity taking into account also the disposal of a portion of any goodwill in the subsidiary and any capital reserve recognized in other comprehensive income, based on the decrease in the interests in the subsidiary.
Transaction costs for transactions with non-controlling interests are also recognized in equity.

Upon the loss of control on disposal of a subsidiary, the Company derecognizes the assets (including goodwill), liabilities, and noncontrolling interests of the subsidiary, and recognizes the fair value of the consideration received and any remaining investment; and reclassifies the components previously recognized in other comprehensive income (loss).

The financial statements of the Company and its subsidiaries are prepared at the same dates and for the same periods. The accounting policy in the financial statements of the subsidiaries is applied uniformly and consistently with the accounting policy in the Company’s financial statements.

NOTE 2: SIGNIFICANT ACCOUNTING POLICIES (CONTD.)

C. Consolidated financial statements (contd.)

Jointly controlled operations

A joint venture is a contractual arrangement where two or more parties undertake oil and gas exploration operations in a jointly-owned asset. Certain joint ventures often involve joint operations by the partners in one or more asset invested in the joint venture.

According to IFRS 11, joint control only exists when there is a formal requirement for unanimous agreement of the joint venture partners. However, a review of these ventures demonstrates that the ventures themselves have no rights in the assets and have no binding commitments on behalf of the participants. The agreements are directly between the participants and the third party. Any participant may pledge its rights in the assets and is entitled to the economic benefits arising from the venture. As a result, the participants have a proportionate share in the assets and liabilities attributable to the joint venture.

For the rights in the joint venture operations, the Group recognizes the following in its financial statements:

a) The share of the joint venture assets
b) Any liabilities undertaken by the partnership
c) The share in any liabilities incurred jointly in respect of the joint venture
d) Any revenues arising from its right in the joint venture
e) Any expenses arising from its right in the joint venture

D. Functional currency and foreign currency

1) Functional currency and presentation currency

The functional currency of the Company and the presentation currency of the financial statements is the Israeli shekel (NIS).

The Group determines the functional currency of each company, including companies accounted for using the equity method.

The assets and liabilities of an investee that is a foreign operation, including surplus, are translated at the exchange rate at each reporting date. Profit or loss items are translated at average exchange rates for the presented periods. All exchange differences are recognized as other comprehensive income (loss).

Intragroup loans for which settlement is neither planned nor likely to occur in the foreseeable future, are a part of the investment in the foreign operation, therefore exchange differences arising on these loans (net of the effect of tax) are recognized in other comprehensive income (loss).

When a foreign operation is fully or partially disposed of, such that control is lost, the cumulative profit (loss) related to that operation, recognized in other comprehensive income is transferred to profit or loss. Furthermore, when a foreign operation is partially disposed of, while retaining control in the subsidiary, a proportionate part of the cumulative amount of the translation difference that was recognized in other comprehensive income is reattributed to non-controlling interests.

NOTE 2: SIGNIFICANT ACCOUNTING POLICIES (CONTD.)

D. Functional currency and foreign currency

2) Transactions, assets and liabilities in foreign currency

Transactions denominated in foreign currency are recorded on initial recognition at the exchange rate at the date of the transaction. After initial recognition, monetary assets and liabilities denominated in foreign currency are translated at each balance sheet date into the functional currency at the exchange rate at that date. Exchange differences, other than those capitalized to qualifying assets or carried to equity in hedging transactions, are recognized in the statement of income. Non-monetary assets and liabilities measured at cost are translated at the exchange rate at the date of the transaction. Non-monetary assets and liabilities denominated in foreign currency and measured at fair value are translated into the functional currency using the exchange rate prevailing at the date when the fair value was determined.

3) CPI-linked monetary items

Monetary assets and liabilities linked to the changes in the Israeli Consumer Price Index ("the Israeli CPI"), other than a lease liability, are adjusted at the relevant index at each balance sheet date according to the terms of the agreement.

E. Operating cycle

The Company's normal operating cycle does not exceed one year.

F. Cash equivalents

Cash equivalents are considered as highly liquid investments, including unrestricted short-term bank deposits with an original maturity of three months or less from the date of acquisition, which are not pledged.

G. Short-term deposits

Short-term bank deposits are deposits with an original maturity of more than three months from the date of acquisition that do not meet the definition of cash value. The deposits are presented according to their terms of deposit.

H. Inventory

Inventory is measured at the lower of cost or net realizable value (other than current produced crude oil inventory, which is measured at fair value less selling expenses). The cost of inventories includes expenditure incurred in acquiring the inventories and the costs incurred in bringing them to their existing location and condition. Net realizable value is the estimated selling price in the ordinary course of business less the estimated costs of completion and the estimated selling expenses.

NOTE 2: SIGNIFICANT ACCOUNTING POLICIES (CONTD.)

H. Inventory (contd.)

Cost of inventories is assigned as follows:

Fuels and consumer goods	–	The cost of fuel in operating inventory is based on the quarterly weighted average. The cost of consumer goods inventory is based on the retail inventory method.
Inventory of crude oil and related materials	–	Current crude oil inventory is measured at its fair value less selling costs. Non-current crude oil inventory is measured at its historical cost. Inventory of related materials is measured at cost, calculated according to the FIFO method.
Other	–	Based mainly on moving average

The Company periodically evaluates the condition and age of inventories and makes provisions for slow moving inventories accordingly.

If in a particular period production is not at normal capacity, the cost of inventories does not include additional fixed overheads in excess of those allocated based on normal capacity. Such unallocated overheads are recognized as an expense in the statement of income in the period in which they are incurred. Similarly, the cost of the inventory does not include exceptional amounts in respect of the materials, labor or other costs resulting from inefficiency.

I. Financial instruments

1) `Financial assets

As at the date of initial recognition, financial assets within the scope of the standard are measured at fair value plus transaction costs that are directly attributable to acquisition of the financial asset, except in the case of a financial asset measured at fair value through profit or loss, when transaction costs are recognized in profit or loss.

The Group classifies and measures the debt instruments in its financial statements on the basis of the following criteria:

(A) The Group’s business model for managing financial assets

(B) The contractual cash flow characteristics of the financial asset

<u>The Group measures debt instruments at amortized cost when:</u>

The Group's business model is the holding of financial assets with the objective of collecting contractual cash flows and the contractual terms of the financial assets give rise on specific dates to cash flows representing solely payments of principal and interest for the amount of the unpaid principle.
Subsequent to initial recognition, instruments in this class will be measured according to their terms at cost plus direct transaction costs, at amortized cost, less a provision for impairment.
In addition, an entity may irrevocably designate a debt instrument for measurement at fair value through profit or loss on initial application if such designation eliminates or considerably reduces measurement or recognition inconsistency, for example, when the related financial liability is also measured at fair value through profit or loss.

NOTE 2: SIGNIFICANT ACCOUNTING POLICIES (CONTD.)

I. Financial instruments (contd.)

1) Financial assets (contd.)

<u>The Group measures debt instruments at fair value through other comprehensive income when:</u>

The Group's business model is the holding of financial assets with the objective of collecting contractual cash flows and selling financial assets, and the contractual terms of the financial assets give rise on specific dates to cash flows representing solely payments of principal and interest for the amount of the unpaid principle.
Subsequent to initial recognition, instruments in this group are measured at fair value. Profits or losses arising from fair value adjustments, other than interest and exchange rate differentials, are recognized in other comprehensive income.

<u>The Group measures debt instruments at profit or loss when:</u>

They do not meet the criteria for measuring at amortized cost or at fair value through other comprehensive income, as set out above.

<u>Equity instruments and other financial assets held for trading</u>

Financial assets that are investments in equity instruments do not meet the above criteria and are therefore measured at fair value through profit or loss.

Other financial assets held for trading, such as derivatives, including embedded derivatives separated from the host contract, are measured at fair value through profit or loss unless they are designated as effective hedging instruments.

For certain equity instruments not held for trading, at initial recognition, the Group may elect irrevocably to present subsequent fair value changes in other comprehensive income that would otherwise not have been measured at fair value through profit or loss. These changes will not be recognized in profit or loss in the future, even when the investment is derecognized.

Revenues from dividends from investments in equity instruments are recognized at the dividend record date in the statement of income.

2) Impairment of financial assets

The Group assesses at each reporting date the provision for loss in respect of financial debt instruments that are not measured at fair value through profit or loss.
The Group differentiates between two situations of recognition of a provision for loss:

(A) Debt instruments with no significant impairment in credit quality since initial recognition or with a low credit risk - the provision for loss recognized for this debt instrument will take into account expected credit losses in the 12 months period after the reporting date.

(B) Debt instruments with significant deterioration in credit quality since initial recognition and their credit risk is not low - the provision for loss recognized will take into account the expected credit losses - over the balance of the useful life of the instrument. The Group applies the expedient in the standard, according to which it assumes that the credit risk of a debt instrument did not increase significantly from the date of initial recognition, if it was determined on the reporting date that the instrument has a low credit risk, for example when the instrument has an external rating of "investment grade".

Impairment for debt instruments measured at amortized cost is recognized in the statement of income against a provision.
The Group has financial assets with short credit periods, such as trade receivables, for which it may apply the expedient set out in the standard, meaning that the Group will measure the provision for loss in an amount equal to expected credit losses throughout the useful life of the instrument. The Group elected to apply the expedient for these financial assets.

NOTE 2: SIGNIFICANT ACCOUNTING POLICIES (CONTD.)

I. Financial instruments (contd.)

3) Derecognition of financial assets

The Group derecognizes a financial asset when and only when:

(A) The contractual rights to the cash flows from the financial asset expire.

(B) The Group transfers the rights to receive the contractual cash flows on the financial asset in a transaction in which substantially all the risks and rewards of ownership of the financial asset are transferred or the Company retains some of the risks and rewards but it can be said that it had transferred control on the asset.

(C) The Group retains the contractual rights to receive the cash flows from the financial asset, but assumes a contractual obligation to pay these cash flows in full to a third party without substantial delay.

4) Financial liabilities

As at the date of initial recognition, the Group measures financial liabilities in the scope of the Standard at fair value less transaction costs directly attributable to the issuance of the financial liability, except in the case of a financial liability measured at fair value through profit or loss, when transaction costs are recognized in profit or loss.

Subsequent to initial recognition, the Group measures financial liabilities at amortized cost in their entirety, except for:

(A) Financial liabilities at fair value through profit or loss, such as derivatives
(B) Financial liabilities created when transfer of the financial asset is not qualified for derecognition
(C) Contingent consideration recognized by a buyer in a business combination

5) Financial liabilities measured at fair value through profit or loss

At initial recognition, the Group measures financial liabilities that are not measured at amortized cost at fair value when transaction costs are recognized in profit or loss.

Subsequent to initial recognition, changes in fair value are attributed to profit or loss.

6) Derecognition of financial liabilities

The Group derecognizes a financial liability when, and only when, it is settled - that is, when the obligation defined in the contract expires or when it is discharged or cancelled.
A financial liability is extinguished when the debtor pays the liability by a cash payment, other financial assets, goods or services, or is legally discharged of the liability.

In the event of a change in the terms of an existing financial liability, the Group examines whether the terms of the liability are materially different from the existing conditions, taking into account qualitative and quantitative considerations.
When there is a substantial modification of the terms of an existing financial liability, or an exchange of debt instruments having substantially different terms between the Company and a lender, the transaction is accounted for as an extinguishment of the original financial liability and the recognition of a new financial liability. The difference between these two financial liabilities in the financial statements is recognized in profit or loss.
When there is a non-substantial modification of the terms of an existing liability, or an exchange of another liability with terms are not materially different, between the Company and the lender, the Group revises the amount of the liability, namely, the discounting of the new cash flows at the original effective interest rate, and the difference is recognized in profit or loss.

NOTE 2: SIGNIFICANT ACCOUNTING POLICIES (CONTD.)

I. Financial instruments (contd.)

7) Offsetting financial instruments

Financial assets and liabilities are offset and the net amount is presented in the statement of financial position if there is a legally enforceable right to set off the recognized amounts and there is an intent to dispose of the asset and liability on a net basis or realize the asset and dispose of the liability simultaneously. The right to offset must not only be legally enforceable in the normal course of business, but must also be enforceable in the event of bankruptcy or insolvency of one of the counterparties. Offset must not be contingent on a future event or periods of time in which they will not apply, or may be removed by a future event.

8) Put option granted to holders of non-controlling rights

When the Group grants a put option to non-controlling interests, these interests are classified as a financial liability that do not confer rights but rather their share in the profits of the Group. At each reporting date, the financial liability is measured at the present value of the estimated consideration to be transferred when the put option is exercised at the fair value of the consideration determined. Changes in the liabilities are recognized in profit or loss.

9) Embedded derivatives

According to the Standard, embedded derivatives in financial assets will not be separated from a host contract. These hybrid contracts will be measured in their entirety at amortized cost or at fair value, in accordance with the criteria of the business model and contractual cash flows.

When a host contract does not meet the definition of a financial asset, an embedded derivative is separated from the host contract and accounted for as derivative when the economic characteristics and risks of the embedded derivative are not closely related to the economic characteristics and risks of the host contract, the embedded derivative meets the definition of a derivative, and the instrument involved is not measured at fair value when changes are recognized in profit or loss.

Reassessment of the deed for separation only occurs if there is a change in the terms of the contract that significantly modifies the cash flows that would otherwise be required.

10) Compound financial instruments

Convertible debentures issued in foreign currency include two components: the conversion component and the debt component. The liability conversion component is initially recognized as a financial derivative at fair value. The balance is attributed to the debt component. Direct transactions costs are allocated between the liability conversion component and the liability debt component, based on the allocation of the consideration for each component.

NOTE 2: SIGNIFICANT ACCOUNTING POLICIES (CONTD.)

J. Hedge accounting and derivative financial instruments

Any profits or losses arising from changes in the fair values of derivatives that do not qualify for hedge accounting are recognized directly in the statement of income.

Hedge transactions qualify as accounting hedging when, at the inception of the hedge, there is formal designation and documentation of the hedging relationships and the risk management objectives and strategy of the Group for hedging. The hedge is tested on an ongoing basis and determined in practice when it is highly effective throughout the financial reporting period to which the hedge is assigned.

Hedging transactions are accounted for as follows:

Cash flow hedges

The effective portion of the profit or loss on the hedging instrument is recognized directly in equity as other comprehensive income (loss), while any ineffective portion is recognized immediately in the statement of income.

Other comprehensive income (loss) is transferred to the profit or loss when the hedged transaction results are recognized in profit or loss, such as when the hedged income or expense is recognized in profit or loss or when a forecast sale occurs. Where the hedged item is a non-financial asset or liability, this cost also includes the amount of the profit (loss) from the hedged instrument.

Hedge accounting is discontinued prospectively only when the hedging relationships (or part of them), no longer comply with the qualifying criteria (after taking into account any rebalancing of hedge relationships, if relevant) including cases where the hedging instrument expires, is sold, canceled or exercised. When the Company discontinues hedge accounting, the amount accrued in the hedge fund will remain in the hedge fund until the cash flow occurs or is classified in profit or loss, if the future hedged cash flows are no longer expected to occur.
When put options are used as hedging instruments, only the internal value of the options are designated for hedging, while the time value is recognized under financing expenses in the statement of income.

K. Treasury shares

The Company's shares held by it are presented at cost offset by the Company's capital. Any profit or loss from purchase, sale, issue or cancellation of treasury shares is recognized directly in equity.

L. Leases

As set out in Note 2FF regarding initial application of IFRS 16, Leases ("IFRS 16"), the Company elected to apply IFRS 16 retrospectively (without restatement of comparative data).

The accounting policy applied as from January 1, 2019 for leases is as follows:

The Group accounts for a contract as a lease when the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration.

1) The Company as a lessee

For transactions in which the Group is a lessee, the Group recognizes a right of use asset and a lease liability on the inception date of the lease, with the exception of leases of up to one year and leases where the underlying asset has a low value, in which case the Group elected to recognize the lease payments as an expense in profit or loss on a straight-line basis over the lease period.

NOTE 2: SIGNIFICANT ACCOUNTING POLICIES (CONTD.)

L. Leases (contd.)

1) The Company as a lessee (contd.)

At the inception date, the lease liability includes all the lease payments that are not paid, discounted by the interest rate implicit in the lease, when it can be readily determined, or at the incremental borrowing rate of the Company. After inception, the Company uses the effective interest method to measure the lease liability.

The right of use asset at the inception date is recognized in the amount equal to the lease liability plus lease payments made on or before the effective date plus transaction costs incurred.
The right of use asset is accounted for using the cost model and depreciated over the shorter of the lease term and the useful life.

Where there are indications of impairment, the Company assesses impairment of the right of use asset in accordance with IAS 36.

2) The Group as a lessor

The tests for classifying leases as finance or operating leases depend on the substance of the agreement and are made at the inception of the lease in accordance with the principles set out in IFRS 16:

A. <u>Finance lease</u>

A lease that transfers substantially all the risks and rewards incidental to ownership of an underlying asset is classified as a finance lease.

B. <u>Operating lease</u>

A lease that does not transfer substantially all the risks and rewards incidental to ownership of an underlying asset is classified as an operating lease. The lease payments are recognized as income in profit or loss, on a straight-line basis over the lease term. Initial direct costs incurred for the lease are added to the cost of the leased asset and recognized as an expense over the lease period on the same basis.

3) CPI-linked lease payments

At the inception date of the lease, the Group uses the CPI rate in effect at the inception date to calculate future lease payments.

In transactions in which the Group is a lessee, changes in the amount of the future lease payments due to a change in the CPI are discounted (without a change in the discount rate applicable to the lease liability) by the right of use asset and are recognized as an adjustment to the lease liability, only when there has been a change in the cash flows from the change in the CPI (meaning, when the adjustment for the lease payments came into effect).

4) <u>Variable lease payments</u>

Variable lease payments that are based on performance or use and are not dependent on the CPI or interest rate are recognized as an expense in transactions in which the Group is a lessee, and as revenue in transactions in which the Group is a lessor, on the inception date.

NOTE 2: SIGNIFICANT ACCOUNTING POLICIES (CONTD.)

L. Leases (contd.)

5) Options to extend and cancel a lease period

The non-cancellable lease period also includes periods covered by an option to extend the lease when it is reasonably certain that the option to extend the lease period will be exercised and periods covered by an option to cancel the lease when it is reasonably certain that the option to cancel will not be exercised.
If there is a change in the expectation that the Company will exercise the option to extend the lease, or will not exercise the cancellation option, the Company re-measures the lease liability according to the revised lease period, using a new discount rate. The total change is recognized against the right-of-use asset until it is reduced to zero, and then in profit or loss.

The accounting policy applied as from December 31, 2018 for leases is as follows:

The tests for classifying leases as finance or operating leases depend on the substance of the agreements and are made at the inception of the lease in accordance with the principles below as set out in IAS 17.

The Company as a lessee

1) Finance lease

Finance leases transfer to the Group substantially all the risks and benefits incidental to ownership of the leased asset. At the commencement of the lease term, the leased asset is measured at the fair value of the leased asset or, if lower, at the present value of the minimum lease payments.

2) Operating lease

Lease agreements are classified as an operating lease if they do not transfer substantially all the risks and benefits incidental to ownership of the leased asset. Initial direct costs incurred for the lease are added to the cost of the leased asset and recognized as an expense together with income from the lease. The lease payments are recognized as income in profit or loss, on a straight-line basis over the lease term.

The Group as a lessor

1) Finance lease

Finance leases transfer to the lessor all the risks and benefits incidental to ownership of the leased asset. The leased asset is derecognized and a finance asset is recognized, payable for a finance lease, in the present value of the lease proceeds.

2) Operating lease

Assets are classified as an operating lease if they do not transfer substantially all the risks and benefits incidental to ownership of the asset. Initial direct costs incurred for the lease are added to the cost of the leased asset and recognized as an expense over the lease period on the same basis. The lease payments are recognized as income in profit or loss, on a straight-line basis over the lease term.

NOTE 2: SIGNIFICANT ACCOUNTING POLICIES (CONTD.)

M. Business combinations and goodwill

Business combinations are accounted for by the acquisition method. The cost of the acquisition is measured at the fair value of the consideration transferred at the acquisition date, including any non-controlling interests in the acquiree. In any business combination, the Company elects whether to measure the non-controlling interests in the acquiree at fair value at the acquisition date or in accordance with the proportionate share of the fair value of the net identifiable assets of the acquiree. Direct acquisition costs are recognized in the statement of income as incurred.

In a business combination achieved in stages, the acquirer remeasures its previously held equity interest in the acquiree at its acquisition date at fair value and recognizes the revalued prior investment in the statement of income at the date control was established.

Contingent consideration is recognized at its fair value at the acquisition date. Contingent consideration is classified as a financing asset or liability according to IFRS 9. Subsequent changes in fair value of the contingent consideration are recognized in the statement of income. If the contingent consideration is classified as an equity instrument, it is measured at fair value on the acquisition date without subsequent measurement.

Goodwill is initially measured at cost which represents the difference between the acquisition consideration and the amount of non-controlling interests over the net identifiable assets acquired and liabilities assumed. If the resulting amount of goodwill is negative, the acquirer will recognize the resulting gain on the acquisition date.

<u>Acquisitions of subsidiaries that are not business combinations</u>

Upon the acquisition of subsidiaries and operations that do not constitute a business, the acquisition consideration is only allocated between the acquired business identifiable assets and liabilities based on their relative fair values on the acquisition date without attributing any amount to goodwill or to deferred taxes, whereby the non-controlling interest, if any, participates at its relative share of the fair value of the net identifiable assets on the acquisition date. Direct costs related to the acquisition are discounted as part of the acquisition consideration.

N. Investments accounted for using the equity method

The investment in an associate is accounted for using the equity method. According to this method, the investment in the associate is recognized in the balance sheet at cost plus changes in the Group’s share in the net assets, including the other comprehensive income (loss) of the associate.

The equity method is implemented up to the earlier of the date the Group loses significant influence or the investment is reclassified as an investment held for sale according to IFRS 5.

Goodwill relating to the acquisition of an associate is initially measured as the difference between the acquisition cost and the Group's share in the net fair value of the associate's identifiable assets, liabilities and contingent liabilities. After initial recognition, goodwill is measured at cost and is not systematically amortized. Goodwill is examined for impairment as part of the investment in an associate as a whole.

If additional shares are acquired in an equity-accounted associate, the Group calculates the purchase price allocation for each tranche separately. Upon a decrease in the equity interests in an associate while retaining significant influence in the associate, the Company realizes a relative portion of its investment in the associate and recognizes a profit or loss from the disposal, including the reclassification of the proportionate share of cumulative amounts previously recognized in other comprehensive income (loss) of the associate.

NOTE 2: SIGNIFICANT ACCOUNTING POLICIES (CONTD.)

N. Investments accounted for using the equity method (contd.)

Losses of associates in amounts which exceed their equity are recognized by the Company to the extent of its investment in the associates with the addition of any losses that the Company may incur as a result of a guarantee or other financial support provided in respect of these associates.

The financial statements of the Company and its associates are prepared as at the same dates and periods, other than one associate whose financial statements are prepared as at the three months preceding the date of the Company's financial statements. The Company makes adjustments for the effect of significant transactions or significant events occurring between the reporting date of the associate and the reporting date of the Company. Profit or loss from transactions between the Group and the associate is eliminated according to the rate of holding.

O. Investment property

An investment property is property (land or a building or both) held by the owner (lessor under an operating lease) or by the lessee under a lease to earn rentals or for capital appreciation or both, rather than for use in the production or supply of goods or services, for administrative purposes, or for sale in the ordinary course of business.

Investment property is measured initially at cost, including costs directly attributable to the acquisition. After initial recognition, investment property, including investment property under construction, is measured at fair value which reflects market conditions at the reporting date. Profits or losses arising from changes in the fair values of investment property are included in the statement of income when they arise.

The cost basis of property under development includes the cost of land plus the costs of credit used to finance the construction, direct incremental planning and development costs and brokerage fees for rental agreements.

The Group determines the fair value of investment property on the basis of a valuation by outside independent valuators who are experts in the valuation of property and have the appropriate expertise experience as well on the valuation of internal expert valuators.

NOTE 2: SIGNIFICANT ACCOUNTING POLICIES (CONTD.)

P. Fixed assets

Items of fixed assets are measured at cost with the addition of direct acquisition costs, less accumulated depreciation and impairment losses and excluding day-to-day servicing expenses. Cost includes spare parts and auxiliary equipment that can be used only in connection with the machinery and equipment.

The cost of self-constructed assets includes the cost of materials, direct labor and borrowing costs as well as any costs directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management, and the present value of the expected cost item for decommissioning and restoring the site on which they are located (see below).

Depreciation is calculated on a straight-line basis over the useful life of the assets at annual rates as follows:

	%	Primarily %
Buildings	2-10	4
Machines, facilities and equipment	2-15	5
Vehicles	15-20	
Computers, furniture, and office equipment	6-33	
Works of art	Without depreciation	
Leasehold improvements	Over the shorter of the lease term, including the extension option held by the Group and intended to be exercised, and the expected life of the improvement.	

The cost of an item of fixed assets includes the initial estimate of the cost of decommissioning and removing the item and restoring the site on which it is located. The liability is first measured at its present value and changes in the liabilities deriving from passage of time are recognized profit or loss. The residual value and the useful life of each asset are reviewed at least at each year-end and changes are accounted for prospectively as a change in an accounting estimate. For further information about impairment of fixed assets, see section S below.

Depreciation of an asset ceases at the earlier of the date that the asset is classified as held for sale and the date that the asset is derecognized.

NOTE 2: SIGNIFICANT ACCOUNTING POLICIES (CONTD.)

Q. Borrowing costs for qualifying assets

A qualifying asset is an asset that necessarily takes a substantial period of time to get ready for its intended use or sale and includes fixed assets and inventories.

The capitalization of borrowing costs commences when the activities to prepare the qualifying asset are in progress and ceases when substantially all the activities to prepare the qualifying asset for its intended use or sale are complete.
The amount of borrowing costs capitalized in the reporting period do not exceed over the borrowing costs that have been incurred in the reported period.

R. Intangible assets

Separately acquired intangible assets are measured on initial recognition at cost with the addition of costs directly attributable to the acquisition. Intangible assets acquired in a business combination are included at the fair value at the acquisition date. After initial recognition, intangible assets are carried at their cost less any accumulated amortization and any accumulated impairment losses. Expenditures relating to internally generated intangible assets, excluding capitalized development costs, are recognized in the statement of income when incurred.

According to management's assessment, intangible assets have a finite useful life. The assets are amortized over their useful life using the straight-line method and reviewed for impairment whenever there is an indication that the intangible asset may be impaired. The amortization period and the amortization method for an intangible asset with a finite useful life are reviewed at least once a year.

The length of the useful life of the intangible assets is as follows:

	Years
Marketing rights and customer relations	10-12
Software	10-33
Brands and trademarks	3-20
Non-competition agreements	5-20

Intangible assets with indefinite useful lives are not systematically amortized and are tested for impairment annually or whenever there is an indication that the intangible asset may be impaired. See also section S. The useful life of these assets is reviewed annually to determine whether their indefinite life assessment continues to be supportable.

S. Impairment of non-financial assets

The Group evaluates the need to record an impairment of the carrying amount of non-financial assets whenever events or changes in circumstances indicate that the carrying amount is not recoverable. When the carrying amount of non-financial assets exceeds their recoverable amount, the assets are reduced to their recoverable amount. The recoverable amount is the higher of fair value less costs of disposal and value in use. When measuring value in use, the expected future cash flows are discounted using a pre-tax discount rate that reflects the risks specific to the asset. The recoverable amount of an asset that does not generate independent cash flows is determined for the cash-generating unit to which the asset belongs. Impairment losses are recognized in profit or loss.

An impairment loss of an asset, other than goodwill, is reversed only if there have been changes in the estimates used to determine the asset's recoverable amount since the last impairment loss was recognized. Reversal of the loss is limited to the lower of the amount of previously recognized impairment of the asset (net of depreciation or amortization) or the recoverable amount of the asset.

NOTE 2: SIGNIFICANT ACCOUNTING POLICIES (CONTD.)

S. Impairment of non-financial assets (contd.)

When assessing the impairment of gas stations operated by a subsidiary in Israel, these stations are considered as a single cash generating unit, among others, due to the common customer base and the business inter-dependency of the various stations. Nevertheless, in cases where the subsidiary's management is of the opinion that certain stations do not contribute to the chain of gas stations, each of these stations is considered as a separate cash generating unit.

To assess impairment of oil and gas assets, the Group’s assets in a number of reservoirs are grouped into one cash generating unit, in cases where there is dependence on positive cash flows arising from the reservoirs or there is joint use of infrastructure.

The following criteria are applied in assessing impairment of these specific assets:

1) Goodwill

The Group reviews goodwill impairment once a year or more frequently if events or changes in circumstances indicate that there is impairment.

Impairment is recognized for goodwill by assessing the recoverable amount of the cash-generating unit (or group of cash-generating units) to which the goodwill belongs. An impairment loss is recognized if the recoverable amount of the cash-generating unit (or group of cash-generating units) to which goodwill has been allocated is less than the carrying amount of the cash-generating unit (or group of cash-generating units). Impairment losses recognized for goodwill cannot be reversed in subsequent periods.

2) Investees accounted for using the equity method

After implementing the equity accounting method, the Group assesses whether it is necessary to recognize further loss for impairment of the investment in associates. At each balance sheet date, the Group assesses whether there is objective evidence that the investment in an associate has been impaired. Impairment is assessed for the entire investment, including goodwill attributable to the associate. Impairment loss, as above, is not allocated specifically to goodwill that forms part of the investment and, accordingly, any reversal of that impairment loss is recognized to the extent that the recoverable amount of the investment subsequently increases.

3) Intangible assets with indefinite useful life

The Group assesses goodwill for impairment annually, or more frequently if events or changes in circumstances indicate impairment.

NOTE 2: SIGNIFICANT ACCOUNTING POLICIES (CONTD.)

T. Results of oil and gas exploration and development and investments in proved reserves

1) Expenses in the exploration and appraisal stage

Oil and gas investments and exploration are accounted for using the successful effort method, according to which:

A) Expenses for participation in geological and seismic tests and surveys, which are used to form a conclusion regarding the continuation of the exploration plan, are recognized in profit or loss as incurred.

B) Investments in oil and gas drillings that are in the drilling stage for reservoirs that are not yet proven to produce oil or gas or that are yet to be classified as being non-commercial, are recognized as exploration and appraisal assets in the balance sheet at cost under investment in oil and gas assets.

C) Investments in oil and gas drillings, for reservoirs proved to be dry and were abandoned, or that were classified as non-commercial, are written off from exploration and appraisal assets in the statement of income.

D) Investments for reservoirs that have technical feasibility and commercial viability of oil or gas production (which are being appraised in a range of events and circumstances, mainly approval from the Commissioner of Petroleum Affairs that the reservoir is a commercial discovery and/or obtaining a lease from the Commissioner in the license area), are classified as oil and gas assets, reclassified from exploration and appraisal assets to oil and gas assets.

2) Oil and gas assets

The oil and gas assets item in the balance sheet includes costs accumulated for the Group's proven oil and gas assets. These costs, which include mainly costs for acquisition of rights (mainly in offshore areas), exploration drillings, engineering planning, development drilling, acquisition and establishment of production facilities and pipelines for the delivery of the oil the gas to the point onshore, and onshore and the estimated costs for disposing of the assets (see section 5 below). The costs in this section are amortized to the statement of income according to the units of production method, based on the actual production volume in the period compared with the total proved and probable reserves (P2), as appraised by an external expert. When calculating the amortization of oil and gas assets on the basis of P2 reserves, the Group takes into account the future amount (in undiscounted values) of the investments required to produce the same amounts. This amount is also estimated on the basis of an external expert opinion.

3) Assessment of impairment of exploration and appraisal assets and oil and gas assets

Oil and gas exploration and appraisal assets are tested for impairment when the facts and circumstances indicate that the carrying amount of the exploration and appraisal asset and the oil and gas asset exceeds its recoverable amount in accordance with IFRS 6 and IAS 36 (see section S above).

NOTE 2: SIGNIFICANT ACCOUNTING POLICIES (CONTD.)

T. Results of oil and gas exploration and development and investments in proved reserves (contd.)

4) Farm-out agreements in the exploration and appraisal stages

In farm-out arrangements, the farmee transfers all the risks and rewards to the farmor for the transferred part in exchange for the farmor's undertaking to finance certain costs.

A) Farm-out agreements

Farm-out is the transfer of part of the rights in an oil and/or gas field in consideration for an agreement by the transferee (the Farmee") to meet, absolutely, certain expenses that would otherwise have to be undertaken by the owner ("the Farmor").

The Farmor accounts for the farm-out arrangement as follows:

(1) The Farmor does not record any expense made by the Farmee on its behalf.
(2) The Farmor will derecognize the part of the oil and gas rights sold to the Farmee.
(3) The Farmor recognizes the farm-out arrangement in the statement of income in the amount of the difference between the consideration received or due and the carrying amount of the derecognized rights.

B) Farm-in agreements

Farm-in is the acquisition of part of the right in an oil and/or gas field in consideration for an agreement with the Farmor to sell part of the rights to the Farmee. In farm-in transactions where the acquired business does not constitute a business, the accounting treatment is as follows:
As the costs are incurred, the Farmee recognizes the expense or asset, as the case may be, for its share in the oil and gas assets and for the Farmor's remaining rights, in compliance with the accounting policy for exploration and appraisal assets.

The Farmee accounts for the farm-out arrangement as follows:

(1) The Farmee recognizes its share in the expenses in accordance with the farm-out agreement, including expenses arising from the part that the Farmor imposed on the Farmee under the farm-out agreement.
(2) The Farmor recognizes expenses in accordance with the farm-out agreement in the same way that it accounts for exploration and appraisal costs that it bears directly.

Expenses entailed in the purchase of rights to licenses, titles and preliminary permits for oil and gas drilling, including increasing the Group's share in joint ventures, are accounted for as aforesaid.

The surplus cost from a business combination or acquisition of companies, partnerships and joint ventures that own such reserves, is allocated to investment in oil and gas reservoirs and amortized as described above. The surplus cost from licenses before start of production is not systematically amortized.

5) Measuring an asset and obligation to dispose of assets

The Group recognized for the first time a liability together with an asset (which is amortized according to the depletion method described above) for its share in the obligation to dispose of assets, mainly the production platform at the end of its use for plugging the wells. The liability was first measured at present value and the expenses arising from the passage of time are recognized in the statement of income. Changes in timing and in the amount of economic resources that are required for disposal of the obligation and changes in the discount rate are added or deducted from the asset in the current period together with a change in the liability.

NOTE 2: SIGNIFICANT ACCOUNTING POLICIES (CONTD.)

T. Results of oil and gas exploration and development and investments in proved reserves (contd.)

6) The tax on oil profits under the Taxation of Profits from Natural Resources Law, 2011 is accounted for in accordance with IFRIC 21, Levies, according to which the expense for the levy is recognized on the date on which the obligation to pay arises. In the reporting year, the Group recognized an expense for the tax on oil profits for the Tamar project. As of the approval date of the financial statements, there are a number of interpretive disputes with the Tax Authority. According to the Partnership’s estimates, as at December 31, 2020, the obligation to pay the tax in the Tamar project arose and the Group’s financial statements included a provision for payment of the tax in 2020. The Partnership's estimates were made to the best of its knowledge and based, among other things, on the opinions of its legal counsel regarding the disputed issues, and it is estimated that it is more likely than not that the Partnership’s claims will be accepted. See Note 12S below.

U. Taxes on income

The tax results for current or deferred taxes are recognized in the statement of income except to the extent that the tax arises from items which are recognized directly in equity or in other comprehensive income

1) Current taxes

The current tax liability is measured using the tax rates and tax laws that have been enacted or substantively enacted by the balance sheet date as well as adjustments required in connection with the tax liability for previous years.

2) Deferred taxes

Deferred taxes are computed for temporary differences between the carrying amounts in the financial statements and the amounts attributed for tax purposes, with a limited number of exceptions. Deferred tax balances are calculated according to the tax rate that is expected to apply to equity at the reversal date, based on tax laws that have been enacted or substantively enacted by the balance sheet date.

At each reporting date, deferred tax assets are assessed in accordance with their expected use. Carryforward losses and deductible temporary differences for which deferred tax assets were not recognized are tested at each balance sheet date and the relevant deferred tax asset is recognized if it is expected to be utilized.

The calculation of deferred taxes does not take into account the taxes that would be applicable in the case of disposal of investments in investees, provided that the sale of these investments is not likely in the foreseeable future. Also, deferred taxes that would apply in the event of distribution of earnings by investees as dividends have not been taken into account in computing deferred taxes, since the distribution of dividends does not involve an additional tax liability or since it is the subsidiary's policy not to initiate distribution of dividends that triggers an additional tax liability.

In the event of sale of shares of a subsidiary, the tax effects arising from net profits or losses accrued up to the date of sale for the exercised shares are recognized in the statement of income or other comprehensive income, as relevant, while the effect of tax for the difference between the consideration received and the balance of the investment in the exercised shares immediately before the sale is recognized directly in equity.

Deferred taxes are offset in the statement of financial position if there is a legally enforceable right to offset a current tax asset against a current tax liability and the deferred taxes relate to the same taxpayer and the same taxation authority.

NOTE 2: SIGNIFICANT ACCOUNTING POLICIES (CONTD.)

V. Share-based payments

The Company's employees are entitled to remuneration in the form of share-based payment transactions as consideration for equity instruments (“Equity-settled Transactions”) and to cash-settled benefits based on the increase in the Company's share price (“Cash-settled Transactions”).

Equity-settled Transactions

The cost of Equity-settled Transactions with employees is measured at the fair value of the equity instruments granted at grant date. The fair value is determined using a standard pricing model. As for other service providers, transaction costs are measured at the fair value of the goods or services received in return for the equity instruments.
The cost of Equity-settled Transactions is recognized in profit or loss, together with a corresponding increase in equity, during the period which the performance and/or service conditions are to be satisfied, ending on the date on which the relevant employees become fully entitled to the award.
If the Group modifies the conditions on which equity-instruments were granted, an additional expense is recognized for any modification that increases the total fair value of the share-based payment arrangement or is otherwise beneficial to the employee at the modification date.

Cash-settled Transactions

The cost of Cash-settled Transactions is measured at fair value on the grant date using a standard pricing model. The fair value is recognized as an expense over the vesting period and a corresponding liability is recognized. The liability is remeasured at each reporting date until settled at fair value with any changes in fair value recognized in the profit or loss.
Benefits that include the right of the employee or service provider to sell back to the Company or to the Group companies its shares are accounted for as Cash-settled Transactions.

W. Liabilities for employee benefits

The Group has several employee benefit plans:

1) Short-term employee benefits

Short-term employee benefits are benefits which are expected to be fully paid up to 12 months after the end of the annual reporting period in which employees provide the services. A liability for a cash bonus or a profit-sharing plan is recognized when the Group has a legal or constructive obligation to make such payment as a result of past service rendered by an employee and a reliable estimate of the amount can be made.

2) Post-employment benefits

The Group has defined contribution plans pursuant to Section 14 to the Severance Pay Law in Israel, under which the Group pays fixed contributions and will have no legal or constructive obligation to pay further contributions if the fund does not hold sufficient amounts to pay all employee benefits relating to employee service in the current and certain periods.

Contributions to the defined contribution plan for severance pay or compensation are recognized as an expense when contributed simultaneously with receiving the employee's services.

NOTE 2: SIGNIFICANT ACCOUNTING POLICIES (CONTD.)

W. Liabilities for employee benefits (contd.)

2) Post-employment benefits (contd.)

In addition, the Group has a defined benefit plan for severance pay under the Severance Pay Law. According to the Law, employees are entitled to severance pay upon dismissal or retirement. The liability for severance pay is measured on the basis of the actuarial value of the projected credit unit. The actuarial assumptions include future salary increases and rates of employee turnover based on the estimated timing of payment. The amounts are based on discounted expected future cash flows using the interest rate based on the yield at the reporting date on CPI-linked high quality corporate debentures with maturity dates approximating the period for the Group's obligation for severance compensation.

The Company makes current deposits for its liability to pay compensation to some of its employees in pension funds and insurance companies ("the Plan Assets").

X. Revenue recognition

Revenue from contracts with customers is recognized in the statement of income when control of the asset or service is transferred to the customer. The price of the transaction is the amount of the consideration expected to be received in accordance with the terms of the contract, less the amounts collected for third parties (such as taxes).
In determining the amount of revenue from contracts with customers, the Group assesses whether it acts as a principal or as an agent in the contract. The Group is a principal when it controls the promised goods or services to the customer. In such cases, the Group recognizes revenue in the gross amount of the consideration. In cases where the Group acts as an agent, the Group recognizes revenue on a net basis, net of the amounts due to the principal.

1. Revenue from the sale of goods

Revenue from the sale of goods is recognized in the statement of income at a point in time when the goods sold are transfered to the customer. Generally, control is transferred when the goods are delivered to the customer.

2. Revenue from production of fuels, storage, and charter of tankers

Revenue from such services is recognized over time, over the period in which the customer receives and consumes the benefits provided by the Group's performance. The revenue is recognized in the reporting periods in which the services are provided.

3. Revenues from the rendering of services (including management fees)

Revenue from services rendered is recognized over time, over the period in which the customer receives and consumes the benefits provided by the Group's performance. The Group charges its customers in accordance with the payment terms in specific agreements. Payments may be made before or after the services are rendered, and accordingly the Group recognizes an asset or liability for the contract with the customer.

4. Revenue from royalties

Revenue from royalties for gas and oil assets is recognized on an accrual basis, in accordance with the nature of the agreement and its terms.

NOTE 2: SIGNIFICANT ACCOUNTING POLICIES (CONTD.)

X. Recognition of income (contd.)

5. Revenue from oil and gas sales

Revenue from the sale of oil and gas is recognized in profit or loss at a point in time when control is transferred to the customer. Control is generally transferred when ownership of the oil or gas is transferred to the customer.
The Group charges its customers in accordance with the payment terms in specific agreements. Payments may be made before or after control is transferred, and accordingly the Group recognizes an asset or liability for the contract with the customer.

6. Variable consideration

The Group determines the transaction price separately for each contract with a customer. When applying such judgment, the Group estimates the effect of each variable consideration in the contract, taking into account discounts, penalties, variations, claims and non-cash consideration. In determining the effect of the variable consideration, the Group generally uses the most likely amount method set out in IFRS 15, according to which the transaction price is based on the single most likely amount in a range of possible amounts of consideration in the contract. The Group includes amounts of variable consideration only if it is highly probable that a significant reversal in the amount of the revenue recognized will not occur when the uncertainty associated with the variable consideration is subsequently resolved.

7. Credit transactions

For some transactions, the Group grants the customer payment terms extending over more than one year. In such cases, the Group recognizes revenue according to the amount reflecting the price the customer would have paid in cash on the date the goods or services are received and the balance is recognized in finance income.

The Group elected to apply the optional expedient in IFRS 15 of not separating the credit component in transactions with credit terms that are for a period of one year of less and recognized revenue according to the consideration determined in the agreement, even if the customer paid for the goods or services before or after they are received.

8. Income from insurance business (refers to the discontinued operations of The Phoenix)

(A) Premiums

1) Premiums in life insurance and health insurance, including savings premiums and with the exception of intakes for investment contracts, are recognized as revenue when the Group is entitled to receive such premiums.
Cancellations are recorded when the notification is received from the policyholder or when initiated by The Phoenix due to arrears in payments, subject to legal provisions. The policyholder's participation in profits is deducted from the premium.

2) General insurance premiums are accounted for as income based on monthly reports. Insurance premiums usually refer to an insurance period of one year. Gross income from premiums and changes in unearned premium are accounted for under earned premiums, gross.
In the motor act branch of insurance in Israel, the insurance comes into effect only after payment of the insurance premium, therefore the premium is accounted for on the date of payment.
Insurance premiums for policies that come into effect after the balance sheet date or premiums for policies for a period exceeding one year are recorded as a prepaid income. Any law less the participation of the policy holders in profits, based on the valid agreements.

NOTE 2: SIGNIFICANT ACCOUNTING POLICIES (CONTD.)

X. Recognition of income (contd.)

8. Income from insurance business (refers to the discontinued operations of The Phoenix) (contd.)

(A) Premiums (contd.)

(2) (contd.):

Some of the premiums in Israel, primarily in the motor casco and comprehensive residential branches, include automatic renewals of policies due for renewal.
The income included in the financial statements is after cancellations requested by policyholders and net of cancellations and provisions due to non-payment of the premiums, subject to the regulations.

(B) Management fees and commissions

1) Management fees for performance-based insurance contracts

Management fees include the following components:
For policies sold as at 1 January 2004 – fixed management fees only
For policies sold up to December 31, 2003 – fixed and variable management fees

The management fees are computed in accordance with the Commissioner's directives on the basis of the yield and the accumulated saving of the policyholders in the profit-participating portfolio.

The fixed management fees are computed at fixed percentages of the accumulated saving and are recorded on a cumulative basis.

The variable management fees are computed as a percentage of the annual real profit (from January 1 to December 31) attributed to the policy, less the fixed management fees collected from that policy. Only positive variable management fees can be collected, net of negative amounts accumulated in the preceding years.
During each period, the variable management fees are recorded on an accrual basis in accordance with the real monthly yield if it is positive. In months when the real yield is negative, the variable management fees are reduced to the amount of the aggregate variable management fees collected since the beginning of the year. Negative yield for which a reduction of the management fees was not made during a current year, will be deducted for the purpose of computing the management fees from the positive yield in the subsequent year.

2) Management fees of non-insurance subsidiaries

Income from the management of pension funds and provident funds is recognized on the basis of the balances of the managed assets and on the basis of the receipts from the members.

Income from the management of mutual funds and income from the management of customer portfolios are recognized on the basis of the managed asset balance.

Income from general insurance commission in insurance agencies is recognized as incurred.

Income from life insurance commissions are recognized on the basis of the date of entitlement for payment of the commissions according to agreements with the insurance companies, net of provisions for refunds of commissions due to expected cancellations of insurance policies.

NOTE 2: SIGNIFICANT ACCOUNTING POLICIES (CONTD.)

X. Recognition of income (contd.)

8. Income from insurance business (refers to the discontinued operations of The Phoenix) (contd.)

(B) Management fees and commissions (contd.)

3) Net investment income (losses) and other finance income

Interest income is recognized as it accrues using the effective interest method.
Revenues from dividends from investments not accounted for using the equity method are recognized when the right to receive the dividend is established.
Investment income includes the profits or losses realized for available-for-sale financial assets. Profits or losses from the disposal of investments are calculated as the difference between the proceeds from the sale, net, and the initial or amortized cost and are recognized at the time of the sale.

Investment income includes profits or losses from revaluation of financial assets measured at fair value through profit or loss.

(C) Recognition of revenues from underwriting and distribution and from brokerage fees

1) Revenues from underwriting and distribution - revenues from commission for underwriting and distribution are recognized when the issuance and distribution is carried out, after fulfillment of the terms in the agreement with the Group and/or issuer.

2) Revenues from brokerage fees - revenues from commissions relating to transactions in securities are recognized on completion of the transactions.

Y. Price reductions from suppliers

Discounts are deducted from cost of purchase when the conditions entitling to those discounts are satisfied. The portion of the discounts relating to that portion of the purchases added to closing inventories is attributed to inventories and the balance reduces the cost of sales.

Supplier discounts received at the end of the year and for which the Group is not obligated to comply with certain targets, are recognized in the financial statements proportionately as the purchases entitling the Group to the discounts.

Supplier discounts for which the Group is required to meet certain targets are recognized in the financial statements in proportion to the purchases made by the Group during the year that qualify for the target, provided that it is expected that the targets will be achieved and the amount of the discount can be reasonably estimated.

Z. Earnings (loss) per share

Earnings (loss) per share are calculated by dividing the net profit (loss) attributable to shareholders of the Company by the weighted number of ordinary shares outstanding during the period..
Basic earnings per share only include shares that were actually outstanding during the period.
Potential ordinary shares are only included in the computation of diluted earnings per share when their conversion decreases earnings per share from continuing operations. Further, potential ordinary shares that are converted during the period are included in diluted earnings per share only until the conversion date and from that date in basic earnings per share. The Company's share of earnings of investees is based on the earnings per share of the investees multiplied by the number of shares held by the Group.

NOTE 2: SIGNIFICANT ACCOUNTING POLICIES (CONTD.)

AA. Provisions

A provision in accordance with IAS 37 is recognized when the Group has a present obligation (legal or constructive) as a result of a past event, it is probable that an outflow of resources embodying economic benefits will be required to settle the obligation and a reliable estimate can be made of the amount of the obligation. If the effect is material, the provisions are measured at their present value.

1) Environmental quality

The Group's financial statements include a provision for expected expenses related to decontamination and remediation of environmental hazards. The provision is recorded when the management believes that it is probable that the Company will be required to pay the costs and the amount of can be reasonably estimated. Environmental liabilities represent an estimate of the costs arising from examination and remediation of the contaminations created.

The management's assessment is based on internal and external estimates of the contaminations and the existing relevant remediation technology, and a review of applicable environmental regulations. Environmental liabilities accrue mostly no later than upon completion of the remedial review. The provision for these liabilities is adjusted as additional information is obtained or the circumstances change. The costs of purchasing the equipment required for the current remediation of environmental hazards are recorded as fixed assets.

2) Legal claims

A provision for claims is recognized if, as a result of a past event, the Group has a present legal or constructive obligation and it is more likely than not that the Group will require its economic resources to settle the obligation, and the amount of the obligation can be estimated reliably. When assessing the need for recognition and measurement of the provisions, Group companies are assisted by legal counsels.

BB. Advertising expenses

Advertising expenses are recognized in profit or loss as incurred.

CC. Non-current assets or a disposal group held for sale and discontinued operations

Non-currents assets or a disposal group are classified as held for sale if their carrying amount will be recovered principally through a sale transaction rather than through continuing use. These assets are not depreciated and are presented separately in the balance sheet, at the lower of their carrying amount and fair value less costs to sell. If the carrying amount is higher than the fair value less costs to sell, an impairment loss is recognized for the assets (or disposal group) to the extent of the difference. At the same time, liabilities associated with these assets are presented separately in the balance sheet, in a similar manner.

When the parent decides to sell part of its interest in a subsidiary so that after the sale the parent retains a non-controlling interest, all the assets and liabilities attributed to the subsidiary are classified as held for sale and the relevant provisions of IFRS 5 are applicable, including presentation as discontinued operations.

A discontinued operation is an operation that either has been disposed of or is classified as held for sale and represents a separate major line of business or geographical area of operations. The operating results of an operation that was discontinued or disposed of for all reporting periods (including comparative figures) are presented separately under profit (loss) from discontinued operations.

NOTE 2: SIGNIFICANT ACCOUNTING POLICIES (CONTD.)

DD. Insurance contracts (refers to the discontinued operations of The Phoenix)

IFRS 4, Insurance Contracts allows the insurer to continue with the same accounting policy that was in effect prior to the transition date to IFRS for insurance contracts that it issues (including related acquisition costs and related intangible assets) and the reinsurance contracts that it acquires

Summary of the accounting policy for insurance contracts:

1) Life insurance and long-term saving

(A) Recognition of revenue – see section X above.

(B) Liabilities for life insurance contracts

Liabilities for life insurance contracts in Israel are calculated according to the Commissioner's directives (regulations and circulars), generally accepted accounting principles and standard actuarial methods. The liabilities are calculated according to the relevant coverage data, such as the age of the policyholder, number of years of coverage, type of insurance and sum of insurance.

Liabilities for life insurance contracts are determined on the basis of actuarial assessments performed by the chief actuary at The Phoenix Insurance Ltd. ("The Phoenix Insurance"), Daniel Sharon. The share of reinsurers in liabilities for life insurance contracts is based on the terms of the relevant contracts.

Liabilities for CPI-linked life insurance contracts and CPI-linked investments used to cover these liabilities were included in the financial statements according to the most recently published CPI prior to the balance sheet date, including liabilities for life insurance contracts for policies with semi-annual linkage.

(C) Directives of the Commissioner regarding liabilities for annuities

Circulars issued by the Commissioner, regarding the calculation of the liabilities for annuities in life insurance policies provide directives on how to calculate the provisions as a result of the improvement in life expectancy that requires monitoring the adequacy of the liabilities for life insurance contracts that permit the receipt of an annuity, and their appropriate supplementation.

(D) Deferred acquisition costs

1) Deferred acquisition costs ("DAC") for life insurance policies sold as from January 1, 1999 include commission for agent and acquisition supervisors and general and administrative expenses related to the acquisition of new policies. DAC is amortized at equal annual rates over the policy period but not over more than 15 years. DAC for cancelled or settled policies are written off at the cancellation or settlement date.

2) The actuary of The Phoenix assesses the recoverability of the DAC every year. This assessment verifies that the liabilities for insurance policies, net of DAC is sufficient, and that the policies are expected to generate future income to cover amortization of DAC and the insurance liabilities, operating expenses and commissions for those policies
The assumptions used in this assessment, including assumptions regarding cancellations, operating expenses, yield on assets, mortality and illness rates, are determined by the Company's actuaries every year on the basis of past experience and relevant current surveys.

3) Commissions to agents and acquisition supervisors and pension agents) that are paid for acquisition of pension contracts for asset management (pension and provident funds) are recognized as deferred acquisition costs (DAC) if they are separately identifiable and reliably measured and if their refund is expected through expected management fees. DAC is amortized at equal annual rates over 10 years.

NOTE 2: SIGNIFICANT ACCOUNTING POLICIES (CONTD.)

DD. Insurance contracts (refers to the discontinued operations of The Phoenix) (contd.)

1) Life insurance and long-term saving (contd.)

(E) Liability adequacy testing for life insurance contracts

The Group tests for reserve adequacy. If the test indicates that the premiums received are insufficient to cover the expected claims, less insurance reserves at the calculation date, a special provision is recorded for the deficiency. Individual policies and collective policies are tested separately. Collective policies are tested on the single collective level.

The assumptions used in these tests include assumptions regarding cancellations, operating expenses, yield from assets, mortality and illness rates, and are determined by the actuary every year on the basis of past experience and other relevant surveys.

(F) Outstanding claims

Outstanding claims, net of the reinsurers' share therein, are computed on an individual case basis, according to the valuation of The Phoenix Insurance experts, based on the notifications regarding the insurance events and the sums insured.
The provisions for pension payments, annuities, long lasting payment claims for disability insurance, the direct and indirect expenses deriving from them, as well as the provisions for incurred but not yet reported claims (IBNR) are included under the liabilities for insurance contracts and investment contracts.

(G) Investment contracts

Intakes for investment contracts are not included in the item of earned premiums but are directly recorded under liabilities for insurance and investment contracts. Surrenders and maturities of these contracts are not included in the statement of income but are deducted directly from liabilities for insurance contracts and investment contracts.
For these contracts, investment revenue, management fees collected from the policyholders, change in liabilities and payments for insurance contracts for the share of the policyholders in investment revenue, commissions to agents, and general and administrative expenses are recognized in the statement of income.

(H) Provision for participation in earnings of policyholders in group insurance

The provision is included under other payables. In addition, the change in the provision is offset by income from the premium.

2) General insurance

(A) Recognition of income – see section X above.

(B) Payments and changes in liabilities for insurance contracts, gross and residual, include settlement and direct handling costs of claims paid and indirect expenses to settle outstanding claims that occurred in the reported year, as well as an adjustment of the provision for outstanding claims (including a provision for direct and indirect costs for handling claims) recorded in previous years.

NOTE 2: SIGNIFICANT ACCOUNTING POLICIES (CONTD.)

DD. Insurance contracts (refers to the discontinued operations of The Phoenix)

2) General insurance (contd.)

(C) Liabilities for insurance contracts and deferred acquisition costs

The insurance reserves and outstanding claims included in liabilities for insurance contracts, and the reinsurers' share in the reserve and in the outstanding claims under reinsurance assets, are computed in accordance with the Control of Financial Services Regulations (Insurance) (Calculation of General Insurance Reserves), 2013 ("the Calculation of Reserves Regulations), the Commissioner's directives, and standard actuarial methods for computing outstanding claims, which are applied according to the chief actuaries' discretion.

(D) Liabilities for insurance contracts are composed of insurance reserves and outstanding claims, as follows:

1) The unearned premium reserve reflects the insurance premium for the insurance period subsequent to the balance sheet date and is calculated on a daily basis.

2) Provision for premium deficiency The provision is recognized if the unearned premium (less deferred acquisition costs) does not cover the expected cost for insurance contracts. In the motor property, comprehensive housing, and business branches, the provision is based on a model in the Calculation of Reserves Regulations.

3) Insurance reserves and outstanding claims are computed according to the methods set out below:

3.1 Outstanding claims and the reinsurers' share therein are included on the basis of an actuarial valuation, except for the branches detailed in section 3.2 below. Indirect expenses to settle claims are included on the basis of an actuarial valuation.

3.2 Insurance for marine hull, aircraft including third-party liability, incoming business and other risks, for which the actuary determines that an actuarial model cannot be applied, due to the absence of statistical significant, included the outstanding claims based on a separate evaluation for each claim according to an opinion received from attorneys and experts of The Phoenix Insurance that handle claims according to the reports of ceding companies for incoming business, with the addition of IBNR if necessary. The evaluations include a suitable provision for settlement and handling expenses not yet paid at the date of the financial statement

NOTE 2: SIGNIFICANT ACCOUNTING POLICIES (CONTD.)

DD. Insurance contracts (refers to the discontinued operations of The Phoenix)

2) General insurance (contd.)

(D) Liabilities for insurance contracts are composed of insurance reserves and outstanding claims, as follows: (contd):

3) Insurance reserves and outstanding claims are computed according to the methods set out below: (contd.)

3.3. Excess of income over expenses

For businesses with long tail claims (branches in which it could be several years before the claim is settled), such as the liability and motor act branches, up to December 31, 2015, excess of income over expenses is calculated on a tri-annual aggregate basis ("the Excess").
The Excess is calculated in accordance with the Reserve Calculation Regulations and the Commissioner's directives, based on revenue from premiums less claims and acquisition costs (up to a limit determined by the Commissioner as a percentage of the premium), plus revenue from investments calculated at an annual rate of 3% (independent of actual return on the investments), less the share of reinsurers, according to insurance branch and underwriting year. The Excess accumulated until its release, from the beginning of the insurance period, net of the unearned premium reserve, net of deferred acquisition costs, and net of outstanding claims as described above aforesaid, is included in liabilities for the insurance contracts up to December 31, 2015. If the actuary estimates that any underwriting year will end in a loss, the loss is recognized in the statement of income in that same year.
For information about cancellation of the Excess, see section 3.6.

3.4 Claims recoveries and salvage are taken into consideration in the data-base by which the actuarial valuations of the outstanding claims are calculated.

3.5 The Phoenix Insurance believes that the outstanding claims are appropriate, given that the outstanding claims are calculated mainly on an actuarial basis and their balance includes appropriate provisions required for IBNR.

(E) Deferred acquisition costs in general insurance include fees for agents and general and administrative expenses for acquisition of polices, referring to unearned insurance premiums. The acquisition costs are calculated for each branch separately, on the basis of the actual rates of expenses or according to standard rates, as a percentage of the unearned premium, at the lower of the two.

(F) Business that is received from the Israeli pool for motor vehicle property insurance of the Association of Insurance Companies in Israel (the Pool), from other insurance companies (including co-insurance and incoming business from abroad) and from underwriting agencies, is reported according to the accounts received up to the balance sheet date with the addition of the relevant provisions, based on the insurance subsidiaries' rate of participation in them.

NOTE 2: SIGNIFICANT ACCOUNTING POLICIES (CONTD.)

DD. Insurance contracts (refers to the discontinued operations of The Phoenix)

3) Healthcare insurance

A. Recognition of income – see section X above.

B. Liabilities for health insurance contracts

Liabilities for health insurance contracts in Israel are computed according to the Commissioner's directives (regulations and circulars), generally accepted accounting principles and standard actuarial methods. The liabilities are calculated according to the relevant coverage data, such as the age of the policyholder, number of years of coverage, type of insurance and sum of insurance.

Health insurance liabilities and the reinsurers' share therein are determined on the basis of actuarial assessments.

C. Liability adequacy testing for health insurance contracts:

The Group tests for reserve adequacy. If the test indicates that the premiums received are insufficient to cover the expected claims, less insurance reserves at the calculation date, a special provision is recorded for the deficiency. Individual policies and collective policies are tested separately. Collective policies are tested on the single collective level.

The parameters and assumptions used in these tests include assumptions regarding cancellations, operating expenses, mortality and illness rates, which are determined by the actuary on the basis of past experience and other relevant surveys. For collective policies, tests are for reserve adequacy in accordance with experience of the collective claims.

D. Outstanding claims

The provisions for long lasting payment claims with respect to long-term care insurance, the direct and indirect expenses deriving from them, as well as the provisions for incurred but not yet reported claims (IBNR) are included under the insurance reserves.

E. Provision for profit sharing of policyholders in collective insurance

The provision for profit sharing of policyholders in collective insurance is included under other payables. In addition, the change in the provision is offset by income from the premium.

NOTE 2: SIGNIFICANT ACCOUNTING POLICIES (CONTD.)

DD. Insurance contracts (refers to the discontinued operations of The Phoenix) (contd.)

3) Healthcare insurance (contd.)

F) Deferred acquisition costs

1) Deferred acquisition costs ("DAC") include commission for agents and acquisition supervisors and general and administrative expenses related to acquisition of new policies. In health and hospitalization branches, policies are amortized at equal rates over the period of the policy, but no longer than six years, and in long-term health insurance branches (such as nursing and dread diseases) the policies are amortized over no more than 15 years. Deferred acquisition costs relating to canceled policies are written off on the cancellation date. (3) Commissions to acquisition supervisors and agents that are paid for acquisition of contracts for asset management of pension funds) are recognized as deferred acquisition costs (DAC) if they are separately identifiable and reliably measured and if their refund is expected through expected management fees. In the pension period, the DAC is amortized over the estimated period for receiving income from management fees, taking into account cancellations.

2) The Company's actuary assesses the recoverability of DAC every year. The assessment verifies that the liabilities for insurance policies (policies sold in 2005 and for which DAC is calculated), net of DAC is adequate and that the policies are expected to generate future income to cover DAC deduction, insurance liabilities, operating expenses and commissions for those policies.

The assumptions used in this assessment, which include assumptions regarding cancellations, operating expenses, yield on assets, mortality and illness rates, are determined by the actuaries every year on the basis of past experience and relevant current surveys.

EE. Adjustment to fair value

Fair value is the price that would be received when selling an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date.

Fair value measurement assumes a transaction taking place in the principal market for the asset or liability, or in the absence of a principal market, in the most advantageous market.

The fair value of the asset or liability is based on assumptions that would have been used by market participants to price the asset or liability, assuming that market participants act in their economic interests.

The Group uses valuation techniques that are appropriate to the circumstances and for which sufficient information is available to measure fair value, while maximizing the use of relevant observable data and minimizing the use of unobservable data.

All assets and liabilities measured at fair value, or for which there was fair value disclosure, are categorized within the fair value hierarchy, based on the lowest level of the data, which is significant to fair value measurement of a whole:

NOTE 2: SIGNIFICANT ACCOUNTING POLICIES (CONTD.)

FF Application of new accounting standards

1) IFRS 3, Business Combinations

In October 2018, the IASB issued an amendment to the definition of a business in IFRS 3, Business Combinations (“the Amendment”).

The Amendment clarifies that to be considered a business, an acquired set of activities and assets will include at least material input and processes that together have a significant contribution to the ability to produce outputs. The Amendment further clarifies that a business can also exist without all the inputs and the processes required to create outputs. The Amendment introduces an optional test to determine whether it is not acquisition of a business, without further testing.

The Amendment will be applied for business combinations and asset acquisitions for which the acquisition date as from the annual reporting period beginning on or after January 1, 2020.

Initial application of IFRIC 23 did not have a significant effect on the Group's financial statements.

2) Amendments to IFRS 7 and IFRS 9

In September 2019, the IASB issued amendments to IFRS 9, Financial Instruments; IFRS 7, Financial Instruments: *Disclosures ("the Amendment").*

The Amendment provides temporary reliefs for companies implementing hedge accounting based on the IBOR interest rate and affected by the uncertainty arising from the expected reform in the interest rate benchmark. *The interest reform results in uncertainty regarding the dates and amounts relevant to future cash flows related to both hedging instruments and to hedged items.*

The Amendment is effective for annual periods beginning as from January 1, 2020.

Application of the Amendment did not have an effect on the Company’s financial statements.

NOTE 2: SIGNIFICANT ACCOUNTING POLICIES (CONTD.)

GG Disclosure of new IFRSs in the period prior to their adoption

1) Amendment to IAS 16, Property, Plant and Equipment

In May 2020, the IASB published an amendment to IAS 16 ("the Amendment"). The Amendment prohibits the deduction from cost of any proceeds received from selling items produced while the entity is preparing the asset for its intended use. Instead, the Company will recognize the proceeds from the sale and the associated costs in profit or loss.

The Amendment will be applied for annual reporting periods beginning on January 1, 2022 or after. Earlier application is permitted. The Amendment will be applied retrospectively, but only to items of property, plant and equipment that are brought to the location and condition necessary for them to be capable of operating in the manner intended by management on or after the beginning of the earliest period presented in the financial statements in which the entity first applies the Amendment. The entity should recognize the cumulative effect of initially applying the Amendment as an adjustment to the opening balance of retained earnings at the beginning of that earliest period presented.

In the opinion of the Company, the above is not expected to have a material effect on the financial statements.

2) Amendment to IAS 37, Provisions, Contingent Liabilities and Contingent assets

In May 2020, the IASB issued an amendment to IAS 37 to clarify what costs an entity considers in assessing whether a contract is onerous (“the Amendment”).

According to the Amendment, this assessment should include both incremental costs (such as raw materials and direct working hours) and the allocation of other costs that relate directly to fulfilling the contract (such as depreciation of fixed assets and equipment used in fulfilling the contract).

The Amendment will be applied for annual reporting periods beginning on January 1, 2022 or after. The Amendment will apply to contracts for which the obligations have not yet been fulfilled as at January 1, 2022. Earlier application is permitted.

In the opinion of the Group, the Amendment is not expected to have a material effect on the financial statements.

3) Improvements to IFRSs 2018-2020

In May 2020, the IASB issued amendments in the annual improvements to IFRSs 2018-2020 project. The following is the main amendment to IFRS 9:

The amendment to IFRS 9 clarifies the fees a company includes when it applies the ‘10 per cent’ test in section B3.3.6 of IFRS 9 in assessing whether the terms of a modified or exchanged financial liability are substantially different from the terms of the original financial liability.

The amendment will be applied for annual reporting periods beginning on January 1, 2022 or after. Earlier application is permitted. The amendment will be applied for the debt instrument that was modified or exchanged as of the year in which the amendment to the standard was first applied.

NOTE 2: SIGNIFICANT ACCOUNTING POLICIES (CONTD.)

GG Disclosure of new IFRSs in the period prior to their adoption

4) Amendment to IAS 1, Presentation of Financial Statements

In January 2020, the IASB issued an amendment to IAS 1 regarding requirements for classifying liabilities as current or non-current ("the Amendment").
The Amendment clarifies the following:

– What is meant by an unconditional right to defer settlement

– That a right to defer must exist at the end of the reporting period

– That classification is unaffected by the likelihood that an entity will exercise its deferral right

– That only if an embedded derivative in a convertible liability is itself an equity instrument would the terms of a liability not impact its classification

The Amendment will be applied for annual reporting periods beginning on or after January 1, 2023. The Amendment will be applied retrospectively.

The Company is assessing the effect of the Amendment on its current loan agreements.

5) Amendments to IFRS 9, IAS 39, IFRS 7, IFRS 4 and IFRS 16 regarding the IBOR interest rate reform

In August 2020, the IASB issued amendments to IFRS 9, Financial Instruments; IFRS 7, Financial Instruments: Disclosures; Amendment to IAS 39, Financial Instruments: Recognition and Measurement; IFRS 4, Insurance Contracts; and IFRS 16, Leases ("the Amendments").

The Amendments include practical expedients regarding the accounting treatment of the financial statements when the interest rate benchmark (interbank offered rates - IBORs) is replaced with risk-free rates (RFRs).

Based on one of the practical expedients, the Company will account for contractual changes or changes to cash flows that are directly required by the reform in the same way as the accounting treatment for changes to variable interest. Meaning, the Company is required to recognize the modifications in interest rates by adjusting the effective interest rate without adjusting the carrying amount of the financial instrument. The use of this practical expedient is subject to the transition from IBOR to RFR taking place on an economically equivalent basis.

The Amendments also permit changes required by the IBOR reform to be made to hedge designations and hedge documentation without the hedging relationship being discontinued when certain conditions are fulfilled. The Amendments provide temporary relief regarding hedge accounting related to a risk defined as 'separately identifiable'.

The Amendments include additional disclosures regarding the anticipated effect of the reform on the Company's financial statements, including reference to how the Company manages the implementation of the interest rate reform, the risks to which it is exposed as a result of the expected reform, and quantitative disclosures about financial instruments at IBOR interest that are expected to change.

The Amendments will be applied for annual periods beginning on or after January 1, 2021. The Amendments are applicable retrospectively, however restatement of comparative figures is not required. Early application is permitted.

At this stage, the Company is assessing the accounting consequences, if any, of the transition from IBORs to RFRs on contractual financial instruments that are expected to exist at the time of the transition, including the effects of application of the Amendments.

NOTE 3: CASH AND CASH EQUIVALENTS

		December 31	
		2020	2019
		NIS millions	
A.	Cash balances and deposits available for immediate withdrawal		
	NIS	11	189
	Foreign currency	122	283
		133	472
B.	Short-term deposits		
	NIS	155	726
	Foreign currency	114	319
		269	1,045
		402	1,517

NOTE 4: SHORT-TERM INVESTMENTS

	December 31	
	2020	2019
	NIS millions	
Financial assets at fair value through profit or loss		
Marketable shares *)	-	282
Monetary fund	-	171
	-	453
Financial assets at fair value through other comprehensive income		
Debentures	-	4
Bank deposits	1	1
Restricted bank deposits *)	558	328
	559	786

*) As at December 31, 2020, the deposits include USD 130 million (NIS 417 million), in connection with the issue of Leviathan Bond debentures in Delek Drilling (see Note 12L(2)). In addition, including deposits in the amount of NIS 92 million in a pledged account for payments to debenture holders of the Company (see Note 19).

NOTE 5: TRADE RECEIVABLES

A. Composition:

	December 31	
	2020	2019
	NIS millions	
Open debts	820	1,923
Checks receivable	-	34
	820	1,957
Less provision for doubtful accounts	-	63
Trade receivables, net	820	1,894

In 2020, the average credit for customers is up to 90 days (in 2019, 38 days).

B. Aging analysis of gross trade receivables balance as at the balance sheet date:

	Debts not yet past due (without (collection in arrears)	Trade receivables past due with collection in arrears of					
		Up to 90 days	91-180 days	181-270 days	271-365 days	Over 1 year	Total
	NIS millions						
December 31, 2019	1,854	14	4	3	3	79	1,957
Less allowance for doubtful accounts	1	1	1	1	1	58	63
December 31, 2019							1,894

C. The decrease in the provision for doubtful debts is due to the deconsolidation of Delek Israel (see Note 10J below).

D. As at December 31, 2020, there are no customers in arrears.

NOTE 6: - OTHER RECEIVABLES

	December 31	
	2020	2019
	NIS millions	
Prepaid expenses and advances to suppliers	77	93
Interest fees receivable (see section 12V)	-	69
Amounts receivable for a loan granted for the sale of the Karish and Tanin leases (2)	46	51
Amounts receivable from the sale of Tamar royalties	-	27
Related parties, interested parties and associates	12	5
Current maturities of long-term debts and loans	33	25
Institutions	2	2
Receivables for joint ventures (1)	15	216
Other receivables	6	26
	191	514

(1) The balance is mainly in respect of transfer of advance payments by Delek Drilling to Noble Energy Mediterranean ("Noble" or "the Operator"), from joint venture activities in gas or oil, mainly to finance the share of Delek Drilling in the joint ventures.

(2) See Note 12H.

NOTE 7: INVENTORIES

	December 31	
	2020	2019
	NIS millions	
Fuel products in gas stations and facilities	-	109
Inventory of consumables in gas stations	-	22
Crude oil inventory	173	196
Related material inventory	133	150
	306	477

NOTE 8: LONG-TERM LOANS, DEPOSITS AND RECEIVABLES

A. Composition:

		December 31	
		2020	2019
	Note	NIS millions	
Loans			
Loan recognized for the sale of The Phoenix	10E	143	140
Seller's loan to Fattal Hotels Ltd.	11A	33	36
Loan provided for the sale of the Karish and Tanin leases	12H	186	242
Loan recognized for the sale of Navitas (1)		-	11
Loans to others (2)		-	37
		362	466
Less - current maturities		33	25
		329	441
Other long-term balances			
Royalties receivable from the sale of the Karish and Tanin leases	12H	779	1,015
Royalties receivable from the sale of the Tamar and Dalit leases		-	41
Access fee for the Dolphinus agreement	12E	384	356
Amounts receivable for undertaking to dispose of assets	10F	787	695
Amounts receivable from an associate	12E	72	110
Restricted deposits (3)		550	555
Ministry of Energy for royalties	12N	40	90
Receivables for joint ventures		194	243
Prepaid expenses for raising bank financing		-	12
Others		41	109
		2,847	3,226
		3,176	3,667

(1) Loan for the acquisition of Navatis Petroleum Ltd. shares In 2020, the loan was repaid in full.

(2) The loans were provided mainly by Delek Israel to owners of gas stations and other customers of Delek Israel.

3) As at December 31, 2020, the deposits include USD 120 million (NIS 386 million), representing a safety cushion for the issue of Leviathan Bond debentures in Delek Drilling (see Note 12K(2)) and debentures by Delek Leviathan Royalties (See Note 12L). In addition, a deposit of NIS 143 million was included for the Company's undertaking to support the bank debt of the buyers of The Phoenix, see section 10E below (in 2019, NIS 355 million representing a safety cushion for the issue of Tamar Bond debentures and NIS 143 million for the Company's undertaking to support the bank debt of the buyers of The Phoenix).

NOTE 8: LONG-TERM LOANS, DEPOSITS AND RECEIVABLES (CONTD.)

B. For information about liens, see Note 25.

NOTE 9: OTHER FINANCIAL ASSETS

	December 31	
	2020	2019
	NIS millions	
<u>Financial assets at fair value measured through profit or loss</u>		
Marketable shares	21	429
<u>Financial assets at fair value through other comprehensive income or loss</u>		
Marketable shares (1)	-	246
	21	675

(1) Delek Drilling holds 22.6% of the issued and paid-up share capital of Tamar Petroleum and 13.42% of the voting rights of Tamar Petroleum. In 2019, the Group recognized a loss of NIS 134 million (USD 36.6 million), under other income (expenses), net, mainly due to the recognition of the holding in Tamar Petroleum at fair value (market value). The share of the Company's shareholders in the loss amounted to NIS 80 million.
In accordance with the accounting policy, any change in the market value of the investment in Tamar Petroleum is recognized in other comprehensive income (loss), other than dividend revenue, which will be recognized in the statement of income. As at December 31, 2020, the market value of the holdings of Delek Drilling in Tamar Petroleum shares amounted to USD 17 million (NIS 55 million). In the reporting period, the Group recognized other comprehensive loss of NIS 105 million. The share of the Company's shareholders in the other comprehensive loss is NIS 57 million. As at December 31, 2020, the balance of the investment in Tamar Petroleum amounts to USD 17 million (NIS 55 million), and is recognized under assets held for sale. The market value of the investment in Tamar Petroleum shortly before the approval of the financial statements amounts to USD 26 million (NIS 86 million).

NOTE 10: INVESTMENTS IN INVESTEE COMPANIES AND PARTNERSHIPS AND DISCONTINUED OPERATIONS

A. (1) Composition

	Associates	
	December 31	
	2020	2019
	NIS millions	
Shares	572	436
Loans	1	56
	573	492

NOTE 10: INVESTMENTS IN INVESTEE COMPANIES AND PARTNERSHIPS AND DISCONTINUED OPERATIONS (CONTD.)

A. (contd.)

(2) Composition by company

	December 31	
	2020	**2019**
	NIS millions	
Delek -The Israel Fuel Corporation Ltd. (see section J(4) below)	307	-
IDE Holdings Ltd. (see section H)	-	134
EMED (see section G below)	216	259
Others	50	99
	573	492

B. Condensed information from the financial statements of associates

Aggregate information for all associates

	Year ended December 31		
	2020	**2019**	**2018**
	NIS millions		
Group share of results of associates based on percentage of interest held during the period (not including associates recognized as a discontinued operation):			
Profit (loss) *)	(10)	(23)	111
Other comprehensive income (loss)	(2)	(4)	7
Total income (loss)	(12)	(27)	118

*) After adjustments for fair value differences

NOTE 10: INVESTMENTS IN INVESTEE COMPANIES AND PARTNERSHIPS AND DISCONTINUED OPERATIONS (CONTD.)

C. Investments in shares of investees listed on the TASE

	December 31, 2020			December 31, 2019	
	Carrying amount	Market value	Market value shortly before publication of the report	Carrying amount	Market value
	NIS millions				
Subsidiaries					
Delek Drilling – Limited Partnership *)	3,556	2,490	3,160	4,225	6,128
Cohen Development Gas and Oil Ltd. **)	-	-	-	305	262
	3,556	2,490	3,160	4,530	6,390
Associates					
GulfSlope	-	4	14	-	24

*) Refers to a direct investment by the Company and an indirect investment through Delek Energy.

**) On April 19, 2020, the Company sold its holdings in Cohen Development (see section L below).

D. Additional information about subsidiaries held directly by the Company

	Country of incorporation	The Company's rights in capital and voting rights	Amounts provided by the Company to a subsidiary		Retained investment in a subsidiary (according to equity value)
			Loans and capital notes	Guarantees	
		%	NIS millions		
December 31, 2020					
Delek Energy Systems Ltd.	Israel	100	77	-	2,596
Delek Drilling – Limited Partnership	Israel	5.06	-	-	408
Delek Sea Maagan 2011 Ltd.	Israel	100	136	-	(1)
Delek Petroleum Ltd.	Israel	100		-	669
DKL Investments Limited	Jersey	100	2,060	161 *)	(866)
1099494 B.C. Ltd.	Canada	100	-	21	
Delek Financial Investments (2012) Limited Partnership	Israel	100	-	-	19
Delek Power Stations - Limited Partnership	Israel	100	254	-	(257)
Delek Infrastructure Ltd.	Israel	100	-	-	(36)
			2,528	182	2,532

*) Guarantees provided to DKL for a convertible loan taken for the acquisition of CNSL, see section F below.

NOTE 10: INVESTMENTS IN INVESTEE COMPANIES AND PARTNERSHIPS AND DISCONTINUED OPERATIONS (CONTD.)

E. The Phoenix Holdings Ltd. ("The Phoenix")

1) On November 3, 2019, after signing the binding agreement in May 2019 and following fulfillment of the preconditions, the transaction was completed for the Company's sale of 32.5% of the share capital of The Phoenix to a company controlled by international private equity funds ("the Buyer") for a consideration of NIS 1.57 billion (after adjustments for dividends distributed by The Phoenix up to the closing date of the transaction). Of this amount, NIS 1.3 billion was received in cash by the Company at the closing date and the balance was provided to the Buyer as a loan (as described below).

The agreement stipulated adjustments to the sales price, which may result in an increase in the total consideration to be received by the Company, beyond the amount of NIS 1.57 billion, in an amount of up to NIS 866 million, subject to certain adjustments, or to a reduction in the total consideration of up to NIS 196 million. These adjustments include reference to the previous profits of The Phoenix at the closing date, adjustments arising from an increase or decrease in the value of The Phoenix shares, including for a notional option granted to the Buyer for 7.5% of The Phoenix shares ("the Option") and the rate of return of the Buyer in the investment period in The Phoenix.

Part of the consideration paid by the Buyer was financed by a senior loan of NIS 548 million received by the Buyer from financial institutions ("the Senior Loan"). The loan is for a period of five years, with two options for extension of one year each, subject to the fulfillment of certain conditions.

The interest will be paid every six months under the terms set out in the agreement below. The interest and principal of the loan will be repaid from the dividends to be received by the Buyer from The Phoenix in the loan period and from the consideration claimed from it from the sale of The Phoenix shares. The Company signed a credit support document ("the Credit Support Document") with the financial institutions to back up the loan in certain events stipulated in the agreement, including backing for interest payments by the Buyer, payment of certain fees for the loan, including early repayment fees, to guarantee some of the Buyer's liabilities and in this respect, to deposit certain marketable securities amounting to NIS 100 million, and under the terms set out in the letter of liability, to deposit additional marketable securities and to pledge financial deposits to secure the liability, in an initial amount of NIS 70 million.
The amounts that the Company is required to deposit in the pledged deposits and the dates on which it is required to deposit them are defined in the agreement, and the amounts may exceed a maximum amount of up to 50% of the amount of the Senior Loan (plus the amount deposited in a reserve to guarantee interest on the Senior Loan), if the events defined in the agreement occur, including: 1) non-compliance with certain financial conditions with respect to The Phoenix and/or the Senior Loan defined in the liability agreement; 2) a downgrade in the credit rating of The Phoenix (below a rating of BBB+); 3) a material debt of the Company (as this term is defined in the agreement) was called for immediate repayment due to an event of default; 4) the Company breached a commitment to pay a debt of least NIS 25 million for a material debt; 5) a downgrade in the credit rating of the Company which constitutes an event of default in respect of the material debt. If the Company breaches its obligation to deposit the required amounts and in the event of a breach of representation for the financial statements of The Phoenix, the maximum amount it may be required to deposit may exceed 100% of the amount of the Senior Loan, and then the Company has the right to call for the endorsement of the Senior Loan. Further to Note 1B above, regarding the calling for immediate payment of certain debts of subsidiaries and/or events of default or events that may be considered as events of default for the loans and liabilities of the Company and the Staff Companies, in June 2020, the Company reached agreements with the financial institutions, according to which, among other things, the Company will pledge additional collateral in favor of the financial institutions (securities and cash amounting to NIS 100 million), and that as long as the debt towards the debenture holders is not called for immediate repayment, or the condition for repayment in the amendment to the deed of trust does not materialize (as defined in Note G below), the financial institutions will not demand completion of additional collateral, unless one or more of the terms set out in the support documents referring to The Phoenix applies, which requires the Company to complete collateral (provide additional deposits) in an amount not exceeding NIS 40 million.

NOTE 10: INVESTMENTS IN INVESTEE COMPANIES AND PARTNERSHIPS AND DISCONTINUED OPERATIONS (CONTD.)

E. The Phoenix Holdings Ltd. ("The Phoenix") (contd.)

1) (contd.)

In addition, as part of the agreement to sell The Phoenix shares, the Company provided a subordinated loan of NIS 235 million to the Buyer (“the Seller’s Loan”). The loan is for a period of five years (with an option to extend for two more years under certain conditions). The loan will bear interest at a rate of 4% per year for the first five years, 7% for the sixth year, and 8% for the seventh year, paid by the Buyer for the Senior Loan and the Subordinated Loan. The interest and principal of the loan will be paid out of the dividend receipts by the Buyer, proceeds from the sale of The Phoenix shares, as well as adjustments to the transaction price that the Company undertook to pay to the Buyer under certain conditions, as set out above. To secure its liabilities related to the loan, the Buyer pledged, among other things, The Phoenix shares that it holds in favor of the Company as a second-ranking lien. It should be noted that if the Company is required to pay interest on the Senior Loan, such interest will be added to the principal of the subordinated loan provided to the Buyer by the Company.

The Seller's Loan, components of contingent consideration, and future adjustments (including for the Option) are measured in the financial statements at fair value through profit or loss. As at December 31, 2020, the net fair value of these instruments amounts to NIS 143 million (as at December 31, 2019, NIS 140 million). The fair value was assessed by the valuator using the Monte Carlo model, on the assumption of risk neutrality. In view of the above, the annual return on The Phoenix shares as well as the capital price were estimated at 0.28%. In addition, the annual standard deviation was estimated at 31% and the rate of the annual dividend to be distributed was estimated at 1.67% of the share value at the end of each quarter.

2) In August and September 2018, the Company entered into separate transactions with three banks for the sale of 37,500,000 shares of The Phoenix shares that it holds (12,500,000 shares in each transaction), representing 14.7% of the issued and paid-up share capital of The Phoenix (“the Sold Shares” or “the Swap Shares”) and at the same time, carried out a swap transaction with each of the banks. The shares were sold in a full sale transaction by the Company in off-floor transactions to third parties, through the banks, for a total consideration of NIS 772 million (before transaction costs), reflecting the TASE price of the shares of The Phoenix directly before execution of the transactions. As part of the swap transaction, at the end of each transaction (at the dates and in the lots that were established), the Company and any bank will carry out accounting for the difference between the sales price of the Sold Shares to the third party, and their value at the accounting date (which will be set according to the selling price for the Sold Shares at that date by the third party, adjusted for dividends). The transactions were made in six equal lots (each transaction for 6,250,000 shares of The Phoenix) The Company provided pledged deposits to the banks for the swap transactions, as is standard for transactions of this type, which the Company undertook to increase in the event of a decrease in the value of The Phoenix shares underlying each transaction, beyond the threshold set in the agreement (as at December 31, 2019, the balance of the pledged deposits amounted to NIS 115 million).

Since the Company remains exposed to the full amount of the variable returns (risks and benefits) for the Swap Shares, the Company did not recognize the transactions for the Sold Shares as qualifying for accounting derecognition, and therefore the Sold Shares were derecognized on the termination date of the swap transactions.

On September 5, 2019, on completion of the first swap transaction, the Company bought back 6,250,000 Swap Shares. These shares were sold as part of the transaction for the sale of control in The Phoenix (see section 1 above). In addition, in December 2019, at the Company's request, another swap transaction was repaid prematurely, in which 6,250,000 shares of The Phoenix were sold to third parties. The net consideration received by the Company on completion of the transaction (in addition to the consideration received at the date of the transaction, as set out above) amounted to NIS 16 million.

NOTE 10: INVESTMENTS IN INVESTEE COMPANIES AND PARTNERSHIPS AND DISCONTINUED OPERATIONS (CONTD.)

E. The Phoenix Holdings Ltd. ("The Phoenix") (contd.)

2) (contd.)

In April and May 2020, the Company informed the banks of early termination of all the swap transactions. The investment in the Swap Shares is accounted for as a financial asset at fair value through profit or loss as from of sale of the controlling interest in The Phoenix, as set out in section 1 above. The Swap Shares (25,000,000 shares) were sold by the banks in off-floor transactions for an amount of NIS 413 million. On completion of the transactions, a cash amount of NIS 143 million, which was pledged to the banks to secure the transactions, was released in favor of the Company. In 2020 and up to the exercise date of the swap transactions, the Company recognized a loss of NIS 110 million for the Swap Shares.

3) On September 18, 2019, The Phoenix distributed its shares in Mehadrin Ltd. (“Mehadrin”) as a dividend in kind to its shareholders. In view of the Company's holdings in The Phoenix shares at that date (32.5%), the Company received 448,581 Mehadrin shares, 33,606 Mehadrin shares were received by the Company for its holdings in the Swap Shares and 134,424 additional Mehadrin shares were acquired by the Company in an off-floor transaction for NIS 20 million. In view of the above, as at December 31, 2019, the Company held 616,611 Mehadrin shares, representing 18.55% of the share capital of Mehadrin. The Company accounted for the investment in Mehadrin as a financial asset measured at fair value through other comprehensive income and the balance of its investment as at December 31, 2019 amounted to NIS 85 million. On May 13, 2020, the Company sold all its holdings in the shares of Mehadrin in an off-floor transaction and for a total consideration of NIS 74 million received by the Company.

4) Below is information about the operating results of The Phoenix presented in the statement of income under profit (loss) from discontinued operations.

	Year ended December 31		
	2020	2019	2018
		NIS millions	
Revenue	-	15,081	11,483
Cost of revenues	-	12,002	7,491
Gross profit	-	3,079	3,992
Selling expenses	-	1,416	1,753
General and administrative expenses	-	998	1,227
Other revenues (expenses), net	-	(2)	21
Operating profit	-	663	1,033
Financing expenses	-	116	184
Share in earnings of associates	-	47	71
Income before tax	-	594	920
Taxes on income	-	185	255
Reversal of impairment of the investment	-	3	(270)
Profit from disposal of The Phoenix shares	-	66	-
Change in the value of the seller’s loan and contingent consideration	(22)	(12)	-
Profit from discontinued operations of The Phoenix	(22)	466	395
Attributable to:			
Shareholders of the Company	(22)	230	35
Non-controlling interests	-	236	360
	(22)	466	395

NOTE 10: INVESTMENTS IN INVESTEE COMPANIES AND PARTNERSHIPS AND DISCONTINUED OPERATIONS (CONTD.)

E. The Phoenix Holdings Ltd. ("The Phoenix") (contd.)

5) Composition of net cash flows attributable to the discontinued operations of The Phoenix:

	Year ended December 31		
	2020	2019	2018
	NIS millions		
Net cash from (used for) activities	-	2,404	(782)
Net cash used for investment activities	25	(386)	(288)
Net cash from financing activities	-	294	587
		2,312	(483)
Cash received from the disposal of the investment in The Phoenix	-	1,320	-
	25	3,632	(483)

F. Investment in shares of Ithaca Energy Limited ("Ithaca")

1. In August 2018, Ithaca entered into agreements to acquire all the rights in the infrastructure and licenses of its partners in the Great Stella Area project ("GSA"), other than the Vorlich license, such that after completion of the transaction, Ithaca will hold all the rights in the floating production facility (FPF-1) in the GSA project.
The effective date for acquisition of the additional rights under the agreement was January 1, 2018, and the consideration paid on the completion date was subject to adjustments reflecting the revenues related to the assets as from the effective date. The consideration for the acquired rights was set at USD 190 million and Ithaca agreed to rescheduling of an existing debt to one of the sellers in the amount of USD 140 million.

The transaction was completed in 2018. Accordingly, on completion of the transaction, Ithaca paid USD 126 million (net of the cash flows received by the selling partners as from the effective date, amounting to USD 80 million, plus USD 16 million which constitutes an advance payment for the existing debt of one of the sellers). An additional USD 120 million will be paid over 2020 through to 2023. In addition, one of the sellers is entitled to an additional consideration of up to USD 25 million, which is contingent on the performances of the Stella and Harrier reservoirs up to 2020 (of which an amount of USD 10 million was paid in 2019).

The profit from the bargain transaction arising on acquisition (bargain acquisition) in the amount of USD 28 million (NIS 105 million) was due to the Group's assessment of the requirement of the selling partners to reduce their operations in the producing reservoirs in the North Sea and due to the fact that Ithaca is the operating partner in these assets, Ithaca utilized its relative advantage and familiarity with the assets to perform the transaction under optimum terms. In addition, as part of the acquisition, significant balances of carryforward tax losses were also acquired, and Ithaca believes that it has the flexibility and the ability to utilize them (therefore an asset was recognized as part of the business combination). The profit from the bargain transaction was included in 2018 under other revenue, net.

NOTE 10: INVESTMENTS IN INVESTEE COMPANIES AND PARTNERSHIPS AND DISCONTINUED OPERATIONS (CONTD.)

F. Investment in shares of Ithaca Energy Limited ("Ithaca") (contd.)

2. On May 29, 2019, Ithaca entered into an agreement with Chevron Products UK Limited ("the Seller") for the acquisition of 100% of the shares of Chevron North Sea Limited ("CNSL") owned by the Seller. CNSL owns rights in ten producing oil and gas assets in the North Sea region of the UK, drilling and exploration licenses, and infrastructure, and has professional and skilled human resources, all of which are part of the acquisition transaction. The oil and gas assets underlying the acquisition agreement are ten producing oil and gas fields and an exploration license. In four of the acquired assets, representing 67% of the total reserves (2P) in the acquired assets, CNSL serves as the operator.
According to the opinion of external experts for estimating reserves, as at December 31, 2019, the total quantity of proved and probable (2P) reserves as a best estimate and the total quantity of contingent resources (2C) attributable to the acquired assets is 206 million BOE and 66 million BOE, respectively. On the signing date of the agreement and as part of the purchase price, a deposit of USD 200 million was deposited in favor of the Seller.

On November 8, 2019, after fulfillment of all the preconditions, the transaction was completed. As part of completion of the transaction, the Seller transferred to Ithaca ownership of the entire share capital of CNSL. Ithaca paid the Seller the consideration, which amounted to USD 1.477 billion (in addition to a deposit of USD 200 million, as set out above), after deducting the funds accumulated at CNSL since January 1, 2019. In addition, an amount of USD 50 million was paid for working capital.

As from the completion date, Ithaca assumed all the rights and liabilities of CNSL for the acquired assets, including the oil assets, and provided guarantees (letters of credit) funded by RBL, for CNSL's decommissioning obligations for the acquired assets, instead of the collateral provided by CNSL or its related companies.
Alongside completion of the transaction, companies in the Ithaca Group signed agreements with companies in the BP International Oil Limited Group ("BP") for the distribution and marketing of gas and oil from the acquired assets for a period of five years.

Financing for the consideration of the transaction and the additional capital required by Ithaca for completion of the transaction is mainly based on the following sources:

- In July 2019, Ithaca entered into an agreement with a consortium of international banks for the provision of a reserve based lending facility of USD 1,650 million ("the RBL Facility"), which was provided to Ithaca to finance its acquisition of CNSL, subject to its completion. The RBL Facility was provided for a period of five years. Most of the RBL Facility bears annual interest of Libor + 3% in the first four years and 3.25% in the fifth year. A facility of USD 550 million out of the total amount will serve as an unused facility, half of which was used by Ithaca to provide collateral for the abandonment obligations of CNSL in the acquired assets as set out above, and this amount will bear annual interest at a rate of 1.5% in the first four years and 1.625% in the fifth year. The other half can only be utilized if certain conditions are fulfilled, based mainly on the expected production rate and forecasted prices of oil and gas.
- Under the terms of the RBL Facility, Ithaca undertook maintain the financial and operational covenants, as follows:
- All the sources should be above the total expected uses in the next 12 months (or for a longer period to start production from the development, if possible).
- The ratio between the net present value of the secured cash flows under the RBL Facility for the life of the projects and the amount drawn under the RBL Facility will not fall below 1:1.15.

NOTE 10: INVESTMENTS IN INVESTEE COMPANIES AND PARTNERSHIPS AND DISCONTINUED OPERATIONS (CONTD.)

F. Investment in shares of Ithaca Energy Limited ("Ithaca") (contd.)

2. (contd.)

– The ratio between the net present value of the secured cash flows under the credit facilities for the life of the RBL Facility and the amount drawn under the credit facility will not fall below 1:1.05.

In addition, financial covenants and ratios were set out in the credit agreement, with which Ithaca is required to comply in order to distribute dividends to its shareholders and increase or maintain the RBL Facility at the reassessment dates set out in the agreement. In this context it should be noted that in November 2020, Ithaca completed the periodic redetermination process (which is performed twice a year) of the RBL Facility. As part of the redetermination process, distribution of a dividend of USD 100 million was approved by Ithaca on November 3, 2020. As part of the proceedings with the consortium of banks, it was determined that there will be a further distribution in 2021 when the average barrel price for a period of six months will be USD 50 or more.

As at December 31, 2020, the balance of the RBL Facility amounts to USD 720 million (shortly before the approval date of the financial statements, USD 570 million).

To secure the RBL Facility, Ithaca pledged the shares of subsidiaries that directly hold rights in the oil assets in a first degree lien, and created floating and fixed liens on the assets, as is standard in this type of transaction.

As at December 31, 2020 and as at the approval date of the financial statements, Ithaca is in compliance with all the financial and operating covenants set out above.

– In July 2019, Ithaca completed an issue of debentures amounting to USD 500 million. Under the terms of the issue, the principal of the debentures will be repaid within five years and the annual interest rate set in the tender is 9.375% (paid every six months). The debentures were issued without any collateral, and Ithaca used the consideration from the issue to finance the CNSL transaction. The consideration of the issuance was held in trust until completion of the acquisition agreement. According to the terms of the debentures, there are no current financial or operational covenants other than financial limitations and covenants on the distribution of the dividend by Ithaca (distribution of a dividend is limited to up to 50% of the profit of Ithaca as defined in the agreement, and for the distribution, Ithaca is required to comply with a leverage ratio of 1.3).

In November 2019, DKL Energy (a wholly-owned subsidiary of the Company, which holds Ithaca shares) raised a loan from a foreign bank in the amount of USD 200 million. Under the terms of the original loan, USD 50 million of the loan principal will be repaid in November 2020, another USD 50 million will be repaid in February 2021, and the balance will be repaid in May 2021 or when Ithaca is listed on the London Stock Exchange, whichever is the earlier. The loan will bear interest based on Libor plus 6.5% per year in the first 12 months of the loan life (as at December 31, 2019, the total interest rate is 8.6%) and will increase by 0.5% in each of the next three-month periods. DKL has the right to make early repayment subject to the terms defined in the loan agreement.

In view of the fact that the loan is not backed by marketable assets (other than 51% of the share capital of Delek North Sea Limited ("DNSL") and the entire share capital of Ithaca, which are not traded companies), the loan agreement sets out margin call events that included a decrease of 20% in the index of benchmark companies (as defined in the loan agreement) or in the FTSE-100 Index, where in such event, the borrower will be required to deposit cash in the amount of the decrease in value as defined in the agreement. Grounds for early repayment under the loan agreement include a 50% decrease in the index of benchmark companies, a decrease of 50% in the FTSE-100 Index, and a decrease of 50% in Company's shares. In addition, a downgrade in Maalot's rating of the Company to BBB (plus) or below, represents grounds for repayment of half of the loan amount. The loan was provided under limited recourse terms and the Company provided the lender a guarantee for the borrower's obligation to unpaid accrued interest, the first margin call, and exceptional violation events. For information about the amendment to the loan agreement signed in 2020, see Note 1C(2)(3).

NOTE 10: INVESTMENTS IN INVESTEE COMPANIES AND PARTNERSHIPS AND DISCONTINUED OPERATIONS (CONTD.)

F. Investment in shares of Ithaca Energy Limited ("Ithaca") (contd.)

2) (contd.)

In 2020, an amount of USD 193 million was repaid from the loan balance, so that as at December 31, 2020, the loan balance amounts to USD 8 million.

– The consideration for the acquisition, including the deposit made when signing the agreement, was financed by the independent sources of the Company and Ithaca, and in view of the financing provided by the Company in the transaction, the Company's existing guarantee to Ithaca in the amount of USD 300 million was cancelled.

The assets and liabilities of CNSL are consolidated in Ithaca's financial statements as from the closing date of the transaction. At the acquisition date, Ithaca recognized the fair value of the assets acquired and the liabilities assumed in the business combination on a provisional basis, based on the draft valuation prepared by an outside valuator, based, among other things, on the reserves of the acquired assets as estimated by an external independent reserves assessor. In 2020, the valuation was completed, without any change to the values set out in a provisional measurement.

Fair value of the identifiable assets acquired and liabilities assumed in the business combination at the acquisition date:

	USD million
	United States
Current assets	145
Investments in oil and gas exploration and production	2,159
Fixed assets, net	10
Other long-term assets	200
	2,514
Current liabilities	133
Non-current liabilities (mainly liabilities for disposal)	967
Deferred taxes, net	492
	1,592
Identifiable assets, net	922
Goodwill *)	805
Total cost of acquisition	1,727

*) The goodwill is mainly "technical" and arises from recognition of a deferred tax liability in view of the fair value of the oil and gas assets for their tax basis as well as for the discounting gaps of the liability for disposal of assets for interest used to calculate the fair value and the risk-free interest according to which the liability is measured in the financial statements.

Transaction costs for acquisition of the investment amounted to USD 17 million in 2019 and were recognized in the statement of income under other expenses, net.

NOTE 10: INVESTMENTS IN INVESTEE COMPANIES AND PARTNERSHIPS AND DISCONTINUED OPERATIONS (CONTD.)

F. Investment in shares of Ithaca Energy Limited ("Ithaca") (contd.)

3) Ithaca performed hedging transactions (mainly put and swap)on the price of oil and gas for part of the future output in the coming years.

   In 2020, Ithaca exercised some of the hedging transactions and, on the other hand, acquired additional hedging transactions. The total consideration (net) received by Ithaca from the transactions amounted to USD 156 million.

   For information about the open hedging transactions on oil and gas prices, as at December 31, 2020, see Note 20A.

4) For information about the issue of a convertible financial instrument in the amount of USD 50 million, see Note 19I to the financial statements.

5) For further information about the oil and natural gas assets of Ithaca and the assessments for impairment in 2020, see Notes 12U and 24A3.

G. Investment in the shares of EMED Pipeline BV (“EMED”)

Delek Drilling holds 25% of the share capital of EMED, which was established for the purpose of the acquisition of EMG shares and the acquisition of rights in the EMG pipeline (see Note 12E below). The balance of the investment of Delek Drilling in EMED as at December 31, 2020, amounts to USD 67 million (NIS 215 million).

H. IDE Holdings Ltd. (“IDE”)

1. On February 28, 2019, the transaction for the sale of 30% of the share capital of IDE Holdings Ltd. (“IDE”) was completed, such that after completion of the transaction, the Group holds 20% of its shares. The shares were sold to Alpha Water 2, a limited partnership holding the remaining 50% of the shares of IDE shortly before the transaction. The Group received a total consideration of NIS 530 million for the transaction. An amount of NIS 348 million was received as payment for the sold shares and an amount of NIS 180 million was received by way of distribution of a dividend from IDE. The profit arising for the Group from the sale of the shares amounted to NIS 123 million (after the effect of tax) and was included under other income, net. In addition, on the closing date of the transaction, the parties will sign a shareholders' agreement that includes the right of first refusal, a tag along right, and the right to appoint a director to the board of directors of IDE by the Company. The Group continued to account for the investment in IDE using the equity method.

NOTE 10: INVESTMENTS IN INVESTEE COMPANIES AND PARTNERSHIPS AND DISCONTINUED OPERATIONS (CONTD.)

H. IDE Holdings Ltd. (“IDE”) (contd.)

2. In March 2020, the Group sold the balance of its investment (20%) in IDE for NIS 169 million. The net profit (after the effect of tax) arising for the Company’s shareholders due to the sale amounted to NIS 20 million and is included in the Group's share in earnings of associates, net.

I. Investment in Delek Drilling

On March 14, 2020, in view of the sharp decline in the value of the participating units of Delek Drilling (see Note 1B and C), a foreign bank contacted Delek Energy, claiming that for a loan secured by a lien in its favor on participating units representing 15% of the capital of Delek Drilling, and in view of the impairment of this collateral, it has grounds to call for immediate repayment of the debt and it demands its immediate repayment. Delek Energy informed the bank that it disputed its claim regarding the call for repayment of the debt, and that its position under the special circumstances in global markets, due, among other things, to the Covid-19 pandemic, did not constitute grounds to call for immediate repayment of the debt and it will invest all efforts at its disposal to uphold this right.

On March 15, 2020, the foreign bank announced that it had entered into an agreement for the sale of 142,341,547 participating units (12% of the Partnership’s capital) in an amount equal to the balance of the loan at that date of USD 57 million, representing a significantly lower price than the market price fixed on the last trading day preceding the transaction.

On March 25, 2020, Delek Energy entered into an agreement with a third party that claimed it had entered into an agreement for the purchase of the participating units from the foreign bank (“the Bidder”) and that it had reached agreements according to which the agreement between the bank and the Bidder will be completed and shortly thereafter, most of the participating units (7% out of 12%) for which the agreement between the Bidder and the bank was signed will be repurchased by Delek Energy.

Under the agreement with the Bidder, Delek Energy purchased from the Bidder 83,768,194 participating units, representing 7% of the Partnership’s share capital, for a consideration of USD 35.8 million (the unit price is the same as the price at which the Bidder purchased the participating units from the bank, plus USD 2.5 million).

The agreement stipulates that if the Bidder seeks to sell the remaining units that it holds (5%), in whole or in part, Delek Energy will have the right of first refusal to announce, within predetermined times, that it seeks to purchase the units offered for sale at a price that will not exceed the closing price of the units on the TASE on the day preceding the date of the Bidder's notice of the sale. Transactions between parties related to the Bidder are excluded from the above, as well as transactions lower than the level specified, starting from a given date.

Delek Energy has reached an agreement with the foreign bank whereby subject to waiving the mutual claims and completion of the transaction with the Bidder, the balance of units held by the foreign bank (3% of the Partnership capital) were released and transferred to Delek Energy.

In view of the above, as at December 31, 2020, the Group directly and indirectly holds 55% of the capital of Delek Drilling. As a result of the above (net disposal of 5% of the capital of Delek Drilling), the capital attributable to the Company’s shareholders decreased by NIS 313 million (in addition for recognition in capital reserve from transactions with non-controlling interests).

For information about the lien of the participating units, see Note 1C and Note 25. For information about the oil and gas assets of Delek Drilling, see Note 12.

NOTE 10: INVESTMENTS IN INVESTEE COMPANIES AND PARTNERSHIPS AND DISCONTINUED OPERATIONS (CONTD.)

J. Delek Israel

1. In July 2020, Delek Israel signed a detailed agreement for the sale of 100% of the shares of IPP Ashkelon Ltd. and IPP Sorek Ltd. (which operate the Ashkelon and Sorek power plants) for a total consideration of NIS 367 million (following the memorandum of understanding signed in May 2020 for the sale of these shares).
Completion of the transaction was subject to preconditions, including regulatory approvals, the consent of the financing entities, and the consent of other third parties. Subsequent to the balance sheet date (and after the completion of the transaction for the sale of Delek Israel shares, as set out in section 4 below), in February 2021 the transaction was completed.
In view of the Covid-19 Crisis and the increased risk in the economy and the concern of a decrease in production prices of the electricity sold by the power plants, and in view of the aforesaid memorandum of understanding and agreement, Delek Israel assessed the fair value of the power plants based on an independent external valuation. The valuation results are an approximation of the price derived from the power plants as set out in the memorandum of understanding and the agreement. Consequently, in the reporting period, Delek Israel recognized a provision of NIS 191 million for impairment of the power plants (before the tax effect).

A. Operating results of the power plants classified as profit (loss) from discontinued operations, net:

	Year ended December 31		
	2020 *)	2019	2018
	NIS millions		
Revenue	362	529	497
Cost of revenues	335	428	443
Gross profit	27	101	54
General and administrative expenses	3	4	5
Other revenues, net	-	55	-
Operating profit	24	152	49
Financing expenses, net	30	30	32
Pre-tax income (loss)	(6)	122	17
Taxes on income	-	-	13
	(6)	122	4
Impairment of an investment	(191)	-	-
Profit (loss) from discontinued operations	(197)	122	4

*) Up to the date of loss of control in Delek Israel, as set out in section 4 below.

NOTE 10: INVESTMENTS IN INVESTEE COMPANIES AND PARTNERSHIPS AND DISCONTINUED OPERATIONS (CONTD.)

J. Delek Israel (contd.)

B Composition of net cash flows attributable to the discontinued operations of the power stations:

	Year ended December 31		
	2020 *)	2019	2018
	NIS millions		
Net cash from operating activities	37	40	76
Net cash from (used for) investing activities	6	4	(91)
Net cash from (used for) financing activities	(23)	(41)	16
	20	3	1

*) Up to the date of loss of control in Delek Israel, as set out in section 4 below.

2. In July 2020, Delek Israel distributed a dividend to the Group in the amount of NIS 150 million.

3. In July 2020, a transaction was completed for the sale of all the rights of Delek Israel in Pi Glilot, Limited Partnership ("Pi Glilot") to a third party and in the land on which the fuel terminals are operated by Pi Glilot in Haifa, Ashdod, Beersheba, and Jerusalem (jointly below: "the Terminals") for a consideration of NIS 720 million, net of certain costs amounting to NIS 30 million, which was paid to Delek Israel on the completion date of the transaction, as set out in the agreement.
In the reporting period, Delek Israel recorded a loss of NIS 58 million for this sale (before the effect of tax).

For information about the disposal of the investment in Delek Israel and the classification of its results (including for Pi Glilot) under discontinued operations, see sections 4 and 5 below.

NOTE 10: INVESTMENTS IN INVESTEE COMPANIES AND PARTNERSHIPS AND DISCONTINUED OPERATIONS (CONTD.)

J. Delek Israel (contd.)

4. On October 16, 2020, Delek Petroleum signed a binding agreement with Lahav L R Real Estate Ltd. and BGM Ltd. (jointly: “the Buyer”) for the sale of 70% of Delek Israel’s issued and paid-up share capital for an amount of NIS 525 million (“the Consideration for the Sold Shares”), reflecting a value of NIS 750 million for Delek Israel. In addition, under the binding agreement, the Buyer was granted an option to purchase an additional 5% of Delek Israel's issued and paid-up share capital (“the Option Shares”) as from the closing date and until June 30, 2021, at the same share price as the price of the sale under the agreement, subject to adjustments that were set out, meaning an additional NIS 37 million, in the event of full exercise of the option. This option is exercisable until June 30, 2021. The transaction was completed on October 28, 2020 and the consideration for the Sold Shares was completed as follows: On the closing date of the transaction, the Buyer paid an amount of NIS 450 million in cash (“the Closing Date Payment”), against the transfer of 60% of Delek Israel’s share capital to the Buyer. The Buyer will transfer the remaining consideration of NIS 75 million (“the Deferred Consideration”) by June 30, 2021 for 10% of Delek Israel’s share capital (“the Additional Shares”). The Additional Shares were deposited with the trustee of the parties until the transfer of their consideration. If the Buyer fails to complete payment of the Deferred Consideration, in full or in part, by June 30, 2021, the trustee for the parties will transfer the proportionate quantity of shares against the part of the Deferred Payment actually transferred by that date, and the remaining purchased shares, held by the trustee for the parties on that date, will be transferred by the trustee for the parties to the trustee of the Company’s debenture holders. The agreement sets out an indemnity section for certain grounds, mainly in respect of Delek Israel's financial statements for a limited period set out in the agreement, and in any case, the indemnity amount for the grounds set out in the agreement will not exceed a cumulative amount of NIS 35 million.

   Subsequent to the balance sheet date, in February 2021, the Buyer transferred half of the deferred consideration in the amount of NIS 37.5 million to the Group, against the transfer of 5% of Delek Israel's capital. In addition, the Buyer exercised part of the purchase option granted to it and acquired 1.66% of Delek Israel's capital for a consideration of NIS 12.5 million. In addition, in March 2021, the Buyer exercised the balance of the option granted to it and acquired 3.34% for a consideration of NIS 25 million. As a result, as at the approval date of the financial statements, the Group holds 25% of the issued and paid-up capital of Delek Israel. The remaining additional shares, which constitute 5% of the share capital of Delek Israel, are held in trust until payment of the deferred consideration.

   Alongside the signing of the agreement, Delek Petroleum and the Buyer signed a shareholders' agreement. The shareholders' agreement stipulates, among other things, that Delek Israel's board of directors will have no more than 10 directors and every 10% holding of Delek Israel's share capital will confer on the shareholders the right to one director in Delek Israel and in its material subsidiaries. A dividend distribution policy was established and it was agreed that the parties will act to distribute a dividend for part of the consideration to be received by Delek Israel upon completion of the power plant transaction. See section 2 above. The shareholders' agreement set out matters that require the consent of Delek Petroleum.

   As at the transaction closing date, the Group no longer consolidates the financial statements of Delek Israel and it recognized profit amounting to NIS 74 million due to revaluation of the disposal of the investment and measurement of the investment and options in Delek Israel at fair value. It should be noted that the estimated fair value as aforesaid and its attribution to Delek Israel's assets and liabilities has not yet been completed (and they are temporary) and they can be completed no later than one year from the closing date of the transaction.

   Following the sale of the shares as set out above, the investment in Delek Israel is accounted for using the equity method. As at December 31, 2020, the Group's investment in Delek Israel amounts to NIS 307 million.

NOTE 10: INVESTMENTS IN INVESTEE COMPANIES AND PARTNERSHIPS AND DISCONTINUED OPERATIONS (CONTD.)

J. Delek Israel (contd.)

5. The operating results of Delek Israel, including profit from the disposal, were presented in the reporting period under profit (loss) from discontinued operations, net, with comparative figures reclassified to this item.
Operating results of Delek Israel (including for Pi Glilot) classified as profit (loss) from discontinued operations, net:

	Year ended December 31		
	2020 *)	2019	2018
	NIS millions		
Revenue	2,193	4,912	5,033
Cost of revenues	1,774	4,181	4,271
Gross profit	419	731	762
Selling, marketing and gas station operating expenses	342	487	539
General and administrative expenses	61	68	66
Group share in profits of operating associates	2	3	4
Other expenses, net	(143)	(15)	(33)
Operating profit (loss)	(125)	164	128
Financing expenses (income), net	(11)	57	30
	(114)	107	98
Group share in profits (losses) of associates, net	-	(5)	2
Pre-tax income (loss)	(114)	102	100
Taxes on income	11	26	28
	(125)	76	72
Profit on disposal of an operation	74	-	-
Profit (loss) from discontinued operations	(51)	76	72

*) Up to the date of loss of control in Delek Israel, as set out above

NOTE 10: INVESTMENTS IN INVESTEE COMPANIES AND PARTNERSHIPS AND DISCONTINUED OPERATIONS (CONTD.)

J. Delek Israel (contd.)

5) (contd.)

C. Composition of net cash flows attributable to the discontinued operations of Delek Israel:

	Year ended December 31		
	2020 *)	2019	2018
		NIS millions	
Net cash from operating activities	283	402	24
Net cash from (used for) investing activities	563	(25)	(477)
Net cash from (used for) financing activities	(876)	(353)	449
	(30)	24	(4)

*) Up to the date of loss of control in Delek Israel, as set out above

K. Cohen Development Gas and Oil Ltd. (“Cohen Development”)

On April 19, 2020, an agreement was signed and a transaction completed for the sale of the Company’s entire share capital in Cohen Development, amounting to 51.76% of the issued and paid-up share capital of Cohen Development (“the Sold Shares”) for a cash consideration of NIS 207 million. In addition to the cash consideration, the Company received a dividend from Cohen Development in the amount of NIS 9 million, which was declared prior to completion of the transaction.

The Sold Shares were sold to three different buyers in unequal parts, each purchased separately. As a result of the transaction, in the second quarter of 2020, the Company recognized a loss attributable to equity holders of the Company in the amount of NIS 235 million (after tax effect) (including for recognition in the statement of income of the foreign operation translation reserve and for to the theoretical disposal of some of the gas and oil assets, as well as the realization of the royalties to which Cohen Development is entitled).

NOTE 10: INVESTMENTS IN INVESTEE COMPANIES AND PARTNERSHIPS AND DISCONTINUED OPERATIONS (CONTD.)

M. Information about non-controlling interests

December 31, 2020

Company	Rate of holding in share capital and voting rights of non-controlling interests	Current assets	Non-current assets	Insurance and finance assets	Current liabilities	Non-current liabilities	Insurance and finance liabilities	Total assets, net	Carrying amount of non-controlling interests
	%	NIS millions							
Delek Drilling (*)	45.3	5,196	14,503	-	4,085	9,448	-	6,166	3,164

2020

Company	Revenue	Net profit	Other comprehensive loss	Total comprehensive loss	Profit attributable to non-controlling interests	Total comprehensive loss attributable to non-controlling interests	Cash flows from operating activities	Cash flows from investing activities	Cash flows from finance activities	Translation differences	Decrease in cash and cash equivalents	Dividends paid to non-controlling interests
	NIS millions											
Delek Drilling (*)	2,659	323	(571)	(248)	64	(293)	1,037	(809)	(647)	(34)	(453)	(232)

(*) Refers to Delek Drilling and Cohen Development up to the disposal date of its investment therein.

NOTE 10: INVESTMENTS IN INVESTEE COMPANIES AND PARTNERSHIPS AND DISCONTINUED OPERATIONS (CONTD.)

N. Information about non-controlling interests

December 31, 2019

Company	Rate of holding in share capital and voting rights of non-controlling interests	Current assets	Non-current assets	Insurance and finance assets	Current liabilities	Non-current liabilities	Insurance and finance liabilities	Total assets, net	Carrying amount of non-controlling interests
	%	NIS millions							
Energy in Israel (*)	(*)	1,588	21,120	-	3,026	12,390	-	7,292	3,440
Others									4
Total									3,444

2019

Company	Revenue	Net profit	Other comprehensive income (loss)	Total comprehensive income	Profit attributable to non-controlling interests	Total comprehensive income (loss) attributable to non-controlling interests	Cash flows from operating activities	Cash flows from investing activities	Cash flows from finance activities	Translation differences	Increase (decrease) in cash and cash equivalents	Dividends paid to non-controlling interests
	NIS millions											
Energy in Israel (*)	1,305	648	(401)	247	315	(377)	1,161	(2,800)	1,649	(47)	(37)	319
The Phoenix (**)	14,878	275	327	602	235	123	2,377	(360)	294	-	2,311	304
Others					2	3						-
Total					552	(251)						623

(*) Refers to Cohen Development, and Delek Drilling (the effective non-controlling interest rate is 40%).

**) Including non-controlling interests in the financial statements of The Phoenix The holding rate of the non-controlling rights is 55%. The figures are for the period from the beginning of the year until the date of sale of control as set out in section E(6) above.

NOTE 10: INVESTMENTS IN INVESTEE COMPANIES AND PARTNERSHIPS AND DISCONTINUED OPERATIONS (CONTD.)

O. Information about non-controlling interests (contd.)

2018

Company	Revenue	Net profit	Other comprehensive income (loss)	Total comprehensive income	Profit attributable to non-controlling interests	Total comprehensive income (loss) attributable to non-controlling interests	Cash flows from operating activities	Cash flows from investing activities	Cash flows from finance activities	Translation differences	Decrease in cash and cash equivalents	Dividends paid to non-controlling interests
	NIS millions											
Energy in Israel (*)	1,384	964	290	1,254	404	288	993	(1,899)	941	(109)	(74)	97
The Phoenix (**)	11,507	695	(137)	558	359	(77)	(818)	(252)	587	-	(483)	68
Others					-	-						3
Total					763	211						168

(*) Refers to Delek Energy, Cohen Development, and Delek Drilling (the effective non-controlling interest rate is 40%).

**) Including non-controlling interests in the financial statements of The Phoenix The rate of holding of non-controlling interests in voting rights in The Phoenix was 55%.

NOTE 11: INVESTMENT PROPERTY

Movement

	2020	2019
	NIS millions	
Balance as at January 1	432	406
Acquisitions and additions	5	-
Disposals	(32)	(15)
Transfer from fixed assets	1	-
Deconsolidation	(78)	-
Fair value adjustment	3	41
Balance as at December 31	331	432

A. In 2016, the Company acquired an office and retail building in Herzliya (the building has four floors above ground, covering 11 thousand square meters, and three floors of underground parking) for a consideration of NIS 260 million.
The acquired office building is partly used by the Group companies (and is recognized under fixed assets) and serves mainly as investment property. In 2017, it was decided to reclassify the office building that is not used by the Group companies to a hotel leased and operated by a third party, and the Company started to make further investments to convert the building into a hotel. In May 2018, the hotel started to operate in accordance with the lease agreement signed between the Company and the operating company of Fattal Hotels Ltd. ("Fattal").
On January 2, 2019, the Company and Fattal signed an agreement according to which 28.3% of the ownership rights of the Company in the property were sold to Fattal for NIS 103 million, and 1/3 of the rental fees paid by it under the lease agreement was transferred to Fattal (as a result, the investment property as at December 31, 2018 was classified as an asset held for sale). As part of the transaction, the Company entered into a loan agreement with Fattal, according to which the Company provided Fattal with a loan of NIS 39 million, linked to the CPI and bearing interest at a rate of 2.96%, to pay the consideration. As at February 3, 2019, all the preconditions set out in the sales had been fulfilled. As a result of the transaction, in 2019, the Company recognized a profit of NIS 23 million, which was included under other income, net.

B. As at December 31, 2020, the Group companies estimated the fair value of the building through an independent external real estate appraiser. In this context, the assessment of the building was performed according to the average of the comparative approach for transaction prices of similar properties in the area and the calculation based on future revenues from appropriate rental fees at a discount rate of 7% plus the value of the additional potential rights, which are in the preparation process but have been approved for deposit by the district committee. According to the assessment, as at December 31, 2020, the value of the building (the Company’s share comprising investment property), including the value of the additional potential rights, amounts to NIS 195 million.

C. In March 2020, an agreement was signed between the Company and Gadot Biochemical Industries Ltd. (“Gadot”, a former subsidiary of the Group) whereby Gadot acquired all of the Company's ownership rights to land in Haifa Bay, on which the Gadot plant is located and which was leased to Gadot for 20 years. The Company acquired the land shortly before the Gadot sale in April 2018 against repayment of the capital notes issued to the Company in the past. The consideration of the sale amounts to NIS 33 million, which was close to the carrying amount of the land.

NOTE 11: INVESTMENT PROPERTY (CONTD.)

Movement (contd.)

D. The Group has rights to real estate in Acre. Subsequent to the balance sheet date, in March 2021, the Group signed a detailed agreement for the sale of investment property in Acre for NIS 200 million as is. The consideration will be paid as follows: NIS 10 million was paid to the Company when the memorandum of understanding was signed, NIS 30 million will be paid by the buyer shortly before signing the agreement and this amount will be held in escrow for the Group and transferred to the Group within one business day after fulfillment of the conditions defined below. The balance of the consideration will be paid on receipt of possession, registration of a lien in favor of the party providing the finance, and confirmations of the transfer for registration of the rights. The agreement sets out certain terminating conditions, which, if they are not fulfilled within 30 days from the date on which a full soil investigation report was provided to the buyer ("the First Period"), the buyer will have the right to cancel the agreement as follows: (1) failure to obtain the required approvals for the buyer from the Israel Land Administration and other relevant authorities ("the Approvals); (2) a contract is not signed with a contractor to treat with the land in accordance with the terms set out in the agreement (under the agreement, if the cost of treating the land under the rehabilitation plan exceeds the amount set out in the agreement, the Company is likely to bear some of the land treatment costs based on the mechanism set out in the agreement) ("the Conditions").
The buyer has the right to extend the First Period by an additional 30 days at its sole discretion ("the Second Period"). In addition, against payment of NIS 20 million out of the balance of the consideration ("the Third Payment"), the buyer has the right to extend the Second Period by an additional 30 days at its sole discretion ("the Third Period").
If, by the end of all the extended periods (90 days after the submission date of the full soil investigation report) any of the Conditions are not met, the buyer will have the right to cancel the agreement, without any party having a claim against the other for canceling the agreement and/or failure to fulfill the Conditions. If the agreement is canceled, the Group and/or the trustee will return the payments made by the buyer on the dates set out in the agreement.
As at December 31, 2020, the real estate is presented in the amount of NIS 136 million, based also on the consideration in the sale agreement less provisions for decontamination and other costs.

NOTE 12: INVESTMENTS IN OIL AND GAS EXPLORATION AND PRODUCTION

The Group operates mainly through Delek Drilling - Limited Partnership (“Delek Drilling” or “the Partnership”) in a number of joint ventures for the exploration, development, and production of oil, natural gas, and condensate in the exclusive economic zone of Israel and Cyprus, and sells natural gas and condensate to a variety of customers. The Group also operates through Ithaca in oil and gas exploration and production in the North Sea (see also section U and Note 10F above). As from the beginning of 2018, the Group began to operate through a foreign subsidiary, Delek GOM Investments LLC (“Delek GOM”) for exploration, development, and production of oil and gas in the Gulf of Mexico in the United States (see also section V below).

A. Composition

	Exploration and appraisal assets	Oil and gas production assets	Total
Cost		NIS millions	
Balance as at January 1, 2019	1,213	22,965	24,178
Movement during the year:			
Effect of initial application of IFRS 16 (*)	-	(113)	(113)
Entry into consolidation	-	7,554	7,554
Investments	92	3,101	3,193
Disposals	-	(135)	(135)
Deconsolidation	-	(53)	(53)
Foreign currency translation differences for foreign operations	(98)	(1,994)	(2,092)
Balance as at December 31, 2019	1,207	31,325	32,532
Movement during the year:			
Investments	27	1,234	1,261
Deconsolidation	(71)	(560)	(631)
Reclassification to assets held for sale ***)	-	(5,656)	(5,656)
Foreign currency translation differences for foreign operations	(79)	(2,167)	(2,246)
Balance as at December 31, 2020	1,084	24,176	25,260
Accumulated depreciation, depletion and amortization			
Balance as at January 1, 2019	40	3,294	3,334
Effect of initial application of FRS 16	-	(24)	(24)
Additions	-	891	891
Disposals	-	(30)	(30)
Deconsolidation	-	(6)	(6)
Provision for impairment (**)	251	696	947
Adjustments for translation of financial statements of foreign operations	(3)	(264)	(267)
Balance as at December 31, 2019	288	4,557	4,845
Additions	-	1,621	1,621
Deconsolidation	-	(32)	(32)
Provision for impairment (**)	-	1,850	1,850
Reclassification to assets held for sale ***)		(1,998)	(1,998)
Adjustments for translation of financial statements of foreign operations	(20)	(660)	(680)
Balance as at December 31, 2020	268	5,338	5,606
Depreciated cost as at December 31, 2020	816	18,838	19,654
Depreciated cost as at December 31, 2019	919	26,768	27,687

NOTE 12: INVESTMENTS IN OIL AND GAS EXPLORATION AND PRODUCTION (CONTD.)

A. Composition (contd.)

(*) The balance of oil and gas production assets as at December 31, 2019 included an amount of USD 25 million (NIS 113 million) for leasehold rights in a drilling facility at the Pierce reservoir, in which Ithaca is not an operator. On initial application of IFRS 16, Leases, for the consistent application of the standard and the accounting practice set out for its application in the oil and gas sector, Ithaca derecognized the right of use for the asset and the related liability, since, according to the accounting practice in the sector, the partner that is not an operator does not control the leasehold rights in the drilling facility.

(**) See sections U and V below.

(***) For information about the classification of oil and gas production assets of the Tamar under assets held for sale, see section C(6) below.

Composition according to joint ventures/reservoirs (1):

	December 31	
	2020	2019
	NIS millions	
Oil and gas assets in Israel and its surroundings		
Michal Matan joint venture (Tamar and Dalit) (2)	-	4,819
Ratio Yam joint venture (Leviathan)	10,758	11,962
	10,758	16,781
Exploration and appraisal assets in Israel and its surroundings		
Block 12, Cyprus	795	915
Other assets	21	4
	816	919
Oil and gas assets in the North Sea		
Assets in the Greater Stella area ("GSA")	1,359	2,174
Captain area	4,377	5,063
Other assets	2,344	2,750
	8,080	9,987
Total	19,654	27,687

(1) Including attribution of surplus cost

(2) As at December 31, 2020, the assets of the Michal Matan joint venture are recognized under assets held for sale. See also section C(6) below.

NOTE 12: INVESTMENTS IN OIL AND GAS EXPLORATION AND PRODUCTION (CONTD.)

B. Rights in oil and gas exploration licenses

1) The rights of the Company and the Partnership in oil and gas exploration licenses in Israel and its surroundings

Project	Name of lease/license	Lease/ concession	Rights valid until	Participation rate of the Company	Participation rate of Delek Drilling Partnership
Israel					
Yam Tethys project	Ashkelon	Lease	June 10, 2032	4.441%	48.50%
Yam Tethys project	Noa	Lease	January 1, 2030	4.441%	48.50%
Michal and Matan	I/12 Tamar	Lease	December 1, 2038	-	22% (*)
Michal and Matan	I/13 Dalit	Lease	December 1, 2038	-	22% (*)
Ratio Yam	I/14 Leviathan South and I/15 Leviathan North	Leases	February 13, 2044	-	45.34%
Ofek Hadash	405/Ofek Hadash	license	June 20, 2021	-	25%
Yahel Hadash	406/Yahel Hadash	license	June 20, 2021	-	25%
Cyprus					
Block 12	Block 12	Concession	November 7, 2044	-	30.00%

(*) Not including the Partnership's 3.79% holding in the Tamar lease through its holdings in Tamar Petroleum (out of 100%)

(1) The validity of the oil rights are extended from time to time and is contingent on fulfilling the commitments on dates set out in terms of the oil assets Non-compliance with the commitments could lead to cancellation of the oil rights.

The leases were issued under the Petroleum Law, and they grant the partners in the leases special rights to produce oil and natural gas from the respective lease area for 30 years, with the right for a 20-year extension, in accordance with and subject to the provisions of the Petroleum Law.

(2) For information about the benefit for the right to royalties from the sale of all the rights in the Karish and Tanin leases, see section H below.

(3) For information about the provisions of the Gas Framework regarding the sale of Delek Drilling's holdings in the Tamar and Dalit leases, see section O(1) below.

(4) The operator of the joint ventures in Israel is Noble Energy Mediterranean Limited ("the Operator" or "Noble"). The operator of the joint venture in Cyprus is Noble Energy International Ltd. (" Noble Cyprus").

On October 5, 2020, Chevron Corporation ("Chevron") announced the completion of the merger of Chevron and Noble Energy Inc. ("Noble Inc.), the operator in the Tamar and Leviathan oil assets, and Noble Cyprus.

NOTE 12: INVESTMENTS IN OIL AND GAS EXPLORATION AND PRODUCTION (CONTD.)

B. Rights in oil and gas exploration licenses (contd.)

2) Ithaca's rights in the main oil and gas exploration licenses in the North Sea

Name of field	Operator	Ithaca's rights as at December 31, 2020
Greater Stella Area (GSA) in the North Sea		
Stella/Harrier	Ithaca	100%
Vorlich	Ithaca	34%
Abigail (formerly: Hurricane)	Ithaca	100%
Austen	Ithaca	100%
Kessog (formerly: West Vorlich)	Ithaca	100%
Courageous	Ithaca	55%
Captain field	Ithaca	85%
Other fields in the North Sea		
Cook	Ithaca	61.35%
Pierce	Shell	7.48%
Fionn	Ithaca	100%
Broom	EnQuest	8%
Ythan	EnQuest	40%
Don SW	EnQuest	40
West Don	EnQuest	21.4%
Blue Sky	Ithaca	100%
Alba	Ithaca	23.40%
Alder	Ithaca	73.68%
Erskine	Ithaca	50%
Britannia	Chrysaor	32.38%
Brodgar	Chrysaor	6.25%
Callanish	Chrysaor	17%
Elgin/Franklin	Total	3.9%
Enochdhu	Chrysaor	50%
Jade	Chrysaor	19.93%
Isabella	Total	10%
Marigold	Ithaca	100%

NOTE 12: INVESTMENTS IN OIL AND GAS EXPLORATION AND PRODUCTION (CONTD.)

C. Michal and Matan joint venture (Tamar and Dalit leases)

The Michal Matan joint venture is an oil and gas exploration, development and production project in the area of the Tamar and Dalit leases. Noble is the operator of the joint venture. Production from the Tamar reservoir began in the first half of 2013.
See section J below for information about the assessment of the gas and condensate.

1) Additional information about the Michal Matan joint venture:

(1) Tamar project

The production system of the Tamar project includes six subsea production wells connected to the production platform (“the Production Platform”) through the subsea production system. The Tamar platform is connected to the onshore receiving terminal by a pipeline system and from there to the national pipeline of Israel National Gas Lines Ltd. ("INGL"). The daily gas supply capacity from the Tamar project to the INGL transmission system is 1.1 BCF.

(2) Option of expanding the supply capacity of the Tamar project

The Tamar Partners assess, from time to time, options for expanding the supply capacity from the Tamar project, if required, in accordance with the expected volume of demand in the local market and for exports.
Expansion of the supply capacity may include, among other things, completion of development of the Tamar SW reservoir and/or the drilling and/or completion of other production wells, which will be connected to the existing subsea production system, as well as the installation of a third supply pipeline from the Tamar field to the Tamar platform and/or the Mari B platform. In addition, the necessity and method of the required upgrade at the Tamar platform and the receiving terminal are being assessed.

(3) Tamar South West (“Tamar SW”)

According to the development plan of the Tamar SW reservoir, which was approved by the Commissioner of Petroleum Affairs, the Tamar SW reservoir will be developed by converting the discovery drilling to a production drilling and connecting it to the subsea facilities of the Tamar project. The development cost of the Tamar SW reservoir was partially approved by the Tamar Partners, and accordingly, equipment was purchased and various operations were carried out for development of the reservoir, including the installation of a subsea pipeline between the Tamar SW reservoir and the subsea manifold of the Tamar project.

NOTE 12: INVESTMENTS IN OIL AND GAS EXPLORATION AND PRODUCTION (CONTD.)

C. Michal and Matan joint venture (Tamar and Dalit leases) (contd.)

1) Additional information about the Michal Matan joint venture (contd.)

(4) In June 2018, following the fulfillment of all the preconditions, Delek Energy assigned to Delek Royalties 2012 Ltd. ("Delek Royalties") its rights to royalties in the Tamar and Dalit lease against a cash payment of NIS 565 million and against the allotment of Delek Royalties shares representing 39.93% of the capital of Delek Royalties after the allotment, and Delek Energy waived all the voting rights for these shares. In view of the Company's waiver of all the voting rights, the investment in the shares of Delek Royalties was accounted for as a financial asset at fair value through profit or loss. See below for further information about the sale of Delek Royalties shares. In 2018, the Group recognized a profit of NIS 105 million from the sale of the rights to royalties from the Tamar project under other income in the statement of income (the profit after tax attributed to the Company's shareholders amounted to NIS 61 million). It is further noted that following the sale of the Rights to Royalties from the Tamar project, in the second quarter of 2018, the Group updated the fair value of the financial asset attributable to the right of the Group companies to receive royalties from Tamar Petroleum and recorded a loss of NIS 86 million. Under the transaction, Delek Energy undertook to indemnify Delek Royalties, so that Delek Royalties will receive royalties from the Tamar reservoir at a rate of 4.875%, regardless of the investment recovery date set for the reservoir.

On September 13, 2020, Delek Energy entered into an agreement with a third party ("the Buyer") for the sale of the entire holdings of Delek Energy in Delek Royalties for a total consideration (subject to the response to the tender offer as set out below) of NIS 46 million, reflecting a share price of NIS 5.7497 (29% on the share price of Delek Royalties at the close of trading on September 10, 2020). Under the agreement, the acquisition will be in two stages: in the first stage, at the date the agreement was signed, the Buyer acquired from Delek Energy 12.3% of the share capital of Delek Royalties in cash for a consideration of NIS 14 million.
in the second stage, the Buyer issued a special tender offer for a quantity of shares that will represent, after completion of the tender offer and together with the holdings held by the Buyer, including those acquired in the first stage, at least 45% of the voting rights of Delek Royalties. In November 2020, as part of the tender offer, the Buyer acquired an additional 5% of the share capital of Delek Royalties from Delek Energy for NIS 23.5 million in cash. The total consideration received for the sale of the shares in both stages amounted to NIS 38 million.
On December 29, 2020, the Company sold the balance of all its holdings in Delek Royalties (7%) in an off-floor transaction for a total consideration of NIS 7.6 million.

NOTE 12: INVESTMENTS IN OIL AND GAS EXPLORATION AND PRODUCTION (CONTD.)

C. Michal and Matan joint venture (Tamar and Dalit leases) (contd.)

1) Additional information about the Michal Matan joint venture (contd.)

(5) On December 26, 2019, after fulfillment of the preconditions, the transaction was completed and the Company sold to a number of institutional entities (“the Buyers”) all of its direct rights to receive overriding royalties from the share of Delek Drilling (22%) and Tamar Petroleum (9.25%) on oil and/or gas and/or other valuable materials to be produced and utilized in the I/12 Tamar and I/13 Dalit leases. Under the agreement for the sale, the right to overriding royalties was transfered to the Buyers retrospectively, as from April 1, 2019 (“the Record Date”) as is, and subject to the same conditions under which the Company held the right to the overriding royalties. The consideration in the agreement was set at USD 52.5 million less the receipts for the overriding royalties from the time of the Record Date to the completion date, such that the total cash consideration received is USD 46.2 million.
Under the agreement for the sale, on February 1, 2023, the parties will account and adjust the consideration, which may increase by up to USD 2 million or decrease by up to USD 1.5 million.
In addition, if it is determined that the investment recovery date is after the Record Date, the Company will indemnify the Buyers in an amount equal to the wellhead market value of the difference between the actual royalty rate prior to the investment recovery date, in a way that the Buyers will receive royalties according to the rate of royalties after the investment recovery date.
In 2019, the Group recognized a profit of NIS 20 million from the sale of the Rights to Royalties from the Tamar project under other income in the statement of income in the amount, after derecognizing a relative part of the cost of the asset in the amount of NIS 83 million attributable to the Tamar project in the financial statements of the Group, since in practice, the Group transferred to the Buyers part of the economic rights in the Tamar project and taking into account the deferral of income amounting to NIS 8 million attributable to the future estimated production costs that will be recognized throughout the entire production period, since the Group provides the Buyers with production services through the Partnership, for which the Buyers paid theoretically in advance when acquiring the rights.

(6) In view of the Group's requirement to dispose of its holdings in the Tamar and Dalit leases in accordance with the Gas Framework described in Note 1201, the short schedules required to dispose of the investment by the end of 2021, and in accordance with indications of impairment, the Group assessed the value of its indirect holdings in the Tamar and Dalit leases. In addition, in view of the schedules defined in the Gas Framework, the Group classified all the assets and liabilities attributable to the Tamar project for the short term under assets held for sale.
The fair value assessment of the Group’s holdings was performed by an outside independent valuator that estimated the fair value through the discounted cash flow based on the projected cash flow from P2 reserves (proved reserves + probable reserves) from the Tamar reservoir as at December 31, 2020. Below are the main assumptions:

1. Natural gas sales of 8.6, 9.2, 9.1, 9.5, and 10.4 BCM in 2021 to 2025, respectively. Gradual increase to 11.65 BCM in 2030, stabilizing at this quantity until 2041. As from 2042, there will be a gradual decrease in production volumes until the reservoir reserves are depleted.

2. Average Brent barrel price forecast of USD 52, 57, 61, 65, and 68 in 2021 to 2025, respectively. Gradual increase to a price of USD 86 in 2030, stabilizing at this price until the end of the forecast period.

3. Adjustment of depreciation expenses for tax purposes to be used by a potential buyer.

4. Use of a weighted average cost of capital (WACC) (after tax) of 9.3%.

5. The valuator discounted 20% on the assessment results, which the valuator believes reflects the difference between the present value of the net cash flow and the net consideration (less disposal costs) expected for the Group from the sale of the asset under the current market conditions.

NOTE 12: INVESTMENTS IN OIL AND GAS EXPLORATION AND PRODUCTION (CONTD.)

C. Michal and Matan joint venture (Tamar and Dalit leases) (contd.)

1) Additional information about the Michal Matan joint venture (contd.)

(6) (contd.)

In view of the results of the assessment, the aggregate fair value of oil and gas assets in the Tamar project (22%) was estimated as at December 31, 2020 at USD 1,104 million (NIS 3,549 million), and was lower than the carrying amount of the assets as at March 31, 2020, which amounted to USD 1,315 million (NIS 4,227 million - investments in oil and gas assets less liabilities for disposal and other long-term assets related to the project and allocation of goodwill attributed to oil and gas exploration and production in Israel and its surroundings). Accordingly, there was an impairment of USD 211 million (NIS 680 million) before the effect of tax. The Company's share in the impairment amounted to NIS 94 million after the effect of tax (the share of the holders of noncontrolling interests in the impairment after the effect of tax amounted to NIS 446 million).

D. Ratio Yam joint venture

The Ratio Yam joint venture is a joint venture for exploration, development and production of oil and gas in the areas of the I/15 Leviathan North and I/14 Leviathan South leases (“the Leases”). Noble is the operator of the joint venture.

See section J below for information about the assessment of the reserves and contingent resources.

1) Plan for development of the Leviathan reservoir

In June 2016, the Commissioner approved the development plan as submitted by Noble. On February 23, 2017, the Leviathan partners made a final investment decision (FID) for the development of Phase I - First Stage in the development plan of the Leviathan reservoir, with an annual capacity of 12 BCM. As at date of the financial statements, the total cost of Phase 1 - First Stage development amounted to USD 3.6 billion (100%, the Partnership’s share is USD 1.6 billion). On December 31, 2019, natural gas started to flow from the Leviathan reservoir.

The plan for full development of the Leviathan reservoir includes supply of natural gas and condensate to the local market and for export and condensate to the local market (in this section below: "the Development Plan" or "the Plan"). The main points of the Plan are as follows:

(1) Eight production wells in the first stage (of which, four have already been drilled and completed for production under Phase 1 – First Stage) will be connected by a subsea pipeline to a fixed offshore platform (in this section below: "the Platform") in the territorial waters of Israel on which the gas and condensate treatment systems were installed. Gas flows from the Platform to the northern entrance of the national pipeline of Israel National Gas Lines (“the Connection Point to INGL”).
The condensate flows to the shore in a separate pipe adjacent to the gas pipeline and connected to the oil pipeline of Europe Asia Pipeline Co. (“EAPC”) leading to the tank farm of Petroleum & Energy Infrastructures Ltd. ("PEI”) and from there to Bazan Ltd. (“Bazan”).
In addition, a pipeline was installed to the Hagit site, where storage and offloading facilities for condensate have been constructed, providing backup if condensate cannot be delivered to Bazan. Construction of the condensate storage system at the Hagit site was completed and the permits required for its operation have been obtained.

NOTE 12: INVESTMENTS IN OIL AND GAS EXPLORATION AND PRODUCTION (CONTD.)

D. Ratio Yam joint venture (contd.)

1) Plan for development of the Leviathan reservoir (contd.)

(2) The production system is designed to supply an annual quantity of 21 BCM after completion of Phase 1 – First Stage and Phase 1 – Second Stage of the development plan, as set out below.

(3) The Development Plan is implemented in two stages, depending on the maturity of the relevant markets, as follows:
Phase I – First Stage: includes, in the first stage, four subsea production wells, a subsea production system connecting the production wells to the Platform, a system for transmission to the shore, and related onshore facilities. At this stage, annual gas production capacity from the reservoir is 12 BCM.
Phase 1 – Second Stage is expected to include another four production wells, related subsea systems, and expansion of the Platform's processing facilities to increase the total production capacity of the system by an additional 9 BCM per year, at an estimated budget of USD 1.5-2 billion (100%, the Partnership's share is estimated at USD 0.7-0.9 billion). As at the approval date of the financial statements, a FID has not yet been made for the development of Phase I - Second Stage.

(4) It should be noted that during the life of the project, additional production wells will be required to allow production in the required volume.

(5) On completion of the trial run of all the systems on the Platform, and in particular, operation of the turbo expanders, the ability to increase the maximum daily supply capacity will be tested, subject to certain conditions, beyond 1.2 BCM.

2) <u>Assessment of alternatives for increasing production in the Leviathan reservoir</u>

As at the approval date of the financial statements, the Partnership is assessing, together with its partners in the Leviathan Project, various alternatives for increasing production from the Leviathan reservoir beyond Phase 1 – First Stage, and concurrently with the assessment of Phase 1 – Second Stage, based on existing facilities, and are working to update the development plan accordingly, to allow expansion of annual production capacity to 24 BCM, all in accordance with assessments that are updated from time to time regarding current and expected demand in the local market and in regional and global target markets, including the following alternatives:

(1) Increasing annual production capacity of Phase 1 – First Stage from 12 BCM to 16 BCM, by adding two wells and related subsea infrastructure and immaterial changes at the platform.
Production wells and related subsea infrastructure and immaterial changes at the platform This alternative will maximize utilization of the treatment infrastructure installed on the Leviathan platform as part of Phase 1 – First Stage, at an estimated cost of USD 875 million (100%, the Partnership's share is USD 397 million).

(2) Increasing annual production capacity from 16 BCM to 24 BCM (subject to implementation of the first alternative described above), including by adding four production wells, related subsea infrastructure, beyond those described in the first alternative, adding a fourth pipeline from the field to the Platform, and expansion of the treatment facilities at the Platform, at an estimated budget of USD 1.5-2 billion (100%, the Partnership's share is between USD 0.7 and USD 0.9 billion). This alternative will allow the supply of additional quantities of gas for export, as required, including to the liquefaction facilities in Egypt and/or for the supply of gas to the floating liquefied natural gas ("FLNG") facility.

NOTE 12: INVESTMENTS IN OIL AND GAS EXPLORATION AND PRODUCTION (CONTD.)

D. Ratio Yam joint venture (contd.)

3) Deep targets

In 2019, an analysis was performed of reprocessing of seismic surveys, among other things, in connection with exploration drilling to the deep targets in the Leviathan leases ("Data Reprocessing"), as a result of which a new isolated carbonate buildup deep target was defined in the area of the Leviathan leases. In addition, the Data Reprocessing analysis revealed that the two deep targets previously defined in the area of the lease should be reclassified and redefined as a single submarine clastic channel ("collectively: "the New Targets").
In January 2020, NSAI submitted a report on the estimated prospective resources in the Leases, updated as at December 31, 2019. According to the report, the best estimate in the carbonate buildup for gas and oil is 4.5 BCM and 155.3 million barrels, respectively. The best estimate in the clastic channel for gas and oil is 6.5 BCM and 223.9 million barrels, respectively.
As at December 31, 2020, there were no changes in the information presented in the report. For information about uncertainty of the estimated reserves, see section J below.

As at the approval date of the financial statements, the partners are assessing, among other things, the performance of another seismic survey in view of technological development in seismic surveys, for the purpose of improving existing knowledge, in order to substantiate the making of a decision on exploration drilling to the New Targets.
In addition, the Partnership is exploring the possibility of adding a strategic partner with relevant knowledge and experience in the specification, drilling, and development of an exploration target (specifically an isolated carbonate buildup target).

E. Agreement for the acquisition of EMG shares and acquisition of rights in the EMG Pipeline

To fulfill the agreements between the Partnership and Noble and between Dolphinus for the export of natural gas to Egypt from the Tamar and Leviathan reservoirs (as set out in sections M1d and M2d), EMED (an associate company of the Partnership) 39% of the share capital of Eastern Mediterranean Gas Company SAE ("EMG"). On November 6, 2019, the EMG transaction was completed, and on January 15, 2020, natural gas began to flow from Israel to Egypt from the Leviathan reservoir and on June 30, 2020, natural gas started to flow from the Tamar reservoir to Egypt through the EMG pipeline ("the EMG Transaction" or "the Transaction" or "the EMG Pipeline"). The closing of the EMG Transaction was subject, among other things, to the signing of a capacity, lease and operatorship agreement ("the CLOA") between EMED and EMG, in which EMG will grant EMED the exclusive right to lease and operate the EMG Pipeline for the transport of natural gas from Israel to Egypt. The CLOA was signed on June 30, 2019, all as set out below:

EMG is a private company registered in Egypt, which owns a 26-inch, 90-kilometer long subsea pipeline connecting the Israeli transmission system near Ashkelon to the Egyptian transmission system near El-Arish, as well as related facilities ("the EMG Pipeline"). The EMG Pipeline was designed for an annual capacity of 7 BCM, with an option to increase the annual capacity to 9 BCM by installing additional systems. The flow of gas through the EMG Pipeline from Egypt to Israel was discontinued in 2012, and to the best of the Partnership's knowledge, as at the signing date of the agreement, EMG had no commercial activity, and remains exposed to claims and debts in significant amounts towards the authorities, financers, suppliers and customers. It should be noted that in the transaction, the Partnership is not required to provide any collateral or guarantees for the existing debts of EMG.

As at the signing date of the agreement, the shareholders in EMG are as follows:

EGI-EMG LP – 12%; Merhav MNP Ltd. – 8.2%; Merhav Ampal Energy Holdings Limited Partnership – 8.6%; Merhav-Ampal Group Ltd. ("Merhav-Ampal Group") – 8.2%; PTT Energy Resources Company Limited ("PTT") – 25%; Mediterranean Gas Pipeline Ltd. ("MGPC") – 28%; Egyptian General Petroleum Corporation ("EGPC") – 10%. (Shareholders (1)-(4) above will be referred to jointly below as "the Sellers").

NOTE 12: INVESTMENTS IN OIL AND GAS EXPLORATION AND PRODUCTION (CONTD.)

E. Agreement for the acquisition of EMG shares and acquisition of rights in the EMG Pipeline (contd.)

It should be noted that some of the Sellers, shareholders of the Sellers, and companies related to the Sellers, are involved in several arbitration proceedings in international arbitration institutions against the government of Egypt and companies held by it, in connection with the suspension of the flow of gas from Egypt to Israel (jointly: “the Arbitration Proceedings”). EMG is also a party to arbitration against companies owned by the government of Egypt.

1) Agreements for the purchase of 39% of the share capital of EMG

(A) On September 26, 2018, EMED signed four separate, essentially similar agreements with the Sellers for the purchase of EMG shares held by the Sellers, at a total rate of 37% of the share capital of EMG (jointly below: “the Share Purchase Agreements"), as well as another agreement for the purchase of shares from MCPC at the rate of 2% (“the MGPC Agreement).
The transaction for the acquisition of EMG shares was completed in November 2019.

In consideration for the purchased shares, waiver of their rights in the Arbitration Proceedings, and the additional rights under the Share Purchase Agreements, as set out above, on the closing date of the transaction, EMED paid the Sellers a total of USD 527 million (“the Consideration”), of which the Partnership and Noble each paid USD 188.5 million, and the balance was paid by the Egyptian partner.

On July 31, 2019, the decision of the Competition Commissioner was handed down in accordance with section 20(b) of the Economic Competition Law, 1988, which allows the merger between EMED and EMG for the purchase of the EMG Pipeline, according to which the Partnership and Noble undertook to comply with the terms set out in the decision.
For information about the petition filed with the Competition Tribunal at the Jerusalem District Court regarding the approval of the Competition Commissioner, see Note 24A1(4).
For information about the agreement between Noble and INGL, see Note 12P.

B) <u>Main points of the MGPC agreement</u>

Concurrently with the signing of the Share Purchase Agreements, an agreement was signed between EMED and MGPC, according to which MGPC transfered to EMED, for no financial consideration, subject to and concurrently with the closing of the Share Purchase Agreements, 2% of the shares of EMG that it holds, against the ending of disputes between some of the Sellers and MGPC.

After the closing of the EMG Transaction, and as at the approval date of the financial statements, EMG’s shareholders are:
PTT – 25%; EMED – 39%; MGPC – 17%; the Egyptian partner – 9%; EGPC– 10%.

NOTE 12: INVESTMENTS IN OIL AND GAS EXPLORATION AND PRODUCTION (CONTD.)

E. Agreement for the acquisition of EMG shares and acquisition of rights in the EMG Pipeline (contd.)

2) Capacity, lease, and operatorship agreement (“the CLOA”)

As aforesaid, the closing of the EMG Transaction was subject, among other things, to the signing of the CLOA between EMED and EMG, in which EMG granted EMED the exclusive right to lease and operate the EMG Pipeline for the entire term of the Dolphinus Agreements (see sections M1d and M2d below), with an option to extend the agreement. According to this agreement, the costs required to refurbish the EMG Pipeline, and the current operating costs of the pipeline, will be covered by EMED (jointly, “the Operating Costs”), and EMG will be entitled to receive the current transport fees to be paid by Dolphinus for use of the pipeline (“the Transport Fee”), net of the Operating Costs. As at the balance sheet date, Noble and the Partnership, together with the Tamar and Leviathan's partners in accordance with the arrangements in the agreement for refurbishment of the EMG pipeline, due diligence, and increase of production capacity through EMED, have invested USD 124 million (the Partnership’s share is USD 53.9 million), most of which will be repaid from the available cash flow of EMG arising from revenue for gas transmission in the EMG pipeline to Dolphinus.

Concurrently with the signing of the agreements for export to Egypt, the Partnership and Noble signed an agreement with the Tamar partners and the Leviathan partners for allocation of capacity (“the Capacity Allocation Agreement”) in the transmission system from Israel to Egypt. The division of capacity in the transmission system from Israel to Egypt (the EMG Pipeline and the transmission pipeline in Israel) will be on a daily basis, according to the following order of priority:

(A) First layer: up to 350,000 MMBTU will be allocated to the Leviathan partners.

(B) Second layer: the capacity above the first layer, up to 150,000 MMBTU/d until June 30, 2022 (“the Capacity Increase Date), and 200,000 MMBTU/d after the Capacity Increase Date, will be allocated to the Tamar Partners.

(C) Third layer: any additional capacity above the second layer will be allocated to the Leviathan partners.

On the closing date of the EMG Transaction, the Leviathan partners paid USD 200 million (“the Access/Participation Fee for the Leviathan-Dolphinus Agreement”) and the Tamar partners paid USD 50 million (“the Access/Participation Fee for the Tamar Agreement”), against an undertaking to allow the flow of natural gas from the Leviathan and Tamar reservoirs and guaranteed capacity in the EMG Pipeline, all for the purpose of fulfilling the agreements for export to Egypt.
It should be noted that the Access/Participation Fee for the Leviathan-Dolphinus Agreement and the Access/Participation Fee for the Final Tamar-Dolphinus Agreement (collectively: “the Leviathan and Tamar Access Fee”) will be determined by June 30, 2022, according to the ratio of the gas quantities actually supplied by the Leviathan partners and the Tamar partners through the EMG Pipeline until that date (including gas quantities not yet supplied and that were paid for under the take or pay agreement).

In addition to the costs invested in refurbishment of the pipeline, as set out above, the Capacity Allocation Agreement includes arrangements for participation in the costs of the EMG Transaction, additional costs related to gas flow, and investments which will be required to maximize utilization of the capacity of the EMG Pipeline, the payment of which will be divided between the Leviathan partners and the Tamar partners, some of which is included in the Leviathan and Tamar Access Fee.

In view of the above, the Partnership's share in the Leviathan and Tamar Access Fee amounts to USD 119.4 million and the Partnership's share in the amounts due from an associate company amounts to USD 22.5 million, and are included under long-term loans, deposits, and receivables.

NOTE 12: INVESTMENTS IN OIL AND GAS EXPLORATION AND PRODUCTION (CONTD.)

E. Agreement for the acquisition of EMG shares and acquisition of rights in the EMG Pipeline (contd.)

2) Capacity, lease, and operatorship agreement ("the CLOA") (contd.)

The Capacity Allocation Agreement further stipulates principles for a backup arrangement between the Tamar partners and the Leviathan partners according to which, as from June 30, 2020, and until the Capacity Increase Date, if the Tamar Partners are unable to supply the quantities which they undertook to supply to Dolphinus, the Leviathan partners will supply the required quantities to the Tamar Partners.

The term of the Capacity Allocation Agreement is until the termination of the Egypt export agreements, unless it had been terminated earlier in one of the following cases: a breach of a payment undertaking that was not remedied by the party in breach; in a case where the Competition Authority does not approve extension of the CLOA according to the decision of the Competition Commissioner, as set out above. Furthermore, each party will have the right to terminate its part in the Capacity Allocation Agreement if its export agreement is cancelled.

3) EMED shareholders agreement

Shortly before signing the Share Purchase Agreements, the shareholders of EMED signed a shareholders agreement governing the relationship between them as shareholders of EMED, including provisions regarding material decisions, which will be made unanimously. In addition, arrangements were established for the right of first refusal for the transfer of shares in EMED.

4) MOU for the use of additional infrastructures

Concurrently with the signing of the Share Purchase Agreements, as described above, an MOU was signed between the Partnership and Noble and between the Egyptian Partner (which holds the Arab Gas Pipeline) in the section from El Arish to Aqaba, and a related company of Dolphinus, in which the parties agreed that the Partnership and Noble would receive access to additional capacity in the Egyptian transmission system, through the Arab Gas Pipeline, at the entry point to the Egyptian transmission system in the Aqaba area, allowing the delivery of additional quantities of gas over and above the quantities of gas that will flow through the EMG Pipeline ("the Additional Infrastructure"), for implementation of the Dolphinus agreement and additional agreements for the sale of natural gas to Egypt. The parties further agreed to assess other projects for the delivery of natural gas from Israel to potential customers and facilities in Egypt.

NOTE 12: INVESTMENTS IN OIL AND GAS EXPLORATION AND PRODUCTION (CONTD.)

F. Block 12, Cyprus

1) The Partnership has a production sharing contract whereby the Partnership holds 30% of the rights in Aphrodite reservoir in Block 12 in the exclusive economic zone of Cyprus. The operator of the joint venture is Noble Cyprus.

2) In June 2015, the Partnership and its partners in the Aphrodite reservoir submitted a declaration of commerciality and a draft proposal for development of the Aphrodite reservoir to the government of Cyprus.

3) On November 7, 2019, the holders of rights in the production sharing contract ("the Partners" and the "PSC", respectively) and the Cyprus government signed an amendment to the PSC), which modified, among other things, the mechanism for distribution of the natural gas output from the reservoir between the Partners and the Republic of Cyprus. Concurrently, the Partners were granted a production and exploitation license ("the Production License"), and a development and production plan for the reservoir was approved ("the Development Plan").

4) In the amendment to the PSC ("the Amendment"), the Partners undertook, among other things, to meet the main milestones for the development of the Reservoir, as follows:

   A. drilling of an appraisal/development well in the area of Block 12 in accordance with the Development Plan and completion within 24 months from the date of receipt of the Production License, or at a later date if certain conditions are met, whereby the partners will be entitled to an extension.

   B. Completion of a detailed front end engineering design ("the FEED"), delivery of the outputs in accordance with the Development Plan and adoption of a final investment decision ("FID") for development of the Reservoir, within 48 months after receiving the Production License (until 2023).

   The PSC sets out circumstances in which the Partners will be entitled to an extension for the purpose of meeting the milestones, with the deadline for adoption of a FID being six years after receiving the Production License. It should be noted that failure to comply with the milestones set out in the PSC will constitute grounds for cancellation of the PSC, other than for reasons of force majeure (as defined in the PSC).

5) It should be further noted that in the Amendment, other changes and updates were made to the PSC, including, with respect to the transfer of rights by the parties, approval of an annual budget and work plan, the manner of approving changes to plans and budgets, the manner of calculating the various expenses, changes in the grounds for termination of the PSC, arrangements for ensuring the plugging, dismantling, and removal of wells and facilities at the end of the term of the PSC, and more.

6) The Republic of Cyprus is entitled to one-time bonuses from the holders of rights in Block 12 when reaching the milestones for the average daily production rate for a continuous period of 30 days. The PSC sets out mechanisms for distribution of oil and natural gas. It should be noted that the Republic of Cyprus may receive its share in the oil or natural gas in kind.

NOTE 12: INVESTMENTS IN OIL AND GAS EXPLORATION AND PRODUCTION (CONTD.)

F. Block 12, Cyprus (contd.)

7) On the date the amendment was signed, the Cyprus government approved the Development Plan and granted a Production License for 25 years with an option for an extension by up to ten more years. The Development Plan is subject to updates in view of the results of the FEED, and the progress in the commercial and financial aspects of the project, and includes the construction of a floating treatment and production facility in the license area, with an estimated maximum production capacity of 800 MMcf/d, through five production wells in the initial stage, and a subsea transmission system to the Egyptian market. According to the updated appraisal of the Operator, which was submitted to the Partnership and to the Cyprus government, and before completion of the technical-economic feasibility tests, including the FEED, the estimated cost of the Development Plan, without the construction cost of the pipelines to the target markets, is between USD 5 billion and USD 3 billion (100%). The estimated budget for the work plan until the date of the FID is USD 150-200 million (for 100%). Formulation of the development plan and the FID for development of the Aphrodite reservoir are subject, among other things, to an appraisal drilling/further development and to a FEED, commercial arrangements to develop the pipelines for export, signing of agreements for supply of natural gas, and compliance with the preconditions in the agreements, regulatory approvals, and financial arrangements. It should be noted that the above estimated costs do not include costs for the development and installation of a pipeline for the export of natural gas from the Aphrodite reservoir.

8) Most of the Aphrodite reservoir is in the exclusive economic zone of Cyprus, with a very small part in the area of the 370/Yishai license, which is in the exclusive economic zone of Israel). It should be noted that the Partners in the Aphrodite reservoir received inquiries from the partners in the Yishai license and from the Ministry of Energy regarding the requirement to regulate the parties' rights before making a decision on the development of the Aphrodite reservoir. The position of the partners in the Aphrodite reservoir is that the matter is within the governments' authority and they will act in accordance with the mechanism for regulation of the parties' rights as to be determined by the governments and in accordance with international law. It is further noted that further to discussions between the governments of Israel and Cyprus to regulate the parties' rights in the Aphrodite reservoir, on March 9, 2021, the governments signed a memorandum of understanding instructing the partners in the Aphrodite reservoir and the holders of the rights in the Yishai license to conduct direct negotiations to regulate the issue of the migration of the Aphrodite reservoir, which includes principles and timetables for the negotiations.

G. Impairment assessment of oil and gas assets in Israel and neighboring countries

Further to Note 1B regarding the spread of Covid-19 and its possible effect on the Group's business, the Group assessed the recoverable amount of its oil and gas assets in Israel and the surroundings (separately or as a group of assets constituting a single cash-generating unit, as the case may be) as at March 31, 2020. The assessment of the recoverable amount was based on an estimated present value and sensitivity analyses of the expected cash flows from the Partnership's oil and gas assets ("the Assessment"). The Assessment was performed by an outside independent valuator who estimated the recoverable amount as at March 31, 2020 through the discounted cash flow, based on the projected cash flow from P2 reserves (proved reserves + probable reserves) from the Tamar reservoir as at December 31, 2019 and based on the projected cash flow from 2P + 2C reserves (best estimate contingent resources including 2P reserves) from the Leviathan reservoir as at December 31, 2019, published by the Company on January 10, 2020 and January 13, 2020, respectively ("the Cash Flow Forecasts"), with application of the adjustments to the data and assumptions used in the Cash Flow Forecasts.

NOTE 12: INVESTMENTS IN OIL AND GAS EXPLORATION AND PRODUCTION (CONTD.)

G. Impairment assessment of oil and gas assets in Israel and neighboring countries

The main adjustments included, among other things:

1) An updated forecast of the price of oil and gas, partially due to: (i) An update to the Brent oil price forecast based on the average of the Brent oil price forecasts of third parties, including the World Bank, the US Department of Energy, and the consulting company IHS Global Insight, which was published shortly before the Assessment date, for 2020-2030, and there increase at a rate of 2% per year as from 2030; (ii) the updated forecast for the energy production price, based, among other things, on the NIS-USD exchange rate and on the fuel price forecast based on the gas price for the IEC; (iii) the updated forecast for natural gas demand in the local market, based on the forecast for the demand of a third party for natural gas in the local market.

2) Reduction of annual sales quantities as described below, based on:

   - The updated demand forecast in the local market shortly before the assessment date

   - Reduction of sales quantities in the Dolphinus agreements (see Note 12M(1)(d) and Note 12M(2)(d) below) to 50% of the annual contractual quantities in years in which the average daily Brent price is less than USD 50 per barrel

3) Adjustment of depreciation expenses for tax purposes to be used by a potential buyer

4) Use of the weighted average cost of capital (WACC) (after tax) of 10.2% in the Tamar reservoir and 8.45% in the royalties attributable to Cohen Development.

5) Use of the weighted average cost of capital (WACC) (after tax) of 11.2% in the Leviathan reservoir and 9.45% in the royalties attributable to the Company, Delek Energy, and Cohen Development.

The aggregate fair value of oil and gas assets in the Tamar project (22%), including the value of the royalties attributable to Cohen Development, less realization costs, was estimated at USD 1,342 million (NIS 4,784 million) as at March 31, 2020, and was lower than the carrying amount of the assets as at March 31, 2020, which amounted to USD 1,358 million (NIS 4,841 million)) (investments in oil and gas assets less liabilities for disposal and other long-term assets related to the project). Accordingly, in the first quarter of 2020, there was impairment amounting to USD 16 million (NIS 57 million) in the assets, fully attributable to non-controlling interests. For information about the value of oil and gas assets in the Tamar Project as at December 31, 2020, see section C(6) above.

The aggregate value in use of a unit that includes oil and gas assets in the Leviathan project (45.34%) and Cyprus, including the value in use of overriding royalties attributable to the Company, Delek Energy, and Cohen Development, amounted to USD 4,254 million (NIS 15,165 million) as at March 31, 2020, and is higher than the carrying amount of the assets at that date, which amounted to USD 3,787 million (NIS 13,501 million) - investments in oil and gas assets less liabilities for disposal and other long-term assets related to the project), therefore there was no impairment in the assets.

As at December 31, 2020, there were no indications of the need to reassess the recoverable amount of the oil and gas assets in the Leviathan project compared with the assessment as at March 31, 2020.

As at March 31, 2020, goodwill attributable to oil and gas exploration and production in Israel and the surrounding area amounted to NIS 468 million. Goodwill arose on acquisition of the shares of Cohen Development in December 2011 and gain of control in Avner Oil Exploration - Limited Partnership. In accordance with the valuation as set out above, the value in use of the operating segment significantly exceeds the carrying amount, therefore no provision was required for goodwill impairment.

As of December 31, 2020, goodwill after the provision for impairment of goodwill attributed to the Tamar reservoir amounts to NIS 330 million, referring to oil exploration and production in Israel and its surroundings (mainly the Leviathan and Aphrodite reservoirs). As at this date, there were no indications of the need to reassess the recoverable amount of oil and gas assets in Israel and the surrounding area, also in view of the resources report as at December 31, 2020 for the Leviathan reservoir.

NOTE 12: INVESTMENTS IN OIL AND GAS EXPLORATION AND PRODUCTION (CONTD.)

H. Rights in the I/17 Karish and I/16 Tanin leases

1. As set out in section O1 below, in accordance with the Gas Framework, the Partnership and Noble were required to sell the entire rights in the leases in the area of the Tanin and Karish reservoirs, no later than the effective date, all in accordance with the terms of the Gas Framework and the terms of the leases. On August 16, 2016, the Partnership ("the Seller") signed an agreement with Ocean Energean Oil and Gas Ltd. ("the Buyer" or "Energean"), for the sale of all of the rights of the Partnership and Noble in the leases, in accordance with the terms set out in the agreement. On the closing date of the transaction, the Buyer paid the Partnership an amount of USD 40 million. The balance of the consideration, amounting to USD 108.5 million, is paid to the Partnership in ten equal annual payments (“the Annual Payments” or “the Loan”), plus interest in the mechanism and at the rate set out in the agreement, as from March 2018. In addition, the consideration for the sale of the leases included the right to royalties from the natural gas and condensate to be produced from the leases, at a rate of 7.5% - before payment of the oil profits tax under the Taxation of Profits from Natural Resources Law, 2011 ("the Levy”) for the leases, and at a rate of 8.25% - from the date payment of the Levy begins, less the liability for overriding royalties that were transferred to the Buyer under the agreement, according to the Seller’s undertaking for its share and in accordance with the duty to pay the royalty holders.

   On February 11, 2021, Energean released, among other things, a reserves report prepared by a third party, from which it arises that the gas flow from the Karish reservoir is expected to commence, in its estimation, at the beginning of 2022.
   On April 15, 2019, Energean announced a natural gas discovery in the Karish North well. According to Energean publications, the development plan that it submitted for the Karish North was approved by the Ministry of Energy in August 2020, and a final investment decision for development of the Karish North reservoir was made on January 14, 2021. Production from this reservoir is expected to begin in the second half of 2023.
   To the best of the Company’s knowledge, the updated data for the resources attributed to the Karish, Tanin, and Karish North reservoirs (in this section below: “ the Reservoirs"), were last published by Energean on February 11, 2021. According to this report, as at December 31, 2020, the Reservoirs contain natural gas reserves (2P) of 98.4 BCM and hydrocarbon liquids (condensate and natural gas liquids, see below) of 99.6 million barrels (compared with natural gas resources (2P+2C) of 98.6 BCM and hydrocarbon liquids (condensate and natural gas liquids, see below) of 82 million barrels according to an earlier publication by Energean in April 2020). In addition, Energean announced that the annual production and processing capacity of its facilities will reach 8 BCM in 2023.
   Below are the main parameters of the valuations used to measure the Royalties and annual payments: The discount rate for the annual payments is estimated at 7.5% (2019: 6.5%); the estimated discount rate for the royalty component is 12% (2019: 11%); gas production from the Karish lease: April 1, 2022 to December 31, 2040; estimated average annual production rate of natural gas from the Karish lease: 3.91 BCM; average annual production rate of condensate from the Karish lease: 5 million; dates of gas production dates from the Tanin lease: January 1, 2027 to December 31, 2036; estimated average annual production rate of natural gas from the Tanin lease: 2.51 BCM; average annual production rate of condensate from the Tanin lease: 0.44 million barrels; total estimated contingent resources of natural gas and hydrocarbon liquids (condensate and natural gas liquids, see below) used in the valuation for measurement of the royalties: 98.4 BCM (2019: 92 BCM) and 99.6 MMBBL (2019: 49 MMBBL), respectively.

   The section on financing income in the reporting period includes an amount of NIS 278 million, on the Partnership level, arising from revaluation of the royalty from the leases. The update is mainly due to an increase in Energean's estimates regarding the contingent resources in the leases, a change in the discount rate, a change in the estimated production rate, the price of the condensate, and for the passage of time.

NOTE 12: INVESTMENTS IN OIL AND GAS EXPLORATION AND PRODUCTION (CONTD.)

H. Rights in the I/17 Karish and I/16 Tanin leases (contd.)

2. On July 8, 2020, the transaction was completed under which the Company and Delek Energy sold to a third party (“the Buyer”) all the rights of the Company and Delek Energy to overriding royalties for the Karish and Leviathan Leases (not including the royalty rights of the Partnership and Cohen Development), for a consideration of NIS 318 million. The consideration is distributed between the Company and Delek Energy in accordance with their holding of the right to overriding royalties (25%, the Company; 75%, Delek Energy). As a result, in 2020, the Group included a loss of NIS 44 million (after tax).

I. Yam Tethys transaction

1) Production from the Yam Tethys reservoir began in 2004. As from 2013, production capacity from the reservoir is declining. In May 2019, the operator of the Yam Tethys joint venture notified the partners in the Yam Tethys project, including the Partnership, that production of natural gas from the Mari B reservoir has been suspended.

A. <u>Commercial arrangement for operation and production from the Yam Tethys project and the Tamar project:</u>

As from May 2013 and up to and including September 2017, and as from May 2019, the Tamar reservoir supplies natural gas (instead of the Yam Tethys reservoir) under gas supply agreements between the Yam Tethys partners and their customers (“the End Customers”). Gas was supplied, as aforesaid, by the Tamar partners that are partners in the Yam Tethys Project and have obligations under the agreements, and by the Tamar partners that are not partners in the Yam Tethys Project (and are not obligated by virtue of the aforesaid agreements). The consideration received from the End Customers, together with the consideration reflecting the share of Delek Group, which holds rights in Yam Tethys but does not hold direct rights in Tamar, was divided such that the Tamar project partners that are not partners in the Yam Tethys project receive a price that is the equivalent of the average monthly price of natural gas supplied in that month under the agreements signed between the Tamar partners and their customers, and the balance was divided among the Yam Tethys partners that have rights in the Tamar project, according to their share in the Tamar project. This division maintained a balance of gas quantities at the Tamar project between the partners according to their share. For information about the claim filed by the Partnership and Noble, which also have rights in the Yam Tethys project, and the state for the rate of royalties due to the state for income arising from the supply of natural gas in accordance with the sales outline, see Note 24A2(3) below.

In May 2018, the Yam Tethys partners entered into an agreement (which was amended in September 2018) for the sale of surplus production from the Yam Tethys reservoir (in an immaterial amount) to the Tamar partners for sale to the Tamar project customers for a period of 24 months as from October 1, 2017. This agreement ended with the discontinuation of production from the Mari B reservoir in May 2019.

B. On May 3, 2020, the Partnership, Noble, Delek Group, and Ratio Oil Exploration (1992) - Limited Partnership ("Ratio") signed an agreement for the supply of natural gas according to which customers that signed earlier agreements with each of the Yam Tethys partners will be supplied with gas from the Leviathan reservoir. Accordingly, the Yam Tethys partners that are partners in the Leviathan project (the Partnership and Noble) take from their gas (according to the share of their holdings in Yam Tethys), while the balance of gas to be supplied by Delek Group will be purchased from Ratio in accordance with the consideration set out in the Agreement, which is the average monthly price set out in the agreements signed between the Leviathan partners and their customers in the local market.

NOTE 12: INVESTMENTS IN OIL AND GAS EXPLORATION AND PRODUCTION (CONTD.)

I. Yam Tethys transaction (contd.)

2) Agreement for the right of use of the Yam Tethys project facilities

In July 2012, an agreement was signed between the Yam Tethys joint venture partners ("the Yam Tethys Group") on the one side and the partners in the I/12 Tamar lease and I/13 Dalit lease ("the Tamar Project" and "the Tamar Group", respectively) on the other side ("the Agreement"). According to the agreement, the Yam Tethys Group will grant the Tamar Group right of use of the Yam Tethys project facilities, including the wells, the Mari B platform, compression system, pipeline and receiving terminal at Ashdod and also granted the Tamar Group the right to upgrade and/or construct facilities to transport and store natural gas from the Tamar project ("the Yam Tethys Facilities"). The rights to use the facilities will be granted subject to maintaining the gas capacity produced from the Yam Tethys project in the pipeline and the receiving station.

3) According to the approvals and guidelines received subsequent to the balance sheet date, In January 2021 from the Commissioner of Petroleum Affairs, the operator is preparing for decommissioning and abandonment of the project facilities, except for the platform, including production wells and subsea equipment, in accordance with an approved decommissioning plan which is expected to be implemented in 2021-2022. At the same time, the parties are discussing the Operator's request to approve a cold stacking model for the Yam Tethys platform, which may allow, among other things, turning it into an unmanned platform. There is also a discussion about possible future uses and/or decommissioning and abandonment of the Yam Tethys platform, considering the connection between the facilities of the Yam Tethys project and production from the Tamar project. The Group’s share in the abandonment costs (excluding the costs of abandoning the platform) amounts to USD 85 million, of which an amount of USD 68 million (NIS 219 million) is presented in the short term under other provisions and liabilities.

NOTE 12: INVESTMENTS IN OIL AND GAS EXPLORATION AND PRODUCTION (CONTD.)

J. Estimates of natural gas reserves, condensate and contingent resources (100% of the projects)

Project (100%)	Oil and gas assets	Reserves report as at	Gas and condensate reserves				Contingent resources			
			Proved + probable reserves		Proved reserves		High estimate		Low estimate	
			Natural gas (BCM)	Condensate (millions of barrels)	Natural gas (BCM)	Condensate (millions of barrels)	Natural gas (BCM)	Condensate (millions of barrels)	Natural gas (BCM)	Condensate (millions of barrels)
Israel										
Michal and Matan	Tamar and Tamar SW	December 31, 2020	296.8	13.6	218.81	10.0	-	-	-	-
Michal and Matan	Dalit	December 31, 2017	-	-	-	-	9.5	-	6.1	-
Ratio Yam	Leviathan (*)	December 31, 2020	370.6	28.8	319.1 (**)	24.8 (**)	379	29.4	154.5	12
Cyprus			-	-	-	-	-	-	-	-
Aphrodite	Aphrodite	December 31, 2020	-	-	-	-	128.8	10.9	56.8	4

(*) The Commissioner believes, based on the opinion of an international company that was submitted to his office, that the estimated quantity of natural gas that would be produced from the Leviathan reservoir is 17.6 TCF, based on the production plan that was submitted in the request for approval of the work plan.

(**) Amount of proved developed producing reserves

These estimates of the natural gas reserves, condensates, and contingent resources in the leases of the Partnership in the leases, licenses, and concessions for oil and gas exploration are partially based on geological, geophysical and other information received from the drillings and from operations in these leases. These estimates are the professional estimates and assumptions only of NSAI, for which there is no certainty. The estimates for actual quantities of natural gas and condensate produced may differ 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 market and/or actual performance of the reservoirs. The estimates and assumptions may be revised if additional information becomes available and/or as the result of a range of factors related to oil and natural gas exploration and production projects.

NOTE 12: INVESTMENTS IN OIL AND GAS EXPLORATION AND PRODUCTION (CONTD.)

K. Financing in the Partnership

1) Debentures (Tamar Bond)

In May 2014, the issue of debentures by Delek and Avner (Tamar Bond) Ltd. ("the Issuer") was completed. The Issuer is a special purpose company (SPC) held fully by the Partnership, according to which debentures amounting to USD 2 billion were issued. The Issuer provided the issue proceeds as loans to the Partnership, back-to-back with the terms of the debenture ("the Loan"). The debentures were issued in five different series. As at the balance sheet date, the balance of the series as is follows:

	Total par value as at December 31, 2020 USD million	Fixed interest	Repayment date
Series 4	320	5.082%	December 2023
Series 5	320	5.412%	December 2025

As collateral for payment of the debentures, the Partnership pledged its rights in the Tamar project, and mainly the rights of the Partnership in the Tamar lease, agreements for the sale of gas and condensate, the joint operating agreement between all Tamar project partners and the parties' rights in the joint equipment (including the platform, wells, facilities, production system and additional equipment), the agreement for right of use of the Yam Tethys Facilities, bank accounts, which include the accounts used for the Partnership's revenues from the sale of gas and condensate from the Tamar project, insurance policies (with the exception of liability insurance) for the Tamar project assets, and the issuer's shares (jointly below: ("the Collateral" or "the Pledged Assets").
The Collateral for repayment of the debentures is from the Tamar project, without any guarantees or collateral unrelated to the Tamar project. However, until certain conditions are fulfilled, and at least up to four years from the issue date of the debentures, the debenture holders will have a right of recourse to other assets of the Partnership for one half of the amount that the Partnership withdrew and will continue to withdraw from the pledged accounts until that date. The debenture holders' right of recourse is limited in amount and only to assets that have not been or will not be pledged by the Subsidiary Partnership (limited recourse) and without the debenture holders being entitled to introduce bankruptcy proceedings against the Partnership. It is noted that the pledges are subject to the state's royalty rights and to the rights of other royalty holders who are entitled to receive royalties from the Partnership (including the Company and interested parties), and that pledges are registered in favor of the royalty holders on the Partnership's rights in the Tamar lease to secure the undertaking to pay the royalties, which will be valid until repayment of the debentures. As part of the transaction, the Issuer and the Partnership assumed several covenants towards the debenture holders, including the following covenants: restrictions on additional pledges on the pledged assets and their sale; restrictions on a merger or restructuring as set out in the issue documents; restrictions on amending or revising the joint operating agreement, the agreement for use of the facilities or agreements for the sale of gas, as set out in the issue documents; restrictions on expansion of the debenture series or taking additional debt secured by the pledged assets, subject to compliance with several conditions; an undertaking to track the debenture rating of the international rating agencies that rated the debt. In addition, restrictions and conditions for withdrawal of the surplus cash flow from the Tamar project were defined.

In addition, events of default were defined, which if they occur, the trustee for the debentures will be entitled, and in the case of a demand of one quarter of the debenture holders will be obligated, to call for immediate repayment of the unpaid balance of the debentures.

The Partnership has the right to prepay all or part of the loan, at any time, subject to a prepayment fee. Early repayment following various events set out in the debenture (including the sale of the rights in Tamar, as set out above) will not be subject to a prepayment fee. It is further noted that a certain period before any repayment date of the principal of a debenture series, the Issuer is required to accrue moneys in the pledged account in preparation for the upcoming principal payment date. As at the date of the financial statements, the Partnership was in compliance with the terms and liabilities under the deed of trust.

NOTE 12: INVESTMENTS IN OIL AND GAS EXPLORATION AND PRODUCTION (CONTD.)

K. Financing in the Partnership (contd.)

1) Debentures (Tamar Bond) (contd.)

In the reporting year, the Partnership repaid the 2020 series, which was partially repaid prematurely in July 2020.

It should be noted that as at December 31, 2020, the balance of the Tamar Bond debentures is presented in the consolidated balance sheet under liabilities attributable to assets held for sale (see also section C(6) above).

2) Leviathan Bond debentures

On August 18, 2020, the issue of debentures by Delek Leviathan Bond Ltd. ("the Issuer") was completed. The Issuer is a special purpose company (SPC) held fully by the Partnership, according to which debentures amounting to USD 2.25 billion were issued.
The debentures were issued in four series. The principal and interest of the debentures are in USD. The interest on the debentures of each of the Series will be paid twice a year, on June 30 and December 30.
On August 3, 2020, the Issuer received the approval of the Tel Aviv Stock Exchange Ltd. (“the TASE”) to list the debentures for on the TACT-Institutional system of the TASE.
The full consideration for the issue was provided by the Issuer as a loan to the Partnership at the same terms as the terms of the debentures (back-to-back), and in accordance with a loan agreement signed between the Issuer and the Partnership (“the Loan”).
The Loan funds were used by the Partnership to repay bank loans in the amount of USD 2 billion, deposit a security cushion in the amount of USD 100 million in accordance with the terms of the debentures, payment of issuance costs estimated at USD 30 million, and the balance will be used for other uses in accordance with the terms of the approval of the Commissioner as described below (“the Commissioner’s Approval”).

To secure the debentures and the loans, under the deed of trust for the debentures and the other documents according to which the debentures will be issued (jointly below: “the Financing Documents”), the Partnership pledged in favor of the debenture trustee (“the Trustee”) in a first fixed lien, its rights in the Leviathan project (45.34%), including its rights in the I/14 Leviathan South and I/15 Leviathan North leases (“the Leases”), the operating approvals of the production system, and the export approvals (jointly below: “the Pledge of the Leases”), the Partnership’s rights and revenues from agreements for the sale of the gas and condensate from the Leviathan project (“the Gas Agreements”), the Partnership’s rights in the joint operating agreement (“the JOA”) for the Leases, the Partnership’s share in the project assets (including the platform, wells, facilities, production system, and system for transmission to the shore), the Partnership’s rights in dedicated bank accounts, certain insurance policies, and various licenses in connection with the Leviathan project. The Partnership also pledged the shares held by it in the Issuer, in NBL Jordan Marketing Limited, and in Leviathan Transportation System Ltd.

In addition, the Issuer pledged its rights in all of its existing and future assets, in a first floating lien, in favor of the Trustee, and pledged its rights in the loan agreement and in its bank accounts in favor of the Trustee (jointly below: “the Pledges” and “the Pledged Assets”, as the case may be).

According to the Financing Documents, the Partnership’s undertakings to the Trustee and the debenture holders are limited to the Pledged Assets, with no guarantee or additional collateral.
It should be noted that the Pledges that the Partnership created in favor of the Trustee are subject, among other things, to the State’s royalties according to the Petroleum Law and to the rights of the parties entitled to royalties for the Partnership’s revenues from the Leviathan project, including the Group.

As is standard in financing transactions of this type, under the Financing Documents, the Partnership assumed stipulations, restrictions, covenants, and there are grounds for calling for immediate repayment of the debentures and exercising the pledges. These include, among other things, the following main commitments:

NOTE 12: INVESTMENTS IN OIL AND GAS EXPLORATION AND PRODUCTION (CONTD.)

K. Financing in the Partnership (contd.)

2) Leviathan Bond debentures (contd.)

The Partnership and the Issuer, as the case may be, undertook, among other things, to fulfill the undertakings and conditions set out in government approvals and licenses, including in relation to the project operator, and including the terms of the Commissioner's approval; to fulfill the terms of the Leases and the JOA (jointly below: "the Leviathan Agreements"); to protect their rights in the Pledged Assets and ensure the validity of the Pledges and the rights of the Trustee and the debenture holders thereunder; not to change or discontinue the Issuer's activity, and not to change the Issuer's articles of association; not to create additional pledges on the Pledged Assets (other than certain exceptions); to comply with the provisions of the law that apply to their activities; to pay the taxes that apply to them; to give the Trustee and the debenture holders certain notices, information and reports that were specified; to act to maintain the listing of the debentures on the TACT-Institutional system; to act to ensure the continued proper operation of the Leviathan project in accordance with the Leviathan Agreements; to take any action possible under the JOA to ensure that the operator fulfills its undertakings under the JOA; to make all of the payments that apply to them and to bear all of the Trustee's expenses that apply to them under the Financing Documents; to purchase and maintain certain insurance policies; to refrain from modifying or amending the Leviathan Agreements or material gas agreements, as set out in the Financing Documents ("the Material Gas Agreements"), or the royalty agreements or engage in a new royalty agreement; and to refrain from approval of certain acts under the JOA.

The Issuer undertook not to assume any additional financial debt, other than the issue of additional debentures or other secured debt of an equal level, subject to the conditions that were set out, including (i) the amount of the secured debt of the Issuer (including the debentures) will not exceed USD 2.5 billion at any time; (ii) certain financial ratios set out in the Financing Documents are maintained in respect of the issuance of the additional debt.

In addition, the Partnership undertook not to assume any additional financial debt secured by the Pledged Assets, other than an additional loan to be received from the Issuer back-to-back to additional debt to be raised by the Issuer subject to the restrictions set out in the Financing Documents.

The Partnership undertook not to perform a merger transaction or change its operations in a manner that is likely to cause a material adverse effect, or to introduce dissolution proceedings or other defined restructuring, and not to sell, transfer, pledge, or otherwise dispose of any or all of its assets, other than permitted transactions as defined in the Financing Documents, including the sale of rights in the Leviathan project subject to mandatory early redemption or a tender offer to the debenture holders in certain cases, or permitted restructuring, as defined, including a transfer of the Partnership's rights in the Leviathan project to a new subsidiary and/or other actions, including the outline under consideration for a split of the Partnership's assets, provided that the rights of the holders are not impaired by such actions and additional terms as defined.

In addition, provisions were set out regarding early redemption of the debentures, including, (1) early redemption initiated by the Issuer, subject to payment of a make whole premium; (2) mandatory early redemption in certain defined cases, including by way of buyback of the debentures and/or a tender offer for all the debenture holders, including upon the sale of all or part of the rights in the Leviathan project. The Issuer and the Partnership undertook that if withholding tax applies to the amounts payable to a foreign resident, in accordance with the debenture terms, then, subject to certain exceptions that were defined, the Issuer and/or the Partnership, as the case may be, will pay additional amounts as required so that the foreign resident will receive the same net amount as the amounts that the foreign resident would have received, had no withholding tax been required. In this context, it should be noted that on July 27, 2020, the Partnership received approval from the Tax Authority that, among other things, the debentures that will be traded on the TACT-Institutional system of the TASE are debentures that are traded on the stock exchange in Israel for the purpose of section 9(15D) of the Income Tax Ordinance (for an exemption from tax on interest paid to a foreign resident on debentures traded on the TASE) and section 97(B2) of the Ordinance (for an exemption from tax for a foreign resident on capital gains in the sale of debentures traded on the

TASE), subject to the terms set out in the Tax Authority's approval and the provisions of the Income Tax Ordinance and the relating regulations.

NOTE 12: INVESTMENTS IN OIL AND GAS EXPLORATION AND PRODUCTION (CONTD.)

K. Financing in the Partnership (contd.)

2) Leviathan Bond debentures (contd.)

The Financing Documents include a waterfall payment mechanism, according to which the entire proceeds of the Partnership from the Leviathan project are transferred to an account pledged in favor of the Trustee("the Revenues Account"), which is used for various payments related to the project and the debentures, including payment of royalties to the State and to the royalty holders; payments to the Trustee; taxes and the levy under the Taxation of Profits from Natural Resources Law, 2011 (in this section: "the Law"); capital investments and operating expenses related to the Leviathan project; principal and interest payments; deposits for safety cushions; and balancing payments related to tax payments under section 19 of the Law. The transfer of the amounts remaining in the Revenues Account after the payments to a non-pledged account of the Partnership is subject to the conditions that were set out, including the fulfillment of an NPV coverage ratio of at least 1.5.

The Financing Documents defined events of default, which if they occur, subject to certain cure periods that were defined, qualifications, and terms, the trustee for the debentures will be entitled (and in the case of a demand of one quarter of the debenture holders, will be obligated) to call for immediate repayment of the unpaid balance of the debentures and may act to exercise the pledges. The main events are as follows: (1) default on payment of principal, interest or other payments required under the Financing Documents; (2) breach of representations; (3) breach of the covenants or negative covenants defined in the Financing Documents; (4) an event or introduction of insolvency proceedings of the Issuer, and an insolvency event as aforesaid or of a party to a Material Gas Agreement (as defined in the Financing Documents), the operator in the Leviathan project or the Partnership, if it is likely to cause a material adverse effect (as defined in the agreement) subject to certain conditions and qualifications; (5) premature termination of any of the Leviathan agreements or a Material Gas Agreement, if it is likely to cause a material adverse effect, subject to certain conditions and qualifications; (6) if a party to a Material Gas Agreement breaches the agreement and it is likely to cause a material adverse effect, subject to certain conditions and qualifications; (7) in the event of abandonment or suspension of operations at the Leviathan project for more than 15 consecutive days, if it is likely to cause a material adverse effect; (8) if damage is caused to the Leviathan project (including physical damage, revocation of a license or transfer of the Partnership's rights in the project by a government entity), which is likely to cause a material adverse effect, which was not remedied; (9) in the event of denial or revocation of government approval related to the Leviathan project, which is likely to cause a material adverse effect; (10) If any of the Financing Documents to which the Issuer or the Partnership are a party, or pledges provided under the Financing Agreements, with an aggregate value of more than USD 35 million, cease to be in effect; (11) if a non-appealable judgment is handed down against the Issuer for payment of an amount of more than USD 35 million, which was not paid; (12) if there is a breach of an undertaking in an agreement for providing other pari passu secured debt of the Issuer with a value of more than USD 35 million; (13) if an undertaking to perform mandatory early redemption is breached; (14) if the provisions for expenses from the Revenues Account are breached.

The debentures were rated by international rating agencies and an Israeli rating agency.

On August 3, 2020, approval from the Commissioner was received for the pledge of the Leases in favor of the Trustee, for the debenture holders. According to the Commissioner's approval, among other things, the pledge is provided to secure repayment of the Debentures, the proceeds of which are intended for providing credit to the Partnership in the total amount of up to USD 2.5 billion, to repay loans amounting to USD 2 billion (used mainly for investments in development of the Leviathan project), deposit a safety cushion in the amount of USD100 million, investments in the Leviathan project alone, and the financing of the construction of a pipeline for the export of gas from the Leviathan and Tamar reservoirs. As at the date of the financial statements, the Partnership has fulfilled its obligations as set out above.

NOTE 12: INVESTMENTS IN OIL AND GAS EXPLORATION AND PRODUCTION (CONTD.)

L. Issuance of debentures by Delek Overriding Royalty Leviathan Ltd.

On October 28, 2020, Delek Overriding Royalty Leviathan Ltd., a subsidiary of Delek Energy, completed of the issuance of debentures to foreign and Israeli classified investors (“the Issuer", “the Debentures”, and “the Issuance", respectively), which was secured by a lien on the rights to overriding royalties from the Leviathan project that were transferred to the Issuer (“the Leviathan Overriding Royalty”).

1. The Debentures were issued in a single series in a total amount of USD 180 million par value, repayable on December 30, 2023 (in a single payment) and bearing fixed annual USD interest rate of 7.494% (the effective rate is 10.1%). The interest on the Debentures will be paid twice a year, on June 30 and December 30.

2. Under the transaction outline, the rights of the Company (25%) and Delek Energy (75%) in the Leviathan Overriding Royalty and the rights attached to the royalty were transferred to the Issuer on the transaction closing date (“the Closing Date”) and were pledged in favor of the trustee of the Debentures in the Issuance (“the Issuance Trustee”), to secure repayment of the Debentures, under the terms of the deed of trust and the other documents under which the Debentures were issued (jointly: “the Issuance Documents”). In addition, the Issuer pledged in favor of the Issuance Trustee the rights attached to the royalty and rights in some of the bank accounts and insurance policies (jointly: “the Pledges”).

3. The full proceeds of the Issuance, less a security cushion in the amount of USD 21 million to secure interest payments (as at December 31, 2020, the security cushion amounts to USD 19.6 million), which will be held in an account pledged in favor of the Issuance Trustee, and the issuance and underwriting costs estimated at USD 8 million (it should be noted that in addition to this amount, the transferors will bear issuance and underwriting costs amounting to USD 3.6 million) were deposited on the Closing Date in the account of the trustees of the Company's debenture holders and will be used for upcoming payments to the debenture holders, in accordance with the provisions of section 6.1.5 to the amendment to the deed of trust valid as from June 17, 2020.

4. The Debentures are rated B+ on the international rating scale of Fitch rating agency.

5. On October 22, 2020, the Commissioner of Petroleum Affairs approved the transfer of the Leviathan Overriding Royalty to the Issuer and the pledge of the royalty in favor of the Issuance Trustee.

6. On October 20, 2020, the Issuer received approval from the Tel Aviv Stock Exchange Ltd. ("the TASE") to list the debentures on the TACT-Institutional System of the TASE, and they were listed for trading.

7. On October 15, 2020, the Issuer received a tax ruling from the Israel Tax Authority for issuance of the debentures, confirming that the debentures listed on the TACT Institutional System will be considered debentures traded on the TASE for the purposes of sections 9(15D) and 97(B2) of the Income Tax Ordinance, subject to certain conditions set out in the ruling.

NOTE 12: INVESTMENTS IN OIL AND GAS EXPLORATION AND PRODUCTION (CONTD.)

L. Issuance of debentures by Delek Overriding Royalty Leviathan Ltd. (contd.)

8. As is standard in financing transactions of this type, the Issuance Documents included covenants, restrictions, undertakings, and grounds to call for immediate repayment of the debentures and exercise the pledges.
It should be emphasized that the information set out below represents a partial and incomplete summary of the relevant provisions in the Issuance Documents and that the Issuance Documents include details of the various undertakings and grounds, restrictions subject to the occurrence of a material adverse effect ("MAE") on the Issuer (as defined in the Issuance Documents), as well as exceptions, additional terms, or cure periods that are not included in the description below.

    A. The Issuer has undertaken, among other things, not to take any financial debt in addition to the Debentures.

    B. The Issuer has undertaken that it will not carry out a merger or change its activities in a manner that is likely to cause a MAE, or that will result in liquidation proceedings or other defined structural changes, and will not sell, transfer, pledge or otherwise dispose of any of the pledged assets, other than transactions that are permitted under the Financing Documents, including full or partial sale of its rights in the Leviathan Overriding Royalty, subject to certain terms that are defined in the Financing Documents.

    C. Provisions were set out regarding early redemption of the Debentures, including, (1) early redemption initiated by the Issuer, subject to payment of a make whole premium; (2) mandatory early redemption in certain defined cases, including at the time of sale of all or most of the rights in the Leviathan Overriding Royalty.

    D. Events of default were defined, whose occurrence, subject to certain cure periods, qualifications, and terms that have been defined, will serve as grounds to call for immediate repayment of the unpaid balance of the debentures and the Issuance Trustee will be entitled to act to exercise the pledges, including in the following cases: (1) default on payment of principal, interest or other payments required under the Financing Documents; (2) material breach of representations; (3) breach of the covenants or negative covenants defined in the Issuance Documents; (4) an event or introduction of insolvency proceedings of a material party to a gas agreement (as defined in the Financing Documents), the operator in the Leviathan project or Delek Drilling, if it is likely to cause a MAE (as defined in the documents); (5) premature termination of the JOA, the terms of the Leviathan lease, or material gas agreements to which Delek Drilling is a party (as defined in the documents), if it is likely to cause a MAE, subject to certain conditions and qualifications; (6) if a party to a material gas agreement (as defined in the documents) to which Delek Drilling is a party breached the agreement, if it is likely to cause a MAE; (7) in the event of abandonment or suspension of operations at the Leviathan project for more than 15 consecutive days, if it is likely to cause a MAE; (8) if damage is caused to the Leviathan project (including physical damage, revocation of a license or transfer of Delek Drilling's rights in the project by a government entity), which is likely to cause a MAE, which has not been remedied; (9) in the event of denial or revocation of government approval related to the Leviathan project, which is likely to cause a MAE; (10) If any of the Financing Documents to which the Issuer is a party, or pledges provided under the Issuance Documents, with a cumulative value of more than USD 10 million, cease to be in effect; (11) if a non-appealable judgment is handed down against the Issuer for payment of an amount of more than USD 10 million, which was not paid; (12) the occurrence of an event that is likely to lead to the sale of the pledged assets or part of them subject to certain terms and restrictions; (13) if an undertaking to perform mandatory early redemption is breached; (14) if the provisions for expenses from the Issuer's account are breached.

    E. The Issuer has undertaken that all the proceeds from the Leviathan Overriding Royalty will be deposited in revenue account pledged in favor of the Issuance Trustee, which is subject to a waterfall payment mechanism, while any surpluses remaining in the account may only be used for buyback of shares or early redemption of the Debentures and cannot be distributed.

NOTE 12: INVESTMENTS IN OIL AND GAS EXPLORATION AND PRODUCTION (CONTD.)

L. Issuance of debentures by Delek Overriding Royalty Leviathan Ltd. (contd.)

8) (contd.)

F. Provisions have been stipulated for a safety cushion for the interest payments, and the Issuer has undertaken to comply with the covenant of an interest coverage ratio, as defined in the documents, such that this ratio will not be less than 1:2 (as at the approval date of the financial statements, the ratio for 2021 is expected to be 2.2).

9. On October 28, 3030, the securitization was completed and on the Closing Date, all receipts for the Issuance were deposited, including the total consideration for the Issuance, net of a safety cushion for interest payment, and issue and underwriting expenses, directly to a designated trust account of the trustee of the Company's debenture holders, and this amount was used for repayment of the debentures in November 2020 and will be used for additional repayments of debentures, in accordance with the provisions of the amendment to the deed of trust.

NOTE 12: INVESTMENTS IN OIL AND GAS EXPLORATION AND PRODUCTION (CONTD.)

M. Natural gas supply agreements

1) Tamar project

A. Agreements for the sale of natural gas and condensate by the Tamar partners (for100% of the rights in the oil asset):

	Year of start of supply	The basic agreement period[1]	Is there an option for an extension?[2]	Total contractual maximum supply quantity (100%) (BCM)[3]	The quantity supplied up to December 31, 2020 (100%) (BCM)	Main linkage basis for the price of gas
IEC[4]	2013	15 years	The IEC has the option to extend the agreement period for another two years if the total contractual gas quantity was not supplied the base period.	54.4	32.6	The linkage basis set out in the supply agreement is the US Consumer Price Index (US CPI).
Delek Energy	2015	17 years	Each of the parties has the option to extend the agreement period for another two years if the total contractual gas quantity was not supplied the base period.	17	6.3	Electricity production tariff including a minimum price[5]
Other private electricity producers	2013-2020	15-18 years other than one agreement for a period of eight years and two agreements for short periods	In most the agreements, both parties have the option to extend for another one to three years if the total contractual gas quantity was not consumed in the base period.	20.2	19.2	Most of the agreements include a linkage formula to the electricity production tariff that includes a minimum price.

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[1] In most of the agreements, the gas supply period, which started at the date of flow for the relevant agreement, will be as set out in the table above or until the Buyer consumes the maximum contractual quantity set out in the agreement, whichever is earlier.

[2] Some of the supply agreements in which customers have options to extend the agreement define conditions for their implementation.

[3] This quantity is the balance of the maximum quantity for gas supply set out in the agreements for the entire term of the agreements. The minimum quantity that customers undertook to purchase is the balance of the maximum quantity for gas supply set out in the agreements for the entire term of the agreements. The minimum quantity of the customers' commitment for acquisition is lower than this quantity. This quantity includes quantities that were reduced in accordance with the reduction option.

[4] For information about the conditions set out in the settlement agreement signed with the IEC on January 30, 2021, see section C below.

[5] The linkage to the electricity production tariff in the supply contracts for electricity producers is in accordance with the terms of the alternative in the Gas Framework, which includes the minimum price. For further information, see section 12K1 below.

NOTE 12: INVESTMENTS IN OIL AND GAS EXPLORATION AND PRODUCTION (CONTD.)

M. Natural gas supply agreements (contd.)

1) Tamar project (contd.)

A. Agreements for the sale of natural gas and condensate by the Tamar partners (for 100% of the rights in the oil asset) (contd.)

	Year of start of supply	Basic gas supply period[6]	Is there an option for an extension?	Total maximum supply quantity (100%) (BCM)[7]	Quantity supplied up to December 31, 2020 (100%) (BCM)	Main linkage basis for the price of gas
Industrial customers and natural gas marketing companies	2013-2020	3-7 years	In some of the agreements, both parties have the option to extend for an additional period, if the total contractual gas quantity was not consumed in the base period.	1.6	6.9	In most agreements, a fixed price is set without linkage.
Export agreements with APC - JBC	2017-2018	15 years	Both parties have the option to extend for another two years if the total contractual gas quantity was not consumed in the base period. provided the contractual gas quantity was not consumed in the base period.	2.3	0.65	The linkage formula is based on Brent prices and includes a minimum price.
Export agreement - Dolphinus	2020	15 years	If the buyer does not purchase the total contractual quantity in the base period, the supply period will be extended by another two years.	25	0.25	The linkage formula is based on Brent prices and includes a minimum price.
Total				120.5	65.9	

6 In most of the agreements (other than the Dead Sea Works agreement), the gas supply period will be as set out in the table above or until the Buyer consumes the maximum contractual quantity set out in the agreement, whichever is earlier.

7 This quantity is the balance of the maximum quantity for gas supply set out in the agreements for the entire term of the agreements. The minimum quantity that customers undertook to purchase is the balance of the maximum quantity for gas supply set out in the agreements for the entire term of the agreements. The minimum quantity of the customers' commitment for acquisition is lower than this quantity. This quantity includes quantities that were reduced in accordance with the reduction option..

NOTE 12: INVESTMENTS IN OIL AND GAS EXPLORATION AND PRODUCTION (CONTD.)

M. Natural gas supply agreements (contd.)

1) Tamar project (contd.)

B. Additional information about all the agreements for sale of natural gas in the Tamar project:

1) In most of the agreements for the sale of natural gas, the buyers have a take or pay agreement for a minimum annual volume of natural gas according to a mechanism set out in the supply agreement ("the Minimum Quantity"). If the buyers do not buy the Minimum Quantity in any year, they will be required to pay the sellers for the difference between the Minimum Quantity that was defined and the quantity actually purchased by the buyers. It should be noted that in agreements that include an obligation for the Minimum Quantity, provisions and mechanisms were established that allow the buyers, after consuming the Minimum Quantity for a given year, to receive gas in that year for no additional payment, up to the quantity of gas that was not consumed in the prior years, for which they paid the sellers under their undertaking to the Minimum Quantity, as aforesaid (make up). The supply agreements also specify a mechanism for the accumulation of surplus quantities consumed by the buyers in a given year, and its use to reduce the buyers’ obligation to purchase the Minimum Quantity, as set out above, in several subsequent years (“Carry-Forward”).

2) Following the decision of the Competition Commissioner regarding an exemption from a restrictive arrangement for the agreements in which the basic supply period is more than seven years, apart from the agreement with the IEC ("the Long-Term Agreements"), in some of the agreements signed with customers, each of the buyers has an option to reduce the Minimum Quantity to 50% of the average annual quantity consumed in the three years preceding the notice of exercise of the option, subject to adjustments as set out in the supply agreement (below in this section: "the Option"). Upon the reduction of the Minimum Quantity, the other quantities in the supply agreement will be reduced accordingly.
In this context, it should be noted that in 2019-2020, the Tamar partners signed amendments to agreements with a number of private electricity producers, including Dalia Energies, under which the producers undertook to purchase from the Tamar project the natural gas consumed in their facilities commencing from the start of gas flow from the Leviathan reservoir until the date the producers exercise the option for reduction, if exercised. In addition, under the amendment, the parties agreed that to calculate the average quantity consumed by the producers under the agreements in the three years preceding the announcement of the exercise of the Option for the period, the calculation will be based on the Minimum Quantity (according to the mechanism set out in the amendments to the agreements) and not on the basis of the quantity actually consumed. All of the amendments to the agreements have come into effect, including the amendment to the agreement with Dalia Energies.

3) It should be noted that in 2020, a number of customers submitted notice of the exercise of the reduction option, including private electricity producers. These notices are expected to take effect at different dates in 2021 and 2022.

NOTE 12: INVESTMENTS IN OIL AND GAS EXPLORATION AND PRODUCTION (CONTD.)

M. Natural gas supply agreements (contd.)

1) Tamar project (contd.)

B. Additional information about all the agreements for sale of natural gas in the Tamar project (contd.):

4) Under the terms of the Gas Framework, in natural gas supply agreements signed as from August 16, 2015 for a period exceeding eight years, the consumer has a unilateral right to shorten the term of the agreement. This right was granted in agreements signed up to December 13, 2020 for a period exceeding eight years. It should be noted that in 2020, two customers submitted notice of exercise of the early termination option, and these ended on March 1, 2021.

5) The supply agreements include further provisions, including the following: the right to end the agreement in the event of a breach of a material undertaking, the right of the Tamar partners to supply gas to the buyers from other natural gas sources, compensation mechanisms in the event of a delay in gas supply from the Tamar project or failure to supply the quantities set out in the agreement, limitations on the liability of the parties to the agreement, provisions regarding the right of the parties to assign their rights under the agreements, exemption from liability of the parties in the event of a force majeure (as defined in the agreements), mechanisms for resolving disputes and disagreements between the parties, and regarding the relations between the sellers themselves, in all matters related to the gas supply to the buyers.

C. Additional information about the gas supply agreement between the Tamar partners and the IEC:

1) The total contractual amount set out in the IEC-Tamar agreement (as amended) is 87 BCM, and the minimum billable amount, as from January 1, 2019 until the end of the agreement period, will be 3 BCM per year. The agreement includes provisions regarding the calculation and adjustment of the minimum billable quantity, including in circumstances of force majeure or non-supply by the sellers. It was further determined that the supply agreements also specify a mechanism for the accumulation of excess volume consumed by the buyers in the course of any year, and its use to reduce the buyers' undertaking to purchase the Minimum Quantity, as set out above, in several subsequent years (“Carryforward”), according to which the IEC may reduce the acquired quantity, using this mechanism, up to 1.75 BCM per year (such that the maximum quantity that can be used in a calendar year is 1.25 BCM). The amount accrued to the IEC under the Carryforward mechanism as at December 31, 2020 is 1.85 BCM (for 100% of the reservoir).

2) The agreement stipulates two dates on which each party may request an adjustment of the price (based on the mechanism set out in the agreement), if that party believes that the contractual price is no longer appropriate for a long-term contract with a significant buyer for consumption of natural gas in the Israeli market: after 8 years and 11 years from the date of commercial operation (as defined in the agreement as from July 1, 2013) from the Tamar Project (namely, July 1, 2021 and July 1, 2014), whichever is earlier. On the first adjustment date (July 1, 2021 - after 8 years), the adjustment to the price will be up to 25% (addition or reduction), and on the second adjustment date (July 1, 2024), the adjustment will be up to 10% (addition or reduction) of the price at that date. If the Tamar partners and the IEC fail to agree on the rate of the price adjustment, either party may refer the matter to arbitration.

NOTE 12: INVESTMENTS IN OIL AND GAS EXPLORATION AND PRODUCTION (CONTD.)

M. Natural gas supply agreements (contd.)

1) Tamar project (contd.)

C. Additional information about the gas supply agreement between the Tamar partners and IEC (contd.)

3) On October 4, 2020, some of the Tamar partners notified the Partnership and Noble that they had signed an agreement that they claimed was an addition to the IEC-Tamar Agreement ("the Agreement in Dispute"). Subsequent to the balance sheet date, on January 30, 2021, the Tamar partners and the IEC signed a settlement agreement regarding disputes that arose in connection with the Agreement in Dispute (in this section below: "the Tamar Settlement Agreement"). The Tamar Settlement Agreement stipulates, among other things, that: (1) The Agreement will be terminated and will be null and void; (2) until June 30, 2021, the IEC may purchase a quantity of BCM 1.25 from the Tamar reservoir, at a price lower than the price in the IEC-Tamar Agreement, which varies according to the quantity purchased, of which a quantity of 0.81 BCM was supplied in 2020, and, under certain conditions, additional quantities provided these quantities are not supplied by the Leviathan partners under the IEC-Leviathan Agreement. The gas quantities supplied and to be supplied at the reduced price will not be taken into account in the calculation of the take or pay and carryforward quantities in 2020 and 2021 in the IEC-Tamar Agreement as set out above.

The Tamar Settlement Agreement further stipulates that the maximum daily contractual quantity that Tamar partners will be required to supply to the IEC under the IEC-Tamar Agreement in the first half of 2021 will be limited to 500,000 MMBTU (compared with 655,000 MMBTU).

Under the settlement agreement, the parties waived their claims regarding the disputes.
The Tamar Settlement Agreement is subject to the fulfillment of preconditions and regulatory approvals, including the approval of the Competition Authority, and the approval of the Competition Tribunal for an agreed order under Section 50B of the Economic Competition Law, 1988, according to which the Competition Commissioner will not continue the process and will not enforce steps against Noble for the complaints filed in connection with the addendum. If the preconditions are not met within 30 days from the date of signing the settlement agreement, and for the approval of the Competition Tribunal, 60 days, each party will have the right to cancel the agreement. In view of the settlement agreement, the Partnership recognized expenses in the amount of USD 14.7 million, which was deducted from revenue from the sale of natural gas. As at the approval date of the financial statements, all the preconditions have not yet been fulfilled.

NOTE 12: INVESTMENTS IN OIL AND GAS EXPLORATION AND PRODUCTION (CONTD.)

M. Natural gas supply agreements (contd.)

1) Tamar project (contd.)

D. Natural gas export agreements

In February 2018, Delek Drilling and Noble signed an agreement with Dolphinus for the export of natural gas from the Tamar project ("the Original Export Agreement" and "the Buyer" respectively). On September 26, 2019, the Tamar partners and Dolphinus signed an agreement to amend the original Tamar-Dolphinus agreement ("the Amendment to the Tamar-Dolphinus Agreement") and the Leviathan partners and the Tamar partners signed an agreement for the allocation of available capacity in the transmission system from Israel to Egypt.

It should be noted that concurrently with the signing of the Amendment to the Tamar-Dolphinus Agreement, the Leviathan partners and Dolphinus signed an amendment to the Leviathan-Dolphinus agreement ("the Amendment to the Leviathan-Dolphinus Agreement). For further information, see section 2D below. On fulfillment of all the preconditions in the Amendment to the Tamar-Dolphinus Agreement, on December 24, 2019, the Partnership announced that the Amendment to the Tamar-Dolphinus Agreement came into effect.

In July 2020, after receiving a permit from the Natural Gas Authority for the flow of natural gas and after completion of the running-in of the compressor installed at the EMG terminal in Ashkelon, gas started to flow from the Tamar reservoir to Egypt.

In July 2020, Dolphinus endorsed the agreements for export to Egypt to Blue Ocean Energy, related company of Dolphinus.

The gas supply to the Buyer according to the Amendment to the Tamar Agreement is on a firm basis (as opposed to supply under the Original Export Agreement, which was on an interruptible basis with an option for the Tamar Partner to transition to a firm basis).

It should be noted that, in a tax decision regarding the amendment to the Tamar-Dolphinus Agreement issued to the Tamar partners by the Tax Authority on December 9, 2019, and under the terms of the Gas Framework, the Tamar partners undertook to offer new customers (as defined in the Gas Framework) with which they have or will have agreements from February 19, 2018 until three full years from the date the tax decision is signed, agreements for the sale of natural gas at a price calculated according to the formula in the Amendment to the Tamar-Dolphinus Agreement, which is based on the Brent Price, while performing several adjustments as set out in the tax decision, including in view of the location of the delivery point in the Amendment to the Tamar-Dolphinus Agreement.

Below is a summary of the details and terms of the Amendment to the Tamar-Dolphinus Agreement:

1) The gas supply to the Buyer according to the Amendment to the Tamar-Dolphinus Agreement is on a firm basis (as opposed to supply under the original Tamar-Dolphinus Agreement, which was on an interruptible basis with an option for the Tamar Partner to transition to a firm basis).
2) The total contractual gas quantity that the Tamar Partners undertook to supply to the Buyer under the Amendment to the Tamar-Dolphinus Agreement is 25.3 BCM ("the Total Firm Contractual Quantity in the Tamar Agreement") (compared with 32 BCM under the original Tamar-Dolphinus Agreement, which was, as aforesaid on an interruptible basis).

NOTE 12: INVESTMENTS IN OIL AND GAS EXPLORATION AND PRODUCTION (CONTD.)

M. Natural gas supply agreements (contd.)

1) Tamar project (contd.)

D. Natural gas export agreements (contd.)

3) Supply under the Amendment to the Tamar-Dolphinus Agreement started on June 30, 2020 and will continue until December 31, 2034 or until full supply of the Total Contractual Quantity in the Tamar Agreement, whichever is earlier ("the Termination Date of the Tamar-Dolphinus Agreement). If the Buyer does not purchase the total contractual quantity by December 31, 2034, each party may extend the supply period by up to an additional two years.

4) According to the Amendment to the Tamar-Dolphinus Agreement, the Tamar partners undertook to supply annual gas quantities to the Buyer as follows: (i) In the period beginning on June 30, 2020 and ending on June 30, 2022, 1 BCM per year; (ii) In the period beginning on July 1, 2022 and ending on the termination date of the Amendment to the Tamar-Dolphinus Agreement, 2 BCM 2 per year, by upgrading the systems at the EMG terminal in Ashkelon, including installation of an additional compressor, and the increase of transmission capacity in the INGL system.

5) The Buyer undertook to take-or-pay for quarterly and annual quantities, in accordance with the mechanisms set out in the Amendment to the Tamar-Dolphinus Agreement, which, among other things, allow the Buyer to reduce the take or pay quantity in a year in which the average daily Brent price (as defined in the agreement) falls below USD 50 per barrel, such that it will be 50% of the annual contractual quantity. It should be noted that, insofar as the contractual quantity is reduced in event of a dispute regarding an adjustment to the gas price, as set out in section 6 below, the right of Dolphinus to reduce the take-or-pay quantity as aforesaid will be null and void. In the reporting year, Dolphinus consumed 0.3 BCM (100%) of the amount in the Tamar-Dolphinus Agreement. It should be noted that following the sharp drop in energy prices in the first half of 2020, the average daily Brent price as defined in the agreement fell below USD 50 per barrel (see Note 24A2(1) for information about a claim and motion for certification as a class action filed against the Company and the Partnership in respect of this stipulation).

6) The price of gas supplied to the Buyer will be calculated by a formula based on the price of a barrel of Brent oil and includes a minimum price. The Amendment to the Tamar-Dolphinus Agreement includes a mechanism for an update of the price at a rate of up to 10% (addition or reduction) after the fifth year and after the tenth year of the Amendment to the Tamar-Dolphinus Agreement (below in this section: "the First Adjustment Date" and "the Second Adjustment Date", respectively), upon the fulfillment of certain conditions set out in the Agreement. If the parties fail to reach an agreement on the price update as described above, the Buyer will be entitled to reduce the contractual quantity by up to 50% on the First Adjustment Date and up to 30% on the Second Adjustment Date. It should be noted that the Agreement includes quantity-based incentives and it is subject to the price of a barrel of oil.

7) The Amendment to the Tamar-Dolphinus Agreement includes standard provisions for termination of the Agreement, as well as a provision to terminate the Agreement in the event of termination of the Leviathan-Dolphinus Agreement due to its breach, and the refusal of the Tamar partners to supply the quantities set out in the Amendment to the Leviathan-Dolphinus Agreement, including compensation mechanisms for such case. The Amendment to the Leviathan-Dolphinus Agreement also includes similar provisions.

NOTE 12: INVESTMENTS IN OIL AND GAS EXPLORATION AND PRODUCTION (CONTD.)

M. Natural gas supply agreements (contd.)

2) Leviathan project

A. Agreements for the sale of natural gas from the Leviathan project to the local market:

In 2016-2020, the Partnership and the other Leviathan partners signed a number of agreements for supply of natural gas from the Leviathan project, the main ones being as follows:

	Year of start of supply	Basic gas supply period[8]	Total contractual maximum supply quantity (100%) (BCM)[9]	Quantity supplied up to December 31, 2019 (100%) (BCM)[10]	Main linkage basis for the price of gas
IEC[11]	2020	Up to June 30, 2021	3.6[12]	2.4	Unlinked fixed gas price
Private electricity producers	2020, or when commercial operation of the Buyer's power station starts (whichever is later).	Some of the agreements are for a short period of up to two and a half years, and others are for long periods of 14 to 20 years. Half of the agreements do not grant the parties an option to extend. In most of the other agreements, each party is granted an option to extend the agreement if the total quantity is not purchased.	38.3	0.7	In most of the agreements, the linkage formula gas prices is based on the electricity production rate, and includes a minimum price. In a number of short-term agreements, there is a fixed price that is not linked.
Industrial customers	2020	Some of the agreements are for a period of 5 to 15 years and the others are for a short period of up to two years. In most agreements, the parties are not given an option to extend the term of the agreement.	3.8	0.4	In most of the agreements, the linkage formula is partially based on linkage to Brent prices and in part to the electricity production rate, and includes a minimum price. There is also a partial linkage to the refining margin index and the general TOU index published by the Israel Electricity Authority.
Export agreement - Nepco	2020	15 years The agreement stipulates that if the buyer does not purchase the total contractual quantity in the base period, the supply period will be extended by another two years.	45	1.9	The linkage formula is based on linkage to Brent prices and includes a minimum price.
Export agreement - Dolphinus	2020	15 years The agreement stipulates that if the buyer does not purchase the total contractual quantity, the supply period will be extended by another two years.	60	1.9	The linkage formula is based on linkage to Brent prices and includes a minimum price. The agreement includes a mechanism for an update of the price at a rate of 10% (addition or reduction) after the fifth year and after the tenth year of the agreement upon the fulfillment of certain conditions set out in the agreement.
Total		Up to June 30, 2021	151	7.25	

8 In most of the agreements, the gas supply period, which started at the date of flow for the relevant agreement, will be as set out in the table above or until the Buyer consumes the maximum contractual quantity set out in the agreement, whichever is earlier.

9 This quantity is the maximum quantity that the Leviathan partners undertook to supply to the customers in the term of the agreements. The quantity of the commitment of customers for acquisition is lower than this quantity. It is noted that in some agreements, there is a mechanism whereby the Buyer may reduce/increase the quantities purchased (including the total contractual quantity) until the date set out in the agreement, based on its requirements and the provisions in the agreement. It should be noted that in some agreements, the maximum supply quantity is not specified.

10 Since this is the first year of operation of the Leviathan project, the quantities in 2020 include accounting for the start date of commercial delivery.

11 For information about the IEC agreement, see section B below.

12 The original supply agreement signed with the IEC did not set a maximum total contractual quantity for supply. The above figure is equal to the quantity of gas supplied under the contract until December 31, 2020 (2.4 BCM) plus an additional quantity of 1.2 BCM which the IEC undertook to order from the Leviathan partners in the first half of 2021 (subject to certain adjustments) under the Leviathan settlement agreement described in section B.

NOTE 12: INVESTMENTS IN OIL AND GAS EXPLORATION AND PRODUCTION (CONTD.)

M. Natural gas supply agreements (contd.)

2) Leviathan project (contd.)

A. Agreements for the sale of natural gas from the Leviathan project (contd.)

Additional information about agreements for sale of natural gas signed by the Leviathan partners

1) In each of the agreements for the sale of natural gas, the buyers have a take or pay agreement for a minimum annual volume of natural gas according to a mechanism set out in the supply agreement ("the Minimum Quantity"). It should be noted that the agreements specify provisions and mechanisms allowing each of the buyers to receive gas at no additional charge up to the volume paid for, on account of gas not consumed. The supply agreements also specify a mechanism for the accumulation of excess volume consumed by the buyer in the course of any year, and its use to reduce the buyer's undertaking to purchase the Minimum Quantity, as set out above, in several subsequent years (“Carry-Forward”).

2) In accordance with the Gas Framework, in agreements signed up to June 13, 2017, and for a period exceeding eight years, there is an option to reduce the Minimum Quantity to an amount equal to 50% of the average annual quantity actually consumed in the three years prior to the notice of exercising the option, subject to adjustments as set out in the supply agreement (in this section: "the Option"). Upon the reduction of the Minimum Quantity, the other quantities in the supply agreement will be reduced accordingly. Each of the buyers may exercise the Option by notice to the Sellers, over a period of three years, starting from five years after gas starts to flow from the Leviathan project to the Buyer or four years after the Commissioner approves the transfer of rights in the Karish and Tanin leases under the Gas Framework (December 13, 2020) (whichever is later). If the Buyer gives notice of exercise of the Option, the quantity will be reduced twelve months after delivery of the notice.

3) Most of the supply agreements set out a number of preconditions which include, obtaining the required approvals from the buyers regarding the agreement.

4) The supply agreements include further provisions, including the following: The right to end the agreement in the event of material breach of liability, the right of the Leviathan partners to supply gas to the buyers from other natural gas sources, compensation mechanisms in the event of delay in gas supply from the Leviathan Project or failure to supply the quantities set out in the agreement, limitations for the parties' liabilities in the agreement, and regarding the relations between the Sellers and themselves in everything connected to gas supply for the buyers.

NOTE 12: INVESTMENTS IN OIL AND GAS EXPLORATION AND PRODUCTION (CONTD.)

M. Natural gas supply agreements (contd.)

2) Leviathan project (contd.)

B. Additional information about the gas supply agreement between the Leviathan partners and the IEC:

In June 2019, the Leviathan partners and the IEC signed an agreement for the supply of natural gas, based on the competitive process principles, according to which the IEC will purchase natural gas from the Leviathan partners based on available capacity (“the Supply Agreement”),
On October 29, 2019, all the preconditions for the entry of the Supply Agreement into force were fulfilled. The supply of gas to the IEC under the agreement began on December 31, 2019, and under the agreement, it will end on June 30, 2021 or on the date gas production starts from the Karish reservoir, whichever is earlier, unless it is terminated earlier under the terms of the agreement. The Supply Agreement sets a fixed gas price that is not linked.
Subsequent to the balance sheet date, on January 30, 2021, concurrently with the signing of the Tamar Settlement Agreement, the Leviathan partners and the IEC signed a settlement agreement (“the Leviathan Settlement Agreement), which amends the IEC-Leviathan Agreement, in which, without derogating from the obligations of the parties under the IEC-Leviathan Agreement, the IEC undertook to order from the Leviathan partners, in the first half of 2021, 1.2 BCM of natural gas, from which certain gas quantities will be deducted, as agreed, mainly gas quantities ordered by the IEC from Leviathan and not supplied, as well as gas quantities that will not be consumed by the IEC due to force majeure events and or malfunctions in significant production units of the IEC (“the Base Quantity”). If the IEC does not order the Base Quantity in the specified period, it will be required to pay the Leviathan partners for the difference between the Base Quantity and the actual quantity ordered. The IEC may use the remaining Base Quantity that it paid for but did not use, according to the mechanism set out in the Leviathan Settlement Agreement.
In addition, the Leviathan partners will grant the IEC a price discount for ordering gas quantities exceeding 0.5 BCM, ordered as from January 1, 2021.
When signing the agreement, the Partnership estimated that 4 BCM will be supplied to the IEC in the agreement period. In 2020, a quantity of 2.4 BCM was supplied to the IEC from the Leviathan reservoir. The Partnership believes that, in accordance with the Leviathan Settlement Agreement, in the first half of 2021, an additional quantity of 1.2 BCM will be supplied to the IEC.
Similar to the Tamar Settlement Agreement, the Leviathan Settlement is also subject to the fulfillment of preconditions and regulatory approvals, including the approval of the Competition Authority and the approval of the Competition Tribunal to the agreed order. As at the approval date of the financial statements, all the preconditions have not yet been fulfilled.

C. Agreement for the export of natural gas from the Leviathan project to the National Electric Power Company of Jordan:

In September 2016, a detailed agreement for the supply of natural gas was signed between NBL Jordan Marketing Limited ("the Marketing Company") and the National Electric Power Company of Jordan ("NEPCO" and "the Export Agreement", respectively). The Marketing Company is a wholly owned subsidiary of the partners in the Leviathan project, which hold it in proportion to their interests in the Leviathan project.
According to the Export Agreement, the Marketing Company undertook to supply natural gas to NEPCO for 15 years after the beginning of commercial supply and until supply reaches 45 BCM. Gas supply began on January 1, 2020.
According to the Export Agreement, the supply point is at the exit of the Israeli pipeline at the Israel-Jordan border. It is estimated that the costs involved in completing Israel's transmission system to the Israel-Jordan border will amount to USD 120 million (100%, the share of the Partnership is USD 54 million).
NEPCO has a take or pay commitment for a minimum annual volume of gas according to a mechanism set out in the Export Agreement.

NOTE 12: INVESTMENTS IN OIL AND GAS EXPLORATION AND PRODUCTION (CONTD.)

M. Natural gas supply agreements (contd.)

2) Leviathan project (contd.)

D. Agreement for the export of natural gas from the Leviathan project to Dolphinus:

In February 2018, the Partnership and Noble signed an agreement with Dolphinus, which endorsed its rights to Blue Ocean Energy (in this section below: "the Buyer") in July 2020, for the export of natural gas from the Leviathan project to Egypt (in this section below: "the Original Leviathan-Dolphinus Agreement"). On September 26, 2019, the Leviathan partners and Dolphinus signed an agreement to amend the Original Leviathan-Dolphinus ("the Amendment to the Leviathan-Dolphinus Agreement") and the Leviathan partners and the Tamar partners signed an agreement for the allocation of available capacity in the transmission system from Israel to Egypt (for further information see section M1d above).

On January 15, 2020, natural gas started to flow in accordance with the agreement. In July 2020, after receiving a permit from the Natural Gas Authority for the flow of natural gas, running-in of the compressor installed at the EMG terminal in Ashkelon was completed. Installation of the compressor made it possible to increase the gas flow to Egypt.

It should be noted that, in a tax decision regarding the amendment to the Leviathan-Dolphinus Agreement issued to the Leviathan partners by the Tax Authority on December 9, 2019, and under the terms of the Gas Framework, the Leviathan partners undertook to offer new customers (as defined in the Gas Framework) with which they have or will have agreements from February 19, 2018 until three full years from the date the tax decision is signed, agreements for the sale of natural gas at a price calculated according to the formula in the Amendment to the Leviathan-Dolphinus Agreement, which is based on the Brent Price, while performing several adjustments as set out in the tax decision, including in view of the location of the delivery point in the Amendment to the Leviathan-Dolphinus Agreement.

Below is a summary of the details and terms of the Amendment to the Leviathan-Dolphinus Agreement:

(A) The total contractual gas quantity that the Leviathan Partners undertook to supply to the Buyer under the Leviathan Agreement Amendment is on a firm basis and it significantly increased to 60 BCM (compared with 32 BCM under the Original Leviathan-Dolphinus Agreement) ("the Total Contractual Quantity in the Leviathan Agreement").

(B) Supply under the Amendment to the Leviathan-Dolphinus Agreement started on January 15, 2020 and will continue until December 31, 2034 or until full supply of the Total Contractual Quantity in the Leviathan Agreement, whichever is earlier ("the Termination Date of the Leviathan Agreement Amendment"). According to the Amendment to the Leviathan-Dolphinus Agreement, the Leviathan Partners undertook to supply annual gas quantities to the Buyer as follows: (i) in the period beginning on January 15, 2020 and ending on June 30, 2020, 2.1 BCM per year; (ii) in the period beginning on July 1, 2020 and ending on June 30, 2022, 3.6 BCM per year; and (iii) in the period beginning on July 1, 2022 and ending on the Termination Date of the Leviathan Agreement, 4.7 BCM per year.

(C) The Buyer undertook to take-or-pay for quarterly and annual quantities, in accordance with the mechanisms set out in the Amendment to the Leviathan-Dolphinus Agreement, which, among other things, allow the Buyer to reduce the take or pay quantity in a year in which the average daily Brent price (as defined in the agreement) falls below USD 50 per barrel, to 50% of the annual contractual quantity. It should be noted that, insofar as the contractual quantity is reduced in event of a dispute regarding an adjustment to the gas price, as set out in section (D) below, the right of Dolphinus to reduce the take-or-pay quantity as aforesaid will be null and void. In the reporting year, Dolphinus consumed 1.9 BCM (100%) of the amount in the Leviathan-Dolphinus Agreement. It should be noted that following the sharp drop in energy prices in the first half of 2020, the average daily Brent price as defined in the agreement fell below USD 50 per barrel (see Note 24A2(1) for information about a claim and motion for certification as a class action filed against the Partnership in respect of this stipulation).

NOTE 12: INVESTMENTS IN OIL AND GAS EXPLORATION AND PRODUCTION (CONTD.)

M. Natural gas supply agreements (contd.)

2) Leviathan project (contd.)

D. Agreement for the export of natural gas from the Leviathan project to Dolphinus (contd.)

(D) The price of gas supplied to the Buyer under the Amendment to the Leviathan-Dolphinus Agreement will be calculated by a formula based on the price of a barrel of Brent oil and includes a minimum price. The Amendment to the Leviathan-Dolphinus Agreement includes a mechanism for an update of the price at a rate of up to 10% (addition or reduction) after the fifth year and after the tenth year of the agreement (in this section below: “the First Adjustment Date” and “the Second Adjustment Date”, respectively) upon the fulfillment of certain conditions set out in the agreement. If the parties fail to reach an agreement on the price update as described above, the Buyer will be entitled to reduce the contractual quantity by up to 50% on the First Adjustment Date and up to 30% on the Second Adjustment Date. It should be noted that the Agreement includes quantity-based incentives and it is subject to the price of a barrel of oil.

(E) The Amendment to the Leviathan-Dolphinus Agreement includes standard provisions for termination of the Agreement, as well as provisions in the event of termination of the Amendment to the Tamar-Dolphinus Agreement between the Buyer and all partners in the Tamar reservoir due to its breach, and the refusal of the Leviathan partners to supply the quantities set out in the Amendment to the Tamar-Dolphinus Agreement. The Amendment to the Tamar-Dolphinus Agreement also includes similar provisions.

E. Agreement for supply of condensate to Bazan

In December 2019, an agreement was signed (“the Bazan Agreement”) according to which condensate produced from the Leviathan reservoir will flow to the EAPC pipeline leading to the tank farm of Petroleum & Energy Infrastructures Ltd. ("PEI”) and from there to Bazan’s facilities, in compliance with regulatory directives.

The Bazan Agreement is on an interruptible basis for 15 years, commencing from the start of condensate flow (in commercial quantities), with each party having the right to terminate the Bazan Agreement with at least 360 days’ notice to the other party. In addition, each party may cancel the Bazan Agreement with shorter notice under certain circumstances, including in the event of a breach by the other party, and in the event of regulatory and other changes that will not allow the flow of condensate in accordance with the Bazan Agreement.

The flow of condensate to Bazan under the Bazan Agreement will be on an interruptible basis up to a maximum quantity agreed on by the parties (“the Maximum Quantity”). The parties may revise the Maximum Quantity from time to time, subject to compliance with the terms established by the authorities in this respect, including conditions laid down by the authorities in this regard, including the Ministry of Energy and the Ministry of Environmental Protection.

Under the Bazan Agreement, the delivery of the condensate to the Bazan will be for no consideration, and the Leviathan partners will bear all expenses, including the tax exposure, incurred for the flow of condensate.

The Bazan agreement sets out a number of preconditions, mainly referring to obtaining regulatory approvals for the flow of condensate to Bazan, including approvals regarding the sale of condensate for no consideration. The Bazan Agreement took effect on January 29, 2020. The loss of revenue incurred by the Leviathan project due to the terms of the agreement is not material to the Partnership.

NOTE 12: INVESTMENTS IN OIL AND GAS EXPLORATION AND PRODUCTION (CONTD.)

M. Natural gas supply agreements (contd.)

3) Force majeure events under agreements for the sale of natural gas

In most of the Partnership’s agreements for the sale of natural gas (“the Agreements”), the customers have a take-or-pay agreement for a minimum annual quantity of natural gas, according to the mechanisms set out in the agreements. However, the customers may be exempt from this obligation, in the event of force majeure that prevents them from fulfilling their obligations, as defined in the Agreements. A force majeure event is defined as an event beyond the customer’s control, which prevents it from fulfilling its undertakings under the agreement and which could not reasonably have been prevented under the circumstances. The Agreements list events that will not be considered force majeure, also where they are beyond the customer’s control. It should be noted that the Partnership may also be exempt from its obligations under the agreements for sale of natural gas in the event of force majeure that prevents it from fulfilling its obligations s under the Agreements.

If a force majeure event continues over a prolonged period as set out in an agreement for the sale of natural gas (usually between one and three years) and it has a material effect on the ability of a party to fulfill its undertakings as aforesaid, this may constitute grounds for termination of the agreement. Accordingly, a force majeure event over a prolonged period, which suspends a customer's undertakings to buy a significant quantity of natural gas, may have a material adverse effect on the Partnership’s revenues.

4) Estimates regarding gas quantities and supply dates

The estimates of the quantity of natural gas purchased by the buyers in the Leviathan and Tamar Projects, and commencement of supply under the supply agreement is forward-looking information, and there can be no certainty that it will materialize, in whole or in part, and it might materialize in a substantially different manner, due to various factors, including non-fulfillment of the preconditions in each of the supply agreements (to the extent they have not yet been fulfilled), failure to obtain regulatory approvals, changes in the volume, rate and timing of natural gas consumption by each of the buyers, the gas price based on the formulas in the supply agreements, the USD-NIS exchange rate (if relevant to the supply agreement), Brent prices (if relevant to the supply agreement), the US-CPI (if relevant to the supply agreement), construction and operation of the power station and/or other facilities of the buyers (if relevant to the supply agreement), exercise of the options granted to each party in the supply agreements, and their exercise date.

NOTE 12: INVESTMENTS IN OIL AND GAS EXPLORATION AND PRODUCTION (CONTD.)

N. Royalties to the State, the Group, and others

1) Since the beginning of production from the Tamar reservoir, the Partnership has been paying, under protest, advances on account of royalties to the state at rates of between 11.3% to 12% as set out by the Ministry of Energy.

2) In September 2020, the Natural Resources Administration at the Ministry of Energy released specific directives for calculation of the value of the royalty at the wellhead in the Tamar project ("the Specific Directives"), which determined the rate of the deductible expenses when calculating the royalty value at the wellhead in the Tamar reservoir. Based on estimates and assessments by Partnership, there are no material discrepancies between the amounts recognized as royalty expenses in the statement of income in the reporting period, and the royalty expenses calculated in accordance with the Individual Provisions. It should be clarified that there are significant discrepancies between the cumulative royalties actually paid to the Ministry of Energy since production started from the Tamar project and the amounts recognized as royalty expenses in the statement of income (see section 7 below).

3) As from the start of gas supply from the Leviathan reservoir, the Leviathan partners make advance payments to the State on account of royalties to the State at a rate of 11.26%, and individual provisions have not yet been published for the calculation method of the royalties at the wellhead for the Leviathan lease.

4) It should be noted that the Partnership believes that calculation of the actual royalty rate to the state from the Tamar and Leviathan projects should reflect the complexity and risks involved in the project, and the scope of investments in the project.

5) In February 2019, the Yam Tethys partners and the Ministry of Energy signed an agreement on the final royalties reports for 2011-2013. According to the agreement, the Yam Tethys partners are entitled to USD 4.4 million (100%), which was offset against monthly royalty payments in the Yam Tethys project.

6) For information about the claim to return royalties paid to the state by the Partnership and Noble, for their revenue from the supply of natural gas, from their part in the Tamar project, to their customers under the Yam Tethys agreements, see Note 24A1(3) below.

7) The difference between the royalties paid to the State and the effective royalty rates used by the Partnership in its financial statements in the Tamar and Leviathan projects, amounted to USD 19.5 million (2019: USD 17.6 million), which was included under long-term loans, deposits, and receivables.

8) The calculation method for royalties to the State as set out above is also used to calculate the wellhead market value of the overriding royalty paid by the Partnership to the Group companies and to third parties, under the Limited Partnership agreement. The effective overriding royalty rate for the sale of natural gas and condensate from the Tamar reservoir in 2017-2019 is between 4.4% and 9% of gross sales for each of the years (of which, the rate of the royalty paid to the Group companies in these years is between 2.6% and 7.2%). The effective overriding royalty rate for the sale of natural gas in the Ashkelon lease in 2017-2019, taking into account commercial regulations (section H1 above) is between 8.6% and 8.9% of gross sales.

NOTE 12: INVESTMENTS IN OIL AND GAS EXPLORATION AND PRODUCTION (CONTD.)

N. Royalties to the state, the Group, and others (contd.)

9) As part of the Partnership's commitment to pay royalties to the Company and Delek Energy at a rate of 6.5% (instead of 1.5%), on September 4, 2018, the Partnership's audit committee, followed by the board of directors, approved the calculation of the investment recovery date, according to which the investment recovery date was in January 2018 (instead of December 2017, according to the draft calculation). In accordance with the calculation, the Partnership adjusted the calculation of the financing expenses and accordingly the royalty expenses in the Partnership and Tamar Petroleum together were reduced by USD 2.8 million (which was returned to the payers of the royalties). The calculation was approved after receiving a special report of the Partnership's auditors, after completion of their special audit, in the prescribed scope and on the basis of an independent legal advisor of the audit committee. For information about the motion for certification as a derivative claim, the statement of claim filed by the supervisor of the operator for the investment recovery date, see Note 24A2(3) below.
As set out in sections 12C1(4) and 12C1(5) above, Delek Energy and the Group sold the right to royalties and an indemnification arrangement was set out at the fixed rate after the investment recovery date.

10) In February 2019, Tamar Petroleum presented the Company, Delek Energy, and Delek Royalties ("the Royalty Holders") with its position that according to the interim calculation report as at the investment recovery date, which was prepared on its behalf in February 2019 (in this section below: "the Interim Calculation Report"), the investment recovery date in the Tamar lease was achieved at the end of February 2018, subject to adjustments and reservations as set out in the Interim Calculation Report. Tamar Petroleum requested a refund of royalties in the amount of USD 852 thousand for the share of the Royalty Holders (in this section below: "the Refund Amount"). On February 27, 2019, after the Company and Delek Energy did not respond to Tamar Petroleum's request for the Refund Amount, Tamar Petroleum offset the Refund Amount from the royalty payments at the end of February 2019 (Delek Energy transferred its share of USD 639 thousand to Delek Royalties as part of the indemnity as set out in Note 12C1(4)).

    The Company and Delek Energy notified Tamar Petroleum of their firm opposition to the contents of Tamar Petroleum's letter, including the attached calculation, and denied Tamar Petroleum's right to the offset (which the Company and Delek Energy claim was made in contravention of the law). Delek Energy and the Company further noted that they have serious claims regarding the advance of the investment recovery date to long before February 2018 (the date claimed by Tamar Petroleum). The Company and Delek Energy also stated that, if Tamar Petroleum does not transfer the Refund Amount that was offset (in contravention of the law), and if it does not agree with the position of the Company and Delek Energy regarding the early the investment recovery date, the Company and Delek Energy will consider their steps as to how to clarify these issues. See also Note 24A2(3).

O. Regulation

1) The Gas Framework

A) On August 16, 2015, Government Decision No. 476 (which was adopted in the government decision of May 22, 2016) approved the outline for increasing the quantity of natural gas produced from the Tamar natural gas field and swift development of the Leviathan, Karish, and Tanin gas fields and other natural gas fields (in this section, "the Government Decision"), which came into effect on December 17, 2015 after the Prime Minister, acting as Minister of the Economy, granted an exemption from certain provisions in the Restrictive Trade Practices Law to Ratio and Noble (in this section below: "the Parties"), in accordance with the provisions of section 52 of the Restrictive Trade Practices Law (in this section below: "the Exemption" or "the Exemption under the Restrictive Trade Practices Law), the main points of which are set out below.

NOTE 12: INVESTMENTS IN OIL AND GAS EXPLORATION AND PRODUCTION (CONTD.)

O. Regulation (contd.)

1) The Gas Framework (contd.)

B) Following are the restrictive trade practices for which the exemption was granted:

1) The restrictive arrangement that ostensibly arose, according to the position of the Competition Commissioner, following acquisition of the rights in the Ratio Yam permit by the parties; and the restrictive arrangement that ostensibly arose after the parties became the joint owners of the Ratio Yam and Leviathan reservoir permit.
2) The restrictive arrangement that will arise, ostensibly, if all or some of the parties will jointly market the gas produced from the Leviathan reservoir to the local market until January 1, 2025.
3) The restrictive arrangement that will arise, ostensibly, if all or some of the parties will jointly market the gas produced from the Leviathan reservoir for export only.
4) The restrictive arrangement that may arise from a certain agreement for acquisition of natural gas from the Leviathan reservoir, provided that the agreement is signed by January 1, 2025
5) In everything relating to their activity in the Tamar and Leviathan reservoirs only, the Partnership and Noble hold a monopoly according to the declarations of the Competition Commissioner.

C) The exemption from the restrictive arrangements set out in section B above is contingent on fulfillment of the following conditions, among others: The sale of all of the Partnership’s rights in the Karish and Tanin leases; the sale of all of the Partnership's rights in the Tamar and Dalit leases within 72 months from the date of the exemption under the Competition Law, certain stipulations relating to existing and future agreements for the supply of gas from the Tamar and Leviathan reservoirs, including price alternatives, linkage and gas quantities; compliance with the guidelines for the development of the Tamar SW reservoir; and an undertaking to invest in local content. In addition, the Gas Framework regulated issues relating to the export of natural gas, the existence of a stable regulatory environment, and various taxation issues. All this is subject to the terms and guidelines set out in the Gas Framework.

D) As at the approval date of the financial statements, the Partnership sold all of its holdings in the Karish and Tanin reservoirs and 9.25% of the rights in the Tamar and Dalit leases, and the Partnership is continuing to take steps to ensure compliance with the terms and provisions set out in the Gas Framework.

E) As at the approval date of the financial statements, the Company and Delek Energy sold the rights to royalties from Tamar and Dalit and the entire holdings in Cohen Development, which has the right to royalties, among other things, from the Tamar and Dalit leases (see Note 10K).

2. Guidelines for providing collateral for oil rights

In September 2014, the Commissioner issued guidelines for collateral for oil rights in accordance with section 57 of the Petroleum Law.

As at the balance sheet date, the Partnership has deposited autonomous bank guarantees with the Ministry of Energy, in the amount of USD 64 million for the Leviathan, Tamar, Dalit, Ashkelon, and Noa leases and for the Alon D, Ofek Hadash, and Yahel Hadash licenses, against bank credit. It is noted that the guarantee for the Tamar lease includes the guarantee that was provided for the approval received by the Tamar partners for operation of the natural gas and condensate system from the Tamar Project.

NOTE 12: INVESTMENTS IN OIL AND GAS EXPLORATION AND PRODUCTION (CONTD.)

O. Regulation (contd.)

3. Financing of projects for export through the national pipeline

On March 23, 2020, the Natural Gas Authority Council issued an addendum to its decision of September 7, 2014, regarding the financing of export projects through the national pipeline and division of the construction costs of the Ashdod-Ashkelon combined section. Under the Dolphinus agreements as set out in sections M1d and M2E above, it was agreed that the Tamar partners and the Leviathan partners, as the case may be, would bear the costs for gas flow in the INGL pipeline. According to the addendum to the decision, among other things, the offshore section of the pipeline to be constructed in the future, beginning at the receiving platform in Ashdod and ending at the facility connecting to the export facilities of Prima Gas Ltd. will be a combined section (“the Combined Section”); 43.5% of the cost of the Combined Section, to be determined, will be financed by the license holder and 56.5% of the Combined Section will be financed by the exporter, according to the milestones set out in the transmission agreement between the exporter and the transmission license holder.

It should be noted that on June 23, 2020, Director General of the Natural Gas Authority announced that he had set the estimated cost of the segment at a total of NIS 738 million (of which the Partnership’s share is estimated at NIS 159 million), in addition to an amount of NIS 48 million from which the exporter will pay the holder of the transmission license NIS 27 million, (of which the Partnership’s share is estimated at NIS 6 million), for bringing forward the doubling of certain transmission segments. Such costs will be adjusted in accordance with the mechanism for updating and accounting between the parties, which will be incorporated in the transmission agreement and will be submitted for approval.

For information about the agreement between Noble and INGL for transmission on a firm basis for the flow of natural gas from the Tamar reservoir and the Leviathan reservoir to the EMG receiving terminal in Ashkelon, for its transmission to Egypt, see section P below.

P. Transmission agreement for export of gas to Egypt

Subsequent to the balance sheet date, on January 18, 2021, Noble signed an agreement with INGL for the supply of transmission services on a firm basis to deliver natural gas from the Tamar and Leviathan reservoirs to the EMG receiving terminal in Ashkelon for its transmission to Egypt (“the Transmission Agreement”).

1) Under the Transmission Agreement, INGL undertook to provide transmission services for the natural gas to be supplied from the Tamar and Leviathan reservoirs, including maintaining a base capacity in the transmission system in the annual scope of 5.5 BCM (“the Base Capacity”). For the transmission services with respect to the Base Capacity, Noble will pay a capacity fee and will pay for the throughput gas quantity, according to the transmission tariffs that are customary in Israel, as updated from time to time. INGL also undertook to provide interruptible transmission services for additional gas quantities over and above the Base Capacity, subject to the capacity that will be available in the transmission system. For the transmission of the additional quantities as aforesaid, Noble will pay a transmission tariff for interruptible transmission services for the throughput quantities. The Partnership believes that the transmission system was designed in such manner as to enable transmission of the full contractual quantity set out in the export agreements.

2) Under the Transmission Agreement, Noble undertook to pay for delivering a gas in a quantity of no less than 44 BCM throughout the entire term of the agreement. If the parties agree to increase the Base Capacity, the minimum quantity for delivery will be increased accordingly.

3) The flow of gas under the Transmission Agreement will commence on the date INGL completed the construction of the Ashdod-Ashkelon transmission section, in accordance with the resolution of the Natural Gas Authority regarding the financing of export projects through the Israeli transmission system and allocation of the construction costs of the Ashdod-Ashkelon combined section (see section 6) ("the Authority’s Decision"), as well as doubling the Dor-Hagit and Sorek-Nesher sections to allow the flow of the full quantities under the Transmission Agreement ("the Commencement Date of Gas Flow"). Under the Transmission Agreement, the Commencement Date of Gas Flow expected in the period between July 2022 and April 2023.

NOTE 12: INVESTMENTS IN OIL AND GAS EXPLORATION AND PRODUCTION (CONTD.)

P. Transmission agreement for export of gas to Egypt (contd.)

4) The transmission period under the 2019 agreement will be extended until January 1, 2024 or until gas starts to flow under the Transmission Agreement, whichever is earlier.

5) The Transmission Agreement will expire at the earlier of: (1) the date on which the total throughput quantity will reach 44 BCM; (2) eight years after the Commencement Date of Gas Flow; or (3) upon the expiry of INGL's transmission license. The Partnership believes that at the end of the term of the Agreement, no difficulty is expected in its extension at the standard capacity and transmission tariffs of the holder of the transmission license at such time.

6) In accordance with the principles set out in the Authority's Decision, Noble undertook to pay for the partners' share (56.5%) of the overall cost of construction of the Ashdod-Ashkelon combined section, which is estimated at NIS 738 million. Noble further undertook to pay NIS 27 million for the partners' share of the costs of acceleration of the doubling of the Dor-Hagit and Sorek-Nesher sections.

7) In accordance with the Authority's Decision, the Leviathan partners and Tamar partners will provide a bank guarantee to secure INGL's share of the construction cost of the infrastructure, and to cover Noble's undertaking to pay the capacity and transmission fee. In February 2021, the Partnership provided NIS 172.9 million in guarantees in favor of INGL.

8) The Leviathan partners and Tamar partners will bear the costs set out in section 6 above and will provide the guarantees set out in section 7 above at the rates of 69% and 31%, respectively.

9) The Partnership believes that its share of the construction cost of the Ashdod-Ashkelon combined section and the acceleration costs of doubling the Dor-Hagit and Sorek-Nesher transmission system sections, may amount to NIS 165 million.

10) Under the Transmission Agreement, in the event of discontinuation of the export of natural gas from the Tamar project and Leviathan project to Egypt, Noble will be entitled to terminate the Transmission Agreement, subject to payment of damages to INGL for the early termination, in the amount equal to 120% of the construction costs of the Ashdod-Ashkelon combined section, together with the costs of acceleration of the doubling of the Dor-Hagit and Sorek-Nesher sections, and net of the amounts paid by Noble until the termination date for such costs of construction and acceleration and for the flow of gas under the Transmission Agreement.
If, subsequent to the termination of the Transmission Agreement, export to Egypt resumes, the Transmission Agreement will be renewed, subject to and in accordance with the capacity which will be available in the transmission system at such time.

11) On February 15, 2019, all the preconditions for the entry of the Transmission Agreement into force were fulfilled.

12) Concurrently with the signing of the Transmission Agreement, Noble, the Partnership, and the other Leviathan partners and Tamar partners signed a back-to-back services agreement, determining that the Leviathan partners and the Tamar partners will be entitled to transport gas (through Noble) under the Transmission Agreement, and will also be responsible for fulfilling Noble's undertakings under the Transmission Agreement, such that the Leviathan partners and the Tamar partners will be deemed to have been party to the Transmission Agreement in lieu of Noble, each according to its share as set out in the capacity allocation agreement between the Leviathan partners and the Tamar partners. The services agreement further stipulates that the Base Capacity retained in the transmission system for Noble, will be allocated between the Leviathan partners and the Tamar partners according to the rates set out in section 8 above and in accordance with the order set out in the capacity allocation agreement. Notwithstanding the aforesaid, the Leviathan partners and the Tamar partners will bear a capacity fee in a fixed ratio of 69% (the Leviathan partners) and 31% (the Tamar partners), other than in the event that a party (the Leviathan partners or the Tamar partners, as the case may be) will have used the other party's share of available capacity.

NOTE 12: INVESTMENTS IN OIL AND GAS EXPLORATION AND PRODUCTION (CONTD.)

Q. Balancing agreement for separate sale from the Tamar reservoir

Subsequent to the balance sheet date, on February 23, 2021, the Tamar partners signed a detailed agreement, the purpose of which is to determine the rules and mechanisms in connection with the share of each of the Tamar partners in gas production in accordance with the joint operating agreement, as well as balancing arrangements between partners if the gas is not marketed in accordance with the proportionate share of the partners in the period (“the Balancing Agreement” or “the Agreement”). Below are the main principles of the Agreement:

1) Each of the partners will be entitled to join as a full party to the gas supply contract from the Tamar reservoir ("the Supply Contract") that will be signed by another partner in accordance with its proportionate share in the reservoir and the mechanisms and terms set out in the Agreement ("the Tag Along Right"). For the Supply Contract for export, the Tag Along Right is subject to arrangements to be agreed on between the partners individually for each Supply Contract for export.

2) The Agreement includes various mechanisms and arrangements that allow a partner to market, subject to available capacity on a daily basis, quantities of natural gas that exceed its proportionate share in the Tamar lease (“the Oversupply Partner”), after each one of the other partners has first been afforded the possibility of ordering its full proportionate share in the output, and a certain partner will not have marketed its full share in the daily output (“the Undersupply Partner”). In such a case, balancing arrangements will apply between the partners with the aim of balancing the partners’ rights in relation to the gas sold according to their proportionate share in the reservoir: in money (meaning: through a payment to be made by the Oversupply Partner to the Undersupply Partner) or in gas (meaning: the Undersupply Partner will receive additional gas quantities in the future, over and above its proportionate share in the output in order to reach a balance), according to the Undersupply Partner’s choice, all in accordance with and subject to the provisions of the Agreement.

   In addition, the Agreement stipulated mandatory monetary balancing arrangements in each of the following cases: (1) when excess gas quantities have accrued in favor of an Undersupply Partner in a volume exceeding a cap stipulated in the Agreement; (2) on the date on which the operator determines that 60 BCM of proven gas reserves remain in the reservoir; (3) on the date on which production from the reservoir comes to an end or on the date on which the lease deed expires or comes to an end, according to the terms and conditions set out in the Agreement.

3) The operator will be responsible, among other things, for implementing the provisions of the Agreement and managing the orders thereunder, as well as for supplying the gas at the delivery point in accordance with its provisions. The operator’s responsibility for a breach of its undertakings under the Agreement will be subject to the restrictions and exclusions set forth in the Joint Operating Agreement.

4) In the case of a discrepancy between the Agreement and the Joint Operating Agreement, the provisions of the Agreement will prevail.

5) Each party to the Agreement will bear the payment of the taxes, the statutory royalties, the levies and the statutory payments applicable to the gas taken thereby, and accounting arrangements were determined with respect thereto between an Undersupply Partner and an Oversupply Partner in the case of monetary balancing. It was further determined that the parties will approach the tax authorities and the Ministry of Energy in joint applications for arrangement of the manner of reporting and payment of statutory royalties, levy, and taxes in relation to the Agreement, and that until receipt of the authorities’ decision, the reports and payments will be made in accordance with the current practice.

6) The Balancing Agreement is subject to the approval of the Competition Authority If such approval is not received by May 31, 2021, the Agreement will be terminated by prior notice of 30 days by any of the parties (unless the approval is received prior to termination of the Agreement). The Agreement will be in effect until the termination of the Joint Operating Agreement.

NOTE 12: INVESTMENTS IN OIL AND GAS EXPLORATION AND PRODUCTION (CONTD.)

Q. Balancing agreement for separate sale from the Tamar reservoir (contd.)

7) If any of the Partners seek to transfer its rights in the Tamar lease to another/others, the rights will be transferred together with the rights and undertakings of the partner under the Balancing Agreement.

8) The law that governs the Agreement is the laws of England and Wales. Any dispute between the parties that is not resolved in accordance with the mechanism set out in the Agreement will be referred to arbitration in accordance with the arbitration rules of the International Chamber of Commerce as stated in the Agreement. A party wishing to appeal determinations of the operator pertaining, among other things, to the available output, the allocation of orders and the date set out in section 2(2) above, or a determination of any party to the Agreement regarding the relevant prices for the monetary balancing, may refer the issue to be decided by an expert who will be appointed in accordance with the provisions of the Agreement and whose rulings will be final and binding, except in the case of blatant error or fraud. If the expert does not decide the dispute, the dispute will be referred to arbitration as aforesaid.

9) The implementation of the provisions of the agreement requires the establishment of various systems and the adoption of procedures, as well as the receipt of approvals and clarifications from the various tax authorities and regulators. Therefore, an interim period is determined in the Agreement, from the signing thereof until July 1, 2021, only at the end of which will it be possible to perform balancing arrangements (in money or in gas)

R. Directives for method of calculation of the royalty value at wellhead

A. In May 2020, the Director of Natural Resources at the Ministry of Energy released the final version of the directives for the calculation of the royalty value at the wellhead in accordance with section 32(b) of the Petroleum Law, 1952 (in this section: “the Directives"):

1) The Directives stipulate that the value of the royalty at the wellhead will be equal to 12.5% of the price of the sale to customers at the point of sale, net of essential costs for treatment, processing, and transportation of the oil actually incurred by the lease holder between the wellhead and the point of sale.

   The expenses to be recognized for the purpose of calculating the royalty value at the wellhead are expenses actually incurred by the leaseholder between the wellhead and the point of sale set out below, provided that the Commissioner believes that they are they are essential for the sale of the oil: (1) the following capital expenses (capex): (a) costs for treatment and processing of the oil; (b) costs for transporting the oil up to the first point of connection point to the national transmission system; (2) operating expenses (opex) arising directly from the types of capital expenses.

2) The Commissioner will determine for each leaseholder, from time to time, specific directives for each lease, specifying the deductible expenses for calculating the royalty, according to the specific characteristics of the lease.

3) Expenses for assets will be recognized in such a way that the depreciation rate for the fixed assets will be calculated according to the depletion method, starting from the date on which the fixed asset started to operate (meaning only when the fixed asset reached the location and condition required for its operation, and started to operate). Total depreciation expenses to be recognized will not exceed the cost of the fixed asset. Depreciation expenses for the fixed assets will be recognized such that at the end of the life of the asset, the value of the asset will be zero. Depreciation expenses will be calculated by multiplying the depreciated cost at the beginning of the year of the recognized part of the fixed asset determined in the specific directives, by the depreciation rate determined in accordance with the depletion method.

NOTE 12: INVESTMENTS IN OIL AND GAS EXPLORATION AND PRODUCTION (CONTD.)

R. Directives for method of calculation of the royalty value at wellhead (contd.)

3) (contd.)
If an agreement is signed granting third parties an ownership right in the fixed asset or a right of use in the fixed asset, for or without consideration, or if an agreement is signed involving the receipt of payment from third parties for the transportation or treatment of the oil, the estimated value of the fixed asset will be adjusted in the year in which an economic value was created for the asset over and above the amortized cost of the relevant fixed asset as determined, taking into account depreciation expenses deducted for calculation of the royalty value at the wellhead.

The estimate will be amended in the year in which the transaction in the relevant asset was made, in accordance with the "disposal principle", while the leaseholder may be required to pay royalties to the State for this value, even if it did not generate income in that year.

The economic value for the purpose of adjusting the estimate will be limited to the amount recognized and depreciated for royalty purposes, for the fixed asset that was sold or the rights in use were transferred.

4) The Directives set out additional provisions, including a specification of the types of expenses that will not be recognized, the method for recognizing abandonment costs, and the method for addressing transactions that are affected by the existence of special relationships between the parties to the transaction.

B. On September 6, 2020, the Director of Natural Resources at the Ministry of Energy released the Directives of the Commissioner of Petroleum Affairs for the calculation method of the royalty value at the wellhead - the Tamar lease. Below is a summary of the directives received for calculating the royalty value at the wellhead in the Tamar lease:

1) Capex that will be recognized for calculating the royalty value at the wellhead and the rate of recognition include: (a) capital cost for the transmission pipeline from the main manifold to the Tamar platform and from the platform to the receiving terminal in Ashdod will be recognized at a rate of 100%; (b) capital costs for the Tamar platform and the receiving terminal in Ashdod will be recognized at a rate of 82%; and (c) capital cost for the transmission pipeline from the Tamar platform up to the entrance to the receiving terminal in Ashdod will be recognized at a rate of 100%.

2) Operating expenses arising directly from the types specified in section A above will be recognized at a rate of 82%: payroll expenses for work at the platform and the receiving terminal; maintenance and repair expenses; expenses for travel and transportation to the platform; expenses for food for workers at the platform and the receiving terminal; expenses for guarding and security at the Tamar platform and the receiving terminal; expenses for professional and engineering consultation; insurance expenses.

3) If the contract sale price includes a component of a transmission tariff paid to INGL, all of the transmission expenses paid by the leaseholder will be recognized.

4) Abandonment costs will be recognized for calculation of the royalty according to the provisions set out in the general directives, provided that a cumulative quantity of at least 170 BCM was produced from the Tamar lease and the abandonment plan has been approved by the Commissioner.

NOTE 12: INVESTMENTS IN OIL AND GAS EXPLORATION AND PRODUCTION (CONTD.)

S. Taxation of Profits and Natural Resources Law, 2011

A. In April 2011, the Knesset passed the Profits and Natural Resources Tax Law, 2011 "(the Law"). Implementation of the Law resulted in a change in the tax regulations applicable to the Partnership, including the introduction of the oil and gas profits levy in accordance with the law and reversal of the depletion deduction. The law includes transitional provisions for producing projects or projects that started production before 2014.
The main provisions of the law are as follows:

1. Introduction of the oil and gas profits levy at the rate set out below. The rate of the levy is based on the recovery factor (“the R Factor”), according to the ratio between the net aggregate revenues from the project and the aggregate investments as defined in the Law. The minimum rate of the levy will be 20% if the R Factor is 1.5, and will increase progressively up to a maximum rate of 2.3. The maximum levy is 50% less the multiple of 0.64 in the difference between the corporate tax rate set out in Section 126 of the Income Tax Ordinance, 1961 for each tax year and the 18% tax rate. In accordance with the corporate tax rate in 2020, the maximum rate is 46.8%.

   Additional provisions were also determined regarding the levy, among other things, the levy will be recognized as an expense for the purpose of calculating income tax; the levy limits will not include transmission facilities used for export; the levy will be calculated and imposed for each lease separately (ring fencing); the charge of a recipient of payment from a holder of an oil right, calculated, among other things, as a percentage of the oil produced (“the Derivative Payment"), in accordance with the amount of the Derivative Payment received, and the amount of the levy attributed to the recipient of the Derivative Payment will be deducted from the amount of the levy due from the holder of the oil right.

   In addition, the Law prescribes regulations for consolidation or separation of oil projects in respect of the Law.

   The provisions regarding the levy on oil and gas profits are effective as from April 10, 2011, and they include transitional provisions for projects that began commercial production before January 1, 2014.

   A) The provisions of this law will apply to a project that commenced commercial production before the effective date, with the following changes:

      1) If a levy is imposed on a project in the tax year of the effective date, the rate of the levy in that tax year will be half of the rate of the levy that would have been imposed on the oil profits were it not for the provisions of this subsection, and no more than 10%.

      2) If the R Factor in the tax year of the effective date exceeds 1.5, rules were determined for calculation of the R Factor for each subsequent tax year.

      3) The rate of levy imposed on the project’s oil profits in each of the tax years from 2012 through to 2015 will be equal to half of the rate of the levy that would be imposed on the oil profits without the provisions of this section.

NOTE 12: INVESTMENTS IN OIL AND GAS EXPLORATION AND PRODUCTION (CONTD.)

S. Taxation of Profits and Natural Resources Law, 2011

1. (contd.)
   B. The following provisions will apply to a project that starts commercial production after the effective date but before January 1, 2014:

      1) The minimum levy factor will be 2 instead of 1.5 and the maximum will be 2.8 instead of 2.3.

      2) The annual accelerated depreciation rate for a deductible asset acquired in 2011-2013 will be 15% instead of 10%.

      3) The law includes provisions for the taxation of oil partnerships as from 2011, see section A above.

      4) According to the Law, the reporting partner of the oil project submits reports with cumulative data regarding proceeds and investments for the purpose of calculating the R factor, as set out in section 1 above.

      5) It is noted that disputes have arisen between the Assessing Officer for Large Enterprises and the holders of rights in the Leviathan leases regarding the levy reports for the Leviathan leases for 2013-2015, related primarily to the data classification and quantification method in the levy reports for the Leviathan leases for these years. In October 2018, the parties reached agreements regarding the disputes, under a levy assessment agreement for 2013-2015, which, in October 2018, was sanctioned as a judgment by the Tel Aviv District Court.

         In addition, in December 2019, the Assessing Officer for Large Enterprises and the holders of the rights signed a levy assessment agreement for the 2016-2017 levy reports. It is further noted that, as at the approval date of the financial statements, several interpretive disputes are being heard in the context of objection proceedings with the assessing officer regarding implementation of the Law in the 2018 levy reports of the Leviathan leases.

         In addition, the holders of rights in the Leviathan project reached agreements with the Tax Authority on the consolidation of the Leviathan leases (north and south) as a single oil project for purposes of the Law and the reports thereunder, in accordance with Section 8(A) of the Law.

      6) It is noted that disputes have arisen between the Assessing Officer for Large Enterprises and the holders of rights in the Tamar project regarding the 2013-2018 levy reports of the Tamar project, which refer mainly to recording of notional revenues and the method for recognition and classification of exploration and construction investments in the Tamar SW reservoir and construction payments in the Tamar SW reservoirs (jointly below: “the “Disputed Issues”). It is noted that the disputes pertaining to the 2013-2017 levy reports are adjudicated between the parties in the context of appeals before the Tel Aviv District Court, whereas the disputes pertaining to the 2018 levy report are adjudicated in the context of an administrative objection before the Assessing Officer for Large Enterprises.

         The Partnership believes, based on the opinion of its legal counsel regarding the Disputed Issues, that it is more likely than not that Partnership’s claims with respect to most of the Disputed Issues will be accepted.

      7) It is noted that disputes have arisen between the Assessing Officer for Large Enterprises and the holders of rights in the Ashkelon project, in respect of the 2018 levy report of the project. The Partnership’s share in the disputed amounts is USD 1.3 million. In March 2021, the holders of rights in the project filed an objection.

      8) Taxation of Profits from Natural Resources Regulations

         In December 2020, the Taxation of Profits from Natural Resources Regulations (Advance Payments Due to the Petroleum Profit Levy), 2020 (in this section: “the Regulations”) were published, for the purpose of regulating advance payments to be made by the holders of oil rights in an oil project, including the method of calculating the advances, the dates of their payment, and the reporting on them.

NOTE 12: INVESTMENTS IN OIL AND GAS EXPLORATION AND PRODUCTION (CONTD.)

S. Taxation of Profits and Natural Resources Law, 2011

8) (contd.)

The Regulations were published under Sections 10(B) and 51 of the Law, and their purpose is to determine the advance payments to be made by the holders of oil rights in an oil project. The Regulations address methods for calculation of advance payments, payment dates and reporting of payments, as defined in the Law.

In 2020, the Partnership paid advances for the oil profit levy in the amount of USD 2 million, for its rights in the Tamar Project. According to the Partnership's estimation and appraisals, based on the existing disputes with the Tax Authority, the levy coefficient in the Tamar project is higher than 2 and therefore, the Partnership recorded expenses for the oil and gas profit levy in the amount of USD 3.8 million (NIS 13 million).

B. Taxation of Profits from Natural Resources Legislative Memorandum (Amendment), 2021: Subsequent to the balance sheet date, on January 7, 2021, the public's comments on the Memorandum of Taxation on Natural Resources Profits (Amendment) Law, 2021 "("the Proposed Memorandum") was published, with several amendments to the Law, including the following proposals: (1) to amend Section 11 of the Law to allow the Tax Authority to collect a disputed levy already after the Tax Authority's decision regarding the objection to the levy assessment, and before the dispute is resolved in court; (2) to amend Section 13 of the Law such that the levy reports require approval by a CPA as defined in the Certified Public Accountants Law, 1955; (3) to amend Sections 14-15 of the law to allow extension of the assessment period of the levy reports from one year after filing the levy reports to four years after the end of the year in which the levy report was filed; (4) to add Section 16A to the Law, which refers to the application of the provisions of Section 86 of the Ordinance regarding the authority of the assessing officer to disregard certain transactions; and (5) to add Section 41A to the Law, which refers to authorizing the assessing officer to impose a penalty on the deficit arising from the difference between the actual levy charge and the levy payment according to a self-assessment. There is no certainty as to whether and when the Proposed Memorandum will be adopted and in which format (if adopted).

NOTE 12: INVESTMENTS IN OIL AND GAS EXPLORATION AND PRODUCTION (CONTD.)

T. Details of income tax regulations and the main arrangements

On December 31, 2017, the general partner in the Partnership filed an appeal against the District Court's judgment (in this section below: "the Partnership's Appeal"), in which the Supreme Court was petitioned to rule on the proper interpretation of section 19, in such a matter as to determine a fixed, known, and industry-wide method for taxing the taxable income of the oil partnerships, whereby all the oil partnerships will be able to act with certainty, among other things, while allocating the tax payment among the holders equally, to avoid the discrimination of holders liable for a lower rate than the maximum tax rate that applies to an individual. The Supreme Court was also petitioned to rule, as follows: (A) the tax paid by an oil partnership under section 19 should be equally allocated among all of the units in the partnership; (B) accordingly, the Partnership should issue equal tax certificates to the unit holders, such that the tax paid by the Partnership, on account of the tax for which the unit holders are liable, will be recorded on the tax certificate in a uniform amount for individuals and for corporations, with no distinction between them, and each holder may use such certificate as required, whether to supplement the tax payment required from the holder, or to receive a tax refund; (C) alternatively, to determine that the ruling of the District Court, whereby the tax should be allocated to holders in a differential manner, will apply prospectively only, whereas in the past, the oil partnerships could allocate the tax paid to the relevant holders equally, and accordingly be entitled to issue equal tax certificates; (D) alternatively again, if it is determined that the tax payment under section 19 is not a distribution within its meaning in the Companies Law, 1999 ("the Companies Law") it will then be determined that a balancing payment made to corporations-holders (to prevent subsidization among holders of the Partnership's units in the payment of the tax) is not a distribution, in order to avoid the discrimination of holders who are liable for a rate lower than the maximum tax rate that applies to individuals (such as companies or institutions).

Since another appeal was filed with the Supreme Court in the matter of another oil partnership – Isramco Negev 2 ("Isramco") on a similar ruling of the District Court regarding the allocation of tax paid by the partnership on account of the holders (in this section: "the Isramco Appeal") and as requested by Isramco and the Partnership, the Supreme Court ruled that the appeal will be heard together with the Isramco Appeal.

On July 28, 2019, the Supreme Court handed down a judgment dismissing the appeals ("the Judgment on the Appeal"). The Supreme Court upheld the judgment of the Tel Aviv-Jaffa District Court, and ruled, among other things, that an arrangement under which the Partnership will bear the full tax rate of the holders, individuals, and corporations alike, as required by section 19, and in addition to or further thereto, will make balancing payments to corporate-holders, does not constitute a "distribution" as defined in the law, but a result that requires payment of profits on account of the tax. However, the Supreme Court clarified that it does not purport to recommend or set hard and fast rules regarding the method of the balancing payments.

Shortly before the end of the 2017-2020 tax years, together with payments on the account of tax applicable to individual-holders, the Partnership made balancing payments to corporate-holders. It should be noted that the aforesaid balancing payments for these tax years do not necessarily represent full balancing of the payment arising from the tax rate applicable to individual-holders against the payment arising from the tax rate applicable to corporate-holders, since if there is a difference between the estimated taxable income according to which payments were made and the final assessment to be issued for the Partnership in the future ("the Differences"), the Partnership will be required to pay the Tax Authority the tax difference required from the Differences (or to receive it as a refund). It should be noted that as at the approval date of the financial statements, there is ambiguity regarding the correct balancing arrangement for tax payments arising from the Differences (see also section 9 and 10 below). Since balancing payments for the tax years 2015 and 2016 ("the Past Periods") were not made as for the tax years 2017 to 2020, as at the date of the financial statements, there is ambiguity regarding the proper balancing arrangement which the Partnership should apply for the Past Periods.

NOTE 12: INVESTMENTS IN OIL AND GAS EXPLORATION AND PRODUCTION (CONTD.)

T. Details of income tax regulations and the main arrangements (contd.)

In view of the existing ambiguity regarding the appropriate balancing arrangements that the Partnership should apply, for both the Past Periods and for the assessment differences that will only transpire in the future, the Partnership and the general partner filed an originating motion at the Tel Aviv District Court, petitioning the court, among other things, to determine the appropriate balancing arrangements between the individuals and corporations holding participation units of the Partnership, in view of tax payments that the Partnership is required to make under section 19, including: (A) tax payments insofar as they arise due to a discrepancy between the Partnership's estimate of the taxable income towards the end of the tax year and the independent assessment filed by the Partnership; and/or tax payments insofar as they arise from a discrepancy between the independent assessment filed by the Partnership and the final tax assessment that will be issued to it ("the Assessment Differences"); (B) the tax payments made for the Past Periods; given that the party holding the participating unit on the record date for a tax year in the Past Periods may no longer hold it until it becomes clear (if at all) that the Partnership is required to pay additional tax for that tax year (or vice versa) and given the difference in tax rates applicable to individuals and corporations. As part of the originating motion, the court was presented with various possible alternatives to the arrangements in respect of the tax payments for the Assessment Differences and for the past periods, in order to decide on the appropriate arrangements as aforesaid. In this context, the Partnership presented to the court a number of possible solutions, including: (a) a solution based on balancing by way of reimbursement; (b) a solution according to which no balancing payments will be made to corporate-holders (for both the Past Period and for the assessment Differences); and (c) a solution according to which the Partnership will make balancing payments to corporate-holders, according to a number of alternatives. For the Past Period, the alternatives for making the balancing payments to corporations that held participating units at the end of each one of the tax years 2015-2016 will include: (1) payment to the corporate-holders in the amount of the "surplus" amount which was paid for individual-holders in the Past Period, in a total amount of USD 13.1 million; (2) payment in the amount which would have been paid to the corporate-holders if full balancing payments would have been made in the Past Period, in a total amount of USD 73.9 million; (3) a combined method payment, taking into account that some of the corporate-holders no longer hold the units today. Regarding the solutions and alternatives for the Past Period, as set out above, the Partnership believes, based on the opinion of its legal counsel, that it is more likely than not that the Partnership will be required to make balancing payments to corporate-holders for the Past Period in the amount of at least USD 13.1 million, however, given the ambiguity in the court ruling for the Past Period and in view of the disadvantages of each of the alternatives, and taking into account all of the circumstances and considerations, as well as the complexity of the case, the Partnership and its legal counsel are unable to assess the probability that any of these alternatives will be adopted by the court, and therefore they are unable to assess the probability that the Partnership will be required to pay more than USD 13.1 million. Accordingly, in 2019, the Partnership recognized a provision of USD 12.3 million, which was recorded against the profit balance in the Partnership's capital and which was adjusted in view of changes in the exchange rate in the reporting year to USD 13.1 million. It should be noted that the estimated amount of the balancing payments for the tax year 2016 is based on the Partnership's independent assessment report, for which there are disputes between the Partnership and the Tax Authority. It should be noted that decisions on these disputes may materially change the Partnership's taxable income for 2016, and accordingly, the amount of the balancing payments arising from it. With respect to Assessment Differences, the alternative of balancing payments includes (over and above payment of the tax required of every holder) an additional payment for all or some of the corporate-holders in the relevant tax year, such that the total expenditure on tax and balancing payments per unit that they hold will be equal to the total expense on tax per unit held by individual-holders in the same tax year. It is noted that the aforesaid amounts were converted from NIS to USD at the USD rate known as at December 31, 2020.

NOTE 12: INVESTMENTS IN OIL AND GAS EXPLORATION AND PRODUCTION (CONTD.)

T. Details of income tax regulations and the main arrangements (contd.)

On October 18, 2020, the court approved the motion filed by the Partnership and the general partner for alternative service of process for holders of participating units by way of a public notice, which allowed each holder of a participating unit of the Partnership at the dates relevant to the originating motion (including all holders of the Partnership's participating units at the time the proceeding is filed) to join as a party to the proceeding. The court also ordered that the originating motion will be heard together with the originating motion filed by the Isramco partnership on the same matter (O.A. 32178-03-20). On December 29, 2020, another pretrial hearing was held, in which the court requested the Tax Authority's position regarding the proposals for various arrangements which arose in the holders' positions. At the end of the hearing, the court instructed that the parties may apply to the Tax Authority for clarification of its detailed position regarding to the proposals and then file a summary document with the court presenting the Tax Authority's position.

Further to a request by one of the groups of holders to the Tax Authority, on March 11, 2021 the Tax Authority's position was filed with the court. The court allowed the parties to respond to such position until March 18, 2021.
It is further noted that based on the 2019 tax report and the Partnership's results for 2020, the Partnership adjusted the estimate of its taxable income for each of the tax years 2019 and 2020.
. Since, as at date of the financial statements, there is ambiguity as to the appropriate balancing arrangements that the Partnership is required to adopt for the Assessment Differences, considering the complexity of the issue and the inability to estimate the probability with respect to the amount that the Partnership will be required to pay as a balancing payment to corporate holders, and based on the opinion of its legal counsel, the Partnership made no provision for the aforesaid in its financial statements.

U. Oil and gas production in the North Sea through Ithaca

(1) Ithaca operates in oil and gas production in the North Sea. Ithaca owns various rates of rights in producing and non-producing assets, mainly in the GSA, Captain, and other regions, some of which its serves as operator.
In 2018, Ithaca acquired all the rights in the facilities and licenses of its partners in the GSA Project, so that after completing the transaction Ithaca holds all the rights in the FPF-1 floating production facility in the GSA Project and in all the rights in the Project licenses, except for the Vorlich, Vorlich West, and Courageous licenses. The objective of the acquisition of the rights is to significantly increase Ithaca's share in the GSA Project reserves and production, and provides Ithaca full control and long-term flexibility in developing the GSA Project producing assets.
In addition, in 2019, Ithaca acquired ten producing assets in the North Sea as part of the acquisition of CNSL shares. For further information, see section 10F above.

(2) GSA Project

The GSA Project comprises several licenses that include the fields in which are located the Stella and Harrier reservoirs and five additional assets - Hurricane, Vorlich, Vorlich West, Courageous and Austen which, as at the reporting date are not producing or production has started as set out below. In all the oil assets in the GSA Project, with the exception of Vorlich West, exploration and appraisal drillings were carried out by third parties, and petroleum reservoirs were discovered.
In 2020, Ithaca completed the development of the Vorlich field and it was connected to the facility. Production from the Vorlich reservoir began on November 9, 2020. In the coming years, Ithaca will continue to connect the other reservoirs it owns to the FPF.

Ithaca pays royalties at a rate of 3.34% of revenues from the sale of oil and gas from the GSA project to the original holders of the license.

NOTE 12: INVESTMENTS IN OIL AND GAS EXPLORATION AND PRODUCTION (CONTD.)

U. Oil and gas production in the North Sea through Ithaca (contd.)

(3) Captain area

The primary asset acquired in the CNSL transaction is the Captain field, which covers an area of 85 sq. km and contains heavy oil and natural gas ("the Captain Field").
In November 2018, the partners in the Captain Field obtained OGA approval for the field development plans referring to development based on enhanced oil recovery (EOR).

The development plan will be implemented in two stages and it mainly includes a commitment to drill another seven wells, and inject polymers in the field to increase the recoverability of the oil. As at the approval date of the financial statements, Stage A of the development plan, which included drilling of five production wells and two polymer injection facilities in Area A of the field, has been completed. The investments for the continuation of development of the field and expansion of implementation of the EOR method in the different areas, and development of the lower layers of the reservoir in the coming years is estimated at USD 400 million.

(4) On March 16, 2020, Total E&P North Sea UK Ltd., the operator in the Isabella oil asset in the area of the continental shelf of the UK in the North Sea region, announced that in the exploratory drilling, indications of petroleum were discovered in the target layers of the well. The operator announced that due to high pressure and temperature, at this stage, production tests could not be performed using the existing equipment. Ithaca was informed that the operator intends to consider various alternatives for production tests at the oil asset at a later date. It should be noted that, under the terms of Ithaca's transaction regarding the oil asset, Ithaca does not bear expenses for its share in the oil asset (10%).

(5) Information about Ithaca's reserves

According to a report prepared by NSAI for Ithaca, which was prepared in accordance with the principles of the Petroleum Resources Management System (SPE-PRMS) as at December 31, 2020, the oil reserves, natural gas, and NGL in the oil assets included in the assets (Ithaca's share only), are as set out below:

	Ithaca reserves				
Reserve category	**Light oil**	**Heavy oil**	**Natural gas**	**NGL**	**Total**
	(Mbbl)	**(Mbbl)**	**(MMcf)**	**(net Mbbl)**	**(MBOE) *)**
Total 1P reserves (Proved reserves)	64,557	19,464	217,487	6,796	128,315
Total 2P reserves (Proved + probable reserves)	95,503	35,648	313,738	10,250	195,494
Total Proved + Probable + Possible Reserves (3P)	132,410	51,674	434,621	14,166	273,185

(*) Equivalent to thousands of barrels of oil

NOTE 12: INVESTMENTS IN OIL AND GAS EXPLORATION AND PRODUCTION (CONTD.)

U. Oil and gas production in the North Sea through Ithaca (contd.)

(5) (contd.)

These estimates of the natural gas reserves, NGL, and contingent resources in Ithaca's rights in reservoirs, are based, among other things, on geological, geophysical and other information. These estimates are the professional estimates and assumptions only of NSAI, for which there is no certainty. The estimates for actual quantities of oil, natural gas and condensate produced may differ 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 market and/or actual performance of the reservoir. The estimates and assumptions may be revised if additional information becomes available and/or as the result of a range of factors related to oil and natural gas exploration and production projects.

(6) Assessment of impairment of oil and gas assets in the North Sea region

- As at December 31, 2019, the Group included a provision for impairment of oil and gas assets in the North Sea region (mainly for the GSA asset) in the amount of USD 199 million (NIS 688 million). The impairment was due, among other things, to a decrease in reserves and forecasts for oil and gas prices. The recoverable amount was determined as the fair value of a cash-generating unit, net of selling costs. The fair value was calculated by an independent outside valuator, based on the future cash flow expected to arise from the sale of oil and gas, less selling costs and taking into account the assumptions that a reasonable market participant uses to determine fair value. The cash flows were discounted at a rate of 9% after tax. The assumptions used to calculate the fair value are the same as those used to assess goodwill impairment attributable to a unit of "oil and gas assets in the North Sea". For further information, see Note 14B(3).

- Further to Note 1A above regarding the spread of Covid-19 and the possible effect on Ithaca's business, including regarding the decrease in oil prices. Therefore, in view of the material effect these prices have on the fair value of the oil and gas assets in the North Sea, the Group assessed the recoverable amount of oil and gas assets in the North Sea area as at March 31, 2020. As a result of the assessment, in the first quarter of 2020 the Group recognized a provision for impairment of oil and gas assets in the North Sea region in the amount of USD 751 million (NIS 2.6 billion) (after the effect of tax - USD 451 million (NIS 1.6 billion)). The recoverable amount was determined as the fair value of each cash-generating unit, net of selling costs.
  In addition, the Company, through an independent outside valuator, examined the impairment of goodwill attributable to the item "Oil and gas development and production in the North Sea" in its entirety. The recoverable amount of the unit was calculated as the fair value of the investment in oil and gas production operations in the North Sea, net of selling costs, and it is estimated as at March 31, 2020 in the amount of USD 1,200 million. As a result of the assessment, the Group recognized impairment of goodwill attributable to these operations in the amount of USD 216 million (NIS 770 million).
  The valuations were performed by an independent outside valuator using the cash flow discounting method, based on a discount rate after tax of 10.5%, future Brent oil prices of USD 35 per barrel in 2020, USD 45 per barrel in 2021, and reaching USD 68 per barrel in 2024, and future gas prices of 24 penny per thermal unit in 2020, 33 penny per thermal unit in 2021, and reaching 43 penny per thermal unit in 2024.

NOTE 12: INVESTMENTS IN OIL AND GAS EXPLORATION AND PRODUCTION (CONTD.)

U. Oil and gas production in the North Sea through Ithaca (contd.)

(6) (contd.)

- As at June 30, 2020, the Group, through an independent outside valuator, re-examined the impairment of goodwill attributable to the item "Oil and gas development and production in the North Sea" in its entirety. The recoverable amount of the unit was calculated as the fair value of the investment in oil and gas production operations in the North Sea, net of selling costs, and it is estimated as at June 30, 2020 in the amount of USD 1.2 billion. This value is higher than the carrying amount of the investment as at this date, which amounts to USD 1.1 billion. Accordingly, the Company was not required to include further impairment of the goodwill. The valuation was performed by a valuator using the cash flow discounting method, based on a discount rate after tax of 10%, future Brent oil prices of USD 35 per barrel in 2020, USD 45 per barrel in 2021, and reaching USD 68 per barrel in 2024 (it should be noted that in subsequent years, a decrease in oil prices compared with those included in the valuation of March 31, 2020 was taken into account), and in future gas prices of 24 penny per thermal unit in 2020, 33 penny per thermal unit in 2021, and reaching 43 penny per thermal unit in 2024. As at September 30, 2020, there were no further indications of impairment.
  According to a sensitivity analysis that was conducted, a decrease of 10% in the oil and gas prices compared with those brought into account will lead to impairment of the total unit of USD 370 million. It should also be noted that an increase of 1% in the discount rate will lead to impairment of the total unit of USD 80 million. The valuations are classified at level 3 on the fair value hierarchy.

- As at December 31, 2020, following the recovery in the price of oil and gas and the increase in the quantity of reserves, the Group, through an independent outside valuator, assessed the need to reverse the impairment of oil and gas development and production assets in the North Sea region. As a result, the Group recognized the reversal of the provision for impairment (before tax) in the amount of USD 452 million (NIS 1,453 million).

  The valuations were performed by an independent outside valuator using the cash flow discounting method, based on a discount rate after tax of 9.75% of future Brent oil prices of USD 52 per barrel in 2021, USD 57 per barrel in 2022, USD 61 per barrel in 2023, and reaching USD 68 per barrel in 2025, and future gas prices of 47 penny per thermal unit in 2022, 43 penny per thermal unit in 2023, and reaching 44 penny per thermal unit in 2025.
  This impairment also includes an impairment of USD 25 million attributable primarily to an increase in disposal costs for assets that are no longer producing.

  According to a sensitivity analysis that was conducted, a decrease of 10% in the oil and gas prices compared with those brought into account will lead to impairment of the total unit of USD 229 million after tax. The valuation is classified at level 3 on the fair value hierarchy.

  As at December 31, 2020, the Company, through an independent outside valuator, assessed the need for a provision for impairment of goodwill attributable to the item "Oil and gas development and production in the North Sea" in its entirety. The recoverable amount of the unit was calculated as the fair value of the investment in oil and gas production operations in the North Sea, net of selling costs, and it is estimated as at December 31, 2020 in the amount of USD 1,878 million, which significantly exceeds the carrying amount of the unit (among other things, in view of the increase in reserves in gas reservoirs for which no depreciation has been made in the past, an increase in future prices mainly in the short term, and in view of impairment of goodwill recognized in previous quarters as aforesaid, and which is non-recoverable). The valuation was made using a discount rate after tax of 9.75% and based on assumptions for future Brent oil prices and future gas prices as set out above.

NOTE 12: INVESTMENTS IN OIL AND GAS EXPLORATION AND PRODUCTION (CONTD.)

V. Exploration and development of oil and gas in the Gulf of Mexico

1) On January 8, 2018, Delek GOM, a wholly owned foreign subsidiary of the Company ("the Buyer") signed an agreement for the purchase of oil and gas rights (in this report: “the Agreement” or “the Rights Purchase Agreement”) with GulfSlope Energy, Inc. and Texas South Energy Inc. (“GulfSlope”, “Texas South”, respectively, and jointly: “the Transferors”). The Transferors are public companies whose shares are listed for trading in the USA (OTC).
The oil assets under the Agreement are 12 federal leases for exploration, development and production of oil and gas in the Gulf of Mexico, USA, in shallow waters (less than 150 m depth) (“the Leases” and “the Oil Assets”). In the area of the Oil Assets, the Transferors identified nine major prospects for exploration drilling (“the Prospects”), seven of which are in deep layers (“Below the Salt" and two in shallow layers (“Above the Salt”). In the Agreement, the Buyers undertook to finance 90% of the cost of the two initial drillings in the Tau and Canoe Prospects (“the First Stage Assets”), in return for 75% of the rights in the First Stage Assets, in the area in which the drillings will be carried out, at a total amount that will not exceed USD 50 million and in addition, the Buyer will have an option to purchase rights in the remaining prospects based on the mechanism set out in the Agreement. The Company will provide the Buyer with a shareholders’ loan to finance the cost of these two drillings from independent sources.
Gulf Slope, which is the drilling operator ("the Operator") signed the agreement with Rowan Companies for the lease of the Ralph Coffman drilling rig (“the Rig”) to perform the two exploration drillings.

2) In August 2018, exploration drilling at the Canoe prospect in Block VR-378 in the Gulf of Mexico was completed. Based on the initial analysis of information from the drilling, sand layers with oil were found. It should be emphasized that the Operator did not announce a discovery.

   The Operator is continuing to examine the drilling findings together with the available seismic information in order to assess potential development of the prospect and to assess the economic feasibility for its development. However, according to the additional information provided to the Company by the Operator, regarding the results of the assessment, it appears that according to the Operator’s internal estimate, it is expected that there will be a significant decrease in the assessment of the quantity of resources in the oil asset compared with the previous estimate. Accordingly, in 2018, the Group reduced the total costs invested in the drilling, which amounted to USD 11 million (NIS 40 million).

NOTE 12: INVESTMENTS IN OIL AND GAS EXPLORATION AND PRODUCTION (CONTD.)

V. Exploration, development, and production of oil and gas in the Gulf of Mexico (contd.)

3) On completion of the exploration drilling in the Canoe prospect, at the beginning of September 2018, the drilling rig reached the site of the Tau prospect exploration drilling to the deep targets in the area of the SS-351 license in the Gulf of Mexico, and started drilling. According to the Operator's notice, when drilling towards the salt layer, the Operator encountered difficulties arising, among other things, from the copies in the rock layers, which required changes in the structure and drilling plan, and resulted in a significant delay in its progress. According to information provided to the Company by the operator of GulfSlope Energy Inc. ("the Operator"), the exploration drilling for Tau prospect had reached a final depth of 15,254 feet, while the original drilling was targeted to test the presence of hydrocarbons up to a depth of 29,857 feet (from which oil is produced in the nearby Mahogany field). The drilling did not penetrate layers containing hydrocarbons, however, hydrocarbon shows were encountered. The Operator did not announce a discovery.

   In view of the complex geomagnetic conditions in the drilling and the contractual obligations of the drilling rig to another operator, in May 2019, the Operator recommended that the drilling should be sealed and abandoned in a manner that would allow for re-entry at a later stage. According to the Operator, the information collected in the drilling confirms its geological, geophysical, and engineering models, and reinforces the Operator's position regarding the potential in the deep layers that have not yet been drilled in the prospect. The Group and the Operator continued to assess various options related to future operations in the drilling area and testing of the deeper layers of the prospect, which have not yet been drilled. The Group's share in the cost of drilling cost up to the temporary sealing amounted to USD 72 million (after receiving insurance proceeds in 2020). In November 2019, the insurers approved insurance coverage for the event underlying suspension of the drilling at a depth of 15,245 feet (as set out above). Under the terms of the policy, the insurers will pay certain costs associated with controlling the well, in addition to the costs required to continue drilling to the aforesaid depth. In view of the uncertainties created and the lack of clarity regarding the plan for continued drilling (which grew in 2020), the Group's management decided, at this stage, to include a provision of USD 53 million (NIS 182 million) for impairment, taking into consideration the insurance proceeds that were received in 2020.

4) On February 11, 2019, Delek GOM signed an agreement with GulfSlope, according to which Delek GOM will provide a loan to GulfSlope in the amount of up to USD 11 million. The loan will be for a period of six months, will bear interest at a rate of 5% and will be secured by liens on the assets of GulfSlope. According to the agreement, GulfSlope will be required to repay the loans out of proceeds from the sale of shares or from any refund from insurance companies or suppliers. In addition to Delek GOM, an option will be granted, for a period of 12 months, to purchase GulfSlope shares up to the amount of the loans provided, at a price of 4.2 cents per share.

   At the beginning of March 2019, Delek GOM provided GulfSlope with USD 10 million. At the same time, Delek GOM exercised the option for the acquisition of shares against offsetting the debt in full, and as a result, Delek GOM holds 22% of the share capital of GulfSlope (the investment in GulfSlope is accounted for under the equity method). In April 2019, Delek GOM invested a further amount of USD 1 million on account of the Loan. In October 2019, Delek GOM signed an agreement with GulfSlope, according to which an additional part of the insurance, amounting to USD 1.6 million, which is due to the Group, were converted into GulfSlope shares. As at December 31, 2020, the rate of the Group's holding in GulfSlope is 23.2%.

   In 2019, in view of the uncertainty regarding the continuation of the drilling plan of the TAU project as set out in section 3 above (which is the main asset of GulfSlope, Delek GOM amortized its investment in GulfSlope in full. The total loss recorded in 2019 for this investment amounted to NIS 43 million (USD 13 million), which is included under the Group's share in the profits (losses) of operating associates, net.

NOTE 13: FIXED ASSETS

A. Composition and changes:

2020

	Land, buildings and leasehold improvements	Machines, facilities, vehicles and office equipment	Pumps, tanks and station equipment	Total
	NIS millions			
Cost				
Balance as at January 1, 2020	1,485	1,661	1,041	4,187
Additions during the year	14	-	23	37
Exchange differences on translation of foreign operations	-	(7)	-	(7)
Deconsolidation *)	(1,132)	(1,555)	(633)	(3,320)
Reclassification to assets held for sale	(7)	-	-	(7)
Reclassification to investment property	(1)	-	-	(1)
Disposals during the year	(308)	(20)	(431)	(759)
Balance as at December 31, 2020	51	79	-	130
Accumulated depreciation				
Balance as at January 1, 2020	565	624	748	1,937
Depreciation	21	32	20	73
Deconsolidation *)	(521)	(597)	(521)	(1,639)
Exchange differences on translation of foreign operations		(1)	-	(1)
Disposals during the year	(53)	(17)	(247)	(317)
Balance as at December 31, 2020	12	41	-	53
Depreciated cost as at December 31, 2020	39	38	-	77

*) Mainly due to the sale of control of Delek Israel and its subsidiaries, see Note 10J.

2019

	Land, buildings and leasehold improvements	Machines, facilities, vehicles and office equipment	Pumps, tanks and station equipment	Total
	NIS millions			
Cost				
Balance as at January 1, 2019	1,504	1,561	1,026	4,091
Additions during the year	-	74	29	103
Exchange differences on translation of foreign operations	-	(3)	-	(3)
Entry into consolidation	-	37	2	39
Disposals during the year	(19)	(8)	(16)	(43)
Balance as at December 31, 2019	1,485	1,661	1,041	4,187
Accumulated depreciation				
Balance as at January 1, 2019	547	523	721	1,791
Depreciation	29	108	42	179
Exchange differences on translation of foreign operations	-	(1)	-	(1)
Disposals during the year	(11)	(6)	(15)	(32)
Balance as at December 31, 2019	565	624	748	1,937
Depreciated cost as at December 31, 2019	920	1,037	293	2,250
Less - provisions for impairments, net	53	55	13	121
Amortized cost as at December 31, 2019	867	982	280	2,129

B. For information about liens, see Note 25.

NOTE 14: GOODWILL AND OTHER INTANGIBLE ASSETS

A. Composition:

	Goodwill	Marketing, brands, concessions, and customer portfolios	Total
		NIS millions	
Balance as at January 1, 2019	1,479	5	1,484
Amortization recognized during the year	-	(1)	(1)
Companies consolidated for the first time (*)	2,837	3	2,840
Adjustments for translation of financial statements of foreign operations	(142)	-	(142)
Balance as at December 31, 2019	4,174	7	4,181
Amortization recognized during the year	(3)	-	(3)
Impairment	(848)	-	(848)
Deconsolidation (**)	(325)	(7)	(332)
Adjustments for translation of financial statements of foreign operations	(200)	-	(200)
Balance as at December 31, 2020	2,798	-	2,798

(*) See Note 10F.

(**) Mainly for the sale of control in Delek Israel and its subsidiaries, see Note 10J.

(***) For information about the presentation of assets attributed to Tamar and Dalit leases under assets held for sale, see Note 12C above.

B. Impairment of goodwill

To assess impairment of goodwill, the goodwill was attributed to business sectors, as follows:

	December 31	
	2020	2019
	NIS millions	
Fuel operations in Israel	-	322
Oil and gas exploration and production in Israel and its surroundings (2)	330	455
Oil and gas exploration and production in the North Sea (3)	2,468	3,397
Total	2,798	4,174

(1) For information about the sale of control in Delek Israel, see Note 10J.

NOTE 14: GOODWILL AND OTHER INTANGIBLE ASSETS (CONTD.)

B. Impairment of goodwill (contd.)

(2) As at December 31, 2020, goodwill attributable to oil and gas exploration and production in Israel and its surroundings amounted to NIS 330 million (as at December 31, 2019, NIS 455 million). Goodwill was created by the increase in control in the Avner Oil Exploration Partnership. The balance as at December 31, 2020 is after the impairment of goodwill attributable to the oil and gas assets in the Tamar project. See Notes 12C(1)(6) and 12G(5).

(3) Goodwill attributable to oil and gas exploration and production in the North Sea after the provision for impairment amounts to USD 768 million as at December 31, 2020 (NIS 2,468 million) and as at December 31, 2019, USD 983 million (NIS 3,397 million). Most of the goodwill arose on acquisition of CNSL's oil and gas operations in the North Sea in 2019 (see also Note 10F above). For information about the assessment for impairment of goodwill in 2020 and the provision for impairment that was recorded, see Note 12U(6).

NOTE 15: SHORT-TERM BORROWINGS FROM BANKS AND OTHERS

A. Composition:

	December 31	
	2020	2019
	NIS millions	
In NIS, unlinked	-	1,131
Current maturities of long-term loans	138	1,877
	138	3,008

B. For information about compliance with financial covenants, see Note 18C and Note 1C.

C. For information about collateral, see Note 25.

NOTE 16: TRADE PAYABLES

	December 31	
	2020	2019
	NIS millions	
Mainly open accounts	315	1,128
In or linked to foreign currency (mainly USD)	2	118
NIS	317	1,246

The trade payables are non-interest bearing.

NOTE 17: OTHER PAYABLES

	December 31	
	2020	2019
	NIS millions	
Institutions	91	246
Prepaid income, advance payments from customers, and expenses payable	385	345
Salaries and incidentals	10	63
Related parties	23	12
Undertaking to dispose of assets (see Note 12I3)	219	-
Payables for joint ventures in oil and gas	108	430
Interest payable	152	230
Dividend to non-controlling interests	53	46
Others	66	67
	1,107	1,439

NOTE 18: LOANS FROM BANKS AND OTHERS

A. Composition and terms:

	Annual interest rate*)	December 31	
		2020	2019
	%	NIS millions	
Loans from banks:			
USD or USD-linked	5.0	2,272	11,676
EUR		-	193
Linked to the CPI	3.5	113	126
Unlinked		-	1,973
		2,385	13,968
Less - current maturities		(138)	(1,877)
		2,247	12,091

*) Most of the loans bear interest at a variable rate. The rate presented is a weighted average as at December 31, 2020.

B. Settlement dates:

	December 31
	2020
	NIS millions
First year - current maturities	138
Second year	922
Third year	644
Fourth year	681
	2,385

C. Additional information

- As at December 31, 2020, the balance of the loans is mainly reserve based lending (RBL). For further information about the financial and operational covenants, see Note 10F.

- Subsequent to the balance sheet date, in January 2021, the Company, together with Fattal, received a loan of NIS 145 million for refinancing real estate property in Herzliya (see also Note 11A), (the Company's share is NIS 104 million). The loan is for three years and is secured by a lien on the property. The outstanding loan principal bears fixed annual interest of 7% and is linked to the CPI. The agreement sets out standard events for calling for immediate payment of the loan. The agreement also stipulates that in the occurrence of any of the events as set out for early repayment with regard to the Company alone or with regard to Fattal Hotels Ltd. alone, it will constitute grounds for immediate repayment with respect to the other borrower as well.

D. For information about other collateral, see Note 25.

E. For further information about agreements with the banks of the Company and the Staff Companies, see Note 19.

NOTE 19: OTHER DEBENTURES AND CONVERTIBLE DEBENTURES

A. Composition of non-convertible debentures:

	Annual Weighted interest rate as at December 31	December 31	
	2020	2020	2019
	%	NIS millions	
CPI-linked debentures issued by the Company	5.1	1,055	1,780
Unlinked debentures issued by the Company	5.3	3,487	3,692
Debentures in or linked to the US dollar, issued by subsidiaries and partnerships	6.6	10,515	6,347
		15,056	11,819
Less - current maturities		(2,153)	(1,998)
Less - debentures classified as short term (*)		(3,656)	-
		9,248	9,821

(*) For further information, see Note 19(5).

(**) For information about the balance of Tamar Bond debentures, amounting to NIS 2,042 million as at December 31, 2020, which were classified as liabilities attributable to assets held for sale, see Note 12K1.

B. Original repayment dates of debentures subsequent to the balance sheet date:

	December 31
	2020
	NIS millions
First year (current maturities)	2,153
Second year	1,050
Third year	2,920
Fourth year	2,356
Fifth year	2,702
Sixth year and onwards	3,875
	15,056

C. Composition of convertible debentures and liabilities:

	Weighted interest rate as at December 31	December 31	
	2020	2020	2019
	%	NIS millions	
Conversion liability (in USD) (see section G below)	6.5	159	171
Debentures convertible into Company shares (unlinked)	3.8	700	694
		859	865
Less - convertible debentures classified as short term (*)		(859)	-
		159	865

For further information, see Note 19(5).

NOTE 19: OTHER DEBENTURES AND CONVERTIBLE DEBENTURES (CONTD.)

D. Original repayment dates of convertible debentures and liabilities subsequent to the balance sheet date:

	December 31 2020
	NIS millions
First year (current maturities)	-
Second year	700
Fourth year	159
	859

E. Additional information about deeds of trust with the debenture holders shortly before the amendment to the deed of trust, for information about the amendment, see section G below.

The various debenture deeds include grounds or preconditions conferring on the debenture holders the right to call for immediate repayment of the debentures, including events that constitute material impairment or there was a material deterioration in the Company's business and there is a real concern that the Company will be unable to repay the debentures on their due date. In particular, it should be noted that, for Debentures (Series B31 and B33), which, as at December 31, 2020, have liabilities amounting to NIS 3.8 billion, and for Debentures (Series B34), with a balance amounting to NIS 0.4 million as at this date, the following terms were determined, among other things, conferring on the debenture holders the right to call for immediate repayment:

(1) Minimum equity: If the Company's equity falls below NIS 2,400 million (Series B34, NIS 2,600 million) in accordance with the Company's audited or reviewed consolidated statements, as the case may be, in two consecutive quarters.

(2) Equity to balance sheet ratio If the Company's equity falls below 20% of the total balance sheet in accordance with the Company's audited or reviewed separate statements, as the case may be, for two consecutive quarters.

(3) Downgraded debenture rating: If the debenture rating is revised by the rating company such that the rating for the debenture is lower than the rating of BBB- of S&P Maalot, or an equivalent rating by another rating company that may replace the current rating company, for a period exceeding 21 business days.

(4) Cross default: If the Company's debt (including a number of cumulative debts, provided that they were called for immediate repayment at the same time or close to each other) towards the banks and/or financial institutions in an amount no less than NIS 150 million ("the Material Debt), has been called for immediate repayment, provided that the call for immediate repayment was not been lifted and/or the Company did not repay the Material Debt within 30 days from the date it was called for immediate repayment. In addition, if another debenture series issued by the Company and listed on the stock exchange is called for immediate repayment by the trustee of that series and/or according to the approval of the general meeting of debenture holders of that series, provided that the call for immediate payment was not lifted within three business days after receiving the trustee's notice of the call for immediate repayment.

(5) Events of change of control in the Company as defined in the deed of trust.

NOTE 19: OTHER DEBENTURES AND CONVERTIBLE DEBENTURES (CONTD.)

F. In addition, the following conditions were set out for Debentures (Series B31, B33, and B34) (shortly before the amendment to the deed of trust, for information about the amendment, see section G below):

1) The Company may distribute a dividend as defined in the Companies Law, subject to fulfillment of the following terms: (a) The distribution is in accordance with section 302 of the Companies Law. (b) The Company does not violate the financial covenants set out in the deed of trust of Debentures (Series B34) prior to the distribution and due to the distribution. (c) The Company's equity will not fall below NIS 2,600 million (Series B34 in the amount of NIS 2,800 million) due to the distribution. (d) There are no grounds to call for immediate repayment of the Debentures (Series B34). (e) As at the approval date of the distribution, there is no material breach of the terms of the deed of trust.

2) Raising the interest rate following the downgrade, at a cumulative rate of up to 1%. Following the downgrade of the debentures in the reporting year, as set out in Note 1C, the annual interest rate for the series increased by 1%.

3) In addition, for Debentures (Series B33), with a balance amounting to NIS 704 million as at December 31, 2020, terms were stipulated, which, on their fulfillment, confer on the Company the right for a forced conversion of the debentures.

G. Amendment to the deeds of trust

Following the outbreak of the Covid-19 pandemic in the reporting year (for further information see Note 1C above), the Company did not fulfill some of the conditions set out in the deeds of trust.

In view of the above, on June 17, 2020, the general meeting of the holders of the various series of the Company’s debentures approved the amended deed of trust of each of the Company’s debenture series, including (among others), the following provisions:

A. Raising capital: The Company’s commitment to raise capital in an aggregate amount of NIS 500 million by April 8, 2021, in accordance with the following milestones: By July 31, 2020, raising of NIS 300 million (the Company raised NIS 313 million in May and August 2020), by December 15, 2020, raising of NIS 150 million, and by April 8, 2021, raising of NIS 50 million.
As at December 31, 2020, the Company raised NIS 450 million in accordance with the amendment to the trust deed.
Subsequent to the balance sheet date and up to the approval date of the financial statements, options have been exercised for the Company's shares in the amount of NIS 17 million. For further information, see Note 26.

B. Negative pledge, prohibition of early payment and other liabilities: the Company’s undertaking that in the stipulated period (as defined below), the Company and the private companies under its control:

1) Will not create liens, will not increase amounts secured by existing liens, and will not provide guarantees, other than liens and guarantees that are exempt as set out in the deed of trust.

2) Will not pay creditors on a date that is earlier that the date set out in the repayment schedule, other than payments that are exempt as set out in the deed of trust.

3) Will not transfer funds and/or assets to Ithaca companies and/or their creditors and will not assume liabilities and/or guarantees regarding Ithaca companies and/or their debts, other than payments that are exempt or that the Company is permitted to perform as set out in the deed of trust.

According to the amendment to deed of trust, “the record period" is the period from the approval date of the deed of trust until seven days have elapsed from the publication date of the Company’s immediate report on the expiration condition; “the expiration condition" means that the following conditions were fulfilled at that date: (A) The Company's equity in the Company statements and the statements of the prior quarter exceed the amount set out in the amendment to the deed of trust; (B) the ratio of equity to the balance sheet in the Company's statements (separate) and in the statements of the prior quarter is not less than 22.5%; (C) the rating of the Company's debentures is at least A (according to Maalot).

NOTE 19: OTHER DEBENTURES AND CONVERTIBLE DEBENTURES (CONTD.)

G. Amendment to the deeds of trust (contd.)

C. Liens: The Company's undertaking to create a lien on the various assets of the Group, in favor of the Company's trustees and debenture holders, including the following assets: (A) Participating units conferring rights in the rights of the limited partner in Delek Drilling, representing 40% of Delek Drilling's share capital (in the fourth quarter of 2020, 40% of Delek Drilling's participating units were pledged in favor of the trustees). As from January 1, 2022, the Company may have the right to demand the release of some of the pledged participating units, in the amount and subject to the terms set out in the amendment to the deed of trust; (B) the shares and rights in most of the companies that are controlled by the Company; (C) the rights by virtue of the loans provided to the Company and/or companies under its control; (D) the assets of Delek Financial Investments Partnership that holds the Company's debentures and shares; (E) the Group's rights in connection with the Leviathan Overriding Royalty, up to the date of securitization against the overriding royalties. For further information about the completion of securitization of the Leviathan Overriding Royalty, see Note 12M above; (F) rights by virtue of loans provided to third parties.

D. According to the amendment to the deed of trust, the trustee and the debenture holders will have grounds to call for immediate payment if the Company does not receive certain amounts of cash from Delek Petroleum Ltd. and/or other sources set out in the amendment to the deed of trust in a cumulative amount of NIS 800 million (including an amount of at least NIS 600 million, which should be received by October 31, 2020, of which NIS 400 million are from a dividend from Delek Israel). In 2020, the Company received NIS 600 million from dividends and the disposal of Delek Israel.

E. Other grounds for immediate repayment in the amendment to deed of trust:

1) For the period up to May 31, 2021, the trustee and the debenture holders will not call for immediate repayment of the debentures based on the established grounds, but only on the state of the Company's business as it was at the publication date of the amendment to the deed of trust and as at June 1, 2021 this restriction will no longer apply to the trustee of the debenture holders.

2) Up to the publication date of the statements for the first quarter of 2021, the grounds for immediate repayment included in the deeds of trust regarding low equity will not apply. For the statements as from the second quarter of 2021 and up to the financial statements for 2021, the debenture holders will have grounds to call for immediate repayment if the equity net of the additional capital from revaluations as defined in the amendment to the deed of trust is lower than the total equity of the Company as at June 30, 2020, with the addition of NIS 600 million, or if the equity in the financial statements is less than NIS 1.6 billion. These limits gradually increase over the years.
In view of the capital attributable to the Company's shareholders as at June 30, 2020, the minimum capital required in the subsequent periods is as follows: with regard to the financial statements commencing from the second quarter of 2021 report through to the annual financial statements for 2021, NIS 1.6 billion; with regard to all the financial statements for 2022 (including quarterly reports), NIS 2 billion; with regard to all financial statements for 2023 (including quarterly reports), NIS 2.4 billion; and commencing from the first quarter of 2024 financial statements, NIS 2.6 billion. Failure to comply with the standard in any of the foregoing financial statements will constitute grounds for immediate repayment.

3) Up to the publication date of the statements for the first quarter of 2021, the grounds for immediate repayment included in the deeds of trust regarding the equity to balance sheet ratio will not apply. For the statements as from the second quarter of 2021 and up to the financial statements for 2021, the equity to total balance sheet ratio in accordance with the separate financial statements falls below 12.5% over two consecutive quarters. This ratio rises gradually over subsequent years, so that as from the first quarter of 2024, the debenture holders will have grounds to call for immediate repayment if the equity to total balance sheet ratio in accordance with the Company's separate financial statements falls below 20% over two consecutive quarters.

NOTE 19: OTHER DEBENTURES AND CONVERTIBLE DEBENTURES (CONTD.)

G. Amendment to the deeds of trust (contd.)

E. Other grounds for immediate repayment in the amendment to deed of trust: (contd.)

4) Low rating - until May 31, 2021, the trustee and debenture holders will not have the right to call for immediate repayment of the debentures due to a rating that is lower than BBB-). As from June 1, 2021, the debenture holders will have the right to call for immediate repayment if the debenture rating is lower than BBB-.

5) If another creditor of the Company or creditors of the Company’s subsidiaries call for payment of their debt (in accordance with the quantitative thresholds set out in the amendment to the deed of trust), and in certain cases, they also have grounds to call for immediate repayment, this will constitute grounds to call for immediate repayment of the debentures.

6) In the effective period: general and administrative expenses in 2020, including those of the Staff Companies, will not exceed (including the costs of the amendment to the deed of trust) those in 2019, based on the Company's financial statements. In 2021, they will not exceed NIS 45 million; in 2022, NIS 40 million; and from 2023, NIS 35 million. For information about the obligations in 2020, see Note 1C(3).

7) The deeds of trust of the debentures include grounds for immediate repayment in the event of a change of control (below 30%) which could impair the Group's solvency.

F. The amendment to the deed of trust includes various declarations and undertakings of the Company, including: (A) In connection with the uses to be made of the proceeds from the capital issuances and/or dividends and/or sale and/or pledge of certain assets; (B) a commitment not to deposit funds and/or securities in banks that are creditors of the Company or companies under its control, other than the exceptions that were established; (C) a commitment not to acquire assets and/or to make investments and/or to take credit and/or to make financial liabilities to financial creditors and/or to change the terms of certain credit agreements, other than the exceptions that were established; (D) in the record period: The Company's general and administrative expenses will not exceed the amounts that were established, the Company will not perform a distribution, the Company and the companies under its control will not enter into transactions in which the controlling shareholder has a personal interest (other than officers, insurance and existing agreements as set out in the statements), the Company and private companies under its control will not sell or purchase the Company’s debentures; (E) an obligation to cover the expenses and fees of the trustees and their representatives. It was further established that a breach of any of the Company's obligations under the amendment to the deed of trust will serve as grounds for the trustees and debenture holders to call for immediate repayment and the right to exercise all the collateral provided to the trustees.

NOTE 19: OTHER DEBENTURES AND CONVERTIBLE DEBENTURES (CONTD.)

G. Amendment to the deeds of trust (contd.)

F. (contd.)

3) The standstill period

a) In the period up to September 30, 2020 ("the Standstill Period"): (A) the Companies will not be required to complete collateral in favor of the Banks, even if the collateral is impaired; (B) the Banks will not take any legal action against the Companies for the credit documents; (C) the loans provided by the Banks will not be called for immediate repayment and the credit facilities will remain in force in the amount of the actual credit used; and (D the Banks will not take steps to exercise the collateral.

b) The Standstill Period may be extended to October 30, 2020, subject to certain conditions set out in the deed of consent, and among other things, that by until September 30, 2020: A binding agreement will be signed for the sale of Delek Israel, to allow repayment of the entire debt to the Banks; the Company will present cash flow sources at a high level of certainty, which will allow payments to the debenture holders with a repayment date by October 31, 2020, and repayment to the Banks of at least 50% of the credit amount at the date the deed of consent is signed. The Company is in compliance with the obligation. For further information about the sale of Delek Israel, see Note 10J above.

c) The deed of consent sets out events, which, if they occur, each of the Banks will have the right to cancel the Standstill Period and implement all the means at their disposal, including to call for immediate repayment of the entire debt and to act to exercise the lien on Delek Israel and dispose of the participating units that are pledged in its favor (“the Terminating Event"), including: if the Companies fail to pay the Banks any amount at its due date; if the Companies breach an undertaking under the deed of consent and/or its appendixes and/or the amendment to the deed of trust with the debenture holders and/or other undertakings of Delek Israel towards a foreign bank; if insolvency proceedings were taken against the Companies; if a decision was taken at a general meeting of the debenture holders of any series to call for immediate repayment of the debt to them or if the amendment to the deed of trust with the debenture holders is cancelled by the debenture holders; if the price of the participating unit is lower than the price set out in the letter consent and the collateral ratio falls below the ratio set out in the deed of consent; if it evolves that a declaration or representation of the Companies in the deed of consent and/or its appendixes is incorrect in a way that could prejudice the lien on Delek Israel shares; if an application for temporary or permanent foreclosure is filed and/or if a temporary or permanent foreclosure is imposed on Delek Israel shares, and it has not been dismissed or canceled within 30 days; if any of the Banks announces the cancellation of the Standstill Period due to the materialization of any of the events described above.

4) Current repayments and advance payments

a) In the Standstill Period, the Companies will continue to make regular repayments of interest to the Banks, in accordance with the agreements signed with them.

b) The Company will transfer to the Collateral Trustee, for repayment of credit to the Banks, up to 75% but not less than 50% of the amounts received and/or to be received as a result of the raising capital performed by the Company in May 2020 and raising additional capital in the Standstill Period (if any). In addition, it was determined that the Company will transfer to the Collateral Trustee, for repayment of the credit to the Banks, up to 75% but no less than 50% of the amounts to be received by the Company for the sale of the overriding royalty in the Karish and Tanin reservoirs. The Company acted in accordance with the agreements, and the proceeds were used to repay debts to the banks of the Company banks and the Staff Companies.

NOTE 19: OTHER DEBENTURES AND CONVERTIBLE DEBENTURES (CONTD.)

G. Amendment to the deeds of trust (contd.)

F. (contd.)

5) End of the Standstill Period

a) If, at the end of the Standstill Period, Delek Israel shares are not sold or not all of the credit to the Banks is repaid, and if an event occurs that allows the Banks to end the Standstill Period - the Banks will be permitted to exercise the lien on Delek Israel.

b) At the end of the Standstill Period, the provisions of the credit documents with the Banks will continue to apply (other than for the credit facilities that will meet the actual level of credit utilized). Notwithstanding the aforesaid, the Banks will not call for immediate repayment of the credit on the grounds of events of default set out in the credit documents, and which occurred before the end of the Standstill Period, and will not cancel the credit facilities before the final repayment date of the credit, subject to the fulfillment of cumulative conditions: (1) By the end of the Standstill Period, the Banks will be repaid at least 60% of the credit amount when signing the deed of consent; (2) the Companies comply with financial ratios (the LTV ratio) set out in the credit documents with each of the Banks.

6) Release of participating units

It was established, together with the repayment of credit to the Banks (which is not from proceeds arising from the shares or assets of Delek Israel), the Banks will release participating units in a quantity to be calculated such that immediately after the release, the collateral ratio set out in the deed of consent will be fulfilled. In accordance with irrevocable instructions issued by the Companies to the Collateral Trustee, the Collateral Trustee will transfer the participating units that will be released as aforesaid to the trustee of the debenture holders, and they will be pledged in favor of the debenture holders, up to a quantity representing 40% of the total units of Delek Drilling. The participating units that will be released in excess of this amount will be transferred to the Companies. As at the approval date of the financial statements, 40% of the units of Delek Drilling have been pledged in favor of the debenture holders.

As at December 31, 2020, the Company has fulfilled all its obligations under the deed of consent with the Banks and the relevant bank debts were repaid in full.

For information about the understandings with financial institutions reached by the Company regarding the support documents for the sale of The Phoenix, see Note 10E.

H. Deed of consent with the banks

1) On June 15, 2020, the Company, Delek Energy, and DKL (jointly below: “ the Companies”) signed a deed of consent with various banks that provided the Company and/or Delek Energy with credit secured by a lien on the participating units of the Partnership, and with a foreign bank that provided a loan to DKL (“the Banks”), as set out below. It should be emphasized that as at the approval date of the financial statements, the Company has fulfilled its obligations under the deed of consent and has repaid its full obligations to the Banks as set out in Note 1 above.

2) Lien on the shares of Delek Israel in favor of the Banks – A subsidiary of the Company will pledge all the shares of Delek Israel that it holds to the Banks. The Company will take steps to sell Delek Israel shares, and the consideration from their sale and/or dividends received for the pledged shares will be used to repay the credit to the Banks, pro-rata, in accordance with the proportion of each bank in the credit balance. A trust company was appointed with the consent of the parties as a trust company for the Banks and the Companies ("the Collateral Trustee"). The Company and the Staff Companies repaid the debt to the banks in full. For further information about the sale of Delek Israel shares, see Note 10J.

NOTE 19: OTHER DEBENTURES AND CONVERTIBLE DEBENTURES (CONTD.)

I. Conversion terms of debentures (Series B33)

The debenture holders will have the right to convert the Company's shares on each trading day until December 31, 2021, such that NIS 1,298.82318 par value of the debentures is convertible into one ordinary share of the Company, subject to adjustments due to distribution of bonus shares, participation in the issue of rights, and dividend distributions.

J. Convertible liability

On December 18, 2019, DKL and the Company signed a subscription agreement with a financial institution on behalf of BP ("the Investor"), according to which USD 50 million was invested in DKL with an automatic conversion mechanism into ordinary shares of the issuing company in the event of an IPO of Ithaca or its related company, at a value of USD 2.5 billion. The investment bears a coupon rate of 6.5% per year in the first three years, 10% in the fourth year, and 12% in the fifth year. The agreement includes a guaranteed minimum yield and an adjustment mechanism linked to the IPO valuation as aforesaid. If the IPO does not occur within the period set out in the agreement (up to three years), the investor will have the right to call for repayment of the investment amount and its yields. In addition, the investor will have the right to call for repayment of the amount in the event of the sale of Ithaca or in the events of default and cross default, and in these cases, the Company has the right to convert the amount of the investment into marketable shares of the Company or of its investees in accordance with the mechanism and restrictions set out in the agreement. In addition, the Company provided a guarantee to the Investor for some of DKL's obligations in relation to the subscription agreement. In view of the above, the amount of the investment is presented in the financial statements of DKL as capital. In the Group's financial statements, the amount is presented as a liability. For further information about cross default, see Note 1C3.

K. For information about USD debentures in Delek Drilling, see Note 12K above.

L. For information about USD debentures in Delek Leviathan Royalties, see Note 12L above.

M. For information about collateral, see Note 25.

NOTE 20: FINANCIAL INSTRUMENTS

A. Financial risk factors

The Group's activities expose it to various financial risks, such as market risk (including currency risk, CPI risk, interest risk, and price risk), credit risk and liquidity risk. The Group's comprehensive risk management plan focuses on measures to minimize possible negative effects on the financial performance of the Group. The Group uses derivative financial instruments to hedge against exposure to certain risks.

1) Exchange rate risk

The Group is exposed to exchange rate risk due to exposure to various currencies, such as the USD, EUR, GBP, and other currencies. The exchange rate risk is due to future commercial transactions (including purchase of goods in foreign currency), and for recognized assets and liabilities denominated in foreign currency other than the functional currency of the different companies.

The Group companies enter transactions involving derivative financial instruments, from time to time, such as forward transactions and options to hedge their exposure to exchange rate fluctuation.

As at December 31, 2020, the subsidiary has open agreements for forward transactions for the purchase of GBP in exchange for USD, averaging GBP 25 million per quarter at a rate of USD 1.3 to the GBP, from January to December 2021. The forward transactions are designated as unrecognized hedge accounting against future cash balances and agreements denominated in GBP. The fair value of these transactions reflect an asset of NIS 22 million.

In addition, it should be noted that the Company has significant investments in foreign operations dominated in USD (mainly Ithaca and Delek Drilling). An increase (decrease) of 1% in the USD exchange rate 1% will result in an increase (decrease) in the capital attributed to the Company's shareholders (before the tax effect) of NIS 71 million.

NOTE 20: FINANCIAL INSTRUMENTS (CONTD.)

A. Financial risk factors (contd.)

2) CPI risk

The Group has bank loans and debentures linked to changes in the CPI.

A 2% increase in the CPI will result in a loss of NIS 23 million and a 2% decrease will result in a profit in the same amount (as at December 31, 2019, NIS 38 million).

3) Credit risk

The Group holds cash and cash equivalents, short- and long-term investments and other financial instruments in various financial institutions in Israel and abroad on the highest level.

The Company has exposure to major customers for oil and gas production in Israel and abroad, although the managements of the subsidiaries estimate the credit risk for these customers as low risk, based on past experience and in view of the collateral provided by some of the customers. The subsidiaries and the Partnership monitor trade receivables regularly. As at December 31, 2020, all trade receivables are current balances for which the Company was not required to recognize a provision for doubtful debts.

4) Liquidity risk

The table below presents the repayment dates of the Group's financial liabilities in accordance with the contractual terms, undiscounted.

December 31, 2020 (*)

	Up to 1 year	1-3 years	3-5 years	More than 5 years	Total
	NIS millions				
Bank loans	231	1,753	720	-	2,704
Trade payables and service providers	317	-	-	-	317
Other payables	475	-	-	-	475
Derivatives	264	76	-	-	340
Lease liability	20	3	-	-	23
Debentures	3,126	5,602	5,991	4,696	19,415
Convertible debentures and liabilities	37	745	180	-	962
Long-term liabilities	-	207	-	-	207
	4,470	8,386	6,891	4,696	24,443

(*) The balances do not include liabilities presented under liabilities attributed to assets held for sale, which amounted to NIS 2,230 million as at December 31, 2020.

NOTE 20: FINANCIAL INSTRUMENTS (CONTD.)

A. Financial risk factors (contd.)

4) Liquidity risk (contd.)

December 31, 2019

	Up to 1 year	1-3 years	3-5 years	More than 5 years	Total
	NIS millions				
Short-term credit	1,149	-	-	-	1,149
Long-term bank loans	2,431	10,425	2,574	534	15,964
Trade payables and service providers	1,246	-	-	-	1,246
Other payables	806	-	-	-	806
Derivatives	202	35	-	-	237
Lease liability	178	274	196	473	1,121
Debentures	2,662	4,350	6,200	1,102	14,314
Convertible debentures and liabilities	31	756	211	-	998
Long-term liabilities	101	214	101	-	416
	8,806	16,054	9,282	2,109	36,251

For information about the Covid-19 Crisis that broke out in the reporting period and its effect on the Company's financial statements, see Note 1.

5) Interest rate risk

Some of the Group companies took loans at variable USD interest therefore they are exposed to changes in these interest rates. In addition, some of the Group companies have bank deposit bearing variable interest.
The table below describes the effect on pre-tax profit following possible changes in market interest rates in respect of financial instruments bearing variable interest.

	Effect on earnings (loss)			
	2020		2019	
	Increase of 0.5%	Decrease of 0.5%	Increase of 0.5%	Decrease of 0.5%
Risk factor	NIS millions			
USD interest	(6)	6	(37)	40
NIS interest	1	(1)	(13)	13
EUR interest	-	-	(1)	1

To hedge LIBOR interest rate fluctuations for its long-term loans, a subsidiary entered into an interest swap agreement in the amount of USD 550 million, setting the LIBOR interest at a weighted rate of 2.1% The transactions are accounted for as hedge accounting. The value of the transactions as at December 31, 2020 reflects a liability of USD 8 million (NIS 25 million).

NOTE 20: FINANCIAL INSTRUMENTS (CONTD.)

A. Financial risk factors (contd.)

6) Price risk

(A) Risk associated with commodity prices

Ithaca is exposed to changes in oil and gas prices for its future sales. To hedge the exposure, Ithaca has hedge transactions (mostly put and swap) on gas prices for part of its future production. Information about open transactions as at December 31, 2020:

Transactions on the price of oil

	Period	Quantity (K barrels of oil)	Average exercise price (USD/barrel)
Swap	January 2021 to December 2022	7,540	40
Put	January 2021 to December 2021	1,927	56

Transactions on the price of gas

	Period	Quantity (ktherms)	Average exercise price (penny per thermal unit)
Swap	January 2021 to March 2023	305,250	45
Put	January 2021 to December 2022	191,500	44

The cost of acquiring the hedging transactions amounts to USD 33 million, most of which will be repaid in 2021.

The transactions are accounted for as hedge accounting. As at December 31, 2020, the fair value, net, of the hedge transactions amounted to a liability of NIS 235 million.

On the background of falling oil prices, in the first half of 2020, Ithaca exercised some of the hedging transactions, replacing them with hedging transactions that reflect the updated forecast for the price of oil. The total net consideration received by Ithaca from the transactions amounted to USD 156 million.

NOTE 20: FINANCIAL INSTRUMENTS (CONTD.)

A. Financial risk factors (contd.)

6) Price risks (contd.)

(B) Risk associated with the market price of financial investments

The Group has investments in marketable financial instruments on the TASE classified as financial assets measured at fair value through other comprehensive income and financial assets measured at fair value through profit or loss, and other financial instruments, for which the Group is exposed to changes in fair value based on the market price on the TASE.

The table below presents the impact of possible changes on market prices of securities on pre-tax income and on comprehensive income after tax.

	Effect on earnings (loss)		Effect on other comprehensive income	
	2020		2020	
	Price increase of 10%	Price decrease of 10%	Price increase of 10%	Price decrease of 10%
Risk factor	NIS millions			
Price of securities	4	(4)	5	(5)
Other instruments	33	(31)	-	-

	Effect on earnings (loss)		Effect on other comprehensive income	
	2019		2019	
	Price increase of 10%	Price decrease of 10%	Price increase of 10%	Price decrease of 10%
Risk factor	NIS millions			
Price of securities	71	(71)	19	(19)

NOTE 20: FINANCIAL INSTRUMENTS (CONTD.)

A. Financial risk factors (contd.)

7) Sensitivity analyses of the value of contingent consideration

Sensitivity analysis of the value of contingent consideration for the sale of rights in the Karish and Tanin leases by Delek Drilling, as set out in Note 12H above, to the main parameters used in the valuation:

A) Change in the discount rate

	Pre-tax income (loss)			
	NIS millions			
	2%	1%	-1%	-2%
	2020			
Amounts receivable for sales of oil and gas assets	(82)	(44)	46	95

B) Change in the price of natural gas

	Pre-tax income (loss)			
	NIS millions			
	10%	5%	-5%	-10%
	December 31, 2020			
Amounts receivable for sales of oil and gas assets	14	(5)	(18)	(35)

8) Main assumptions used in calculation of sensitivity tests

The changes selected in the relevant risk variables were based on management assessments of the reasonable changes that are likely to occur in these risk variables.

The Company performed sensitivity tests for the main market risk factors that might affect the operating results or financial position. The sensitivity analyses present the profit or loss and/or change in equity (before tax) for each financial instrument for the relevant risk variable for each reporting date. Risk factors are tested on the basis of the significance of the exposure of the operating results or financial position of each risk factor in relation to the functional currency and assuming that all the other variables are constant.

The risk is not exposed to interest risk in loans at fixed interest. For loans at fixed interest, the sensitivity test for interest risk will only be performed on the variable component in the interest.
Sensitivity tests for marketable investments with a quoted market price (TASE price) were based on possible changes in these market prices.

NOTE 20: FINANCIAL INSTRUMENTS (CONTD.)

B. Fair value

The table below describes the balance in the financial statements and the fair value of groups of financial instruments, presented in the financial statements, not on the basis of fair value.

	Carrying amount		Fair value	
	December 31		December 31	
	2020	2019	2020	2019
	NIS millions			
Financial liabilities *)				
Long-term loans	2,385	14,086	2,385	14,232
Debentures	15,999	12,758	15,231	12,801
Total	18,384	26,844	17,616	27,033

*) Not including financial liabilities presented under liabilities attributable to assets held for sale.

The measurement of the fair value of the loans is classified to level 3 in the fair value hierarchy. The fair value of most of the debentures is classified to level 1 in the fair value hierarchy.

The carrying amount of financial instruments such as cash and cash equivalents, short-term investments, trade receivables, other receivables, long-term loans provided, borrowings from banks and others, liabilities to trade payables and other payables is equal to or approximates their fair value.

NOTE 20: FINANCIAL INSTRUMENTS (CONTD.)

C. Classification of financial instruments according to fair value level

Financial assets measured at fair value

	Level 1	Level 2	Level 3
		NIS millions	
December 31, 2020			
Financial assets at fair value through profit or loss			
Shares	21	-	-
Seller's loan to the buyers of The Phoenix			143
Royalties receivable for the sale of the Karish and Tanin leases	-	-	779
Loan provided for the sale of the Karish and Tanin leases	-	232	-
Financial derivatives	-	22	-
Financial assets at fair value through other comprehensive income			
Shares	55	-	-
Cash flow hedging transactions	-	80	-

Financial liabilities measured at fair value

	Level 1	Level 2	Level 3
		NIS millions	
December 31, 2020			
Financial liabilities at fair value through profit or loss			
Contingent consideration	-	-	46
Financial liabilities at fair value through other comprehensive income			
Cash flow hedging transactions	-	340	-

Financial assets measured at fair value

	Level 1	Level 2	Level 3
		NIS millions	
December 31, 2019			
Financial assets at fair value through profit or loss			
Shares	711	-	-
Seller's loan to the buyers of The Phoenix	-	-	140
Financial derivatives	23	372	-
Royalties receivable for the sale of oil and gas assets	-	41	1,015
Loan provided for the sale of the Karish and Tanin leases	-	293	-
Monetary fund	171	-	-
Financial assets at fair value through other comprehensive income			
Shares	246	-	-
Debentures	4	-	-

NOTE 20: FINANCIAL INSTRUMENTS (CONTD.)

C. Classification of financial instruments according to fair value hierarchy (contd.)

Financial liabilities measured at fair value

	Level 1	Level 2	Level 3
		NIS millions	
December 31, 2019			
Contingent consideration	-	-	41
Financial derivatives	-	237	-
Financial liabilities at fair value through other comprehensive income			
Cash flow hedging transactions		-	19

In 2020 and 2019, there were no transfers between the different fair value levels.

NOTE 21: ASSETS AND LIABILITIES FOR EMPLOYEE BENEFITS

Post-employment benefits

Labor laws and the Severance Pay Law in Israel requires Group companies operating in Israel to pay compensation to employees if they are dismissed or when they retire or to make routine deposits in defined deposit plans under section 14 of the Severance Pay Law, 1963 (“the Severance Pay Law), as described below. The liability of the Group companies for this is recognized as a post-employment benefit. The liability of the Group companies for employee benefits is based on the valid labor agreement and the employee's salary, which generate the right for compensation.

Post-employment benefits are usually financed by deposits classified as a defined benefit plan or as a specific deposit plan as described below.

Defined deposit plan

The provisions of section 14 of the Severance Pay Law, 1963 (“the Severance Law) apply to part of the compensation payments, according to which the Group's routine deposits in the pension fund and/or insurance policies exempt it from any other liability towards the employees.

Defined benefit plan

The Group has a defined benefit plan for severance pay under the Severance Pay Law. By law, employees are entitled to compensation if they are dismissed or on demand. The liability for severance is based on the actuarial method.

NOTE 22: LEASES

As at December 31, 2020, the Group has a lease agreement for a floating production facility used for the operating activities of a subsidiary. The balance of the agreement term is 1.5 years.

1. Information about lease transactions

	Year ended December 31, 2020
	NIS millions
Interest expenses for lease liabilities	2
Total negative cash flows for leases	23

2. Movement in right-of-use assets

	Real estate	Vehicles	Oil and gas assets	Total
	NIS millions			
Cost				
Balance as at January 1, 2020	996	10	46	1,052
Additions during the year				
Additions to right of use assets for new leases in the period	144	1	-	145
Updates to right of use assets for linkage to the CPI	(5)	-	-	(5)
Updates to right of use assets for changes in the lease terms	11	2	-	13
Disposals of right of use assets for leases that ended in the period	(95)	(12)	-	(107)
Foreign currency translation differences for foreign operations	-	-	(4)	(4)
Deconsolidation *)	(1,051)	(1)	-	(1,052)
Balance as at December 31, 2020	-	-	42	42
Accumulated depreciation				
Balance as at January 1, 2020	137	5	-	142
Amortization and depreciation	113	2	22	137
Disposals of right-of-use assets	(40)	(6)	-	(46)
Foreign currency translation differences for foreign operations	-	-	(2)	(2)
Deconsolidation	(210)	(1)	-	(211)
Balance as at December 31, 2020	-	-	20	20
Amortized cost as at December 31, 2020	-	-	22	22

*) For information about the deconsolidation of Delek Israel see Note 10J.

NOTE 23: PROVISIONS AND OTHER LIABILITIES

	December 31	
	2020	2019
	NIS millions	
Liability for remediation of environmental hazards	-	32
Costs for undertaking to dispose of assets (1)	4,870	4,754
Payables for an investment in oil and gas assets (2)	228	396
Others	167	152
	5,265	5,333

(1) For production assets of oil and gas, see Note 12. The annual discount rate used in calculating the undertaking to dispose of oil and gas assets in Israel and the surrounding area as at December 31, 2020 is 1.1%-3.3% (in 2019, 2.8%-4.08%). The annual discount rate used in calculating the undertaking to dispose of oil and gas assets in the North Sea area as at December 31, 2020 is 3% (in 2019, 4%) and the inflation rate is 2% (in 2019, 2%). The liability for disposal of assets includes an amount of USD 330.5 million (2019, USD 273.8 million) for the liability in the Heather and Strathspey fields, which Ithaca assumed as part of the acquisition of CNSL (see Note 10F above). Under the terms of the acquisition, the costs incurred by Ithaca under the liability and under incentive agreements for disposal of assets, net of tax, will be returned in full by Chevron. Accordingly, the Group included the balance of the debt attributable to Chevron other long-term receivables.

(2) Changes in costs for undertaking to dispose of assets:

	December 31	
	2020	2019
	NIS millions	
Balance as at January 1	4,754	1,364
Entry into consolidation	-	3,313
Additions	22	98
Effect of the passage of time	175	82
Effect of the adjusted discount rate	750	104
Reversal of the provision	(102)	(31)
Translation differences	(387)	(176)
Transfer of liabilities attributable to assets held for sale	(123)	-
	5,089	4,754
Less - amounts presented under other payables	(219)	-
Balance as at December 31	4,870	4,754

(3) Mainly reflects the present value of deferred consideration (partially contingent) to be paid in 2021 to 2023, see Note 10F.

NOTE 24: CONTINGENT LIABILITIES, GUARANTEES AND COMMITMENTS

A. Contingent liabilities

There are contingent claims, including motions for certification of class action suits, against the Company and certain investees for significant sums that might reach billions of shekels. The financial statements of the Company or of the relevant Group companies include provisions for the costs that might arise from these claims only if it is more likely than not (meaning a probability of more than 50%) that a liability arising from a past event will be created, and the amount of the liability can be reliably quantified or estimated. The amounts of the provisions are based on the assessment of the relevant Group companies regarding the extent of the risk in each of the claims (other than for some claims which are in the preliminary stage and therefore, the chances of their success cannot be estimated. The estimates of the relevant Group companies regarding the risk are based on the opinion of their legal counsel and on the estimate of the relevant Group companies regarding the reasonable amounts in the settlements that these companies are expected to bear as a result of the settlement proceedings.

Details of the material claims filed against the Group companies are provided below (claims against Group companies that were closed up to the approval date of the financial statements, without material effect on the statements, were not included in this disclosure):

2) Contingent claims to which the Partnership is a party

(1) On February 4, 2019, a claim and a motion for its certification as a class action (in this section below: “the Motion for Certification”) was filed with the Tel Aviv District Court (Economic Department) by a shareholder of Tamar Petroleum and the Public Representatives Association (jointly in this section below: “the Applicants”), against Tamar Petroleum, the Partnership, the CEO of the general partner in the Partnership and a director in Tamar Petroleum at the issuance date, the CEO of Tamar Petroleum, the CFO of Tamar Petroleum, and Leader Issues (1993) Ltd. (jointly below in this section: “the Respondents”), regarding the issue of Tamar Petroleum shares in July 2017 (in this section below: “the Issuance”).
According to the Applicants, in brief, the Respondents misled the investors at the time of the Issuance, in relation to the ability of Tamar Petroleum to distribute a dividend to its shareholders, for the period commencing on the date of the Issuance and ended at the end of 2021 (in this section below: “the Period”), and breached its duties under various laws, including breach of the duty of care of the officers and breach of the Partnership's duty as a shareholder and as the controlling shareholder of Tamar Petroleum prior to the Issuance.

The remedies sought in the class action include mainly monetary relief in the amount of at least USD 53 million, which, according to the petitioners, is the difference between the total dividend expected to be paid by Tamar Petroleum for the Period, as set out in the issuance document to institutional investors of July 12, 2017, and the total dividend, which, according to the expert opinion attached to the motion for certification, Tamar Petroleum is expected to distribute for the Period.

On August 13, 2019, the court ordered the Applicants to send the court documents in the case to the Attorney General so that he could give notice by September 15, 2019 of whether he wishes to join the proceeding. On February 6, 2020, the Attorney General gave notice that at this stage he does not deem fit to join the proceeding. On November 1, 2020, the Applicants filed a motion to amend the motion for certification (in this section below: “the Motion for Amendment”) with a request to add another applicant that participated in the issuance to the motion for certification, unlike the current petitioners that did not take part in the issue. In addition, the Motion for Amendment seeks to increase the amount of the alleged damage to USD 153 million.
The parties' responses were submitted to the court and as at the approval date of the financial statements, a ruling has not yet been handed down on the Motion for Amendment. The Partnership believes, based on the opinion of its legal counsel, that it is more likely than not that the Motion for Certification will be dismissed.

NOTE 24: CONTINGENT LIABILITIES, GUARANTEES AND COMMITMENTS (CONTD.)

A. Contingent liabilities (Contd.)

2) Contingent claims to which the Partnership is a party (contd.)

(2) In June 2014, a motion for certification of a class action was filed with the Tel Aviv District Court by a consumer of the IEC against the Tamar partners ("the Applicant" and "the Motion for Certification", respectively). The claim refers to the price of natural gas sold by the Tamar partners to IEC.
In the Motion for Certification, the price of gas sold to IEC is unfair and constitutes an abuse of the status of the Tamar partners as a monopoly for supply of natural gas in Israel, in contravention of section 29A to the Economic Competition Law.

The following remedies are requested in the Motion for Certification: Compensation for all electricity consumers in the difference between the price paid to IEC for natural gas supplied by the Tamar partners and its fair price, which is estimated at NIS 2.456 billion (100%) on the filing date of the motion, and declaratory orders stating that the Tamar partners are required to refrain from selling natural gas from the Tamar Project at the amount exceeding the amount set in the Motion for Certification, and its sale at a higher price constitutes abuse of their power as a monopoly.

In July 2016, a court hearing was held on the motion for dismissal in limine filed by the Tamar partners in April 2016, after the Attorney General submitted his position according to which the Motion for Certification should be dismissed in limine. In his position, the Attorney General claimed that there is no basis for investigating the class action, since it is not possible to separate the price regulation (which is one component in the Gas Framework) from the entire Gas Framework, and the place of judicial review of the Gas Framework is in the High Court of Justice. The Attorney General further claimed that the investigation of the class action is liable to thwart the realization of the Gas Framework.

In November 2016, a decision was handed down whereby the motion for dismissal of the motion for certification was dismissed in limine, and in December 2016, the Tamar partners submitted a motion for leave to appeal this decision.

In September 2017, the Supreme Court handed down a judgment on the motion for leave to appeal. The Supreme Court heard the motion as if leave had been granted and an appeal filed, and on the merits ruled that there is no room to intervene in the District Court ruling and that the appeal should be dismissed. However, the Supreme Court ruled that there should be an additional factual investigation, and therefore ordered that the hearing be remanded to the District Court for it to hear the Motion for Certification on its merits.

On June 1, 2020, an oral hearing was held for the parties' closing statements at the Tel Aviv District Court On July 27, 2020, the court accepted the motion of the Tamar Partners to submit the Attorney General's position of his interpretation of Section 29A(b)(1) of the Economic Competition Law, 1988, which has been recently filed with the Supreme Court in another proceeding (in this section: "the Position of the Attorney General") Accordingly, the Tamar Partners filed the Position of the Attorney General on July 29, 2020.

The Partnership believes, based on the opinion of its legal counsel, that it is more likely than not that the claim will not be certified as a class action.

NOTE 24: CONTINGENT LIABILITIES, GUARANTEES AND COMMITMENTS (CONTD.)

A. Contingent liabilities (Contd.)

2) Contingent claims to which the Partnership is a party (contd.)

(3) On March 12, 2015, the Partnership and Noble (jointly in this section: “the Plaintiffs”) filed a complaint with the District Court in Jerusalem against the State of Israel, through its representatives from the Ministry of Energy (“the Defendant”), which refers mainly to the refund of revenues paid by the Plaintiffs, in excess and under protest, to the Defendant, for revenues arising from gas supply agreements signed between third party customers (below in this section: “the End Customers”) and the Yam Tethys partners, while some of the gas underlying these agreements was supplied from the Tamar project, based on the accounting mechanism, according to which the consideration received from the End Customers, together with the consideration reflecting the share of Delek Group, which holds rights in Yam Tethys but does not hold direct rights in Tamar, was divided such that the Tamar partners that are not also Yam Tethys partners (Isramco, Dor Gas, Tamar Petroleum, and Everest) received a natural gas price equal to the average monthly price of natural gas supplied in that month under agreements signed between the Tamar partners and their customers, and the monetary balance was divided among the Yam Tethys partners that also hold rights in the Tamar project (the Plaintiffs), according to their share in the Tamar project. This accounting mechanism maintained a balance of gas quantities at the Tamar project between the partners according to their share. The refund remedy sought by the Plaintiffs, as at the date of the claim, amounted to USD 15.3 million, reflecting the excess royalties paid by the Plaintiffs between May 2013 and up to the date the claim was filed (“the Refund Amount”). The basis of the claim is the Plaintiffs’ argument that, unlike the Defendant’s argument, the Plaintiffs, as holders of rights in both the Yam Tethys project and the Tamar project, use the gas in their possession, so that there is no sale between the Tamar project and the Yam Tethys project, therefore, the basis of the royalties is the basis of the consideration that was received from the End Customers, plus the share of Delek Group, which does not hold direct rights in Tamar. As a result, the defendant collects excess royalties from the Plaintiffs for amounts exceeding the amounts received from the End Customers, reflecting the market value of the gas, and this in view of the fact that the End Customers are an unrelated party.

As at December 31, 2020, the refund remedy for the primary argument of the Plaintiffs amounts to USD 28 million (the amount of the excess royalty refund principal for the period between May 2013 and September 2017, and for the period between May 2019 and December 2020, as claimed by the Plaintiffs) (in this section below: “the Updated Refund Amount”), with the Partnership's share in the principal being USD 13 million. Adjustment of the Updated Refund Amount is subject to payment of a further fee by the Plaintiffs.

Alternatively , the Plaintiffs argue that even if such sale actually took place, it would have been for the share of the holders of Tamar Project rights who were not holders of the rights in the Yam Tethys project (Isramco and Dor: 32.75% and for part of the period, also in Tamar Petroleum and Everest: 45.5%) and the holders of Yam Tethys Project rights, and the remaining gas supplied to the end customers by the Plaintiffs (67.25% and for part of the period in Tamar Petroleum and Everest: 54.5%) is gas that the Plaintiffs are entitled to use for supplying gas to the end customers, as aforesaid (below in this section: "the Partial Sale Approach").

As at December 31, 2020, the refund remedy for the Partial Sale Approach is USD 19.3 million (the amount of the excess royalty refund principal for the period between May 2013 and September 2017, and for the period between May 2019 and December 2020, according to the Partial Sale Approach), with the Partnership’s share in the principal being USD 9 million.

The evidentiary hearings were held on June 21, 2020. On February 23, 2021, the Plaintiff filed summations on their behalf. Accordingly, the Defendant may file its summary of response by May 31, 2021 and the Plaintiffs may file their summary of response, in reference to the Defendant’s summations, by June 30, 2021.

The Partnership believes, based on the opinion of its legal counsel, that it is possible that the Plaintiffs’ primary argument will be accepted, and that they will be entitled to the Updated

Refund Amount, and that it is more likely than not that the Partial Sale Approach will be accepted.

NOTE 24: CONTINGENT LIABILITIES, GUARANTEES AND COMMITMENTS (CONTD.)

A. Contingent liabilities (Contd.)

2) Contingent claims to which the Partnership is a party (contd.)

(4) Further to Note 12E above, following the decision of the Competition Commissioner (in this section: “the Commissioner”), in accordance with section 20(B) of the Economic Competition Law, to approve, conditionally, the merger between EMG and EMED, under which a series of agreements were signed to allow the export of gas to Egypt from the Tamar and Leviathan gas reservoirs (“ the Merger), on September 8, 2019, Lobby 99 Ltd. (Halutz) and Hatzlacha – For Promotion of a Fair Society (R.A.), filed an appeal with the Competition Court at the Jerusalem District Court. The appeal was filed against the Commissioner (as a respondent) and against EMED and EMG. In summary, the appeal argues that the Merger will allow the Partnership and Noble to block any possibility of importing natural gas from Egypt that will compete with gas produced from the Tamar and Leviathan reservoirs that they own, and that the approval of the Merger includes conditions that cannot be implemented and that do not remedy the competitive damage that may be incurred, according to them, by the approval of the Merger. In the appeal, the court was petitioned to revoke or modify the Commissioner’s decision.
On December 15, 2020, a preliminary hearing was held for the appeal. As at the approval date of the financial statements, dates for the evidentiary hearings have not yet been scheduled. The Partnership believes, based on the opinion of its legal counsel, that it is more likely than not that the appeal will be dismissed.

5) On August 28, 2019, the Homeland Guards Association (“the Petitioner”) petitioned the Jerusalem District Court against the Ministry of Environmental Protection and its officials and against Noble and the Ministry of Energy, requesting that it instructs the Ministry of Environmental Protection and its officials to require Noble or the Ministry of Energy to provide information, which, the Petitioner claims, is required for the purpose of making a decision on the application for the Emissions Permit of Leviathan; to publish the full information to the public and to allocate a 45-day period for comments; and to refrain from issuing an Emissions Permit for the platform until the petition is heard. Concurrently with the petition, a motion was filed for an interim injunction and a temporary injunction, aimed at preventing the issuance of the Emissions Permit of Leviathan until the petition was heard. On September 5, 2019, the application for an interim injunction and a temporary injunction was dismissed. On December 19, 2019, the court handed down its judgment, dismissing the petition and instructing the Petitioner to pay the respondent’s expenses amounting to NIS 60 thousand. On February 3, 2020, the Petitioner appealed the District Court’s judgment with the Supreme Court. The Supreme Court scheduled the appeal for hearing on October 20, 2021. On October 26, 2020, the Petitioner filed its closing statements and on March 1, 2021, Noble filed closing statements on its behalf. As at the approval date of the financial statements, the Partnership believes, based on the opinion of the legal counsel representing the operator in the proceeding, that it is more likely than not that the appeal will be dismissed.

NOTE 24: CONTINGENT LIABILITIES, GUARANTEES AND COMMITMENTS (CONTD.)

A. Contingent liabilities (Contd.)

2) Contingent claims to which the Partnership is a party (contd.)

(6) On November 21, 2019, a petition against the director of the Air Quality Division at the Ministry of Environmental Protection and against Noble (in this section below: “the Respondents”) was filed at the Jerusalem district court by Zichron Yaacov Local Council; Zalul - Environmental Association; Jasr a-Zarqa Regional Council; Megiddo Regional Council; Pardes Hanna-Karkur Local Council; and Emek Hefer Regional Council (in this section below: “the Petitioners”) In the petition, the court is petitioned to order the nullification of the Emissions Permit of Leviathan and to rule that no activity involving the emission of gases will take place at the Leviathan platform. Alternatively, the court was petitioned to rule the cancellation of the pilot plan of the platform. An interim injunction was also sought to prevent platform activity that requires an emissions permit. On December 17, 2019, the Court handed down a temporary injunction whereby, until another decision, the Respondents will refrain from operation at the Leviathan rig involving emission of gases, and that the emissions permit will be frozen (“the Temporary Injunction”). On December 19, 2019, the Court handed down a ruling on the cancellation of the Temporary Injunction and dismissal of the application for an interim injunction. On January 5, 2019, an evidentiary hearing for the petition was held. On March 15, 2020, the court dismissed the petition. On June 22, 2020, an appeal on the judgment was filed with the Supreme Court (in this section below: “the Appeal”). The Appeal seeks to amend the emission permit and to order that the pollutants emitted from the rig are not monitored by Noble or an entity with which it has contracted and that monitoring will be by the director of the Air Quality Division at the Ministry of Environmental Protection or someone that he appoints; and to amend the emission permit so that all the provisions relating to maintenance, environmental management, the environment, and the detection and treatment of leaks will be set out in the emission permit itself and not in an external plan. The hearing of the Appeal is scheduled for June 30, 2021. In November 2020, the Petitioners filed a motion to bring forward the hearing, and the hearing was scheduled for April 5, 2021. As at the approval date of the financial statements, the Partnership believes, based on the opinion of the legal counsel representing the operator in the proceeding, that at this stage it is more likely than not that the appeal will be dismissed.

(7) On February 27, 2020, the Partnership learned of a class action and motion for its certification (“the Motion for Certification") filed at the Tel Aviv District Court by an electricity consumer (“the Applicant”) against the Partnership and Noble and against the other holders of the Tamar project and the Leviathan project (as litigants against which no remedy is sought), in connection with the competitive process for the supply of natural gas conducted by the IEC and in connection with a possible amendment to the agreement for the supply of gas from the Tamar project to the IEC (“the Amendment to the Tamar Agreement”), as agreed by the other holders in the Tamar project, without the involvement of the Partnership and Noble.

NOTE 24: CONTINGENT LIABILITIES, GUARANTEES AND COMMITMENTS (CONTD.)

A. Contingent liabilities (Contd.)

2) Contingent claims to which the Partnership is a party (contd.)

(7) (contd.)

The main arguments of the Applicant are, in brief, that the bids made by the holders in the Tamar project and the holders in the Leviathan project in the competitive process amount to abuse of monopolistic power and to a restrictive arrangement, as defined in the Economic Competition Law; the fact that the Partnership and Noble did not sign the amendment to the Tamar agreement also amounts to abuse of monopolistic power; the price set in the agreement for the supply of gas from the Leviathan project to the IEC further to the competitive process is an unfair price; and profits generated and to be generated by the Partnership and Noble under the agreement, while harming competition, amount to unjust enrichment.

The Applicant claims that the actions of the Partnership and Noble have caused and are expected to cause damage to the classes he seeks to represent in the amount of NIS 1.16 billion, according to which the court is petitioned to award compensation and fees. However, the Motion for Certification does not present a motion for monetary remedy. The main remedy sought in the class action is a ruling by the court that the Partnership and Noble are not entitled to prevent the other holders in the Tamar project from signing the Amendment to the Tamar Agreement.

The pretrial hearing of the Motion for Certification is scheduled for November 17, 2021.

The other holders in the Tamar and Ratio leases and the other holder in the Leviathan lease were also added to the Motion for Certification as respondents, with no remedy being sought against them. On December 22, 2020, the other holders in the Tamar lease filed a motion to dismiss in limine (in this section: “the Motion to Dismiss"”), the Petitioner filed an objection, and the Partnership, Noble and Ratio did not object.

On January 31, 2021, the Court scheduled the hearing on the Motion to Dismiss for May 5, 2021. The date for filing responses to the Motion for Certification has not yet been determined.

The Partnership believes, based on the opinion of its legal counsel, that it is more likely than not that the motion for certification will be dismissed.

(8) To the best of the Partnership's knowledge, on December 30, 2018, Bazan filed a request for arbitration against EMG with the International Chamber of Commerce in accordance with the agreement for the sale of natural gas signed between them on December 12, 2010 (“the EMG-Bazan Agreement”). Bazan claims that due to the failure to supply natural gas in the period of the EMG-Bazan Agreement and the termination of the Agreement, it incurred damage estimated at USD 304 million. EMG claims that Bazan is not entitled to compensation at all since the EMG-Bazan Agreement was suspended due to force majeure, and that the statute of limitations applies to Bazan’s claims. EMG further claims that even if Bazan is found to be entitled to damages, the amount of the damages is limited to USD 11 million, under the terms of the EMG-Bazan Agreement. Arbitration hearings were held from October 12, 2020 until October 16, 2020, and included written presentations that continued until December 18, 2020. The arbitration ruling was issued to the parties on March 5, 2021, in which all of the claims against EMG were dismissed, and Bazan was charged with costs.

(9) On August 26, 2019, PTT, which owns 25% of the shares of EMG, filed a claim at the Economic Court in Egypt against EMG, EMED, and other parties to the EMG transaction. For information about the transaction, see Note 12E above.

In the statement of claim, PTT seeks the revocation of the resolutions of EMG’s general meeting on June 10, 2019, including the resolution to approve the signing of the CLOA. PTT claims that these resolutions constitute discrimination of the minority shareholders and are contrary to the Company’s best interests, in violation of the Egyptian companies law, which applies to EMG.

As at the approval date of the financial statements, the hearing of the petition was postponed to April 2021.

NOTE 24: CONTINGENT LIABILITIES, GUARANTEES AND COMMITMENTS (CONTD.)

A. Contingent liabilities (Contd.)

2) Contingent claims to which the Partnership is a party (contd.)

(10) For information about a claim and motion for its certification as a class action filed with the Economic Department of the Tel Aviv District Court by a person claiming to hold participating units of the Partnership see section 2(1) below.

3) Contingent claims to which the Company is a party

(1) On April 23, 2020, a claim and motion for its certification as a class action (“the Motion for Certification”) was filed with the Economic Department of the Tel Aviv District Court, by a person claiming to hold participating units of the Partnership (“the Applicant”). The claim and the Motion for Certification were filed against the Partnership, the general partner, the Company, the controlling shareholder in the Company, the board of directors of the general partner in the Partnership (including former and current officers in the company), and the CEO of the general partner in the Partnership ("the Respondents").
In the Motion for Certification, it is alleged that the Respondents failed to disclose, in the Partnership’s reports, the existence of a term in the agreements for the sale of natural gas from the Leviathan and Tamar reservoirs to Dolphinus Holdings Limited (“the Sale Agreements” and “the Buyer”, respectively) according to which, in a year in which the average daily price of a Brent barrel (as defined in the Sale Agreements) falls below USD 50 per barrel, the Buyer may reduce the minimum annual quantity purchased under the Sale Agreements to 50% of the annual contractual quantity.
According to the Applicant, the alleged non-disclosure in the Partnership’s reports establishes grounds for a claim under various sections in the Israel Securities Law, 1968, breach of statutory duty, and negligence. The main remedy sought in the Motion for Certification is compensation of the class that Applicant intends to represent for the alleged damage it incurred, which is estimated, based on an opinion attached to the Motion for Certification, in the amount of NIS 55.5 million. In addition, the Applicant petitioned the court to order any other compensation in favor of the class, as the court deems fit under the circumstances.
On January 17, 2021, the Respondents filed their response to the Motion for Certification and the Applicant is required to file a response by March 31, 2021.
The Company believes, based on the opinion of its legal counsel, that it is more likely than not that the motion for certification will be dismissed.

It is further noted that for the possibility given to the Buyer under the agreements for export to Egypt, to reduce the take or pay amount as described in Notes 12M1(d) and 12M2(d)above, the Company received a request from the Israel Securities Authority to provide information and documents as part of an administrative inquiry with the Company. In August 2020, the Company submitted a response to this request.

NOTE 24: CONTINGENT LIABILITIES, GUARANTEES AND COMMITMENTS (CONTD.)

A. Contingent liabilities (Contd.)

3) Contingent claims to which the Company is a party (contd.)

(2) On December 25, 2016, a motion for certification of a class action was filed (below in this section: "the Motion for Certification") on the grounds that the merger transaction between the Delek Drilling and Avner Partnership was approved in an unfair process and the consideration that was paid to the holders of the non-controlling units in Avner, as set out in the merger agreement, is unfair. The Motion for Certification was filed against Avner Partnership, the general partner in Avner Partnership and members of its board of directors, Delek Group as the controlling shareholder in Avner Partnership (linked), and against PricewaterhouseCoopers Consulting Ltd. (PWC), as the economic advisor of an independent board committee established by Avner Partnership. The Motion for Certification includes allegations that the members of the committee, board of directors of Avner Partnership and companies of the general partner in Avner Partnership, breached the duty of care towards Avner Partnership, and that Avner Partnership acted in a way that discriminated against the non-controlling interests. It was also claimed that the merger transaction presented a clear conflict of interests for Delek Group by virtue of its being the controlling shareholder of Avner and Delek Drilling, and therefore, with the approval of the merger transaction, Delek Group violated its duty of fairness under the Partnerships Ordinance. The plaintiffs estimate that the damage amounts to NIS 320 million.

On February 13, 2017, the court approved a procedural arrangement whereby the Motion for Certification will be amended by adding a claim of discrimination against a minority by Delek Group. On July 6, 2017, the court ordered the Partnership to join as a respondent, pursuant to its motion. On July 27, 2017 and November 13, 2017, responses to the motion for certification were filed, and on 14 January 2018, the applicants filed their reply to the responses. In March 2021, evidentiary hearings took place and the evidentiary stage in the case was concluded. An order for summaries was issued such that the last closing statement will be submitted by October 18, 2021. The Partnership believes, based on the opinion of its legal counsel, that it is more likely than not that the Motion for Certification will be dismissed.

(3) A derivative claim regarding the investment recovery date in the Tamar project:

In January 2019, the Supervisors on behalf of the holders of the Partnership’s participating units filed a discrimination claim with the Tel Aviv District Court (Economic Department), against the Partnership, the general partner in the Partnership, the Company, Delek Energy, and Delek Royalties (Delek Group, Delek Energy, and Delek Royalties will be referred to jointly in this section below as “the Royalty Holders”). Concurrently with filing the claim, a motion was also filed for an interim injunction as described below. The claim was defined as a declaratory claim and a claim for remedy to eliminate discrimination, and in which the court was petitioned to declare, among other things, that the calculation of the investment recovery date in the Tamar project should include the payments due by the Partnership to the state (in this section below: “the Sheshinski Levy”). The court was further petitioned to declare that the investment recovery date in the Tamar lease has not yet been achieved and to determine when this date will be achieved; and to declare that the Royalty Holders are required to return the alleged surplus payments to the Partnership.

In February 2019, the Partnership filed a motion for a stay of proceedings in the claim due to the existence of an arbitration clause (“the Motion for a Stay of Proceedings).

NOTE 24: CONTINGENT LIABILITIES, GUARANTEES AND COMMITMENTS (CONTD.)

A. Contingent liabilities (Contd.)

3) Contingent claims to which the Company is a party (contd.)

(3) A derivative claim regarding the investment recovery date in the Tamar project: (contd.)

On April 3, 2019, a statement of defense and a statement of counter-defense were filed on behalf of the royalty holder. The counterclaim included claims that the investment recovery date should be earlier (in 2015, 2016, or 2017 ("the Royalty Holders' Claim"). In the Royalty Holders' Claim, the royalty holders claim, among other things, that in the calculation of the investment recovery date in the Tamar project, the Partnership included expenses that were attributed to the calculation, including the financing expenses of the Partnership itself, future expenses of an uncertain amount for disposal and removal of facilities, headquarter expenses of the Partnership, and any expense intended for the project stages after the wellhead. According to the Royalty Holders, after deducting these expenses, the investment recovery date in the Tamar project had already been achieved in August 2015, or alternatively, in 2016 or alternatively again, in 2017. Accordingly, the Royalties Holders petitioned the court to declare which expenses should be included in the calculation of the investment recovery date, and to order the Partnership to re-calculate the investment recovery date accordingly, and the royalties due to the Royalty Holders, and to submit the calculation to the Royalty Holders.
The Royalty Holders further claim that the investment recovery date should be examined in arbitration, and not in court, and that if the Supervisor's claim is sent to arbitration, so should the hearing of the counterclaim.

According to the court ruling, on July 9, 2020, the parties filed an agreed notice with the court that the preliminary proceedings between the supervisors and the Partnership have ended and that the supervisors and the royalty holders have reached an agreement according to which the preliminary proceedings between them will be completed by July 23, 2020. The parties further agreed that within this period, they will hold discussions in order to reach agreements as to how to advance the proceedings and the filing of evidence in the case. On July 12, 2019, court gave the validity of a ruling to the parties' agreement. The filing of evidence (affidavits and opinions) on behalf of all the parties, both in the Supervisors' claim and in the Royalty Holders' Claim, is nearing completion and the case is scheduled for another pretrial hearing on April 5, 2021.

As stated above, together with filing the claim, in January 2019, the supervisors filed an urgent request for an interim injunction.
In the motion for an interim injunction, the court was petitioned, among other things, to order the Partnership and the general partner to refrain from transferring the higher overriding royalty to the royalty holder, and instead, to transfer it to the trust fund of the Partnership, at least until the ruling on the claim. In addition, the court was petitioned to order the royalty holders to return the higher overriding royalty that they had received until this date and to transfer it to the above trust account, at least until the ruling on the claim.

On January 22, 2019, the Royalty Holders filed a response (objection) to the injunction (above and below: "the Response to Motion for an Injunction"), in which it was argued that the motion should be dismissed for several reasons.

NOTE 24: CONTINGENT LIABILITIES, GUARANTEES AND COMMITMENTS (CONTD.)

A. Contingent liabilities (Contd.)

3) Contingent claims to which the Company is a party (contd.)

(3) A derivative claim regarding the investment recovery date in the Tamar project: (contd.)

On April 1, 2019, a notice was submitted by the parties, according to which the parties had reached an arrangement regarding the issue of a letter of undertaking by Delek Energy, which would obviate the hearing on the motion for an interim injunction (“the Arrangement”). Under the Arrangement, it was determined that the plaintiffs will not be able to renew a motion of this kind or similar motions in the future. On April 11, 2019, the mediation settlement was sanctioned as a judgment.

On May 12, 2020, the supervisors filed an urgent motion for temporary relief (and a motion for a second review) ("the Second Motion for an Injunction"). The supervisors claim that the motion was filed in view of the extreme and dramatic change in circumstances and the court was petitioned to order the Partnership and the general partner to refrain from transferring to the Royalty Holders, including the Company, the overriding royalty at the increased rate, or alternatively to order the Partnership and the general partner to transfer the overriding royalty at the increased rate to an escrow account owned by the Partnership, at least until the ruling on the claim. Alternatively, the court was petitioned to hand down a temporary injunction or an additional or different injunction at the court's discretion, to ensure the possibility of collecting the overriding royalties, if a judgment is handed down that they overpaid. The court was further petitioned to schedule an urgent hearing of the motion.

On May 19, 2020, a response (objection) to the Second Motion for an Injunction was filed on behalf of the Royalty Holders, alleging that the mere filing of the motion is a breach of the supervisors’ obligation under the arrangement between the parties, according to which it was agreed that the plaintiffs cannot renew the motion for a temporary injunction or file similar motions.

On June 23, 2020, the supervisors submitted a motion and an agreed notice to the court, claiming that following negotiations with the Royalty Holders, including the Company, an agreement was reached whereby at this time, there is no need to decide on the matters of dispute between the parties to the motion. The court was petitioned to order the cancellation of the scheduled hearing. The court upheld the agreed notice and cancelled the scheduled hearing.

On July 9, 2020, the parties filed the agreed notice described above, regarding the completion of the preliminary proceedings between the Supervisors and the Partnership by July 23, 2020. In view of the aforesaid, filing of evidence (affidavits and opinions) on behalf of all the parties, both in the Supervisors' claim and in the Royalty Holders’ Claim, is nearing completion and the case is scheduled for another pretrial hearing on April 5, 2021.

In view of the disputes described above, and if the claim of the royalty holders regarding the advance of the investment recovery date to August 2015 is accepted, the total financial scope of the claims for the royalty owners accounts to USD 56 million (the Company is entitled to 25% of this amount and Delek Energy is entitled to 75 % of this amount). On the other hand, to the best of the Company's knowledge and as announced by the Partnership, according to the assessment of the professional advisor of the supervisors, in the report submitted to the Partnership in June 2018, the inclusion of the Sheshinski Levy in the calculation of the investment recovery date will postpone the investment recovery date by 12 to 18 months (until the middle of 2019), and the total financial effect for this postponement is expected to amount to USD 35 million for the period.

Regarding the supervisors’ claim, the Company and Delek Energy believe, after examining all of the allegations and based on the opinion it received, and on the assessments of its legal advisors, that it is more likely than not that the supervisors’ claim against the Company will be dismissed.

Regarding the Royalty Holders’ Claim, the Company believes, based on the opinion of its legal counsel, that in view of the early stage of the proceeding, as set out above, the chances of the claim cannot be assessed at this stage.

NOTE 24: CONTINGENT LIABILITIES, GUARANTEES AND COMMITMENTS (CONTD.)

A. Contingent liabilities (Contd.)

3) Contingent claims to which the Company is a party (contd.)

(4) On August 4, 2019, the Company, Delek Energy, and Delek Royalties entered into an agreement according to which they agree to mediation proceedings with Tamar Petroleum before former Honorable Justice, Yoram Danziger, and should the mediation fail, the parties agree to appoint the former Justice to act as a single arbitrator in the arbitration proceedings between them. When signing the agreement, the Company signed a memorandum of undertaking, according to which, if the arbitrator rules that Delek Royalties or any party in its place, is required to refund royalties that were paid to it in excess due to the exclusion of the Sheshinski levy in the calculation of the investment recovery date, the Company will cover this payment within 14 days of the date of the judgment. On September 22, 2019, a preliminary mediation meeting was held, in which it was decided that each of the parties will meet separately with the mediator to present their principal claims. According to Tamar Petroleum, the Sheshinski levy should be included in the calculation of the investment recovery date, which will postpone the investment recovery date. On the other hand, the royalty holders claim that this calculation cannot include a series of expenses that have been "loaded" into the calculation, and in particular, the Sheshinski levy cannot be included. The mediation is ongoing and at this stage, the parties are meeting separately and together with the mediator. The Company believes, based on the option of its legal counsel, taking into consideration the preliminary stage of the mediation, that if the claim of Tamar Petroleum regarding the Sheshinski levy is the same as the claim of the Supervisors in this matter, as set out in section 3 above, in view of the professional opinion submitted to the Company, it is more likely than not that Tamar Petroleum's claim against the Company will be dismissed.

(5) On April 16, 2020, a motion was filed with the Tel Aviv-Jaffa District Court (Economic Department) for certification of a class action against the Company, all members of the Company's board of directors, and the Company's present and former CEO ("the Respondents").
According to the motion, the applicant's main allegation is that the Respondents failed (allegedly) to disclose to the investors material information about the collateral and liens and about the rights that the loan agreements conferred on the lenders, and in particular, regarding their repayment, including the immediate repayment.
According to the applicant, the class that is represented is whoever purchased shares in the Company between November 28, 2019 and March 23, 2020, other than the Respondents and related parties.
According to the applicant, due to the alleged breaches described in the statement of claim, the class that is represented incurred financial losses estimated at many millions of shekels.
On December 28, 2020, the Company and the other Respondents filed their responses to the motion for certification. In its response, the Company sought to dismiss the motion for certification in limine, or alternatively to dismiss it on its merits. The first pretrial hearing is scheduled for April 18, 2021.
The Company believes, based on the opinion of its legal counsel, that in view of the early stage of the proceeding, as set out above, the chances of the claim cannot be assessed at this stage.

NOTE 24: CONTINGENT LIABILITIES, GUARANTEES AND COMMITMENTS (CONTD.)

A. Contingent liabilities (Contd.)

3) Contingent claims to which the Company is a party (contd.)

(6) On April 16, 2020, a motion was filed with the Tel Aviv-Jaffa District Court (Economic Department) for certification of a class action against the Company, all members of the Company's board of directors in the relevant period, and the Company's present and former CEO ("the Respondents").
According to this motion, the applicant's allegation is that the Company refrained (allegedly) from reporting material information to the holders of its securities about the changes to the scope and terms of the hedging transactions on the price of oil and natural gas made by the subsidiary Ithaca Energy Ltd.
According to the applicant, the class that is represented is whoever purchased the Company's debentures from any of its series between January 1, 2020 and March 22, 2020 and held the debentures at the close of trading on March 22, 2020.
According to the applicant, due to the alleged breaches described in the statement of claim, the class that is represented incurred financial losses estimated at many millions of shekels.
On November 16, 2020, the Respondents filed their response (objection) to the motion for certification ("the Response to the Motion for Certification"), in which it was argued that the motion should be dismissed for several reasons. On December 21, 2020, the applicant filed a motion for discovery and viewing of documents ("the Motion for Discovery") and on January 17, 2021, the respondents filed their response (objection) to the Motion for Discovery. A pretrial hearing is scheduled for April 19, 2021, at which time the Motion for Discovery will also be heard.
The Company believes, based on the opinion of its legal counsel, that in view of the early stage of the proceeding, as set out above, the chances and risks of the proceeding cannot be assessed at this stage.

(7) On April 22, 2020, a motion for certification of a class action was filed with the Tel Aviv-Jaffa District Court (Economic Department) against the Company, including the Company's auditors, members of the committee for reviewing the Company's financial statements, and the chairman of the board of directors, and the former CEO ("the "Respondents").

According to the motion, the main claim of the applicant is that the Respondents were misleading and did not disclose (allegedly) material information about the Company's business regarding a provision in the Company's financial statements for the risk of payment of tax amounting to NIS 170 million (for capital gains tax liabilities of Delek Hungary arising from the disposal of shares of Delek US Holdings Inc. in 2012-2013), and that it was forbidden to cancel the provision in the Company's financial statements after receiving the District Court ruling, knowing that an appeal would be filed.
The applicant claims that the total damage is estimated at NIS 90 million for the entire class.
On November 1, 2020, the Company and its officers filed their response (objection) to the motion for certification, claiming that the motion for certification should be dismissed for several reasons.
On February 24, 2021, the court handed down its ruling, according to which the parties will work to reach a procedural arrangement authorizing the court to rule on the motion based on the evidence in the case without requiring questioning. The parties have not yet reached an agreement and a ruling on the matter has not yet been handed down.
The Company believes, based on the opinion of its legal counsel, that in view of the early stage of the proceeding, as set out above, the chances and risks of the proceeding cannot be assessed at this stage.

NOTE 24: CONTINGENT LIABILITIES, GUARANTEES AND COMMITMENTS (CONTD.)

A. Contingent liabilities (Contd.)

3) Contingent claims to which the Company is a party (contd.)

(8) On May 18, 2020, the Company received a motion for certification of a class action that was filed at the Tel Aviv-Jaffa District Court (Economic Department). The motion is directed at the Company, the members of the Company's board of directors, CEO, Deputy CEO, and CFO at the relevant date. As arises from the motion, the applicant's principal allegations refer to misleading information and(alleged) non-disclosure of material details about the Company's affairs and its financial situation in connection with the cash flow forecast published by the Company on March 8, 2020. The applicant claims that the damage incurred by him and the class he seeks to represent is the difference in the price of securities between their purchase price and their selling price or the price at which they will be sold and the damage was estimated at NIS 80 million for all members of the class.

According to the applicant of the motion, the damage for each class member will be calculated according to the actual figures for which details will be requested as part of the proceedings.
On December 13, 2020, the Respondents filed their response, dismissing the claims of the applicants and claimed that the Motion for Certification should be dismissed in limine. On March 17, 2021, the applicant's response to the Motion for Certification was filed. The pretrial hearing is scheduled for April 25, 2021.
The Company believes, based on the opinion of its legal counsel, that it is more likely than not that the claim will be dismissed.

(9) On September 21, 2020, a motion for certification of a claim as a derivative claim (multiple) was filed in the name of the Delek Foundation for Science, Education, and Culture Ltd. ("the Delek Foundation"), which is a wholly owned subsidiary of the Company. The motion was filed at the Central-Lod District Court and the respondents are the Delek Foundation, the Company, the controlling shareholder in the Company - Yitzhak Sharon Tshuva, the chairman of the Company's board of directors - Gabi Last, and a number of employees and officers in the Company, present and past, who held various positions in the Delek Foundation. The claim refers to the distribution of donations from the funds of the Delek Foundation, which, according to the applicant, were allegedly made contrary to the objectives of the Delek Foundation and without obtaining the approvals required in the Companies Law for transactions with interested parties. As a result, the court was petitioned, among other things, to order the respondents (other than the Delek Foundation and the Company) to return to or compensate the Delek Foundation for all donations made to the Western Wall Heritage Foundation in the seven years preceding the date of the motion, which the applicant claimed were made contrary to the objectives of the Delek Foundation.

On March 1, 2021, the court approved a procedural arrangement scheduling dates for filing court documents and a hearing was scheduled for July 15, 2021.
The Company believes, based on the opinion of its legal counsel, in view of the preliminary stage of the procedure, its chances cannot be assessed, however it is clarified that in any case, even if the motion is accepted and the derivative action is filed, the derivative action does not create exposure to the Company itself

NOTE 24: CONTINGENT LIABILITIES, GUARANTEES AND COMMITMENTS (CONTD.)

A. Contingent liabilities (Contd.)

3) Contingent claims to which the Company is a party (contd.)

(10) On December 23, 2020, a motion was filed with the Tel Aviv-Jaffa District Court (Economic Department) for certification of a derivative action (“the Motion for Certification”) on behalf of the Company against members of the Company's board of directors (some who no longer serve in the Company), including a controlling shareholder in the Company, the Company’s CEO, and two wholly owned companies of the Company (“the Respondents”).
According to the motion, the main claims of the applicant are that the Respondents approved and carried out a buyback of the Company's shares and debentures at the beginning of 2020 (January and February) amounting to NIS 86 million, alleging that this acquisition does not meet the distribution tests under the Companies Law, 1999. The applicant further raises allegations regarding the controlling shareholder's personal interest in the buyback.
The amount of the claim is at least NIS 86 million, which, according to the applicant, constitutes the amount that was paid for shares and debentures in the buyback in January and February 2020. According to the court ruling on March 22, 2021, the Respondents' responses to the motion will be filed by May 2, 2021.
The Company believes, based on the opinion of its legal counsel, in view of the preliminary stage of the Motion for Certification, its changes cannot be assessed, however it is clarified that in any case, even if the motion is accepted and the derivative action is filed, the derivative action does not create exposure to the Company itself.

4) Additional claims

(1) Contingent claim to which Ithaca is a party

On May 26, 2015, a class action lawsuit was filed against Ithaca at the High Court of Justice in Alberta, Canada, by an investor who alleges that Ithaca published information that constitutes a false representation, regarding the expected timetable for completion of the installation of the floating production facility(“FPF-1) in the GSA project. According to Ithaca, the claims of the class action lawsuit have no grounds. On March 7, 2019, a preliminary hearing was held on the motion. On June 24, 2019, a ruling was handed down certifying the motion for a certification of a class action, but because the plaintiff did not present evidence that Ithaca was acting unreasonably regarding the immediate report published on August 12, 2014, the period to which the class action refers, the period was shortened from October 7, 2014 to February 25, 2015. In December 2019, Ithaca filed the statements of claim of Ithaca and the CEO, and the parties agreed on a discovery protocol. Ithaca has insurance cover for this claim, which it believes is sufficient to cover its liability, if the claim is accepted. At this stage, Ithaca believes, based on the opinion of its legal counsel, that it is not possible to estimate the chances of the claim and the financial exposure arising from the claim, and therefore Ithaca did not include a provision for this claim in the financial statements.

(2) On April 27, 2020, the Company received a motion for certification of a class action that was filed at the Haifa District Court against a subsidiary of the Company, another company that purchased the land in trust for the subsidiary, and the directors of these companies, two of which are senior officers in the Company (“the Applicants”).
The motion was filed by Zalul Environmental Association and two private applicants. According to the Applicants, the respondents, jointly and severally, are liable for compensation to the general public in Israel (which falls within the definition of "the Class" as defined in the application and described below) for their alleged liability for pollution of groundwater and the marine environment, due to the existence of hazardous and pollutive materials in the area purchased by the subsidiary in 2011 and which is south of Acre, at the site where Electrochemical Industries operated (“the Site”). According to the Applicants, these materials are continuing to pollute the soil at the Site while spilling over into the environment, damaging the groundwater, seawater, and nature.

NOTE 24: CONTINGENT LIABILITIES, GUARANTEES AND COMMITMENTS (CONTD.)

A. Contingent liabilities (Contd.)

4) Additional claims (contd.)

(2) (contd.)

According to the Applicants, when the subsidiary acquired ownership of the Site, it assumed the liability for damage caused due to materials that remained at the Site since its acquisition, and these materials continued to leak or spill over in the period since control was transferred. The Applicants further claim that when the subsidiary acquired ownership of the Site, it assumed the responsibility for action to prevent the continuation of pollution and to clean the land

The class that is represented is defined in the motion as any residents and citizens of Israel who use the services of Acre's coastal environment, or any other class as the court may determine. At this time, there is no way to estimate the size of the class underlying the level of compensation that the applicants claim is payable by the respondents to each of the class members. The motion stipulates an amount of “at least NIS 2.5 million” as compensation for the alleged damage that the applicants claim was incurred by the class due to the continuation of pollution in the period when the Site was under the control of the subsidiary. In addition, the applicants request that the court order the respondents to pay of all the restoration expenses, which they estimate at hundreds of millions of shekels, as well as the environmental damage that they claim that the respondents must pay to the public for compensation.

Some of the compensation components were not included in the application; therefore, the exact amount of the claim is unknown.

In addition, the claim includes a motion for an injunction directed to the respondents and requiring them to take steps to prevent the pollution, including preparation of a plan to control pollution. The motion does not specify the actions required under these remedies, and their cost cannot be estimated.

On November 22, 2020, the respondents filed their response to the motion, claiming that the motion should be dismissed in limine or alternatively dismissed on its merits, as it has no factual or legal grounds. The pretrial hearing is scheduled for April 13, 2021.

The Company believes, based on the opinion of its legal counsel, that at this preliminary stage, it is not possible to assess the likelihood that the motion will be accepted against any of the respondents and therefore it is not possible to assess the financial exposure to the respondents in general and the Company in particular, in respect of the motion.

B. Guarantees

(1) As at December 31, 2020, there are guarantees for agreements with third parties amounting to NIS 26 million.

(2) `The Company signed an unlimited performance guarantee in favor of the Republic of Cyprus to secure full implementation of all undertakings of the Partnership. See also Note 12F above.

NOTE 24: CONTINGENT LIABILITIES, GUARANTEES AND COMMITMENTS (CONTD.)

C. Agreements

Material agreements by the Group companies:

(1) For information about natural gas and condensate supply agreements in the Tamar Project and Leviathan Project, see Note 12M.

(2) As at December 31, 2020, Ithaca has agreements for investments in oil and gas assets amounting to USD 65.5 million (NIS 211 million).

D. Indemnification and insurance of officers

(1) The Group has undertaken to indemnify all entitled officers of the Group for any action taken in virtue of their service as officers in the Group in the past, present and future. The Group has undertaken to indemnify all entitled officers of the Group for any action taken by virtue of their service as officers in the Group in the past, present and future.

(2) The Group has decided to exempt officers of the Group from their liability under the duty of care toward the Group pursuant to Chapter three, Part six of the Companies Law, 1999.

(3) The Company has insured the liability of officers for a total liability limit of USD 150 million until June 2020. As the term of the policy ended on June 30, 2020, and in view of the dramatic adverse changes in the D&O liability insurance market, as explained below, especially in the wake of the Covid-19 Crisis, in June 2020 תthe Company exercised its right under the previous policy to purchase runoff insurance that would cover events of professional liability for a further period of seven years applicable from July 1, 2020. Under the extension, the policy will continue to apply for claims filed during the runoff period for the first time due to events prior to the commencement of the runoff period of July 1, 2020, within the limit of liability under the previous policy, meaning for a total amount of USD 150 million per claim and cumulatively (including the extended disclosure period of seven years). The premium for the runoff period is USD 1.5 million.

As the Company was informed by its insurance advisor, the D&O liability insurance market changed dramatically at the time when the Company renewed its policy, after many insurers incurred heavy losses. In view of the numerous claims in the D&O liability insurance market and due to the significant adverse changes in the industry in general, and with regard to corporations that operate in the energy sector in particular, among other things, due to both the global and the domestic economic crisis resulting from the outbreak of the Covid-19 pandemic, when renewing the policy, when renewing the policy, it is difficult to purchase a new insurance policy that would cover claims filed due to events from July 1, 2020 onwards, and if such a new current policy could be obtained, the amount of the premium and deductible required thereunder are significantly higher than the costs and terms of the previous policy, as aforesaid. On August 25, 2020, after approval by the Company’s compensations committee and board of directors, the Company's general meeting approved the purchase of the New Current Policy, which reflects the best insurance offer that could be purchased under the circumstances at the time, with limit of liability of USD 25 million per claim and cumulatively, with the addition of reasonable legal fees, at a premium of USD 2.629 million and deductible of up to USD 750 thousand for a securities claim, and which will not apply for the officers without the Company's ability to indemnify them. Furthermore, it was decided to authorize the Company's management to purchase an increase in insurance coverage of up to an additional USD 75 million (in addition to the existing USD 25 million), in exchange for an additional premium, so that the total annual premium for the New Current Policy does not exceed USD 4 million.

In August 2020, the Company acquired additional insurance coverage with a liability limit of USD 6 million and an annual premium of USD 575 thousand.

NOTE 25: LIENS

A. To secure bank loans, debentures, and loans from others, amounting to NIS 17.3 billion as at December 31, 2020, collateral was provided as follows:

- The Company and its subsidiaries recorded fixed and floating liens on their non-current and current assets, including inventories, specific deposits, the right to trade receivables, certain oil and gas assets, the right to receive overriding royalties, specific liens on certain shares of investees and participating units of Delek Drilling and mortgages on all the companies' rights in properties for which credit was granted.
- Subsidiaries have undertaken to meet certain conditions, including to refrain from recording a lien in favor of others without the prior agreement of the lending corporations
- For undertakings to meet financial covenants, see Note 18 and Note 19.

B. For information about liens and financial covenants for investments in oil and gas assets and for the issue of debentures by the Partnership and the SPC, see Notes 12K and 12 L.

NOTE 26: CAPITAL

A. Composition of share capital

	December 31, 2020		December 31, 2019	
	Registered	Issued and paid up	Registered	Issued and paid up
	Number of shares			
Ordinary shares of NIS 1 par value each (*)	26,000,000	17,159,717	16,000,000	11,983,595
Preference shares	2,000,000	-	2,000,000	-

The shares are listed on the TASE.

(*) On June 23, 2020, the Company's general meeting approved the increase in registered capital from 16,000 to 26,000.

B. Changes in capital in 2020

(1) On May 17, 2020, the Company completed an issue of capital, under which 1,371,350 ordinary shares of the Company, 329,124 options (Series 7), and 329,124 options (Series 8) were allocated.
Each Option (Series 7) and Option (Series 8) is exercisable for one ordinary share of the Company in consideration for an exercise price of NIS 100 (adjusted to the dividend, benefit, and rights). Each Option (Series 7) was exercisable until July 15, 2020 and each Option (Series 8) is exercisable until December 31, 2020.
The immediate consideration (before offering expenses) received by the Company for the offering amounts to NIS 137 million (NIS 136 million after offering expenses).

Up to December 31, 2020, 53 Options (Series 7) were exercised for a non-material amount and the balance of the Options (Series 7) expired.
In addition, up to December 31, 2020, 232,272 Options (Series 8) were exercised for same amount of the Company's shares for NIS 23 million and the balance of the Options (Series 8) expired.

NOTE 26: CAPITAL (CONTD.)

B. Changes in capital in 2020 (contd.)

(2) On August 4, 2020, the Company completed an issue of capital, under which 2,198,200 ordinary shares of the Company, 758,000 Options (Series 9), 379,000 Options (Series 10), 758,000 Options (Series 11), and 379,000 Options (Series 12) were allocated. The immediate consideration (before offering expenses) received by the Company for the offering amounts to NIS 176 million (NIS 172 million after offering expenses).

Each Option (Series 9) and Option (Series 10) is exercisable for one ordinary share of the Company in consideration for an exercise price of NIS 75 (adjusted to the dividend, benefit, and rights). Each Option (Series 9) is exercisable until December 15, 2020 and each Option (Series 10) is exercisable until April 1, 2021. Up to December 31, 2020, Options (Series 9) were exercised for 758,000 shares of the Company for NIS 57 million.

Each Option (Series 11) is exercisable for one ordinary share by December 15, 2020, against cash payment of an exercise price (adjusted for a dividend, benefit and rights) in the amount of NIS 77, and from December 16, 2020 through June 30, 2023, against cash payment of an exercise price (adjusted for a dividend, benefit and rights) in the amount of NIS 150. As at December 31, 2020, 255,242 Options (Series 11) were exercised for the same amount of the Company's shares, for NIS 20 million. As at December 31, 2020, 502,758 Options remain (Series 11).

Each Option (Series 12) is exercisable for one ordinary share by April 1, 2021, against cash payment of an exercise price (adjusted for a dividend, benefit and rights) in the amount of NIS 77, and from April 2, 2021 through May 31, 2023, against cash payment of an exercise price (adjusted for a dividend, benefit and rights) in the amount of NIS 150. As at December 31, 2020, five Options (Series 12) were exercised for the same amount of the Company's shares, for a non-material amount. As at December 31, 2020, 378,995 Options remain (Series 12).

(3) On December 16, 2020, the Company completed an issue of capital under which 361,000 shares of the Company were allotted. The proceeds of the issuance (before issuance expenses) amounted to NIS 40 million (NIS 38 million).

C. Changes in capital subsequent to the balance sheet date and up to the approval date of the financial statements

Subsequent to the balance sheet date and up to the approval date of the financial statements, 193,359 options (Series 10) were exercised for 193,359 shares of NIS 1 par value of the Company in exchange for NIS 14.5 million and 29,625 options (Series 12) for 29,625 shares of NIS 1 par value each for NIS 2.2 million. After the exercises, the issued and paid-up share capital of the Company is 17,383,621 shares of NIS 1 par value each. Options in circulation: 185,641 options (Series 10), 502,758 options (Series 11), and 349,370 options (Series 12).

NOTE 26: CAPITAL

D. Treasury shares

As at December 31, 2020, a wholly-owned subsidiary partnership, Delek Financial Investments - Limited Partnership ("the Subsidiary Partnership") holds 586,422 Company shares of NIS 1 par value.
Information about acquisitions and disposals by the Subsidiary Partnership in 2019-2020:

	Par value quantity	Acquisition amount (derecognition)
		NIS millions
Balance as at January 1, 2019	242,939	146
2019 - acquisitions	207,821	111
Balance as at December 31, 2019	450,760	257
2020 - acquisitions	135,662	60
Balance as at December 31, 2020	586,422	317

*) Cost of shares exercised

In 2020, the Subsidiary Partnership acquired an additional 135,662 shares for NIS 60 million. Following the sale, the Subsidiary Partnership holds 586,422 shares of the Group.

E. Dividends

1) On March 31, 2019, the Company declared a dividend of NIS 140 million, which was paid on April 29, 2019. The dividend per share is NIS 11.6826. An amount of NIS 3 million was distributed to the Subsidiary Partnership.

2) On May 29, 2019, the Company declared a dividend of NIS 120 million, which was paid on June 27, 2019. The dividend per share is NIS 10.0137. An amount of NIS 2 million was distributed to the Subsidiary Partnership.

F. For information about debentures and liabilities convertible to Company shares, see Note 19.

NOTE 27: COST OF REVENUES

	Year ended December 31		
	2020	2019 *)	2018 *)
	NIS millions		
Other production expenses and costs	-	1	34
Depreciation, depletion and amortization	1,671	980	529
Production cost of oil and gas sold and oil and gas exploration expenses net	1,865	920	593
	3,536	1,901	1,156

*) Restated, see Note 10J.

NOTE 28: GENERAL AND ADMINISTRATIVE EXPENSES

	Year ended December 31		
	2020	2019 *)	2018 *)
	NIS millions		
Salary and incidentals	95	55	44
Amortization and depreciation	2	3	1
Professional services	107	41	41
Others	37	22	33
	241	121	119

*) Restated, see Note 10J.

NOTE 29: OTHER REVENUES (EXPENSES), NET

	Year ended December 31		
	2020	2019 *)	2018 *)
	NIS millions		
Provision for impairment of oil and gas assets, fixed assets and investment property, net	(1,846)	(829)	(95)
Goodwill impairment of intangible assets **)	(848)	-	(24)
Profit on disposal of assets	-	27	17
Profit (loss) from disposal of oil and gas assets **)	-	(3)	96
Profit from a bargain transaction ***)	-	-	105
Profit (loss) from disposal of investees	(254)	5	(12)
Other expenses, net	(25)	(65)	(38)
	(2,973)	(865)	49

*) Restated, see Note 10J.

**) For further information see Note 12C.

***) For further information see Note 10F.

NOTE 30: - FINANCE INCOME AND EXPENSES

	Year ended December 31		
	2020	2019 *)	2018 *)
	NIS millions		
A. Finance income			
Net change in the fair value of financial assets at fair value through profit or loss.	-	42	81
Income from investments	7	46	46
Dividends from securities accounted for at fair value through profit or loss	-	-	1
Dividends from securities accounted for at fair value in other comprehensive income	1	38	-
Derivative financial instruments	-	49	32
Profit from disposal of securities through other comprehensive income	3	-	-
Finance expenses, net, from associates and related parties	-	-	36
Finance income from loans to the seller	6	6	39
Revaluation of royalties receivable and loans provided for the sale of oil and gas assets	321	302	277
Others	44	77	41
	382	560	553
B. Financing expenses			
Finance expenses for credit from banks, debentures and others	1,572	1,146	882
Net change in the fair value of financial assets at fair value through profit or loss.	167	19	35
Derivative financial instruments	291	17	137
Revaluation of contingent consideration for oil and gas assets	47	3	134
Change in liability for disposal	152	17	12
Exchange differences from a loan to buyers	-	8	-
Loss from disposal of an investment in a financial asset at fair value through profit or loss	35	-	-
Others, net	30	9	13
	2,294	1,219	1,213

*) Restated, see Note 10J.

NOTE 31: TAXES ON INCOME

A. Tax laws that apply to the Group companies

Income Tax (Inflationary Adjustments) Law, 1985

According to the law, until 2007, the results for tax purposes are adjusted for the changes in the CPI. In February 2008, the Knesset passed an amendment to the Income Tax (Inflationary Adjustments) Law, 1985, which limits the scope of the Adjustments Law from 2008 onwards. As from 2008, the results for tax purposes are measured at nominal values, with the exception of certain adjustments for changes in the Israeli CPI up to December 31, 2007.

B. Tax rates applicable to Group companies

1) Group companies in Israel

In December 2016, the Economic Efficiency Law (Legislative Amendments for Implementing Economic Policy for the 2017 and 2018 Budget Year), 2017 was ratified. The Law includes a reduction in the rate of corporate tax as from January 1, 2017, to a rate of 24% (instead of 25%), and as from January 1, 2018, to a rate of 23%.

The rate of corporate tax in Israel in 2019 and 2018 is 23%; and in 2017, 24%.
An association of individuals is taxed on real capital gain at the corporate tax rate in the year of the sale.

In August 2013, the Law for Changing National Priorities (Legislative Amendments for Achieving Budgetary Goals for 2013-2014), 2013 was published. The Law includes provisions for changes in revaluation gains taxes, as from August 1, 2013, however the entry into force of the provisions for revaluation gains is subject to publication of regulations defining "retained earnings exempt from corporate tax" and regulations that define provisions for preventing double taxation that is liable to apply to assets outside of Israel. As of the date of approval of these financial statements, these regulations have not yet been published.

2) Group companies abroad

(A) Ithaca is subject to UK tax laws, which include corporate tax income, supplementary charge tax and petroleum revenue tax. As at December 31, 2019, the effective tax rate applicable to oil and gas companies in the UK was 30%, the supplementary charge tax was 10%, and the tax on oil revenues, if applicable, was 0%.

(B) Profits of the US company (see Note 12V) will be taxed under US federal corporate tax at a rate of 21%. In addition to the federal tax, revenue arising from the projects in Louisiana will be subject to state tax at the rate of 4-8%. The state tax will be recognized as an expense in the calculation of federal tax.

NOTE 31: TAXES ON INCOME (CONTD.)

C. Tax assessments

1) The Company has final tax assessments up to and including 2014.

2) The majority of the other subsidiaries have received tax assessments that are considered final up to and including 2014.

3) Delek US

In prior years, the Group (through its subsidiary Delek Hungary) sold shares of Delek US. Orders were issued for Delek Hungary in connection with the calculation of the capital gain from the disposal of the shares of Delek US (the main objection was the ability of Delek Hungary to offset, from the capital gain of Delek Hungary, the distributable profits of Delek US that were not distributed as a dividend). Delek Hungary filed appeals against these orders at the Lod District Court. In July 2018, the District Court ruled that it accepted the appeal of Delek Hungary regarding the main issue. In view of the aforesaid, the Group canceled the provision in its financial statements for this matter and in 2018, recognized NIS 170 million in the statement of income under profit from discontinued operations, net.

On December 2, 2018, the tax assessor filed an appeal with the Supreme Court, and requested the reversal of the ruling of the District Court and the reinstatement of the orders. In the order for summations, the Supreme Court ruled that the parties will file their written summations by June 2019.

On November 6, 2019, a hearing was held at the Supreme Court on the matter underlying the appeal, which is the offset of the distributable profits of Delek US that were not actually distributed as a dividend from the capital gain derived by Delek Hungary in prior years.
On January 26, 2020, the judgment of the Supreme Court was handed down, accepting the position of the tax assessor and reversing the judgment of the district court.
In view of the above, the Group included a provision in the financial statements as at December 31, 2020 for the tax payable (plus interest and linkage differences), amounting to NIS 213 million, which was included under profit (loss) from discontinued operations, net. It should be noted that in January 2021, subsequent to the balance sheet date, Delek Hungary and the Tax Authority signed an agreement regulating the payment schedule for the debt over three years until March 30, 2024.
In addition, it should be noted that the Company received a motion for certification of a class action for the provision. See Note 24A2(7) above.

4) Subsequent to the balance sheet date, Delek Energy received best judgment tax assessments for the 2015-2018 tax years under section 145(A)(2)(b) of the Income Tax Ordinance. The main dispute refers to the Company's right to allow deduction of financing expenses that it incurred. According to the tax assessments, and if all the claims of the Tax Authority are accepted, Delek Israel will be required to pay tax (including interest) in the amount of USD 58 million. Delek Energy filed objections to the assessments and the response of the Tax Authority has not yet been received. The Company believes that these assessments have no sound basis and the exposure for them, if any, is not material.

NOTE 31: TAXES ON INCOME (CONTD.)

D. Carryforward losses for tax purposes

As at December 31, 2020, the Company has carryforward losses of NIS 3.3 billion for tax purposes (of which, an amount of NIS 1.53 billion is capital losses). No deferred tax assets were recognized for these losses, due to the uncertainty regarding future taxable income.

As at December 31, 2020, the subsidiaries have carryforward losses of NIS 6 billion for tax purposes. Deferred tax assets of NIS 2.3 billion were included in the financial statements for the balance of the business losses.

In this context, it should be noted that as at December 31, 2020, Ithaca has carryforward tax losses amounting to USD 1.8 billion (partially due to recognition of accelerated depreciation for tax purposes, as well as from tax benefits to encourage investments in oil and gas in the North Sea, which contributed to a significant increase in losses for tax purposes), and on the other hand, Ithaca has temporary differences in respect of accelerated depreciation of oil and gas assets in the North Sea in the amount of USD 0.8 billion (meaning, net differences of USD 1 billion). The financial statements include deferred tax assets for the net differences amounting to USD 382 million. It should be noted that the net differences mainly arose in the development period of the significant oil and gas assets. Ithaca expects that in the coming years, it will have taxable income in amounts sufficient to utilize the net differences.

E. Deferred taxes

Composition:

	Balance sheet		Statement of income		
	December 31		Year ended December 31		
	2020	2019	2020	2019 *)	2018 *)
	NIS millions				
Fixed assets	-	(5)	-	-	-
Financial instruments presented at fair value	79	(145)	157	(34)	35
Intangible assets	-	(59)		-	-
oil and gas assets	(3,060)	(4,144)	891	317	154
Carryforward losses for tax purposes	2,309	3,245	(758)	256	99
Liabilities for disposal of assets	558	330	268	32	6
Other temporary differences	(41)	(20)	(7)	-	(47)
Deferred tax income			551	571	247
Deferred tax liabilities, net	(155)	(798)			

*) Restated, see Note 10J.

As at December 31, 2020, the deferred taxes for Group companies in Israel are calculated according to the tax rate of 23% based on the expected applicable tax rate at the time of exercise. The deferred taxes for the wholly owned subsidiary in the UK are calculated according to a tax rate of 40%.

NOTE 31: TAXES ON INCOME (CONTD.)

E. Deferred taxes (contd.)

Deferred taxes for items recognized in other comprehensive income

	Year ended December 31		
	2020	2019 *)	2018 *)
	NIS millions		
Taxes for cash flow hedges	39	6	59

*) Restated, see Note 10J.

F. Income taxes (tax benefits) in the statements of income

	Year ended December 31		
	2020	2019 *)	2018 *)
	NIS millions		
Current taxes	138	153	190
Deferred taxes (see also section E above)	(551)	(571)	(247)
Taxes for prior years	7	1	-
	(406)	(417)	(57)

*) Restated, see Note 10J.

NOTE 31: TAXES ON INCOME (CONTD.)

G. Adjustment of theoretic tax

Below is a presentation of the tax amount that would be applicable if all the income was taxable at the regular corporate tax rates in Israel and the tax amount charged to the statement of income for the reporting year:

	Year ended December 31		
	2020	2019 *)	2018 *)
		NIS millions	
Profit (loss) before taxes on income	2,001	(213)	823
Statutory tax rate	23%	23%	23%
Tax computed at the statutory tax rate	(466)	(49)	189
Increase (decrease) in tax liabilities for:			
Utilization of carryforward losses from previous years	(4)	(11)	(36)
Losses and other differences for which no tax benefit was recorded	237	99	84
Share of non-controlling interests in gains of the Partnership	(133)	(88)	(89)
Company's share the results in companies and partnerships accounted for at equity, net	2	5	(30)
Current taxes for prior years	7	1	-
Deferred taxes for prior years	(46)	(138)	(36)
Tax benefit for foreign oil and gas assets	(99)	(209)	(165)
Other tax benefit for foreign tax assets	(20)	(29)	(6)
Adjustments for different tax rate in merged companies	(328)	(113)	25
Exempt revenue, unrecognized expenses and other adjustments, net	438	115	7
	(406)	(417)	(57)

*) Restated, see Note 10J.

H. The Company is registered for value added tax purposes as a joint licensed dealer (consolidation of dealers) together with some of its subsidiaries.

NOTE 32: NET EARNINGS (LOSS) PER SHARE

A. Quantity of shares and the earnings and loss attributable to the shareholders of the Company used to calculate the net earnings (loss) per share from continuing operations:

	Year ended December 31					
	2020		2019 *)		2018 *)	
	Weighted qty. of shares	Net profit	Weighted qty. of shares	Net profit	Weighted qty. of shares	Net profit
	Thousands	NIS millions	Thousands	NIS millions	Thousands	NIS millions
For calculation of basic net earnings (loss)	13,271	(1,659)	11,628	(113)	11,279	479
Adjustment for the Group's portion in basic loss (earnings) per share of investees	-	10	-	23	-	(111)
The Company's portion in diluted earnings (loss) per share of investees	-	(10)	-	(23)	-	111
Effect of potential ordinary shares, diluted **)	-	-	-	-	388	11
For calculation of diluted net earnings (loss)	13,271	(1,659)	11,628	(113)	11,667	490

B. Quantity of shares and the earnings (loss) attributable to the shareholders of the Company used to calculate the net earnings (loss) per share from discontinued operations:

	Year ended December 31					
	2020		2019 *)		2018 *)	
	Weighted qty. of shares	Net profit	Weighted qty. of shares	Net profit	Weighted qty. of shares	Net profit
	Thousands	NIS millions	Thousands	NIS millions	Thousands	NIS millions
For calculation of basic net earnings (loss)	13,271	(215)	11,628	347	11,279	38
Adjustment for the Group's portion in basic earnings per share of investees	-	267	-	(296)	-	208
Group's portion in diluted earnings per share of investees	-	(267)	-	296	-	(208)
Effect of potential ordinary shares, diluted **)	-	-	-	-	388	-
For calculation of diluted net earnings (loss)	13,271	(215)	11,628	347	11,667	38

*) Restated, see Note 10J.

In 2018-2020, the dilutive effect of convertible securities was not taken into account.

NOTE 33: OPERATING SEGMENTS

A. General

In accordance with IFRS 8, the Group's operating segments are determined on the basis of management reports, which are mainly based on the investments in each subsidiary.

The operating segments are as follows:

- Oil and gas exploration and production in Israel and its surroundings: The main operation is in the Tamar joint venture, the Ratio Yam joint venture, the Yam Tethys joint venture, and other oil rights, mainly offshore the coast of Israel through Delek Drilling.

- Development and production of gas and oil assets in the North Sea: The activity is carried out by Ithaca, which owns rights in oil and gas assets in the North Sea region (for information about the operations of Chevron in North Sea by Ithaca in November 2019, see Note 10F). The activity includes mainly production and marketing of oil and gas from the producing reservoirs and the development of additional reservoirs.

- Others: Other sectors included mainly desalination up to the date of the sale of the investment in IDE, as set out in Note 10H above. In addition, as of the fourth quarter of 2020, Delek Israel's operations are included under other segments, the investment in which is accounted for in accordance with the equity method as at the date of sale of control.

It should be noted that operations presented under profit (loss) from discontinued operations (including the operations of Delek Israel up to the date of sale of control) (see Notes 10E, 10G and 10J above), are not presented as reportable segments. Comparative figures were reclassified to reflect the operations of Delek Israel as a discontinued operation.

B. Segment reporting

1) Revenue

	Year ended December 31		
	2020	2019 *)	2018 *)
	NIS millions		
Oil and gas exploration and production in Israel and its surroundings **)	2,667	1,332	1,412
Development and production of oil and gas assets in the North Sea	4,052	2,062	1,174
Other segments	8	22	55
Inter-segment and adjustments **)	(56)	(60)	(43)
Total in statement of income	6,671	3,356	2,598

*) Restated, see Note 10J.

**) Inter-segment sales are mainly for the sale of gas to other segments.

NOTE 34: OPERATING SEGMENTS (CONTD.)

B. Segment reporting (contd.)

2) Segment results – operating profit (loss)

	Year ended December 31		
	2020	2019 *)	2018 *)
	NIS millions		
Oil and gas exploration and production in Israel and its surroundings	705	649	1,114
Development and production of oil and gas assets in the North Sea	(734)	(104)	510
Other segments	24	(63)	(83)
Adjustments **)	(89)	(55)	(80)
Operating profit (loss)	(94)	427	1,461

*) Restated, see Note 10J.

**) Mainly administrative and general expenses attributable to the Staff Companies

3) Contribution to net profit (loss) from continuing operations attributable to the shareholders of the Company

	Year ended December 31		
	2020	2019 *)	2018 *)
	NIS millions		
Oil and gas exploration and production in Israel and its surroundings	117	476	520
Development and production of oil and gas assets in the North Sea	(1,132)	(128)	364
Other segments	24	(30)	(5)
Adjustments **)	(668)	(431)	(400)
Earnings (loss) from continuing operations attributable to shareholders of the Company	(1,659)	(113)	479

*) Restated, see Note 10J.

**) Mainly administrative and general expenses, financing and taxes attributable to the Staff Companies

NOTE 34: OPERATING SEGMENTS (CONTD.)

B. Segment reporting (contd.)

4) Segment assets

	December 31 2020	December 31 2019
	NIS millions	
Fuel in Israel	-	3,872
Oil and gas exploration and production in Israel and its surroundings	19,181	22,630
Development and production of oil and gas assets in the North Sea	13,470	16,635
Other segments	202	1,352
	32,853	44,489
<u>Investments in associates</u>		
Oil and gas exploration and production in Israel and its surroundings	266	259
Fuel in Israel	-	98
Other segments	307	134
	573	491
Assets not attributed to segments	851	1,983
Total consolidated assets	34,277	46,963

5) Segment liabilities

	December 31 2020	December 31 2019
	NIS millions	
Fuel in Israel	-	3,245
Oil and gas exploration and production in Israel and its surroundings	13,433	15,401
Development and production of oil and gas assets in the North Sea	9,706	11,293
Other segments	43	656
	23,182	30,595
Liabilities not attributed to segments	5,909	8,791
Total consolidated liabilities	29,091	39,386

NOTE 34: OPERATING SEGMENTS (CONTD.)

B. Segment reporting (contd.)

6) Acquisition cost of long-term assets

	Year ended December 31		
	2020	2019 *)	2018 *)
	NIS million		
Oil and gas exploration and production in Israel and its surroundings	355	2,347	2,980
Development and production of oil and gas assets in the North Sea (including in business combinations)	857	8,317	1,742
Other segments	12	87	228
	1,224	10,751	4,950

7) Amortization and depreciation (including impairment)

	2020	2019 *)	2018 *)
Oil and gas exploration and production in Israel and its surroundings	1,080	221	224
Development and production of oil and gas assets in the North Sea	2,401	1,395	294
Other segments	34	252	2
	3,515	1,868	520

*) Restated, see Note 10J.

C. Geographic information

The revenue of the oil and gas exploration and production segment in the North Sea region is mainly from sales to customers in the UK and the assets used in this segment are in the UK. Most of the revenue of other segments is from sales to customers in Israel and most of their assets are in Israel.

NOTE 35: INTERESTED AND RELATED PARTIES

A. CEO of the Company

In December 2020, the Company's board of directors approved the payment of a bonus to the CEO, following the approval of the compensation committee in November 2020. Subsequent to the balance sheet date, in February 2021, a bonus in the amount of NIS 600 thousand was paid to the CEO of the Company for 2019.

In 2019, the Company's board of directors and compensation committee approved the payment of a bonus of NIS 1,400 thousand to the CEO for 2018. In 2018, the Company's board of directors and compensation committee approved the payment of a bonus of NIS 1,400 thousand to the CEO for 2017.

On November 24, 2019, the Company’s board of directors appointed the deputy CEO, Idan Wallace, as CEO of the Company, as from January 1, 2020 (the termination date of the term of Asi Bartfeld is December 31, 2019).

NOTE 35: INTERESTED AND RELATED PARTIES

B. Chairman of the board of directors

In December 2020, the Company's board of directors approved the payment of a bonus amounting to NIS 500 thousand to the chairman of the board of directors, following the approval of the compensation committee in November 2020. Subsequent to the balance sheet date, on February 1, 2021, the general meeting approved the bonus and the chairman of the board of directors was paid NIS 500 thousand for 2019.

In 2019, the Company's board of directors and compensation committee approved the payment of a bonus amounting to NIS 700 thousand to the chairman of the board of directors for 2018. In 2018, the Company's board of directors and compensation committee approved the payment of a bonus amounting to NIS 600 thousand to the chairman of the board of directors for 2017.

C. For further information about guarantees provided to related parties, see Note 24B.

D. Balances with interested and related parties

	December 31	
	2020	**2019**
	NIS millions	
Trade receivables (mainly associates)	10	24
Other receivables	5	5
Long-term loans, deposits, and receivables	74	111
Loans to associates	1	56
Liabilities to suppliers and service providers (Mostly associates)	-	4
Other payables	6	12

E. Transactions with interested and related parties

	Year ended December 31		
	2020	**2019**	**2018**
	NIS million		
Sales (mainly associates)	18	176	353
Purchases	-	22	16
Sales, administrative and general expenses	-	91	19
Financing income (expenses)	(2)	42	11
Loss from discontinued operations, net	-	55	51

NOTE 35: INTERESTED AND RELATED PARTIES (CONTD.)

F. Benefits for key managers (including directors) employed in the Group

The senior managers and some of the members of the board of directors in the Company are eligible, in addition to their salary, to non-monetary benefits, such as the use of a company car. In addition, the Company contributes to defined post-employment benefit plans.

Benefits for key managers (including one director) employed in the Company:

	Year ended December 31					
	2020		2019		2018	
	No. of people	Amount NIS millions	No. of people	Amount NIS millions	No. of people	Amount NIS millions
Short-term benefits	9	28	6	21	5	17

Benefits to the Company's directors who are not employed by the Company:

	Year ended December 31					
	2020		2019		2018	
	No. of people	Amount NIS millions	No. of people	Amount NIS millions	No. of people	Amount NIS millions
Benefits for non-employee directors *)	8	2	6	1	7	2

*) Including directors' compensation for the daughter of the controlling shareholder in the amount of NIS 334 thousand in 2020 (in 2019, NIS 230 thousand; in 2018, NIS 314 thousand).

**) It should be noted that two directors of the Company have ended their tenure.

G. Agreements with the controlling shareholder

1) Agreements with the controlling shareholder to repay expenses

The Company's controlling shareholder has served as a director in the Company since September 18, 2014 and as a director in the subsidiary, Delek Energy. The controlling shareholder does not receive directors' fees for his position as director. The controlling shareholder provides, from time to time as requested by the Company's management, management advice and contributes of his time and numerous skills in promoting the interests and business if the Company and its subsidiaries in Israel and abroad.

On January 6, 2016, the general meeting of the Company approved a mechanism for reimbursement of expenses to the controlling shareholder for a three-year period commencing January 1, 2015. On February 28, 2018, the general meeting of the Company approved an extension of the reimbursement mechanism for Yitzhak Tshuva for an additional three years, from January 1, 2018 to December 31, 2020. On March 22, 2021, the Company's compensation committee approved an extension of the reimbursement mechanism for Yitzhak Tshuva, for an additional three years, from January 1, 2021 to December 31, 2023, subject to the approval of the Company's board of directors and general meeting.

Under the mechanism, the Company will reimburse expenses incurred and expended relating to the aforesaid advice, and all against duly produced invoices. The expense reimbursement mechanism includes a closed list of the types of expenses to be reimbursed and does not have a limit to the amount of the expenses. The expenses will be reviewed according to nature, and accepted control and supervision mechanisms will be set up for reviewing the necessity of the reimbursed expenses. In 2020, the Company was required to reimburse expenses in the amount of NIS 242 thousand.

At the beginning of 2019, Yitzhak Tshuva was paid NIS 84 thousand for expenses in 2017-2018.

NOTE 35: INTERESTED AND RELATED PARTIES (CONTD.)

G. Agreements with the controlling shareholder (contd.)

2) Agreements with the controlling shareholder in the office building

The Company's audit committee approved the agreement with a private company of the controlling shareholder, for rental of space in an office building acquired by the Company under market conditions according to the opinion prepared by an independent real estate appraiser to determine the appropriate rental fee for the leased area.
The lease period is from September 19, 2019 until September 18, 2021 and includes an option to extend for two additional periods ending on September 18, 2031. In 2020, the lessee was charged an amount of NIS 516 thousand (before VAT) for rent in 2020.
In 2019, the lessee was charged an amount of NIS 491 thousand for rent in 2019.

3) Employment of consultants

The employment of an officer as a consultant in the Company and the subsidiaries, who is also employed by the controlling shareholder and private companies owned by the controlling shareholder; the employment of consultants in a company that provides services to private companies owned by the controlling shareholder in the Company.

4) The highest balance for 2020 is the balance as at December 31, 2020, which amounts to NIS 1.2 million (a total of NIS 900 thousand was repaid subsequent to the balance sheet date).

H. In the regular course of business, the Group companies conduct transactions at market prices and at regular credit terms with corporations that are related parties, in insignificant amounts.

Principal partnerships and investees

Holding company	Company	Rate of holding and control of the investee as at December 31, 2020 (1)	Rate of holding of the Group in final retention as at December 31, 2020 (1)	By way of presentation
		%	%	
Delek Group Ltd.	Delek Petroleum Ltd.	100	100	Subsidiary
	Delek Infrastructure Ltd.	100	100	Subsidiary
	Delek Power Stations - Limited Partnership	100	100	Subsidiary
	Delek Energy Systems Ltd.	100	100	Subsidiary
	Delek Drilling Limited Partnership (2)	5.06	54.18	Subsidiary
	Yam Tethys Joint Venture	4.441	33.5	Proportionate consolidation
	Delek Sea Maagan (2011) Ltd.	100	100	Subsidiary
	Israel Delek Holdings Group Ltd.	100	100	Subsidiary
	Delek Financial Investments 2012 - Limited Partnership	100	100	Subsidiary
	DKL Investments Limited	100	100	Subsidiary
Delek Petroleum Ltd.	Delek The Israel Fuel Corporation Ltd.	40	40	Associate
	Ltd. Delek Hungary Holding Ltd.	100	100	Subsidiary

(1) Rate of direct and indirect ownership and control

(2) Held also by Delek Energy

Principal partnerships and investees (contd.)

Holding company	Company	Rate of holding and control of the investee as at December 31, 2020 (1)	Rate of holding of the Group in final retention as at December 31, 2020 (1)	By way of presentation
		%	%	
DKL Investments Limited	DKL Energy Limited	100	100	Subsidiary
	Delek GOM Holdings Inc.	100	100	Subsidiary
	Delek Royalty US LLC	21	21	Associate
Delek GOM Holdings Inc.	Delek GOM Holdings LLC	100	100	Subsidiary
Delek GOM Holdings LLC	GulfSlope Energy Inc.	23.2	23.2	Associate
DKL Energy Limited	Delek North Sea Limited	100	100	Subsidiary
Delek North Sea Limited	Ithaca Energy Limited	100	100	Subsidiary
Ithaca Energy Limited	Ithaca Energy (Holdings) Limited	100	100	Subsidiary
	Ithaca Energy (UK) Limited	100	100	Subsidiary
	Ithaca Minerals (North Sea) Limited	100	100	Subsidiary
	Ithaca Energy Holdings (UK) Limited	100	100	Subsidiary
	Ithaca Petroleum Limited	100	100	Subsidiary
	Ithaca Causeway Limited	100	100	Subsidiary
	Ithaca Alpha (NI) Limited	100	100	Subsidiary
	Ithaca Gamma Limited	100	100	Subsidiary
	Ithaca Epsilon Limited	100	100	Subsidiary
	Ithaca Oil and Gas Limited	100	100	Subsidiary

(1) Rate of direct and indirect ownership and control

Principal partnerships and investees (contd.)

Holding company	Company	Rate of holding and control of the investee as at December 31, 2020 (1)	Rate of holding of the Group in final retention as at December 31, 2020 (1)	By way of presentation
		%	%	
Delek Energy Systems Ltd.	Delek Drilling Management (1993) Ltd.	100	100	Subsidiary
	Delek Drilling Trusts Ltd	100	100	Subsidiary
	Delek Drilling Limited Partnership (2)	49.12	54.18	Subsidiary
	Avner Oil and Gas Ltd.	50	50	Associate
	Avner Trusts Ltd.	50	50	Subsidiary
	Delek Leviathan Royalty Ltd.	100	100	Subsidiary
Delek Drilling – Limited Partnership	Yam Tethys Joint Venture (2)	48.5	33.5	Proportionate consolidation
	Michal Matan Joint Venture	22	13.2	Proportionate consolidation
	Ratio Yam joint venture	45.34	27.1	Proportionate consolidation
	Cyprus transaction	30	17.9	Proportionate consolidation

(1) Direct and indirect ownership and control (without the participating holdings of The Phoenix)

(2) Also held directly by Delek Petroleum Ltd.

Delek Group Ltd.

Financial Information from the Consolidated Financial Statements Attributed to the Company

December 31, 2020

Breakdown of Financial Information from the consolidated statement of financial position attributable to the Company

	Note	As at December 31 2020	2019
		NIS millions	
Current assets			
Cash and cash equivalents		130	685
Short-term investments (primarily limited deposits)		84	112
Assets in respect of swap transactions		-	261
Income tax receivable		29	13
Financial derivatives		-	6
Other receivables	3	67	72
		310	1,149
Assets held for sale,		51	-
Total current assets		361	1,149
Non-current assets			
Investments in investees and partnerships	4	2,532	4,817
Loans and capital notes to investees	4 B	4,913	4,923
Financial assets		21	185
Assets in respect of swap transactions		-	261
Long term loans and debit balances	3	307	407
Financial derivatives		-	34
Investment property	6	196	222
Fixed assets, net	6	39	49
Total non-current assets		8,008	10,898
		8,369	12,047

The additional information constitutes an inseparable part of the financial information and of the separate financial information.

Breakdown of Financial Information from the consolidated statement of financial position attributable to the Company

	Note	As at December 31 2020	As at December 31 2019
		NIS millions	
Current liabilities			
Debentures including current maturities		5,263	894
Current bank and other borrowings and loan maturities		113	253
Current maturities of bank liabilities in respect of the swap transactions		-	259
Loan from a subsidiary		28	135
Financial derivatives		-	16
Other payables		158	170
Total current liabilities		5,562	1,727
Non-current liabilities			
Long Term Bank Loans		-	502
Loans from subsidiaries		774	123
Long term bank liabilities in respect of the swap transactions		-	234
Debentures	7	-	4,578
Debentures convertible into Company shares	7	-	694
Financial derivatives		-	19
Other liabilities (primarily liability for decommission of long term assets)		11	37
Total non-current liabilities		785	6,187
Equity attributable to equity holders of the Company	9		
Share capital		18	13
Share premium		2,341	1,919
Proceeds for conversion options		18	18
Options		20	-
Retained earnings		1,532	3,382
Foreign currency translation differences for foreign operations		(933)	(653)
Reserve for transactions with non-controlling interests		(677)	(289)
Other reserves		17	(3)
Treasury shares		(314)	(254)
Total capital		2,022	4,133
		8,369	12,047

March 30, 2021			
Date of approval of the financial statements	Gabriel Last Chairman of the Board of Directors	Idan Wallace CEO	Tamir Polikar Deputy CEO and CFO

The additional information constitutes an inseparable part of the financial information and of the separate financial information.

Financial information from the consolidated statements of income attributable to the Company

	Note	2020	2019	2018
		Year ended December 31		
		NIS millions		
Revenue from overriding royalties and gas sales (net of royalties)		7	27	28
Rental fees		5	9	8
Company's share in earnings (losses) of partnerships and investees, net		(1,195)	37	979
Management fees from investees		1	2	3
Total revenue (expenses)		(1,182)	75	1,018
Production cost of gas sold		6	11	1
General and administrative expenses		30	51	44
Other revenues (expenses), net		(124)	157	(40)
Operating profit (loss)		(1,342)	170	933
Net financing income with respect to loans to investees and others		40	22	109
Financing income (expenses) (mainly for financial investments), net		(207)	71	115
Financing expenses (mainly with respect to debentures)		(343)	(389)	(432)
Profit (loss) before taxes on income		(1,852)	(126)	725
Taxes on income	8	-	(1)	-
Profit (loss) from continuing operations		(1,852)	(127)	725
Profit (loss) from discontinued operations, net		(22)	361	(208)
Net profit (loss) attributed to Company shareholders		(1,874)	234	517

The additional information constitutes an inseparable part of the financial information and of the separate financial information.

Breakdown of Financial Information from the consolidated statements of comprehensive income attributable to the Company

	2020	2019	2018
	Year ended December 31		
	NIS millions		
Net profit (loss) attributed to Company shareholders	(1,874)	234	517
Other comprehensive income (loss)			
<u>Amounts not reclassified to profit or loss:</u>			
Loss from investment in equity instruments measured at fair value through other comprehensive income	(11)	(19)	-
Other comprehensive loss attributable to partnerships and investees	(64)	(88)	-
Revaluation for transfer from fixed assets to investment property	20	-	24
Total	(55)	(107)	24
<u>Amounts classified or reclassified to profit and loss under specific conditions:</u>			
Profit for financial assets at fair value through other comprehensive income	-	-	1
Loss with respect to cash flow hedges	-	(8)	-
Transfer to profit or loss for cash flow hedges	-	9	-
Adjustments for translation of financial statements of foreign operations	(310)	(94)	(1)
Transfer to statement of income for foreign currency translation differences for foreign operations	-	-	17
Other comprehensive income (loss) attributable to investees and partnerships (after effect of	84	(558)	637
Total	(226)	(651)	654
Total other comprehensive income (loss) from continuing operations	(281)	(758)	678
Total other comprehensive income (loss) from discontinued operations	-	23	(66)
Total other comprehensive income (loss)	(281)	(735)	612
Total comprehensive income (loss) attributed to Company shareholders	(2,155)	(501)	1,129

The additional information constitutes an inseparable part of the financial information and of the separate financial information.

Financial information from the consolidated statements of cash flows attributable to the Company

	Year ended December 31		
	2020	2019	2018
		NIS millions	
Cash flows from the Company's operating activities			
Net profit (loss) attributed to Company shareholders	(1,874)	234	517
Adjustments to reconcile statement of cash flows from the Company's ongoing operations (a)	1,692	798	(253)
Net cash from (used for) the Company's ongoing operations	(182)	1,032	264
Cash flows from the Company's investment activities			
Investments in property, plant and equipment and investment property	(2)	-	(55)
Proceeds from disposal of financial assets	90	48	421
Proceeds from sale of investments in investees	207	1,723	100
Short term deposits, net	(53)	(31)	-
Investments in other financial assets	(13)	(27)	(5)
Proceeds from disposal of investment property	33	65	-
Long-term deposits	(178)	(70)	(219)
Collection of long-term deposits	220	105	-
Collection (provision) of loans from others	(2)	210	30
Proceeds from sale of right to receive an overriding royalty for a subsidiary	239	-	-
Proceeds from sale of oil and gas assets including overriding royalty	80	160	-
Provision of loans and capital investments of investees, net	(357)	(2,096)	(124)
Net cash from the Company's investment operations	264	87	148
Cash flows from the Company's financing activities			
Dividend paid to shareholders of the Company	-	(260)	(490)
Issue of share capital and options (less issue costs)	347	-	-
Proceeds from exercise of options for shares of the Company	100	-	-
Short term borrowings from banks and others, net	(631)	(127)	(206)
Issue of debentures		-	515
Loans received from a subsidiary	862	257	-
Repayment of loans from a subsidiary	(301)	-	-
Receipt of bank loans	-	404	846
Repayment of loans from banks and others	(92)	(208)	(137)
Buy back of debentures	(5)	-	-
Repayment of Debentures	(916)	(1,129)	(844)
Net cash used for the Company's financing operations	(636)	(1,063)	(316)
Exchange differences for cash and cash equivalents	(1)	1	2
Increase (decrease) in cash and cash equivalents	(555)	57	98
Cash and cash equivalents at the beginning of the year	685	628	530
Cash and cash equivalents at the end of the year:	130	685	628

The additional information constitutes an inseparable part of the financial information and of the separate financial information.

Financial information from the consolidated statements of cash flows attributable to the Company

		Year ended December 31		
		2020	2019	2018
			NIS millions	
(A)	Adjustments for presentation of statement of cash flows from the Company's ongoing operations (a)			
	Adjustments for profit and loss items of the Company:			
	Depreciation, depletion and amortization	2	3	1
	Loss (profit) from disposal of investment in an investee	127	(66)	12
	Decrease (increase) of loans granted, net	(26)	30	(92)
	Impairment (appreciation) of investments and loans provided, net	179	(34)	(81)
	Company's share in the expenses of investees and partnerships *)	1,383	998	(188)
	Impairment of liabilities, net	29	52	72
	Change in fair value of financial derivatives, net	17	(20)	(11)
	Other revenues (with respect to disposal of gas and oil assets including overriding royalty)	-	(103)	-
	Revaluation of other long-term assets	6	(11)	8
	Exchange differences for cash balance and cash equivalents, net	1	(1)	(2)
	Gain from disposal of investment property	(1)	(23)	-
	Appreciation of an investment property	(3)	(31)	(9)
	Changes in the Company's asset and liability items:			
	Decrease in other receivables	14	33	18
	Increase (decrease) in other accounts payable	(36)	(29)	19
		1,692	798	(253)
	*) Net of dividends received	191	1,343	583
(B)	Company's significant non-cash activities			
	Acquisition of shares in an investee against issue of Company shares	-	-	320
	Dividend receivable from investees and partnerships	-	6	6
	Acquisition of Company shares by a subsidiary partnership	60	111	-
	Purchase of debentures and convertible debentures of the Company by subsidiaries	21	-	-
	Investment in a financial asset as a result of distribution in kind	-	83	-
	Acquisition of investment property against repayment of promissory note issued by a subsidiary	-	-	32
	Sale of investment property against loan provided	-	39	-
	Investment in investment property	-	-	3
	Repayment of a liability to a bank against the sale of shares in swap transactions	-	132	-
	Disposal of subsidiary against provision of a loan	-	152	10
(c)	Additional information on cash flows			
	Cash paid by the Company during the year for:			
	Interest	330	350	377
	Cash received by the Company during the year for:			
	Interest	2	17	11
	Taxes	-	56	24
	Dividends	191	1,344	584

The additional information constitutes an inseparable part of the financial information and of the separate financial information.

NOTE 1 – A. METHOD OF PREPARATION OF THE FINANCIAL INFORMATION FROM THE COMPANY'S CONSOLIDATED FINANCIAL STATEMENTS FOR 2020, ATTRIBUTED TO THE COMPANY

1. Definitions

The Company	-	Delek Group Ltd.
The Group	-	The Company and its subsidiaries and partnerships which are consolidated in the consolidated financial statements
Consolidated companies, subsidiaries, investees, controlling shareholders, interested parties and related parties	-	As these terms are defined in the Company's consolidated financial statements for 2019 ("the Consolidated Financial Statements").

2. Manner of preparing financial information

The financial information from the consolidated financial statements attributed to the Company itself as the parent company ("the Financial Information"), was prepared in accordance with Regulation 9 C of the Securities Regulations (Periodic and Immediate Reports), 1970.

The accounting policy applied for presenting this financial information are set out in Note 2 to the consolidated statements.

3. Assets and liabilities included in the consolidated financial statements that are attributable to the Company:

The amounts of assets and liabilities in the consolidated statements that are attributable to the Company itself as the parent company are presented with a description of the type of assets and liabilities. This information is classified in the same manner by which the consolidated statements of financial position are classified. Furthermore, these figures reflect the mutual balances between the Company and its subsidiaries which were cancelled in the consolidated statements.

In this matter these figures were presented according to the provisions of IAS 1 and adjusted, where relevant, as detailed in the statement of financial position.

4. Income and expenses included in the consolidated financial statements that are attributable to the Company:

The amounts of income and expenses in the consolidated financial statements, with a breakdown of profit or loss, attributable to the Company itself as the parent company, are presented with a description of the type of income and expenditure. This information is classified in the same manner by which the consolidated financial statements of income are classified. In addition, these figures reflect the results of operations for mutual transactions that were cancelled in the consolidated statements.

In this matter these figures were presented according to the provisions of IAS1 and adjusted, where relevant, as detailed in the statement of income.

5. Cash flows included in the consolidated financial statements attributable to the Company:

The amounts for cash flows in the consolidated financial statements attributable to the Company itself as the parent company are taken from the consolidated financial statements of cash flows with breakdown of cash flows from ongoing operations, cash flows from investment activities and cash flows from financing activities with a description of their composition. This information is classified in the same manner by which the consolidated financial statements of income are classified.

NOTE 1 – GENERAL

B. The Covid-19 crisis and the decline in oil and gas prices

In December 2019, the Covid-19 pandemic broke out in China. In 2020, the Covid-19 virus spread to many countries around the world and in March 2020, it was declared a pandemic by the World Health Organization ("the Covid-19 Crisis"). The spread of Covid-19 has caused widespread morbidity and mortality in many countries. Due to the Covid-19 Crisis, many countries have imposed and are continuing to impose significant restrictions that included and/or include, among other things, self-isolation, restrictions on traffic and transportation (including flights), and closure and reduction of business activity. The crisis and the associated restrictions have caused a significant slowdown in global economic activity, and sharp declines and extreme volatility in capital markets around the world. Following the decline in business activity, there has been a slump in demand for oil products. Moreover, in March 2020, the Russia-Saudi Arabia oil price war was reflected in an increase in oil production compared with the decline in demand. These events resulted in plummeting oil and natural gas prices during 2020 in some countries worldwide. However, agreements have recently been reached between countries to reduce the volume of daily oil production in the coming months. In addition, in the second half of 2020, many countries started to adopt an exit strategy and controlled and gradual return to routine and since the end of 2020 various countries began to vaccinate their populations to eradicate and/or slow down the pandemic. In this context, it should be noted that in 2020 and shortly before the approval date of the financial statements, oil prices were extremely volatile: as at December 31, 2019, the Brent oil price was USD 65 per barrel, and at its lowest point in 2020, the Brent oil price was USD 16 per barrel, as at December 31, 2020 it was USD 52 per barrel and close to date of approval of the financial statements, after further recovery of the markets, it was USD 64 per barrel.

As at the date of approval of the financial statements, there is uncertainty regarding when the pandemic will be contained and/or will break out again and the continuation and/or deepening of the global economic crisis, and future oil and natural gas prices.
Since the Group's main activity is in the energy sector, oil and natural gas prices (as well as the USD to NIS exchange rate) have a material effect (positive or negative) on the Group's operating results, on the value of its assets (marketable and non-marketable), capital, cash flows from its operating activity, as well as on its ability to dispose of assets and on the expected considerations from the disposals, and on its ability to raise additional sources of financing and/or financing costs.

With regard to impairment of assets and amortization (cancellation of amortization) and loss from disposals carried out during 2020, see Notes 10, 12 and 14 to the Consolidated Financial Statements. In this context, it should be noted that the estimates used by the Group for the assessments may be volatile, among other things, due to the aforesaid uncertainty. The Group will continue to review its estimates and update them according to developments in connection with the crisis, its effect on the economy in Israel and globally, and its effect on prices of oil and natural gas.

It should further be noted that, due to the economic crisis in 2020, there has been a very significant decline in the trading value of the shares of the Company and its investees (mainly the participating units of Delek Drilling - Limited Partnership ("Delek Drilling or the Partnership"), which resulted in significant impairment of the Group's financial position and its liquid resources, mainly due to the fact that some of these shares served as collateral for the credit facilities provided to the Group. In 2020, the Group repaid in full the credit facilities that were provided and that were mainly secured with Delek Drilling participating units. See section C below for information about the Group's financial position. It is further noted that from the beginning of 2021 until the approval date of the financial statements, there was a significant increase in the marketable value of the Company's shares and Delek Drilling's participating units, although the marketable value did not reach its value prior to the outbreak of Covid-19.

NOTE 1 – GENERAL (CONTD.)

C. Financial position of the Group

1. General

- As at December 31, 2020, the Company (separate) has a working capital deficit of NIS 5.2 billion, and the Group (consolidated) has a working capital deficit of NIS 4.5 billion, mainly due to classification of debentures and other liabilities (beyond current maturities) in the amount of NIS 4.6 billion to short term. This classification is mainly in due to the fact that some of the waiver items in the amended the deed of trust of the debenture series of June 2020 (see Note 19 to the Consolidated Financial Statements) are for less than twelve months from the date of the financial statements, and in view of the failure to comply with the provisions of the amended Deed of Trust with regard to the limit on general and administrative expenses in 2020 (see also Note 19 to the Consolidated Financial Statements).

  It should be noted that, in addition to the aforesaid regarding the liabilities of the Company (separate), the Company provided certain guarantees to banks and other institutions for loans and credit taken out by certain subsidiaries (“the Staff Companies"). With regard to the Companies’ liabilities under the support documents provided for The Phoenix, see Note 10E(1) to the Consolidated Financial Statements.

  According to the original repayment schedules, in 2021, the Company and its Staff Companies have repayments (principal and interest) amounting to NIS 1.3 billion and in 2022, another NIS 2 billion.

- As at December 31, 2020, liabilities (short- and long-term) to financing entities (mainly to debenture holders and banks and other institutions) of the Company and the Staff Companies amount to NIS 5.9 billion, against a cash balance, tradable securities and deposits pledged in favor of the debenture holders of the Company and the Staff Companies that as at that date amount to NIS 275 million.

- Shortly before the approval date of the financial statements, the liabilities amount to NIS 5.6 billion, against financial assets amounting to NIS 70 million. For information about the updated collateral for these liabilities (taking into consideration agreements with the debenture holders and others as described above). For further information, see Notes 18 and 19 to the Consolidated Financial Statements.

As set out in section B above, in the reporting period, the Covid-19 Crisis broke out (and it is still ongoing), which resulted in a significant slowdown in the local land global economy and a significant drop in oil and gas prices over numerous intervals (having an adverse effect on the Group's main activity).

- It should be noted that, as a result of the above, from the beginning of 2020 until the approval date of the financial statements, the following main events occurred:

  - There was a significant decrease in the TASE value of the shares of the Company and its investees (mainly Delek Drilling).

NOTE 1 – GENERAL (CONTD.)

C. Financial position of the Group (contd.)

1. General (contd.)

- o In 2020, there was a significant increase in returns on the Company's debentures, although following the economic recovery and the actions taken by the Group, the returns on the debentures decreased significantly (shortly before the approval date of the financial statements, the returns on the various debenture series were between 11% and 17%), which may make it difficult to refinance/raise additional debt and debentures.
- o There was a significant decrease in capital attributable to the Company's shareholders, which amounted to NIS 2 billion as at December 31, 2020 (as at December 31, 2019, NIS 4.1 billion). As set out in Note 19 to the Consolidated Financial Statements, in accordance with the provisions of the revised deed of trust, the capital attributed to the Company's shareholders as at June 30, 2021, should amount to a minimum amount of NIS 1.6 billion, and as at March 31, 2022, to NIS 2 billion. It should be noted that the continuation of the Covid-19 pandemic and further declines in oil prices and/or the dollar exchange rate and/or hasty sale of assets may adversely affect the balance of capital attributed to the Company's shareholders. On the other hand, future capital raising, an increase in oil prices, and continued improvement in the results of the investees will lead to an increase in capital attributed to the Company's shareholders.
- o As at the date of approval of the financial statements, the Company and its Staff Companies have paid off their debts to banks and others in full, other than a debt to a foreign bank in the amount of USD 8 million. Furthermore, the Company has a loan in the amount of NIS 100 million that the Company pledged in favor of the building that it owns in Herzliya, and a convertible loan in the amount of USD 50 million, for further information see Notes 18 and 19 to the Consolidated Financial Statements.

- Following the spread of Covid-19, which led to sharp volatility in the capital markets in Israel and the world and plummeting oil and gas prices (in some of the period), there was an impairment in market value of the collateral (mainly Delek Drilling participating units) provided by the Company and its subsidiary Delek Energy Systems Ltd. ("Delek Energy") in favor of the credit providers. Under the provisions of the financing agreements, the impairment in the collateral against the balance of the debt to the credit providers fell below the rates set out in the various loan agreements, and as a result, at certain times in 2020, the Company and Delek Energy were required to provide (pledge) additional collateral and/or to deposit cash (under the provisions of any agreement) in favor of the credit providers to meet the requirements of the agreements and/or to attempt to avoid a call for immediate repayment of the debt. It is further noted that in the fourth quarter of 2020, the Group repaid the balance of the foregoing bank debts in full. In this context, it is noted that:

1) With regard to a certain loan provided to Delek Energy by a foreign bank in 2013, the balance of which in March 2020 amounted to USD 57 million, and with respect to which at that time, participating units constituting 15% of the share capital of Delek Drilling were encumbered in favor of the foreign bank, in March 2020 the bank claimed that, in view of the extraordinary decline in the price of the participating units of Delek Drilling, grounds were established (as it claimed) for calling the debt for immediate repayment. Accordingly, on March 15, 2020, the foreign bank entered into an agreement with a third party for the sale of 12% of Delek Drilling's participating units. Under the settlement arrangement between Delek Energy, the foreign bank, and a third party, which was completed on March 26, 2020, Delek Energy acquired 7% of the participating units of Delek Drilling (out of the 12%) for a consideration of USD 35.8 million. The remaining 3% of Delek Drilling's participating units were released back to Delek Energy.

NOTE 1 – GENERAL (CONTD.)

C. Financial position of the Group (contd.)

1. General (contd.)

After the completion of the aforesaid, the Group holds 55% of the capital of Delek Drilling. Following the aforesaid (net disposal of 5% of the capital of Delek Drilling), the capital attributable to the Company's shareholders decreased by NIS 313 million. For further information see Note 10I to the Consolidated Financial Statements.

2. Decrease in oil and gas prices and its effect on the Group

2) For the loan of NIS 100 million backed by Delek Drilling's participating units, provided by an Israeli bank ("the Bank") to Delek Energy and guaranteed by the Company, on March 31, 2020, the Bank informed Delek Energy and the Company that the participating units that had been pledged in its favor had fallen below the value set in the agreement and since additional participating units had not been pledged to it in accordance with the terms of the loan, it seeks to call for immediate repayment of the loan and to immediately exercise the collateral provided in its favor.

In discussions between the Company and Delek Energy with the Bank, the Bank sent an update letter stating the terms and requirements for postponing the exercise of the collateral. To avoid a situation in which the Bank exercises the participating units that were pledged to it, Delek Energy pledged additional participating units in favor of the Bank (at a lower rate than that stipulated in the loan terms), even though Company and Delek Energy believe that under the special circumstances, partially due to the Covid-19 Crisis, the Bank does not have the right to demand additional collateral and/or immediate repayment of the loan. Following the foregoing addition, the participating units were pledged in favor of the bank constituting 5.7% of the share capital of Delek Drilling (compared with 4.4% of the share capital of Delek Drilling prior to the addition).

The Bank gave Delek Energy until April 30, 2020 to fulfill the requirements in the letter of suspension of exercise, and on this date, if the requirements have been fulfilled, the financing facility will be provided again. As at April 30, 2020, the Company was unable to reach agreements with the Bank, on that date, that would ensure the non-exercise of the pledged participating units. Accordingly, on April 30, 2020, Delek Energy filed a motion for a temporary injunction ordering the Bank to refrain in any way from exercising the participation units pledged in its favor (among other things, in view of the Company's position that it has no grounds to call for immediate repayment). Following the court hearings, in May 2020, Delek Energy repaid its debt to the bank.

With regard to a loan of USD 200 million taken by a wholly-owned foreign subsidiary (DKL Energy), as set out in Note 10J(2) to the Consolidated Financial Statements, and in view of the fact that the loan is not backed by marketable assets (other than 51% of the share capital of Delek North Sea Limited ("DNSL") and the entire share capital of Ithaca, which are not a traded company), the loan agreement sets out margin call events that include a decrease of 20% in the index of benchmark companies (as defined in the loan agreement) or in the FTSE-100 Index, where in such event, the borrower will be required to deposit cash in the amount of the decrease in value as defined in the agreement. Grounds for early repayment under the loan agreement included a 50% decrease in the index of benchmark companies, a decrease of 50% in the FTSE-100 Index, a decrease of 50% in Company's shares, and a downgrade in Maalot's rating of the Company to BBB (plus) or below, represent grounds for repayment of half of the loan amount. The loan was provided under limited recourse terms and the Company provided the lender a guarantee for the borrower's obligation to unpaid accrued interest, the first margin call, and exceptional violation events.

NOTE 1 – GENERAL (CONTD.)

C. Financial position of the Group (contd.)

2. Decrease in oil and gas prices and its effect on the Group (contd.)

3) (contd.)

In 2020, DKL Energy failed to comply with specific financial covenants in connection with the loan, conferring on the bank the right to call for immediate repayment of part/or of its debt. On April 7, 2020, the Bank signed an amendment to an agreement according to which the cash deposit amounting to USD 43.3 million was used for partial repayment of the loan and extension of the cure period for the call for immediate repayment.

On August 27, 2020, wholly-owned foreign subsidiaries of the Group, DKL Energy and Delek North Sea Limited (“DNSL” and jointly “the Foreign Subsidiaries”) signed an amendment and addition to the agreement with a foreign bank in connection with the loan (“the Amended Agreements”, which will come into effect after completing registration of the collateral in October 2020. According to the Amended Agreements, a waiver of the non-compliance with financial covenants condition was received from the foreign bank (due to which, until October 2020, a waiver was granted for limited periods that were extended from time to time). There was no change in the original repayment dates of the principle. There will be a 2% increase in the interest rate on the loan up to November 2020, followed by further 2% increase. The existing collateral remain in place, and collateral of the remaining DNSL shares was added, such that 100% of the shares of DNSL, the parent company (100%) of Ithaca were pledged, and a loan and capital note between DKL Energy and DNSL will be pledged. Under the Amended Agreements, there was no change in events underlying the Company’s guarantee.

Further to the foregoing, a negative charge was placed on 6% of the total of Delek Drilling participating units.

In May and November 2020, USD 120 million of the loan balance was repaid in view of a dividend received from Ithaca, and in November 2020 a further USD 32 million was repaid (as at December 31, 2020, the balance of the loan amounts to USD 8 million).

The Amended Agreements eliminated the margin call events that were set out in the original agreement and removed criteria relating to ratings and the Company's share price and various indexes described above.
Under the Amended Agreements, the undertaking to comply with financial covenants remained unchanged, according to which the ratio of total net debt to net profit before taxes and financing, net of depreciation and amortization and net of appraisal and exploration expenses (EBITDAX) does not exceed 2.5. A review of this ratio is required at each calculation date (March 31, June 30, September 30, and December 31 of each year). At December 31, 2020 this ratio was 1.6.

NOTE 1 – GENERAL (CONTD.)

C Financial position of the Group (contd.)

2. Decrease in oil and gas prices and its effect on the Group (contd.)

3) (contd.)

Under the Amended Agreements, the lender has the right to call for immediate repayment of the loan (after the cure period), among other things, in the event of default, non-compliance with the dividend obligations set out above, non-compliance with the financial covenants set out above, changes in inter-company loans in the Foreign Subsidiaries, non-compliance with undertakings under the agreement, events of change in control of assets, events of insolvency and liquidation in Delek Group companies, and impairment of the closing value of the S&P Global Oil Index below the level set in the agreement. The right to call for immediate repayment was also determined in the event of cross default within the borrower group (DKL Energy and subsidiaries and its investees) and in the event of the materialization of this right.

- On March 23, 2020, Midroog Ltd. ("Midroog") downgraded the rating of the Company's debentures from A2.il to Ca.il (down 14 ratings), due to Midroog's assessment of a high probability of default. The Company disputed the rating report of Midroog and its result. In this context, it should be noted that on April 13, 2020, the Company announced the termination of its relations with Midroog and that Midroog will cease to serve as the Company's rating company from that date. The Company's series of debentures will continue to be rated by Maalot.

  On April 1, 2020, Maalot downgraded the Company's debentures from ilA to ilBBB (a downgrade of four ratings), keeping it on CreditWatch with negative outlook, due to weak liquidity reflected in a material gap between short-term sources and uses. Following the foregoing downgrade, the annual interest rate for some of the debenture series was increased by 1%. It is further noted that on May 5, 2020, Maalot downgraded the Company's debenture rating to ilCCC (a downgrade of another 5 ratings) with negative outlook due to the increased risk of default. On September 30, 2020, Maalot updated the foregoing rating to ilCCC with developing outlook. On January 31, 2021, among other things, due to measures adopted by the Company to reduce the debt and improve its resources, Maalot upgraded its rating of the Group's debentures to ilB with developing outlook.

- A downgrade of the debenture rating such that the rating falls below Maalot's BBB- or equivalent rating for more than 21 business days represented grounds to call for immediate repayment of the debentures.

- Further to the above, regarding the impairment of the various collaterals, the rating downgrade, the deterioration in the ratios of Company's debt to asset value, and the going concern remark in the financial statements, in the reporting period, there were events that are considered or that may be considered to be events of default for some of the liabilities of the Company and the Staff Companies towards the financial institutions and the debenture holders. For information about the agreements and the amendment to the deeds of trust that were approved on June 17, 2020 with the Company's debenture holders, and the standstill agreement with some of the banks, under which the grounds for calling for immediate payment were revised and/or frozen, see section 3 below and Note 19 to the Consolidated Financial Statements.

NOTE 1 – GENERAL (CONTD.)

C. Financial position of the Group (contd.)

3. Discussions and agreements with representatives of the debenture holders and with banks on the outline for reinforcing capital and collateral

In March 2020, the general meeting of the Company's debenture holders approved the establishment of a joint representation on their behalf and joint legal and economic advisors for all debenture series, with the aim of assisting the debenture holders and trustees and to act as their representative in the assessment of the Company’s financial position, the alternatives, and the actions available to the debenture holders to protect their rights and in negotiations and proceedings with the Company and/or its controlling shareholder. The Company and the representation held discussions, with the aim of regulating the terms of the debentures and the Company's obligations to them. In addition, in April-June 2020, the Company held negotiations with certain banks, in view of breaching of the covenants, with the aim of rearranging the terms of the loans that were provided and the Company’s obligations towards them. In June 2020, amendments to the deeds of trust for the debenture holders and the agreement with the banks were approved. Under the agreements, the Company undertook to raise capital, dispose of assets, pledge assets and investments in favor of the debenture holders and the banks, and comply with various financial covenants, some of which were revised in the agreements. The agreements set out events and covenants, which, if breached, will allow the debenture holders and the banks to call for immediate repayment of the Company's liabilities to them. In this context it was decided that, among other things, as of June 1, 2021, the ratings for the Company’s debentures will be no less than BBB- and that the Company is required to comply with minimum equity and equity to balance sheet ratios, based on various parameters that increase gradually over the years. With respect to 2021, it was determined that as of the financial statements for the second quarter of 2021 through to, and including, the annual financial statements for 2021, the Company requires minimum equity of NIS 1.6 billion and that the equity to balance sheet (separate) ratio will not be less than 12.5%, and with regard to 2022, as of the financial statements for the first quarter of 2022 through to, and including, the annual financial statements for 2022, the Company requires minimum equity of NIS 2 billion and that the equity to balance sheet (separate) ratio will not fall below 15 %. For further information, see Note 19 to the Consolidated Financial Statements.

It was further decided that general and administrative expenses in 2020, including those of the Staff Companies, will not exceed (including the costs of the amendment to the deed of trust) those in 2019, based on the Company's financial statements. In 2021, they will not exceed NIS 45 million; in 2022, NIS 40 million; and from 2023, NIS 35 million. For further information see Note 19 to the Consolidated Financial Statements.

It is noted that, in 2020, the general and administrative expenses of the Company and of the Staff Companies (including the costs of the amendment to the deed of trust) exceeded those for 2019 by an amount of NIS 5.4 million, and the Company failed to comply with this undertaking. Nonetheless, it is noted that, further to discussions in 2020, between DKL (a Staff Company) and Ithaca, subsequent to balance sheet date, in March 2021, it was agreed that Ithaca will participate in the general and administrative expenses of DKL for 2020. Subsequently, in March 2021, Ithaca transferred an additional amount of USD 1.7 million (NIS 5.7 million), over and above the amount of USD 0.7 million that it had already transferred for such expenses. The additional amount that was transferred subsequent to balance sheet date exceeds the deficit attributed to 2020. Consequently, in the Company’s opinion, based also on a legal opinion received on this matter, as at date of approval of the financial statements, the foregoing non-compliance has been amended.

It should be emphasized that the right for immediate repayment of the debenture holders also establishes a similar right for other lenders, including a convertible loan and credit provided to the Group in the amount of USD 58 million (NIS 190 million). These credit amounts of are classified in the Financial Statements as short term liabilities.

If the Company assesses that it may fail to comply with other financial criteria on the dates set out above, it intends to act in advance to obtain a waiver and/or extension and/or amendment of the relevant criterion, and it believes that it can reach understandings with the debenture holders on the matter.

NOTE 1 – GENERAL (CONTD.)

C Financial position of the Group (contd.)

4. Disposal of assets and investments and raising capital

- In March 2020, the Group sold its remaining holdings (20%) in the shares of IDE Holdings Ltd. (“IDE”) for NIS 169 million (see Note 10H to the Consolidated Financial Statements) and an investment property for an amount of NIS 33 million. In addition, in April 2020, the Company disposed on the balance of its holdings in the shares of Cohen Development for NIS 207 million (see Note 10K to the Consolidated Financial Statements).
- In April and May 2020, the Company informed the banks of early termination of all the swap transactions in connection with The Phoenix shares. The swap shares (25,000,000 shares) were sold by the banks in off-floor transactions for an amount of NIS 413 million. On completion of the transactions, a cash amount of NIS 143 million, which was pledged to the banks to secure the transactions, as is standard in this type of transaction, was released in favor of the Company. For further information see Note 10E to the Consolidated Financial Statements
- In July 2020, the transaction was completed for the sale of the rights of the Company and Delek Energy to overriding royalties in the Karish and Tanin reservoirs for a consideration of NIS 318 million (for further information, see Note 12H to the Consolidated Financial Statements).

  In July 2020, Delek - the Israeli Fuel Company Ltd. (“Delek Israel”) completed a transaction for the sale of its holdings in the Pi Glilot terminals for a consideration of NIS 720 million, and a binding agreement was signed for the sale of Delek Israel's holdings in IPP Delek Ashkelon Ltd. and IPP Delek Sorek Ltd., which own power plants for electricity generation, (subsequent to the balance sheet date, in February 2021, the transaction for the sale of the power plants was completed). In July 2020, Delek Israel distributed a dividend to the Group in the amount of NIS 150 million.

  For further information, see Note 10J to the Consolidated Financial Statements.

  In October 2020, the Group sold 70% of the share capital of Delek Israel for a consideration in the amount of NIS 525 million. On the closing date of the transaction, the buyer paid an amount of NIS 450 million in cash (“the Closing Date Payment”), against the transfer of 60% of Delek Israel’s share capital to the buyer, and it was agreed that the Buyer will transfer the remaining consideration of NIS 75 million by June 30, 2021 for a further 10% of Delek Israel’s share capital, and that the Buyer would be given the option to purchase another 5% of the share capital of Delek Israel. Subsequent to balance sheet date, in February 2021, the Buyer exercised half of the additional shares and 1.67% of the option for a total amount of NIS 50 million. Furthermore, in March 2021, the Buyer exercised the rest of the option granting it 3.34% of the issued and paid up share capital of Delek Israel for consideration of NIS 25 million. For further information see Note 10J to the Consolidated Financial Statements.

- In May, August and December 2020, as required under the provisions of the amended deed of trust of the debenture series, the Group completed capital raisings (shares and options) in amounts of NIS 137 million, NIS 176 million and NIS 140 million (NIS 100 million from exercising options), respectively. For further information, see Note 26 to the Consolidated Financial Statements. Furthermore, the Company is required, or may be required, to raise additional capital in accordance with the revised deed of trust for the debenture series, for further information, see Note 19 to the Consolidated Financial Statements. In this regard it is noted that, by April 8, 2021, the Company is required to raise capital in the amount of NIS 50 million (as at date of approval of the financial statements, options convertible for Company shares were exercised for an amount of NIS 17 million).

NOTE 1 – GENERAL (CONTD.)

C Financial position of the Group (contd.)

4. Disposal of assets and investments and raising capital

- On October 28, 2020, Delek Leviathan Overriding Royalty Ltd. (“the Issuer”), a special purpose company of Delek Energy, completed the issuance of debentures to foreign and Israeli classified investors in the amount of USD 180 million (gross), which was secured by a lien on the rights to overriding royalties from the Leviathan project that were transferred to the Issuer. The net amount transferred to the Company and to Delek Energy amounted to USD 147 million. For further information, see Note 12L to the Consolidated Financial Statements.

- In October 2020, the Company signed a loan agreement with a third party for a loan against a mortgage on a building that it owns in Herzliya. Subsequent to balance sheet date, in January 2021, a loan was received in the amount of NIS 104 million, that is linked to the CPI and bears annual interest of 7%. The repayment date is in January 2024. The loan was mainly used to repay an earlier loan received with regard to this Property.

- Subsequent to the balance sheet date, in March 2021, the Group signed a detailed agreement for the sale of investment property in Acre for NIS 200 million as is. The consideration will be paid as follows: NIS 10 million was paid to the Group upon signing of the memorandum of understanding, NIS 30 million will be paid by the buyer shortly before signing the agreement and this amount will be held in escrow for the Group and transferred to the Group within one business day after fulfillment of the conditions defined below. The balance of the consideration will be paid on receipt of possession, registration of a lien in favor of the party providing the finance, and confirmations of the transfer for registration of the rights. The agreement provides terminating conditions which, if they are not fulfilled within a set period, the buyer will have the right to cancel the agreement. For further information, see Note 11 to the Consolidated Financial Statements.

  Furthermore, the Group is exploring options for disposing of additional assets (including partial disposal of the Group's investment in Ithaca) and obtaining loans and/or partial exchange of debentures.

5. Repayments to debenture holders and banks and pledge of assets

In 2020 and shortly before the approval date of the financial statements, the Company and its Staff Companies repaid the full amount of their liabilities to the debenture holders and the banks and financial institutions under the agreements with them, including in connection with the agreements set out in section 3 above, amounting to a total of NIS 3.5 billion. For further information, see Note 19 to the Consolidated Financial Statements.

NOTE 1 – GENERAL (CONTD.)

C. Financial position of the Group (contd.)

6. Conclusion

Under the agreements with the debenture holders and financial institutions, and for the Company and the staff companies to meet repayment of their required liabilities, the Company is required to raise a substantial amount of capital, dispose of assets and investments on a substantial scale, raise debt based on assets and investments, and receive dividends from investees. The amounts of such resources are required for the repayment of the Company's liabilities, which amount to substantial sums (in 2021, the Company and its Staff Companies are required to repay liabilities to the debenture holders, financial institutes and others amounting to NIS 1.3 billion, and in 2022 to NIS 2 billion).

As aforesaid, repayment of the liabilities of the Company and the staff companies at their due date is subject to their ability to dispose of assets and investments on a significant scale; raise debt and capital on a significant scale, some of which is required in the near future and is greatly affected by oil and natural gas prices; and receive dividends from investees and partnerships.

It should be noted that the Company's ability to receive a substantial amount of dividend from investees refers mainly to the receipt of dividends from Delek Drilling and Ithaca. The ability of these companies to distribute dividends is subject, among other things, to their ability to comply with financial covenants, and to obtain the consent of the financing entities and/or their ability to generate significant available cash flows, which is also dependent on the demand for natural gas and oil and the price of oil and natural gas. In 2020, Ithaca distributed a dividend of USD 120 million (NIS 410 million), and Delek Drilling distributed and/or announced a dividend of USD 100 million (the Group’s share is NIS 185 million).

Furthermore, as set out above, the Company is also required to comply with the terms of the agreements and covenants with the debenture holders (and financial institutes) and/or to reach understandings with them so as to avoid establishing for them cause and/or to avoid them calling for immediate repayment of the liabilities of the Company and the Staff Companies towards them (primarily upgrading of the rating for the debentures by May 31, 2021, complying with the general and administrative amounts, and minimum equity ratios, as set out in section 3 above). The Company’s management believes that if required, it will be able to reach an understanding with the debenture holders with regard to the foregoing financial criteria.

As aforesaid, the Company worked and is working to realize its plans, including the raising of capital, disposal of substantial assets and investments, raising of debt based on assets and receipt of dividends from investees, in order to meet its various obligations. The Company believes that it is highly likely that its plans will be realized, and in this regard, it is noted that, as set out above, that the significant and important measures that the Group was able to complete over the past year, in accordance with the outline enabled it to make early repayments of substantial amounts to the banks and to the debenture holders on time and as required. Nonetheless, since completion of the Company's plans is not under its sole control and depends, as described above, among others, on third parties and/or the occurrence of incremental events, some of which must occur within relatively short periods and/or in a significant scope, and in view of the financial criteria that were set with the debenture holders and other lenders, which may require obtaining their agreement not to call for immediate repayment, there is uncertainty as to the actual fulfillment of these plans. These factors, together with the other factors described above, raise substantial doubt about the Company's ability to continue as a going concern. The financial statements do not include adjustments for the values of assets and liabilities and their classification, which might be required if the Company is unable to continue as a going concern.

NOTE 1 – GENERAL (CONTD.)

D. Financial positions of subsidiaries

1. Delek Drilling

- In August 2020, Delek Drilling (through a special purpose company) issued debentures in an amount of USD 2.25 billion (“Leviathan Bond”, for further information see Note 12K2 to the Consolidated Financial Statements) which were used primarily to repay short-term loans of USD 2 billion.

- With respect to the Covid-19 Crisis, it should be noted that in the first half of 2020, and in particular in the second quarter, there was stagnation in local demand for natural gas compared with the corresponding period last year, mainly due to the effect of the Covid-19 Crisis on demand for electricity in this market, resulting from lockdowns and restrictions on economic activity. It should be noted that, notwithstanding the continuation of the Covid-19 Crisis, there was an increase in demand for natural gas in the second half of 2020 compared with the corresponding period last year.

  As at date of approval of the financial statements, it is difficult to estimate how the Covid-19 Crisis will continue and develop over the coming years, what the scope of its impact will be on the global economy and what its impact will be on demand and sales from the Leviathan and Tamar Reservoirs in the next few years. Under such circumstances, the Covid-19 pandemic constitutes a global macro economic risk that generates uncertainty concerning future economic activities worldwide and its expected effect on the financial markets, interest margins, currency exchange rates and prices of commodities in the energy sector, and could cause impairment in many sectors, including in the energy sector in which the Partnership operates.

  As part of their strategy to deal with the Covid-19 Crisis, the Tamar Partners, Leviathan Partners and Block 12 Partners in Cyprus, have adopted measures for streamlining and reducing operating budgets for 2020 and for postponing planned investment budgets for later years, and accordingly, the partners in the foregoing projects approved revised budgets for 2020. The Partnership is continuing to work, together with the other partners in the foregoing projects, to expand streamlining plans also for the coming years.

  It is further noted that, Noble, the operator in the Tamar and Leviathan Projects, formulated a plan together with the relevant parties for dealing with the Covid-19 crisis, aiming to ensure, as far as possible, its ability to reach the various facilities and to continue carrying out the essential operations on them.

2. Ithaca

As at December 31, 2020, Ithaca has negative working capital of USD 110 million (NIS 353 million).

The Covid-19 pandemic and the decline in oil and gas prices had a material effect on the results of Ithaca’s operations. The management of Ithaca is closely following the crisis and the market developments and is taking steps and formulating plans to minimize the implications. As aforesaid, the recent positive developments in the markets and oil and gas prices have had a positive effect on Ithaca’s results, the value of its assets and its liquidity.

In this context, Ithaca adopted measures to isolate and separate work teams to the minimum required level, reduce capital investment in 2020, and reduce operating and production costs in substantial amounts. It is further noted that Ithaca has hedge transactions on oil and gas prices for 2021-2022 in a material scope (see Note 20A to the Consolidated Financial Statements). For further information concerning Ithaca see Notes 10F and 12U to the Consolidated Financial Statements.

In May 2020, Ithaca distributed a dividend in the amount of USD 20 million (NIS 70 million). Furthermore, in November 2020, Ithaca distributed an additional dividend in the amount of USD 100 million (NIS 340 million).

NOTE 2 – FINANCIAL INSTRUMENTS:

Financial risk factors

The Company's operations expose it to various financial risks, such as market risk (including currency risk, CPI risk, interest risk), credit and liquidity risk. The Company's comprehensive risk management plan focuses on measures to minimize possible negative effects on the financial performance of the Company.

1. Liquidity risk

The table below presents the repayment dates of the Company's financial liabilities in accordance with the contractual terms, in undiscounted amounts (including interest payments):

December 31, 2020

	Up to one year	1-2 years	2-3 years	3-4 years	4-5 years	More than 5 years	On demand	Total
	NIS million							
Debentures (including current maturities)	1,151	1,255	923	880	838	275	-	5,322
Debentures convertible into Company shares	27	718	-	-	-	-	-	745
Loans from Banks and Others	113	-	-	-	-	-	-	113
Loans from subsidiaries	60	71	326	56	-	405	-	918
Guarantees	-	-	-	-	-	-	487	487
	1,351	2,044	1,249	936	838	680	487	7,585

December 31, 2019

	Up to one year	1-2 years	2-3 years	3-4 years	4-5 years	More than 5 years	On demand	Total
	NIS million							
Debentures (including current maturities)	1,167	1,121	1,227	901	866	1,102	-	6,384
Debentures convertible into Company shares	20	20	714	-	-	-	-	754
Loans from Banks and Others	262	438	14	14	14	51	-	793
Loans from a subsidiary	137	125	-	-	-	-	-	262
Liabilities in respect of The Phoenix swap transactions	267	261	-	-	-	-	-	528
Guarantees	-	-	-	-	-	-	2,144	2,144
	1,853	1,965	1,955	915	880	1,153	2,144	10,865

NOTE 2 – FINANCIAL INSTRUMENTS (CONT'D.)

Financial risk factors (cont'd)

2. Index and foreign currency risks

Exposure to index and foreign currency assets and liabilities risks, including financial instruments

	December 31, 2020						
	Unlinked	Linked to CPI	Linked to USD	Linked to CAD	At fair value	Non-financial items	Total
				NIS million			
Current assets							
Cash and cash equivalents	124	-	6	-	-	-	130
Short-term investments	81	-	3	-	-	-	84
Income tax receivable	-	-	-	-	-	29	29
Other receivables	22	33	8	-	-	4	67
Assets held for sale,	-	-	-	-	51	-	51
Non-current assets							
Investments in investees and partnerships	-	-	-	-	-	2,532	2,532
Loans to investees	470	-	4,443	-	-	-	4,913
Financial assets	-	-	-	-	21	-	21
Long term loans and debit balances	143	-	-	21	143	-	307
Investment property	-	-	-	-	196	-	196
Fixed assets, net	-	-	-	-	-	39	39
Total assets	840	33	4,460	21	411	2,604	8,369
Current liabilities							
Debentures and convertible debentures including current maturities	4,208	1,055	-	-	-	-	5,263
Loans from others	-	113	-	-	-	-	113
Loan from a subsidiary	28	-	-	-	-	-	28
Other payables	115	9	24	-	-	10	158
Long-term liabilities							
Loans from subsidiaries	532	-	242	-	-	-	774
Long-term liabilities	-	-	11	-	-	-	11
Total liabilities	4,883	1,177	277	-	-	10	6,347
Net exposure	(4,043)	(1,144)	4,183	21	411	2,594	2,022

NOTE 2 – FINANCIAL INSTRUMENTS (CONT'D.)

Financial risk factors (cont'd)

2. Index and foreign currency risks (cont'd)

Exposure to index and foreign currency assets and liabilities risks, including financial instruments

	December 31, 2019						
	Unlinked	Linked to CPI	Linked to USD	Linked to CAD	In fair value	Non-financial items	Total
	NIS million						
Current assets							
Cash and cash equivalents	681	-	4	-	-	-	685
Short-term investments	87	-	-	-	25		112
Assets in respect of swap transactions	-	-	-	-	261	-	261
Income tax receivable	-	-	-	-	-	13	13
Financial derivatives	-	-	-	-	6	-	6
Other receivables	16	8	46	-	-	2	72
Non-current assets							
Investments in investees and partnerships	-	-	-	-	-	4,817	4,817
Loans to investees	459	-	4,464	-	-	-	4,923
Financial assets	-	-	-	-	185	-	185
Assets in respect of swap transactions	-	-	-	-	261	-	261
Long term loans and debit balances	128	31	-	22	226	-	407
Financial derivatives	-	-	-	-	34	-	34
Investment property	-	-	-	-	222	-	222
Fixed assets, net	-	-	-	-	-	49	49
Total assets	1,371	39	4,514	22	1,220	4,881	12,047
Current liabilities							
Debentures including current maturities	176	718	-	-	-	-	894
Current bank and other borrowings and loan maturities	241	12	-	-	-	-	253
Current maturities of bank liabilities in respect of the swap transactions	259	-	-	-	-	-	259
Loan from a subsidiary	135	-	-	-	-	-	135
Financial derivatives	-	-	-	-	16	-	16
Other payables (particularly interest payable)	132	14	4	-	-	20	170
Long-term liabilities							
Long Term Bank Loans	249	114	139	-	-	-	502
Loan from a subsidiary	-	-	123	-	-	-	123
Long term bank liabilities in respect of the swap transactions	234	-	-	-	-	-	234
Debentures	3,517	1,061	-	-	-	-	4,578
Debentures convertible into Company shares	694	-	-	-	-	-	694
Financial derivatives	-	-	-	-	19	-	19
Long-term liabilities	-	-	37	-	-	-	37
Total liabilities	5,637	1,919	303	-	35	20	7,914
Net exposure	(4,267)	(1,880)	4,212	22	1,185	4,861	4,133

3. For further information pertaining to debentures issued by the Company see Note 19 to the consolidated financial statements.

NOTE 3 – LONG TERM LOANS AND DEBIT BALANCES

1. For further information concerning a loan provided for the acquisition of Navitas Petroleum Limited, see Note 8 to the Consolidated Financial Statements.

2. On January 2, 2019, an agreement was signed between the Company and Fattal Hotels Ltd. ("Fattal") under which 28.3% of the Company's title rights in a property (part of the office building that was converted into a hotel) to Fattal for a consideration of NIS 103 million and 1/3 of the rental paid by Fattal under the rental agreement of the hotel were refunded to Fattal. As part of the transaction, the Company entered into a loan agreement with Fattal, according to which the Company provided Fattal with a loan of NIS 39 million, linked to the CPI and bearing interest at a rate of 2.96%, to pay the consideration. As at February 3, 2019, all the preconditions set out in the sale agreement were met. As a result of the transaction, in 2019, the Company recognized a profit of NIS 23 million, which was included under other income, net.

   As at December 31, 2020 and December 31, 2019, the balance of the loan provided to Fattal amounted to NIS 33 million and NIS 36 million, respectively. Subsequent to balance sheet date, in January 2021, the loan was repaid in full.

3. On November 3, 2019, following fulfillment of the preconditions, the transaction under which the Company sold 32.5% of the share capital of The Phoenix to a company controlled by Centerbridge Partners LP and Gallatin Point Capital LLC ("the Buyer") was closed, for a consideration that as at transaction closing amounted to NIS 1.57 billion, after adjustments for dividends distributed by The Phoenix up to the closing date. Of this amount, NIS 1.335 billion was received in cash by the Company at the closing date and the balance was provided to the Buyer as a loan.

   The agreement stipulated adjustments to the sales price, which may result in an increase in the total consideration to be received by the Company, beyond the amount of NIS 1.57 billion, in an amount of up to NIS 866 million, subject to certain adjustments, or to a reduction in the total consideration of up to NIS 196 million. These adjustments include reference to the previous profits of The Phoenix at the closing date, adjustments arising from an increase or impairment in the value of The Phoenix shares, and the rate of return of the Buyer in the investment period in The Phoenix.

   Part of the consideration paid by the Buyer was financed by a first degree loan of NIS 548 million received by the Buyer from financial institutions ("the First Degree Loan"). The loan is for a period of five years, with an option to extend for two more years under certain conditions.
   In addition, as part of the agreement to sell The Phoenix shares, the Company provided a subordinated loan of NIS 235 million to the Buyer ("the Subordinated Loan"). The loan is for a period of five years (with an option to extend for two more years under certain conditions). The loan will bear interest at a rate of 4% per year for the first five years, 7% for the sixth year, and 8% for the seventh year, paid by the Buyer for the Senior Loan and the Subordinated Loan. The interest and principal of the loan will be paid out of the dividend receipts by the Buyer, proceeds from the sale of The Phoenix shares, as well as adjustments to the transaction price that the Company undertook to pay to the Buyer under certain conditions, as set out above. To secure its liabilities with regard to the loan, the Buyer pledged, among other things, The Phoenix shares that it holds in favor of the Group as a second-ranking lien.

   The Subordinated Loan and option are measured in the financial statements at fair value through profit and loss. The discounted value of the loan as at December 31, 2020 is estimated at NIS 267 million (2019 - NIS 200 million) and the value of the option is a liability of NIS 124 million (2019 - NIS 60 million). The fair value was estimated by the valuator using the Monte Carlo model, on the assumption of risk neutrality. In view of the above, the annual return on The Phoenix shares as well as the capital price were estimated at 0.28%. In addition, the annual standard deviation was estimated at 30.3% and the rate of the annual dividend to be distributed was estimated at 1.67% of the share value at the end of each quarter.

NOTE 4 – LOANS, BALANCES, SUBSTANTIAL AGREEMENTS AND TRANSACTIONS WITH INVESTEES

A. Material guarantees as at December 31, 2020

1. The Company provided guarantees, unlimited in amount, in favor of the Republic of Cyprus to secure full compliance with the commitments of Delek Drilling Partnership. For further information see Note 12F to the Consolidated Financial Statements.
2. The Company provided a guarantee in favor of a foreign corporation in respect of a convertible loan it provided to DKL in the amount of USD 50 million (NIS 159 million). For further information, see Note 19I to the Consolidated Financial Statements

Additional financial liabilities:
As part of the First Degree Loan taken by the buyers of The Phoenix, the Company signed a credit support agreement with the financial institutions
(“the Credit Support Document”) to back up this loan in the occurrence of specific events stipulated in the agreement, including backing for interest payments by the Buyer, and partial backing for amounts to be distributed by the Buyer to its shareholders as a dividend alongside repayment of the First Degree Loan. Furthermore, under certain events, the Company may be required to secure a deposit with respect to the First Degree Loan in an amount of up to NIS 275 million. For further information see Note 10E to the Consolidated Financial Statements.

B. Loans granted to investees

The Company has loans and investments in capital notes of investees, the balance of which as at December 31, 2020, amounted to NIS 4,913 million. The Company provided loans in the amount of NIS 959 million, of which NIS 78 million were shekel loans, NIS 881 million were dollar loans provided to Ithaca at fixed annual interest of 4.75%. In addition, the Company invested in capital notes issued by subsidiaries in the amount of NIS 3,954 million (of which NIS 3,564 million are USD denominated capital notes). The capital notes are unlinked and interest free,

C. Agreements

1. Under an agreement dated June 4, 2000 (as amended on July 31, 2007), the Company undertook to provide management and consultancy services for Delek - The Israel Fuel Corporation Ltd. ("Delek Israel"), required for the ongoing management of Delek Israel. This agreement states that, in return for providing the services, Delek Israel will pay the Company USD 25,000 per month. The agreement was valid until July 31, 2012.

   As of August 1, 2012, the Company undertook to provide Delek Israel with the services of directors, as required for the ongoing management of Delek Israel. Under the terms of the agreement, Delek Israel will pay annual remuneration and participation remuneration for the participation of the director in each board meeting, an amount equivalent to the amount set in the Second Addendum and Third Addendum of the Companies Regulations (Regulations for Compensation and Expenses of an External Director), 2000. The agreement was valid until July 31, 2015. In August 2015, an agreement was signed, extending the agreement that ended on July 31, 2015, for a further term of three years until July 31, 2018. In August 2018, another agreement was signed, extending the agreement that ended on July 31, 2018, for a further term of three years until July 31, 2021. The agreement ended in 2019.

   The management fees and director's remuneration in 2019 and 2018 amounted to NIS 252 thousand, NIS 260 thousand, respectively.

NOTE 4 – LOANS, BALANCES, SUBSTANTIAL AGREEMENTS AND TRANSACTIONS WITH INVESTEES - CONTD.

C. Agreements (cont.)

2. Under an agreement dated October 11, 2012, the Company undertook to provide the services of directors as of September 1, 2012, to Delek Energy Systems Ltd. ("Delek Energy"), a wholly owned subsidiary, required for the ongoing management of Delek Energy. Under the terms of the agreement, Delek Energy will pay annual remuneration and participation remuneration for the participation of the director in each board meeting, an amount equivalent to the amount set in the Second Addendum and Third Addendum of the Companies Regulations (Regulations for Compensation and Expenses of an External Director), 2000. The agreement was valid until August 31, 2015. In October 2015, an agreement was signed, extending the agreement that ended on July 31, 2015, for a further term of three years until August 31, 2018. In August 2018, another agreement was signed, extending the agreement that ended on August 31, 2018, for a further term of three years until August 31, 2021. Subsequent to completing a tender offer for Delek Energy shares, the terms and conditions were revised so that the agreement will be renewed every year.
   Directors' remuneration for 2019 and 2018 amounted to NIS 440 thousand, and NIS 350 thousand, respectively. With regard to 2020, the Company charged Delek Energy for overheads and general and administrative expenses in an amount of NIS 8 million in accordance with the Company's agreement with Delek Energy, of February 2021.

3. As of August 15, 2012, the Company undertook to provide management and consultation services to Cohen Gas & Oil Development Ltd (formerly: Cohen Development and Industrial Buildings Ltd.) ("Cohen Development"), that are required for the ongoing management of Cohen Development. This agreement states that, in return for providing the services, Cohen Development will pay the Company an amount of USD 350,000 per year that is paid quarterly. The agreement was valid until August 14, 2015. In August 2015, an agreement was signed, extending the agreement that ended in August 2015, for a further term of three years until July 31, 2018. In August 2018, another agreement was signed, extending the agreement that ended in August 2018, for a further term of three years until July 31, 2021.
   The management fees for 2020, 2019 and 2018 amounted to NIS 542 thousand, NIS 1,246 thousand, and NIS 1,267 thousand, respectively. Following the sale of Cohen Development shares in April 2020, these management fees ceased. Under the sale agreement management fees were set, until August 31, 2020, in an amount of USD 10 thousand per month. For further information see Note 10K to the Consolidated Financial Statements.

4. On May 22, 2018, the Company signed a lease agreement with Gadot for leasing the land on which Gadot is located, for a term of 20 years. In March 2020, the land was sold to Gadot for a consideration of NIS 33 million. For further information see Note 11C to the Consolidated Financial Statements.

5. In January 2018, the Company signed a lease agreement with Fattal to lease the hotel space in the building owned by the Company, as of May 2018 and for a period of five years and in return for an annual amount of NIS 9 million with the addition of variable amounts. The amount of the income in 2020 was negligible. For further information with regard to the sale of part of the building, see Note 11A to the Consolidated Financial Statements.

6. For 2020, the Company charged DKL Investment Limited ("DKL") for overheads and general and administrative expenses an amount of USD 1.4 million (NIS 4.6 million) in accordance with the Company's agreement with DKL of February 2021.

7. With regard to 2020, the Company charged Delek Petroleum for overheads and general and administrative expenses an amount of NIS 1.8 million in accordance with the Company's agreement with Delek Petroleum of February 2021.

NOTE 4 – LOANS, BALANCES, SUBSTANTIAL AGREEMENTS AND TRANSACTIONS WITH INVESTEES - CONTD.

C. Agreements (cont.)

For further information concerning investees see Note 10 to the Consolidated Financial Statements.

D. Investments in investees

For information concerning the disposal of the Company's holdings of shares of investees, see Note 10 to the Consolidated Financial Statements.

E. Liens

To secure secured debts to the debenture holders, the Company and its wholly owned subsidiaries pledged the shares of certain investees and partnerships, including loans provided to third parties and investees. In addition, the Company mortgaged the office building in favor of a loan, the balance of which at December 31, 2020 amounts to NIS 113 million.

F. Contingent liabilities

There are contingent claims, including motions for certification of class action suits, against certain investees for significant sums that might reach billions of shekels. In some cases, it is not possible to assess their outcome at this stage, and therefore no provision was recorded in the financial statements. For further information concerning lawsuits filed against the Group companies, see Note 24A to the Consolidated Financial Statements.

NOTE 5 – INVESTMENTS IN OIL AND GAS EXPLORATION AND PRODUCTION

With regard to the sale of Cohen Development shares in 2020, see Note 10K to the Consolidated Financial Statements.

NOTE 6 – INVESTMENT PROPERTY

For information concerning the sale of part of the office and commercial building in Herzliya in 2019, see Notes 11 and 13 to the Consolidated Financial Statements.

NOTE 7 – DEBENTURES AND DEBENTURES CONVERTIBLE FOR SHARES OF THE COMPANY

For further information with regard to the buy back of debentures and debentures convertible for shared of the Company see Note 19 to the Consolidated Financial Statements. For further information concerning the covenants that the Company is required to comply with under the amended deed of trust for the debenture series, see Note 19 to the Consolidated Financial Statements.

NOTE 8 – INCOME TAX

A. Tax Laws that apply to the Company

The Income Tax Law (Inflationary Adjustments), 1985

According to the law, until 2007, the results for tax purposes are adjusted for the changes in the CPI.

In February 2008, the Knesset passed an amendment to the Income Tax (Inflationary Adjustments) Law, 1985, which limits the scope of the Adjustments Law from 2008 onwards. As from 2008, the results for tax purposes are measured at nominal values, with the exception of certain adjustments for changes in the Israeli CPI up to December 31, 2007.

B. Tax rates applicable to the Company

The corporate tax rate in Israel in 2020, 2019 and 2018 was 23%.
An association of individuals is taxed on real capital gain at the corporate tax rate in the year of the sale.

C. Losses carried over for tax purposes and other interim differences

The Company has carry-forward losses for tax purposes that amounted. as at December 31, 2020, to a total of NIS 3.3 billion (of which, NIS 1.5 billion are capital losses). No deferred tax assets were recognized for these losses, due to the uncertainty regarding future taxable income. The Company is conducting assessment discussions with the Tax Authorities for the 2015-2017 tax years. As the Company has not created deferred tax assets on the carry forward losses, the outcome of these discussions is not expected to have a material effect the financial information from the Consolidated Financial Statements attributed to the Company.

D. Tax assessments

The company has final tax assessments through to and including the 2014 tax year

NOTE 9 – CAPITAL

For further information concerning the dividends distributed by the Company in 2019 and changes in the Company's shares that are held by the Partnership in 2019 and 2020, see Note 26 to the Consolidated Financial Statements.

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Chapter D

Additional Information on the Corporation

Chapter D: Additional Information About the Corporation

Name of Company:	Delek Group Ltd.
Company number in the Register of Companies	52-004432-2
Date of Statement of Financial Position: (Regulation 9)	December 31, 2020
Date of periodic report:	March 30, 2021

Regulation 8B: **Valuation**

1. **Assessment of impairment of goodwill attributable to the Oil and Gas Development and Production in the North Sea cash-generating unit and assessment of impairment of oil and gas assets in the North Sea region**

As at December 31, 2020, the Group conducted a material valuation to assess the impairment of goodwill attributable to a cash-generating oil and gas development and production in the North Sea unit and impairment of oil and gas assets in the North Sea Region. The financial paper that includes the foregoing valuations is attached to the Group's financial statements.

Breakdown of the main points specified in this valuation:

Topic of the valuation:	Assessment of the recoverable amount of a cash generating unit to which the goodwill was attributed as aforesaid, ad assessment of the recoverable amount of the oil and gas assets in the North Sea Region.
Date of valuation:	December 31, 2020
The value of the evaluated item shortly prior to the valuation date, if GAAP, including depreciation and amortization, did not require its re-evaluation based on the valuation	N/A
Value of the evaluated item based on the evaluation:	The recoverable amount of the North Sea oil and gas development and production assets cash-generating unit to which the estimated goodwill was attributed was valued at USD 1,878 million. The recoverable amount of the oil and gas assets in the North Sea Region was valued at USD 2,755 million (NIS 8,858 million). Based on the foregoing valuation, in 2020 the Company cancelled the provision for impairment of assets that amounted to a profit attributable to the Company's shareholders (net of tax) in the amount of USD 271 million (NIS 871 million).
Identity and qualifications of the Valuator:	The PPA was carried out by Duff & Phelps, a global advisory firm that employs over 3,500 employees in 28 countries worldwide. The firm was founded in 1932, and provides advisory services to a large number of clients, including more than 50% of the companies on the S&P 500 list. The firm provides diverse advisory services, including, among others, valuation, tax services, and merger and acquisition consultation. The firm's valuation team consists of over 1,200 professional and financial advisors with expertise in PPA, assessment of impairment of goodwill and intangible asset, and valuation. Under the agreement with the Valuator, other than in the event of misconduct or fraud by the Valuator, its liability is limited to its fee.

	The Company has also undertaken to indemnify the Valuator for any damages it may incur as a result of a third party claim, with the exclusion of any case where a competent court rules that the claim is directly due to gross negligence, willful misconduct, or fraud by the Valuator.
Valuation model used by the Valuator:	Discounted cash flows
Key assumptions according to which the valuation was conducted, based on the valuation model:	The key underlying assumptions of the valuation include forecasts of revenues and expenses, taking into account, among other things, production rate and volumes, projected oil and gas prices, inflation rate and clearing costs. In determining the value, the valuator used the discounted cash flow method, taking into account a discount rate after tax of 9.75% and future Brent oil prices of USD 52 per barrel in 2021, USD 57 per barrel in 2022, reaching up to USD 65 per barrel in 2024.

2. <u>Assessment of the impairment of the Group's investments in oil and gas assets in the Tamar Leases</u>

As at December 31, 2020, the Group conducted a very material valuation to assess the impairment of the Group's investments in oil and gas assets in the Tamar Leases. The financial paper includes the foregoing valuation is attached to the Group's financial statements.

Breakdown of the main points specified in this valuation:

Topic of the valuation:	Assessment of the recoverable amount of the Tamar Project by reconciling the Group's expected net proceeds (less exercise costs) from the sale of the asset at the current market conditions.
Date of valuation:	December 31, 2020
The value of the evaluated item shortly prior to the valuation date, if GAAP, including depreciation and amortization, did not require its re-evaluation based on the valuation	N/A
Value of the evaluated item based on the evaluation:	The recoverable amount of the Tamar Project by reconciling the Group's expected net proceeds (less exercise costs) from the sale of the asset at the current market conditions, that amounts to USD 1,104 million (NIS 3,549 million). Based on the foregoing valuation, the Group included a provision for impairment of assets that amounted to a loss attributable to the Company's shareholders (net of tax) in the amount of USD 94 million.
Identity and qualifications of the Valuator:	The paper was prepared by GSE Financial Advisory Ltd., which is a subsidiary of Giza Singer Even Ltd. The team working on the paper was headed by CPI Eitan Cohen. For further information concerning the Valuator's experience see section 1.3 of the Valuation. There is no dependence between the Valuator and the Company. The agreement with the Valuator included reference to indemnification as set out in section 1.1 of the Valuation.
Valuation model used by the Valuator:	Discounted cash flows

Key assumptions according to which the valuation was conducted, based on the valuation model:	1) Volumes of natural gas sales of 8.6, 9.2, 9.1, 9.5 and 10.4 BCM in the years 2021 through 2025, respectively. A gradual increase to 11.65 BCM in 2030 and stabilization of this quantity until 2041. From 2042, a gradual decline in production quantities until exhaustion of the reservoir reserves. 2) Average Brent oil price forecast (in USD) of USD 52, USD 57, USD 61, USD 65, USD 68 and USD 71 per barrel in the years 2021 through 2026, respectively. A gradual increase up to a price of USD 86 in 2030 and stabilization at this price until the end of the forecast period. 3) Discounting of 20% that the Valuator believes reflects the difference between the above present value of the cash flows for the Group's expected net consideration (less disposal costs) from the sale of the asset under current market conditions' 4) Adjustment of depreciation expenses for tax purposes to be used by a potential buyer 5) Use of a weighted average cost of capital (WACC) (after tax) of 9.3%.

3. **Valuation of Delek Drilling's rights to receive royalties from Karish and Tanin Leases**

As at December 31, 2020, Delek Drilling conducted a material assessment to ascertain the value of its rights to receive royalties from Karish and Tanin Leases.

Breakdown of the main points specified in this valuation:

Topic of the valuation:	Delek Drilling's rights to receive royalties with respect to the sale of Karish and Tanin Leases
Date of valuation:	December 31, 2020
The value of the evaluated item shortly prior to the valuation date, if GAAP, including depreciation and amortization, did not require its re-evaluation based on the valuation	N/A
Value of the evaluated item based on the evaluation:	The value of these rights at December 31, 2020 was USD 242.2 million (NIS 779 million). The total profit derived for the Company's shareholders (net of tax) with respect to the value of the foregoing rights in 2020 amounted to NIS 117 million.
Identity and qualifications of the Valuator:	The valuation was conducted by GSE Financial Advisory Ltd. (a subsidiary of Giza Singer Even Ltd.), which is a leading financing and investment banking advisory firm in Israel. The firm has gained vast experience in serving large-scale companies, high profile privatizations and significant transactions in Israel, over thirty years of operation. Giza Singer Even operates in three sectors, through autonomous and independent business divisions: financial advisory; investment banking; and analytical and corporate governance research. The Report was prepared by a team headed by CPA Eitan Cohen, a partner OF Giza Singer Even and the head of its Economics Department, with more than ten years of experience in the economic and business consulting and in valuation of companies and financial instruments. Eitan is a Certified Public Accountant and holds a B.Com in Economics and Business Administration from Ben Gurion University and a master's in financial mathematics from Bar Ilan University. The Valuator has no personal interest in and/or dependence on the Partnership and the Group, other than the fact that it receives a fee for the valuations that it conducts for the Group. The Valuator also confirmed that its fee is not conditional on the results of the valuation. Furthermore, if the Valuator is required,

	under a final judgment, to pay any amount to a third party with respect to this paper, Delek Drilling will indemnify the Valuator for any amount that the Valuator is required to pay in excess of an amount equivalent to three times the fee paid to it. It is noted that the undertaking to indemnity will not apply if it is found that the Valuator acted with malicious intent or negligence in the preparation of its paper.
Valuation model used by the Valuator:	The discounted cash flow method, by adjusting discounting rates for the risks inherent in cash flow forecasts.
Key assumptions according to which the valuation was conducted, based on the valuation model:	Below are the key assumptions on which the valuation was based: 1. Gas production dates from the Karish Lease: April 1, 2022 through December 31, 2040 2. Average annual production rate from the Karish Lease is 3.91 BCM of natural gas; average annual production rate of condensate from the Karish Lease is 5 million barrels 3. Gas production dates from the Tanin reservoir: Jan 1, 2027 through Dec 31, 2036 4. Average annual production rate from the Tanin Lease is 2.51 BCM of natural gas; average annual production rate of condensate from the Tanin Lease is 0.44 million barrels 5. Royalties component discount rate: 12.0%; 6. Effective rate of royalties to be paid to the State for the gas and condensate: 11.5%; 7. Gas price formula: The base price in contracts according to which the Valuation was assessed was estimated using formula set out in the pricing mechanism between Energean and ICL and Bazan, and between Energean and OPC, and the weighted price of gas in the Ramat Hovav contract; 8. Price of condensate: The projected condensate price was estimated on the basis of the average long term oil price forecast of the World Bank1 and the EIA2, and the forward prices of Brent based on Bloomberg figures and the assumption that the price of condensate derives from the Brent price, with adjustments for differences in the quality of the oil; 9. On February 11, 2021, Energean published an updated resources report by D&M, a certified reserves and resources appraiser, with regard to the Karish and Tanin Leases. According to this report, the volume of gas in Karish Center is 40.2 BCM and the volume of hydrocarbon liquids is 65.1 MMBBL; in Karish North the volume of gas is 33.1 BCM and the volume of hydrocarbon liquids is 30.6 MMBBL; and the volume of gas in Tanin is 25.1 BCM and the volume of hydrocarbon liquids is 3.9 MMBBL. 10. Oil and gas profits levy: As per Petroleum Profits Tax Law, 2011 Rate of corporate tax: 23%, based on the statutory tax rate over the projected years.

[1] A World Bank Quarterly Report: Commodity Markets Outlook, October 2020

[2] U.S Energy Information Administration: Analysis & Projections, February 2021

<u>Regulation 9D</u>: **The Company's report on the state of liabilities, by repayment dates.**

Parallel to publication of this periodic report, the Company is publishing an immediate report regarding the state of the liabilities of the Company and its investees consolidated in its financial statements, by repayment dates, constituting an integral part of the periodic report.

<u>Regulation 10A</u>: **The Company's condensed statements of comprehensive income for each quarter**

See section 3 of Part I of Chapter B (Board of Directors Report on the Status of the Company's Affairs), which is attached to this Report.

<u>Regulation 10C</u>: **Use of proceeds for securities**

In May, August and December 2020, the Company issued ordinary shares, nominally listed, of the Company of NIS 1 par value each, for proceeds in a total amount of NIS 450 million (including proceeds deriving from the exercise of the Company's options for shares). The proceeds of the issue were used and will be used by the Company to repay Company debentures and to pay current expenses.

Regulation 11: **The Company's investments in each of its subsidiaries and material affiliates as at the date of the statements of income:**

Active companies held directly by the Company

Company	Security no. on the TASE	Type of security	Par value	No. of par value/participating unit held by the Group	Capital held (%)	% % in voting rights	Total investment at date of statements of income (NIS millions)	NIS price of securities on the TASE at date of statements of financial position	Balance of outstanding loans, debentures and capital notes (including interest receivable) in statements of financial position (NIS millions)
Delek Petroleum Ltd.	-	Ordinary shares	NIS 0.01	1,100	100	100	669	-	-
Delek Sea Maagan (2011) Ltd.	-	Ordinary shares	NIS 0.1	10,000	100	100	(1)	-	136
Delek Energy Systems Ltd.	565010	Ordinary shares	NIS 1	5,143,529	100	100	2,596	-	77
Delek Drilling – Limited Partnership (1)	475020	Participating units	-	59,477,005	5.06	5.06	408	3.88	-
Delek Financial Investments (2012) Limited Partnership (2)	-	-	-	1,000	100	100	19	-	-
Delek Power Stations Limited Partnership	-	-	-	-	100	100	(257)	-	254
DKL Investments Limited (3)	-	Ordinary shares	EUR 1	10,000	100	100	(866)	-	3,327
Delek Infrastructure Ltd. (4)	-	Ordinary shares	NIS 1	100	100	100	(36)	-	-

(1) Also held through a wholly owned company, Delek Energy Systems Ltd. ("Delek Energy").

(2) As at December 31, 2020 and close to date of publication of the Report, the Subsidiary Partnership holds 586,422 shares of the Company.

(3) As at December 31, 2020 and close to date of publication of the Report, it indirectly holds 100% of the shares of Ithaca Energy Limited. The capital notes include an amount of NIS 1,267 million provided to a 100% held subsidiary, DKL Investments Ltd.

(4) On March 26, 2020, the Company closed a transaction for the sale of all its holdings (20%) of IDE shares. For further information see section 1.2.2(A) above, in the Description of the Company's Businesses chapter.

Material companies held by the Company's subsidiaries (Delek Energy, DKL, Delek Petroleum)

Company name:	Security no. on the TASE	Type of security	Par value	No. of par value/participating units held by the Group	Capital held (%)	% in voting rights	Total investment at date of statements of income (NIS millions)	NIS price of securities on the TASE at date of statements of financial position	Loan balances (including interest receivable) in statements of financial position (NIS millions)
Delek Drilling – Limited Partnership (1)	475020	Participating units	-	576,521,467	49.12	49.12	3,119	3.88	-
Delek -The Israel Fuel Corporation Ltd. (2) (3)	-	Ordinary shares	NIS 1	3,404,592	30	30	307	-	1
Ithaca Energy Limited	-	Ordinary shares	USD 0.1	64,097,908,167	100	100	2,884	-	881
Delek GOM Holdings LLC (4)	-	Ordinary shares	USD 1	10,000	100	100	(238)	-	237
Delek Leviathan Overriding Royalty Ltd. (5)	-	Ordinary shares	NIS 1	1,001,000	100	100	(71)	-	-

(1) As at December 31, 2020, the holding is through Delek Energy.

(2) The holding is through a wholly owned company, Delek Petroleum Ltd. (“Delek Petroleum”). The remainder of the loan presented was provided directly by the Company to the IPP Delek Soreq Ltd. power station, which until February 22, 2021, was wholly owned by Delek The Israel Fuel Corporation Ltd. (“Delek Israel”). The loans were consolidated in the financial statements of Delek Israel.

(3) As at December 31, 2020, the Company held, through Delek Petroleum, 30% of the share capital of Delek Israel. Close to the date of publication of the Report, Delek Petroleum holds 2,837,160 shares of Delek Israel, constituting 25% of the share capital of Delek Israel. It is hereby clarified that based on the provisions of the Delek Israel sales agreement, additional shares from the share capital of Delek Israel were deposited in trust and will be transferred the Buyer against the payment of the balance of the consideration. For further information concerning the transaction for the sale of the Delek Israel holdings, see section 1.2.1(C) above in the Description of the Company's Businesses chapter.

(4) Held by DKL Investments Limited

(5) As at December 31, 2020, the holding is through Delek Energy.

<u>Regulation 12</u>: **Material changes in investments in subsidiaries, investees and affiliates in the reporting period:**

Date of change	Nature of the change	Company	Share no. on the TASE	Class of share	Total par value	Par value	Consideration
Mar 25, 2020	Acquisition (*)	Delek Drilling – Limited Partnership	475,020	Ordinary shares	83,768,194	NIS 1	USD 36 million
Mar 26, 2020	Sale	IDE Holdings Ltd.	-	Ordinary shares	260,455	NIS 0.01	NIS 164 million.
Apr 19, .2020	Sale	Cohen Development Oil and Gas Ltd.	810,010	Ordinary shares	3,406,165	NIS 1	NIS 207 million
Oct 26, 2020	Sale	Delek The Israel Fuel Corporation Ltd.	-	Ordinary shares	6,809,184	NIS 1	NIS 450 million.
Feb 14, 2021	Sale	Delek The Israel Fuel Corporation Ltd.	-	Ordinary shares	756,501	NIS 1	NIS 50 million.

(*) 142,341,547 Participating Units of Delek Drilling that were pledged in favor of Citi Bank NA London Branch were sold by it on March 14, 2020. 83,768,194 of these Participating Units were bought back by the Company on March 25, 2020.

<u>Regulation 13</u>: Comprehensive and net income of subsidiaries, investees and affiliates and the Company's revenues therefrom as of the date of the financial statements for the year ended December 31, 2020 (NIS millions).

Company name:	Net earnings (loss) for year		Annual comprehensive profit (loss)		Income received by the Company from:					
					Dividends		Interest		Management fees	
	Attributable to the Company's shareholders	Equity attributed to holders of minority rights	Attributable to the Company's shareholders	Equity attributed to holders of minority rights	Through Dec 31, 2020	From Jan 1, 2021 through date of publication of the report	Through Dec 31, 2020	From Jan 1, 2021 through date of publication of the report	Through Dec 31, 2020	From Jan 1, 2021 through date of publication of the report
Delek Energy Systems Ltd.	417	619	276	438	-	-	-	-	-	-
Delek Drilling – Limited Partnership	1,257	-	1,165	-	185	65	-	-	1.3	-
Delek -The Israel Fuel Corporation Ltd. (1)	(309)	-	(310)	-	194	-	-	-	0.2	-
IDE Holdings Ltd. (2)	10	-	(13)	-	165	-	-	-	0.3	-
Cohen Development Oil and Gas Ltd. (3)	(17)	-	(16)	-	9	-	-	-	0.5	-
Delek Leviathan Overriding Royalty Ltd. (4)	(2)	-	(2)	-	-	-	-	-	-	-
Ithaca Energy Limited	(1,383)	-	(1,324)	-	-	-	-	-	-	-
Delek GOM Holdings LLC	(10)	-	(7)	-	-	-	-	-	-	-

(1) On October 26, 2020, the Company completed the transaction for the sale of the majority of its holdings in Delek Israel. For further information concerning the transaction for the sale of the Delek Israel holdings, see section 1.2.1(C) above in the Description of the Company's Businesses chapter. The management fees presented were received from IPP Delek Soreq Ltd. and IPP Delek Ashkelon Ltd. (the "Power Stations") that were wholly owned by Delek Israel until February 22, 2021. For information concerning closing of the transaction for the sale of the Power Stations, see section 1.2.1(C) above in the Description of the Company's Businesses chapter.

(2) On March 26, 2020, the Company closed a transaction for the sale of all its holdings (20%) of IDE shares. For further information see section 1.2.2(A) above, in the Description of the Company's Businesses chapter. The figures presented are for a period of 3 months.

(3) On April 19, 2020, the sale of the Company’s entire holdings in Cohen Development Oil and Gas Ltd. Was closed. For further information see section 1.2.2(B) above, in the Description of the Company's Businesses chapter. The figures presented are for a period of 3 months.

(4) A wholly owned subsidiary of Delek Energy, which was secured by a lien on rights to receive overriding royalties from the Leviathan Project, for further information see section 1.7.22(B) above, in the Description of the Company's Businesses chapter.

Regulation 20: **Trading the Company's securities on the TASE, dates and reasons for interruption of trade**

Securities listed for trade:

- On August 6, 2020, 758,000 Options (Series 9), 379,000 Options (Series 10), 758,000 Options (Series 11), and 379,000 Options (Series 12) were listed for trading, which the Company had issued under a shelf prospectus and offering memorandum dated August 2, 2020.

- On May 19, 2020, 329,124 Options (Series 7), and 329,124 Options (Series 8) were listed for trading, which the Company had issued under a shelf prospectus and offering memorandum dated May 17, 2020.

Interruption of trade:

- On March 16, 2020, there was a limited interruption of trading of the Company's shares of 32 minutes due to extreme volatility of the index. Other than the forgoing interruption of trade, to the best of the Company's knowledge, in the Reporting Period there were no interruptions of trade of the Company's securities, other than the short interruptions for publication of the financial statements and announcements of the Company.

Regulation 21: **Payments made to senior officers (NIS thousands)**

21A(1): Below is a breakdown of the benefits given in 2020 to each of the five recipients of the highest benefits among the executive officers at the Company or companies under its control, and which were given to them in lieu of their position in the Company or companies under its control, as recognized in the financial statements (the figures hereunder represent the cost to the employer):

Recipient				Benefits in lieu of services					
Name	**Position**	**Employment basis**	**Rate of holding in equity of the Company**	**Wages**	**Management fees**	**Bonus**	**Share-based payment**	**Other***	**Total**
Yossi Abu (1)	CEO of Delek Drilling Partnership	Full-time	-	2,351	-	2,169	2,223	330	7,073
Graham Forbes (2)	Served as CFO of Ithaca Energy Ltd. until February 28, 2021	Full-time	-	1,358	-	1,323	-	1,545	4,225
Les Thomson (3)	Served as CEO of Ithaca Energy Ltd. until September 24, 2020	Full-time	-	1,761	-	1,714	-	530	4,005
Idan Wallace (4)	CEO of the Company	Full-time	-	2,489	-	600 (*)	-	395	3,484
Richard Smith (5)	Served as Corporate Development Manager of Ithaca Energy Ltd. until January 31, 2021	Full-time	-	1,081	-	1,103	-	1,161	3,345

21[A](2): Below is a breakdown of the benefits paid in 2020 to each of the Company's three senior officers who are not among those appearing in the foregoing table, and the royalties awarded them with respect to their tenure at the Company, as recognized in the financial statements:

Recipient				Benefits in lieu of services					Total
Name	Position	Employment basis	Rate of holding in equity of the company	Wages	Directors' remuneration	Bonus (*)	Share-based payment	Other	
Barak Mashraki (6)	Served as Deputy CEO and CFO of the Company until August 31, 2020, and continued to serve as Deputy CEO until October 31, 2020	Full-time	-	1,609		400		925	2,934
Gabi Last (7)	Chairman of the Board of Directors	Full-time	0.04%	2,016		500		311	2,827
Leora Pratt Levin (8)	Executive VP, Chief Legal Counsel, Company Secretary	Full-time	0.01%	1,573		600		205	2,378

(*) Paid subsequent to the balance sheet date

21[A](3): Breakdown of the remuneration paid in 2020 to each of the Company's interested parties, who are not represented in the foregoing table, with respect to their office in the Company and in its investees, in NIS thousands:

Recipient				Benefits in lieu of services								Other Benefits	Total
Name	Position	Employment basis	Rate of holding in equity of the company	Wages	Bonus	Share-based payment	Management fees	Consultancy fees	Commission	Other	Directors remuneration		
Yitzchak Sharon Tshuva (9)	Director and controlling shareholder of the Company	-	-	-	-	-	-	-	-	242 (reimbursement of expenses)	-	-	242
Carmit Sharon Elroi (10)	Director (also serves as director of Delek Israel)	-	-	-	-	-	-	-	-	-	306	-	306
Regular directors (11)	-	-	-	-	-	-	-	-	-	-	484	-	484
Independent director (12)	-	-	-	-	-	-	-	-	-	-	325	-	325
Directors – External Directors (13)	-	-	-	-	-	-	-	-	-	-	833	-	833

<u>Notes on the figures represented in the tables:</u>

(1) **<u>Mr. Yossi Abu</u>** - serves as CEO of Delek Drilling Management (1993) Ltd. ("Delek Management" or the "General Partner"), in full time (100%) position since April 1, 2011. During the period from July 3, 2018 through March 14, 2020, Yossi Abu served in his current position as CEO of the General Partner in a part time (80%) position (instead of 100%), and simultaneously served as CEO of Delek Energy in a part time (20%) position.

The terms of Yossi Abu's former office and employment were set in an employment contract of June 2016, the terms of which were approved by the competent organs of Delek Drilling Limited Partnership (the "2016 Agreement"). On July 10, 2019, the general meeting of the holders of participating units approved the revised terms of Yossi Abu's office and employment, as of May 1, 2019 through April 30, 2024, in accordance with the Partnership's compensations policy (the "2019 Terms"). Thus, the terms and conditions of Yossi Abu's term in office and employment are as follows: Yossi Abu's monthly salary is NIS 160 thousand gross (100%) (the salary is revised every three months in accordance with the CPI). Yossi Abu is eligible for the customary ancillary benefits for managers on the market, including provisions for pension fund and/or officers insurance; provisions for a study fund; disability insurance; company car (the value in use of the car is included and paid by the employer); communications costs (mobile phone, internet, newspapers, etc.); participation in advanced supplementary professional training; annual leave (including the right for pay in lieu of leave); convalescence pay; duly permitted sick leave; health insurance; severance compensation (as of the date of the 2016 Agreement, Yossi Abu is signed on Section 14 of the Severance Pay Law, 1963, and consequently the severance compensation that he is entitled to receive as of this date is in accordance with this law); reimbursement of per diem expenses from the General Partner that were incurred as part of and for the purpose of fulfilling his role in the General Partner, including for overseas travel expenses, all in accordance with the compensation policies of the Partnership, as revised from time to time. Yossi Abu is also covered under the insurance arrangements and is entitled to officers' indemnification and exemption. Yossi Abu is eligible for an annual bonus for each calendar year throughout the term of the employment agreement and a one-time special bonus in accordance with the compensation policies as revised from time to time. In the event of the termination of his employment, Yossi Abu will be eligible for an adjustment grant and retirement bonus, in accordance with the current compensation policy.

Under the 2016 Agreement, the General Partner awarded Yossi Abu 2,959,860 phantom units (the underlying asset of which are participation units conferring participation rights in the limited partner's interests in the Partnership, subject to the adjustments set out in the 2016 agreement) (the "Original Phantom Units"). As at the present, all the Original Phantom Units have vested and are exercisable through to the end of 90 days following the termination of Yossi Abu's employment under the 2016 Agreement (i.e., on June 30, 2021). The exercise price of the Original Phantom Units issued by the General Partner (below in this section: "Delek Options") is NIS 11.33 for the first tranche; the exercise price of the Original Phantom Units issued by the general partner of Avner Partnership (below in this section: "Avner Options") is NIS 10,55 for the first tranche (based on the adjustment mechanism fixed in the Employment Agreement), and all with increments of 5% per tranche from the first tranche.

According to the valuation that the General Partner received, the financial value of the Original Phantom Units at December 31, 2020 amounted to NIS 340 thousand (calculated according to the nominal model).

In addition, the General Partner awarded Yossi Abu, under the 2019 Terms, 2,742,231 phantom units (the underlying asset of which are participation units conferring participating rights in the Limited Partner's interests in Partnership (below in this section: (the "Revised Phantom Units"). the Revised Phantom Units will vest (the General Partner may, subject to the approval of the Remunerations Committee and the Board of Directors, to approve accelerated vesting in accordance with the terms and conditions set for this purpose in the Compensations Policy) in three tranches, such that the first tranche will vest on June 1, 2020, the second tranche will vest on June 1, 2021 and the third tranche will vest on June 1, 2022 Each tranche included in the total package will be exercisable as from the vesting date for that tranche and up to the end of one year from the vesting date of the third tranche (i.e. until June 1, 2023). The exercise price of the Revised Phantom Units is NIS 10.79 for the first tranche; NIS 11.33 for the second tranche; and NIS 11.89 for the third tranche. According to the valuation that the General Partner received, the financial value of the Revised Phantom Units at December 31, 2020 amounted to NIS 1.1 million (calculated using the Binomial model).

In 2020, Yossi Abu received an annual bonus in the amount of NIS 2,169 thousand for 2019.

(2) **<u>Mr. Graham Forbes</u>** - served as CFO of Ithaca Energy Limited (below: "Ithaca") until day February 28, 2021, under an employment agreement dated March 8, 2010 as updated from time to time. In addition to his office as CFO, Graham Forbes also served as a director of Ithaca and of its subsidiaries, and as a director of foreign companies belonging to the controlling shareholders of Ithaca. Graham Forbes' annual salary was GBP 307 thousand. Graham Forbes was eligible for an annual bonus in accordance with the company's policies. In 2020, he received a bonus in the amount of NIS 1,323 thousand and additional remuneration upon resigning, in the amount of NIS 1,545 thousand. Graham Forbes was eligible to receive ancillary terms such as insurances and reimbursement of expenses, in accordance with the customary terms for managers at Ithaca.

(3) **<u>Mr. Les Thomas</u>** - served as CEO of Ithaca until September 24, 2020 under an employment contract dated August 7, 2013, as revised from time to time. Les Thomas also served as a director of Ithaca and of its subsidiaries, and of foreign companies belonging to the controlling shareholders of Ithaca. Les Thomas' annual salary was GBP 399 thousand. Les Thomas was eligible for a bonus based on the discretion of the company's board of directors. He was also eligible to receive ancillary terms such as insurances and reimbursement of expenses, in accordance with the customary terms for managers at Ithaca. In 2020 Les Thomas received an annual bonus of NIS 1,714 thousand. In September 2020, Les Thomas resigned from all his positions and upon his resignation he received a bonus of NIS 530 thousand.

(4) **<u>Mr. Idan Wallace</u>** - serves as CEO of the Company since January 1, 2020. Idan Wallace served as Deputy CEO of the Company since August 2015. Prior to his appointment as Deputy CEO of the Company, Idan Wallace served in 2015 as a director of the Company and from 2010 through 2015, he served as an advisor. Under the employment contract between Idan Wallace and the Company, dated January 1, 2020, as approved by the competent organs of the Company, Idan Wallace serves as CEO in a full-time position. Under the contract, his employment is for an unlimited term commencing January 1, 2020. Either party may terminate the employment at any time with 6 months' prior written notice. In any event of termination of his employment, the CEO will be eligible for an adjustment bonus equivalent to 6 monthly salaries (gross). The Company may waive his employment for the prior notice period and terminate the relationship immediately, provided that it pays the CEO the full compensation he would have received for the prior notice period. The CEO's gross monthly salary is NIS 160 thousand. The base salary is linked (upwards only) to the CPI for December 2019, and will be revised accordingly, once every three months. The CEO is eligible to receive social benefits, perks and ancillary terms to his salary, as customary for managers in the Company and its investees, and in accordance with the Compensations Policy, including provisions for officers' insurance and/or pension fund, provisions for a study fund; company car (inclusion of full tax) and all expenses involved in its use; communications costs (mobile phone, internet, newspapers); annual leave, convalescence pay; letters of exemption and undertaking of indemnification as is customary in the Company, and to be covered by the officers' insurance as customary in the Company. He is also eligible to receive reimbursement of expenses incurred as part of and for the purpose of fulfilling his role, including per diem expenses (as well as overseas travel expenses). He is also eligible to receive an annual bonus that will be fixed each year based on measurable indices, in accordance with the provisions of the Compensations Policy. Subsequent to balance sheet date, in February 2021, Idan Wallace received a bonus in the amount of NIS 600 thousand for 2019.

(5) **<u>Mr. Richard Smith</u>** - served as Corporate Development Manager of Ithaca until January 31, 2021, under an employment contract dated August 17, 2010, as revised from time to time. Les Thomas' annual salary was GBP 245 thousand. Richard Smith was eligible to receive ancillary terms such as insurances and reimbursement of expenses, in accordance with the customary terms for managers at Ithaca. In 2020, he received a bonus in the amount of NIS 1,103 thousand and upon his resignation, he received remuneration in the amount of NIS 1,161 thousand.

(6) **<u>Mr. Barak Mashraki</u>** – served as CFO of the Company until August 31, 2020, and as Deputy CEO until October 31, 2020, under a personal employment contract with the Company dated July 16, 2006, as revised from time to time. As of March 1, 2019, Barak Mashraki's monthly salary in the amount of NIS 120 thousand. Barak Mashraki was also eligible for an annual bonus based on the mechanism set out in the Company's compensations policy as described in sub-section 14 below, and convalescent pay, annual leave, sick leave, provisions for pension savings and study fund, subscription to a daily newspaper, mobile phone and company car as customary for an executive VP of the Company. On October 31, 2020 Barak Mashraki's employment relationship ended and he received a special retirement bonus equivalent to 6 monthly salaries, that also included payment for prior notice. He also received payment in lieu of accrued leave and convalescence pay. Furthermore, as part of the terms of termination of his employment, at the beginning of 2021 Barak Mashraki received a bonus in the amount of NIS 400 thousand for 2019.

It should be noted that Barak Mashraki holds an interest of 12.3% in Delek Royalty US llc, a subsidiary in which the Company holds 20% of its share capital, ("Delek Royalty"). Delek Royalty's main business is investing in the acquisition of royalty rights in oil and gas projects in the United States. To date, no investments have yet been made. The Company's engagement with Barak Mashraki was approved by the Board of Directors on October 10, 2010, after it was approved by the Audit Committee in its seat as Compensations Committee, on the same date.

(7) **Mr. Gabi Last** – serves as active Chairman of the Board of Directors of the Company under an employment agreement that was approved by the Company on August 30, 2001. Gabi Last has served as Chairman of the Company's Board of Directors since September 4, 2003. His monthly salary under the contract is revised from time to time and amounts to NIS 121 thousand. The salary is linked to the CPI. Gabi Last is eligible for an annual bonus in accordance with the Company's compensations policy, as set out in subsection 14 below.

Apart from the foregoing, Gabi Last is entitled to convalescent pay, annual vacation days, sick leave, provisions to an in-service study fund, reimbursement of job-related expenses, a mobile phone and costs incurred in connection therewith, reimbursement of expenses for a landline, and a company car provided by the Company, as well as maintenance and operating costs. Under the contract, each party may terminate the agreement with three months' advance notice to the other party. The Company may waive employment during the advance notice period and pay a salary for this period. In the event of termination of employment by the Company, Gabi Last is entitled to an acclimation bonus in the amount of six monthly salaries. Under special circumstances, the Company is granted the option of terminating the agreement immediately, without giving an acclimation bonus. In 2021, Gabi Last received a bonus in the amount of NIS 500 thousand for 2019 in accordance with the Company's previous compensations policy as effective during 2019, as set out in subsection (14) below.

(8) **Ms. Leora Pratt Levin** - serves as Executive VP, Chief Legal Counsel and Company Secretary of the Company since 2007. Under Leora Pratt Levin's employment contract, she is eligible for a monthly salary linked to the consumer price index. Leora Pratt Levin's monthly salary was adjusted over the years and as at March 2021, her salary amounts to NIS 90 thousand. Leora Pratt Levin is also eligible for an annual bonus based on the mechanism set out in the Company's compensations policy as described in sub-section 14 below. She is also entitled to insurance under the Company's officers insurance policy, exemption of liability and indemnification arrangements as customary in the Company, as well as vacation pay, annual leave, sick leave, provisions for pension savings and study fund, mobile phone and company car as generally accepted for an executive VP of the Company. The Company bears all expenses incurred for the maintenance of the car. The employment contract also includes Leora Pratt Levin's undertaking to maintain confidentiality and a non-competition clause during her employment at the Company and for three months after termination of her employment at the Company. In 2021, Leora Pratt Levin received a bonus in the amount of NIS 600 thousand for 2019 in accordance with the Company's compensation policy that was in force during 2019, as set out in subsection 14 below.

Loans: under loan agreements of June 2005 and December 2007, Leora Pratt Levin received in 2006 and 2007, respectively, loans in a total amount of NIS 1,032 thousand for acquiring securities of the Company and of its investees. These loans are linked to the CPI and bear annual interest of 4%. Under the loan agreement, the securities acquired with the loan moneys, were deposited as security for repayment of the loans. Leora Pratt Levin is entitled to sell the collateral provided that the proceeds for the sale will be transferred to the Company to repay the balance of the non-recourse loan. The loan repayment date was extended a few times over the years. The value of the loan principal as at December 31, 2020 is NIS 2.3 million.

(9) **Mr. Yitzchak Sharon Tshuva** - director and controlling shareholder of the Company, for further information concerning reimbursement of expenses paid to the controlling shareholder, see section 1A to Regulation 22 below.

(10) **Ms. Carmit Sharon Elroi** - director of the Company and daughter of the controlling shareholder of the Company. For further information regarding remunerations paid to Carmit Elroi from the Company and from Delek Israel, see section 2A to Regulation 22, below.

(11) **Regular directors**

Mr. Avi Harel - served as a director of the Company until June 30, 2020. Avi Harel served as a director with accounting and financial expertise and received the remuneration for an external director with accounting and financial expertise as provided in the Fourth Schedule to the Remunerations Regulations, as these may be updated from time to time, based on the classification of the Company for each fiscal year. The total remuneration paid to Avi Harel in 2020 through to the termination of his term in office, amounted to NIS 393 thousand (excluding VAT).

Mr. Udi Erez - is a director of the Company as of July 1, 2020, with accounting and financial expertise. He is eligible to receive expert remuneration at the maximum amounts for expert external directors as appears in the Fourth Schedule of the Remunerations Regulations. The total remuneration paid to Udi Erez in 2020 amounts to NIS 91 thousand (excluding VAT).

(12) Independent director

Mr. Roni Milo - serves an independent director, is eligible to receive annual remuneration and participation remuneration in amounts equivalent to the amounts fixed in the Second and Third Schedule of the Remuneration Regulations**.** Total remuneration paid to Roni Milo in 2020 amounts to NIS 325 thousand (excluding VAT).

(13) External directors

Ms. Judith Teitelman Zeidenberg - served as an external director with accounting and financial expertise until June 30, 2020. She was eligible for the expert remuneration, according to the maximum amount for an expert external director as provided in the Fourth Addendum to the Remunerations Regulations. The total remuneration paid to Judith Teitelman in 2020 through to the termination of her term in office, amounted to NIS 410 thousand (excluding VAT).

Mr. Shimon Doron - serves as an external director. He is eligible to receive an annual remuneration and participation remuneration in amounts equivalent to the maximum amount fixed in the Second and Third Schedules to the Remuneration Regulations. The total remuneration paid to Shimon Doron in 2020 amounts to NIS 384 thousand (excluding VAT).

Ms. Ruth Dahan Portnoy - serves as an external director of the Company since August 25, 2020. She has accounting and financial expertise, is eligible for the expert remuneration, according to the maximum amount for an expert external director as provided in the Fourth Addendum to the Remunerations Regulations. The total remuneration paid to Ms. Portnoy in 2020 amounts to NIS 39 thousand (excluding VAT).

(14) Adjustments in the Compensations Policy

Pursuant to the requirements of Amendment 20 to the Companies Law, 1999, the Company instituted a compensation policy for the Company's officers. On February 1, 2021, the general meeting of the Company approved a revised Compensations Policy.[3]

The Compensations Policy that was effective with regard to bonuses paid to officers of the Company for 2019 was the Compensations Policy approved on April 2, 2017 by the general meeting of the Company (the “Previous Compensations Policy”). Under the Previous Compensations Policy, among other things, a mechanism was set for a variable cash bonus component ("the Bonus"). The Bonus, is made up of three components, which reflect the Company's long-term goals to maximize value for its shareholders while maintaining prudent risk management, particularly in view the Company's unique and complex holdings structure:

1. Change in adjusted net income - the rate arrived at by dividing the adjusted net income in the year for which the bonus is paid by the adjusted net income of the Company in the three years preceding the year for which the bonus is paid. A prerequisite for bonus eligibility regarding this parameter is achievement of adjusted income that does not fall below NIS 250 million. The change in adjusted net income component awards a bonus ranges between 80% to 120%. Eligibility is calculated on a linear basis.

2. Change regarding adjusted leverage - to be calculated by dividing the adjusted leverage ratio of the Company and its wholly owned subsidiaries in the year for which the bonus is paid by the average adjusted leverage ratio in the three years preceding the year for which the bonus is paid. A prerequisite for bonus eligibility regarding this parameter is that the leverage ratio that will not exceed 65%. The change in the adjusted net income for which a bonus is awarded ranges between 110% - 100% (this is a reverse index, i.e., 100% awards the maximum bonus). Eligibility is calculated on a linear basis. The adjusted leverage ratio is calculated by dividing the net financial debt of the

[3] For further information concerning the amendment to the Company’s revised Compensations Policy, see the immediate reports issued by the Company on December 24, 2020 (Ref. No: 2020-01-139893), January 25, 2021, (Ref. No.: 2021-01-010980), and February 1, 2021, (Ref. No.: 2021-01-013030)

Company and its wholly-owned subsidiaries less the treasury shares item (net financial debt as appears in the chapter on financing sources and liquidity in the directors' report) by the Company's equity less treasury shares as appeared in the annual financial statements.

3. Scope of annual dividends - the scope of the annual dividends for which a bonus is awarded ranges between NIS 200 million and NIS 400 million. Eligibility is calculated on a linear basis.

Breakdown of the calculation for the foregoing financial indices used for fixing bonuses for 2019 - based on the Previous Compensations Policy:

Performance Index 1 - Adjusted Net Profit:

Breakdown of adjusted net profit in 2016 through 2019:

	2019	2018	2017	2016
	NIS millions			
Net profit (loss) attributed to Company shareholders	234	517	1,216	625
Plus (minus):				
Revaluation losses (revaluation gains) due to increase and/or decrease in means of control (net of tax) attributable to the Company's shareholders	-	(82)	(659)	-
Other amortization (other revaluation gains) for non-financial assets directly held by the Company and its wholly-owned subsidiaries, which do not involve cash flow input or output (net of tax), attributable to the Company's shareholders	163	510	32	270
Amortization of surplus costs (net of tax) attributable to the Company's shareholders due to foregoing revaluation and less the increase in value recognized as a result of such revaluation	(120)	74	66	(84)
Profit (loss) from disposal of non-financial assets directly held by the Company and its wholly owned subsidiaries, attributed to capital reserves (net of tax)	(97)	(23)	(93)	-
Adjustments made in the preceding periods for non-financial assets that were held directly by the Company and its wholly-owned subsidiaries and which were disposed of during the year, until date of disposal of the asset, based on the pro rata share of the disposed holding during the year	(76)	(109)	332	(232)
Adjusted net income	104	887	894	579

Criteria used to calculate the adjusted net income:

The adjusted net income is calculated in accordance with the definitions in Appendix A to the Company's Previous Compensations Policy for officers, taking the following into account (with respect to 2019):

1. With the deduction of revaluation gains or addition of revaluation losses due to increase and/or decrease in means of control (net of tax) attributable to the Company's shareholders
2. With the deduction of other revaluation gains or the addition of other amortization for non-financial assets directly held by the Company and its wholly-owned subsidiaries, which do not involve cash flow input or output (net of tax), attributable to the Company's shareholders
3. With the addition of amortization of surplus costs (net of tax) attributable to the Company's shareholders due to foregoing revaluation and deducting the increase in value recognized as a result of such revaluation.
4. With the addition of profit or the deduction of loss from disposal of non-financial assets directly held by the Company and its wholly owned subsidiaries, attributed to capital reserves (net of tax)

5. With the addition of adjustments made in the preceding periods for non-financial assets that were held directly by the Company and its wholly-owned subsidiaries and which were disposed of during the year, until date of disposal of the asset, based on the pro rata share of the disposed holding during the year

Upon occurrence of a future event that will cause the recording of accounting gains or losses in a specific year that is not backed by incoming or outgoing cash flows (net of tax) and that is not included under the foregoing adjustments (such as due to changes in the accounting standard or due to another event that was not anticipated at the time the policy was formulated), but according to the best estimate of the Compensations Committee, will require additional adjustment of the adjusted net income, the Compensations Committee has the authority (subject to approval by the Board of Directors) to implement additional adjustments for the purpose of calculating the adjusted net income.

Changes in adjusted net income	
The adjusted net income of the Company in the year for which the bonus is to be paid (NIS millions)	104
Average adjusted net income of the Company in the three years preceding 2019	787
Changes in adjusted net income	13%

In view of the foregoing, nobody is eligible for a bonus for this index.

Performance Index 2 - Adjusted Leverage Ratio:

Breakdown of the changes in the adjusted leverage ratio (NIS millions):

Changes in the adjusted leverage ratio				
Adjusted leverage ratio A = (as set out in the compensations policy)	**2019**	**2018**	**2017**	**2016**
Net financial debt of wholly-owned subsidiaries as in Chapter 5 of the Company's directors' report	5,915	6,041	6,047	4,420
Dividend payable	-	-	-	-
Less value of treasury shares as in Chapter 5 of the Company's directors' report	(237)	(130)	(408)	(524)
Net financial debt less treasury shares	6,152	6,171	6,455	4,944
Equity less treasury shares = B				
Equity of the Company	4,133	4,965	4,255	4,612
Less treasury shares As per the separate financial information (Regulation 9C of the Securities Regulations)	254	143	469	433
Equity less treasury shares	4,387	5,108	4,724	5,045
Adjusted leverage ratio = A/(A+B)	58%	55%	58%	49%
Changes in the adjusted leverage ratio				
Adjusted leverage ratio in the year for which the bonus is paid	58%	-	-	-
Average adjusted leverage ratio in the three years preceding the year for which bonus is paid	54%	-	-	-
Changes in the adjusted leverage ratio	108.13%	-	-	-

Criteria used to calculate the adjusted leverage ratio:

The adjusted leverage ratio is calculated in accordance with the definitions in Appendix A to the Company's officers' compensation policy dated April 2, 2017, taking into account that the financial liabilities does not include amounts paid for an announced dividend that was not yet paid at balance sheet date.

In view of the foregoing, eligibility for a bonus for this index: the Chairman of the Board - NIS 37 thousand and the CEO - NIS 93 thousand.

In addition, the Board of Directors confirm that the auditors provided an unqualified opinion without calling attention to any issues, according to which the adjusted net profit figures for the year ended December 31, 2019 and the adjusted leverage ratio as at December 31, 2019 are adequately presented, from all material aspects.

Performance Index 3 - Scope of Annual Dividends

In 2019, dividends totaling an amount of NIS 260 million were distributed and therefore, eligibility for a bonus with respect to this index is as follows: the Chairman of the Board of Directors is eligible for a bonus of up to NIS 110 thousand, the CEO is eligible for up to NIS 275 thousand, and executive officers are eligible for up to 2 salaries.

(15) Waiver, Indemnification and Insurance for Officers

For information regarding waiver, indemnification and officers' insurance see Regulation 29[A](4) below.

Regulation 21A: Control of the Company:

The controlling shareholder of the Company is Mr. Yitzhak Sharon (Tshuva), who holds 48.64% of the equity and 50.34% of the voting rights in the Company and 46.72% of the equity, fully diluted, and 48.21% of the voting rights in the Company, fully diluted.

Regulation 22: Transactions with a controlling shareholder

The controlling shareholder who has a personal interest in all the engagements set forth under Regulation 22 below is Yitzhak Sharon (Teshuva). The personal interest of Yitzhak Sharon (Teshuva) arises from the fact that these engagements are with companies under his control, or with his relatives or with companies under their control.

A. Transactions stipulated in section 270(4) of the Companies Law

1. Engagement with Yitzhak Sharon Tshuva:

The controlling shareholder of the Company, who serves as a director in the Company, contributes his time, experience and vast expertise to advancing the businesses and interests of the Company and its subsidiaries in Israel and abroad, as requested by the Company's management. Yitzhak Tshuva does not receive any directors' fees for his position as director. On February 28, 2018, the general meeting of the Company approved a mechanism for the reimbursement of expenses incurred by Yitzhak Tshuva, for a period of three years from January 1, 2018 through December 31, 2020, under which the Company will reimburse expenses that were and will be incurred by Yitzhak Tshuva with regard to the foregoing consultation services, all against presentation of invoices as required by law.

The foregoing reimbursement mechanism includes an exhaustive list of the types of expenses permitted and does not include a fixed maximum amount of the expenditure. The expenses will be reviewed according to nature, and accepted control and supervision mechanisms will be set up for reviewing the necessity of the reimbursed expenses.

In 2021, the Company incurred an amount of NIS 242 thousand for reimbursement of expenses incurred in 2019-2020.

For further information, see immediate reports issued by the Company on January 19, 2018 (Ref. No. 2018-01-007372) and February 28, 2018 (Ref. No: 2018-01-020104) The information appearing therein is noted here by way of reference.

On March 22, 2021, the Company's Compensations Committee approved the extension of the mechanism for the reimbursement of expenses incurred by Yitzhak Tshuva, for a further period of three years from January 1, 2021 through December 31, 2023, subject to the approval of the Company's Board of Directors and general meeting.

2. Engagement with Ms. Carmit Sharon Elroi

A) On November 28, 2012, the Company's audit committee and board of directors approved the remuneration for Carmit Elroi, daughter of the controlling shareholder, for her service as a director of the Company. Under the terms of the agreement with her, Carmit Elroi is eligible to receive annual remuneration and participation remuneration in amounts equivalent to the amount fixed in the Second Addendum and Third Addendum of the Remunerations Regulations, as updated from time to time as per the Company's classification for each fiscal year.

The Company's audit committee and Board of Directors confirm that the approval of the engagement with Carmit Elroi is in compliance with the conditions of Regulation 1B (3) of the Relief Regulations, as the fee paid to her does not exceed the maximum amount permitted under Regulations 4, 5 and 7 of the Remunerations Regulations. Carmit Elroi has served as a director of the Company since November 28, 2012. The total amount paid to Carmit Elroi by the Company for 2020 is NIS 206 thousand (excluding VAT). The Company's compensation committee and board of directors also approve engaging with The Phoenix in a collective officers liability insurance policy for Carmit Elroi, pursuant to the provisions of Regulation 1B(5) of the Relief Regulations.

B) On February 21, 2011 the general meeting of Delek The Israel Fuel Corporation Ltd. ("Delek Israel") approved the agreement with Carmit Elroi regarding the terms of her term in office as a director of Delek Israel. Pursuant to the terms of the agreement, Carmit Elroi will be entitled to annual and participation remuneration in amounts equivalent to the amount fixed in the remuneration regulation, in accordance with the Company's classification for each fiscal year. Moreover, on January 29, 2012 the general meeting of Delek Israel resolved to approve providing a letter of undertaking for indemnity Carmit Elroi. The total amount paid to Carmit Elroi by the Delek Israel for 2020 is NIS 100 thousand (excluding VAT). Carmit Elroi also serves as a member of the board of directors audit committee of Delek Israel.

C) Moreover, Carmit Elroi also serves as a director of Delek Foundation for Education, Culture and Science Ltd. (external director), and does not receive remuneration.

3. <u>Engagements with Ms. Keren Eldar and Mr. Uri Eldar</u>

Keren Eldar, the daughter of the controlling shareholder of the Company, serves as a director of Delek Foundation for Education, Culture and Science Ltd. (external director), and does not receive remuneration.

4. <u>Engagement with Ronen Yafo</u>

On November 28, 2016, following approval by the audit committee, the Company's Audit Committee and Board of Directors approved the Company's engagement with Alter Yafo Ltd. through its CEO, Ronen Yafo (the “Manager”) pursuant to Regulation 1(5) of the Companies Regulations (Relief for Transactions with Interested Parties), 2000 ("the Relief Regulations"). On October 10, 2018 the Board of Directors of the Company approved an extension of the engagement in accordance with Regulation 1(5) of the Relief Regulations, for a further term of 24 months commencing September 1, 2018. The Manager's primary business is serving as the CEO of a private company owned by the controlling shareholder of the Company that engages in private construction and in real estate ventures. Under the terms of the engagement, the Company received consultation services concerning real estate from the Manager, on issues related to the initiation, supervision and management of real estate properties held by the Company and its subsidiaries. On June 30, 2020, the engagement between Ronen Yafo and the Company terminated.

For further information see the immediate reports issued by the Company on December 15, 2016 (Ref. No: 2016-01-139648), and October 10, 2018, (Ref. No.: 2018-01-095367), whereby the information appearing in said reports are noted here by way of reference.

B. <u>Transactions not specified in section 270 (4) of the Companies Law.</u>

1. <u>Rental of offices</u>

As of September 2016, the Company’s head offices are located in a building owned by the Company in Herzliya. For further information see section 1.10.1(A) to the Report (the “Offices”). The controlling shareholder and private companies under his control rent office space in the Offices.

On December 18, 2016 the Company’s audit committee approved the engagement in a lease agreement to rent offices to a private company controlled by the Company (the “Lessee”), at market terms, based on an opinion estimated by an independent real estate valuation firm for determining the basis for appropriate rental for the rented space. The term of the lease is from September 19, 2016 through September 18, 2021 and includes an option to extend for a further two terms, ending on September 18, 2031. The monthly rental fee is based on the size of the leased offices and on the proportionate size of the public spaces. According to the above, the rental fee per sq.m paid by the Lessee is between NIS 80-85 (depending on which floor) and NIS 40 per sq.m. for a storeroom. The rental is linked to the CPI. In addition, the Lessee pays a monthly management fee for the office and public spaces of NIS 15 per sq.m. and NIS 7.5 per sq.m. for the storeroom, and an additional monthly payment for the rental of parking spaces of between NIS 500-700 per parking space. In 2020, the Lessee was charged an amount of NIS 516 thousand (before VAT) for rental and management fees for 2020. It is noted that, pursuant to a resolution adopted by the general meeting concerning the reimbursement of expenses to the controlling shareholder, as set out in section A1 of Regulation 22 above, the Company provides the controlling shareholder with office space, which is not included in the calculation of the leased space. In addition, accounts are also settled between the Company and the Lessee regarding ongoing expenses involved in maintaining the offices, such as municipal taxes, electricity, office cleaning, refreshments, etc.

2. Negligible transactions:

Apart from the transactions described above, there are additional agreements that were in effect during the reporting year and which are classified as negligible transactions as defined in section 9 of the Board of Directors report, as follows: Transactions for providing Delek Israel's Dalkan services; payments with regard to Delek Israel information systems; the engagement between Delek Israel and a company that in 2020 was wholly owned by the controlling shareholder regarding rental of property used as a parking lot and shade structures for drying cars at a car wash, adjacent to the Doron Kfar Saba gas station; the employment of officers of the Company who provided services to private companies owned by the controlling shareholder of the Company;

Regulation 24: Shares and other securities held by interested parties and executive officers of the Company, in the Company itself, in its subsidiaries and its related companies, as at December 31, 2020

For information regarding the holdings of the Company's shares and debentures by its interested parties and executive officers, and for the holdings of interested parties in the shares or other securities of the Company's material investees, see the Company's immediate report regarding the status of the holdings of interested parties and officers dated January 7, 2021 (Ref. No: 2021-01-003600), where the information appearing in said reports are noted here by way of reference.

Regulation 24A: Registered and issued share capital

The Company's registered share capital is NIS 28,000,000, divided into 26,000,000 ordinary shares of NIS 1 par value each, and 2,000,000 preference shares of NIS 1 par value each.

The Company's issued and paid up share capital as at December 31, 2020 constitutes 17,159,717 ordinary shares and close to Reporting Date is 17,382,701 ordinary shares of NIS 1 par value each.

Delek Financial Investments - Limited Partnership, a wholly-owned subsidiary partnership, holds 586,422 par value ordinary shares of the Company, as at December 31, 2020 and close to reporting date. These shares do not confer voting rights.

Convertible securities - the Company has options exercisable for ordinary shares of the Company, as follows:

1. Options (Series 10) exercisable for ordinary shares of the Company, on any trading day from their listing for trading on the TASA through to April 1, 2021 (inclusive), so that each Option (Series 10) will be exercisable for one ordinary share of NIS 1 par value each of the Company against a cash payment of the exercise price (adjusted to dividends, bonus shares and rights) in an amount of NIS 75 per share, and are not linked to any index or currency.

2. Options (Series 11), exercisable for ordinary shares of the Company (each Option (Series 11) is exercisable for one ordinary share) from December 16, 2020 through to the exercise deadline on June 30, 2023, and this against a cash payment of the exercise price (adjusted for dividend, bonus shares and rights) in the amount of NIS 150. Options (Series 11) are not linked to any index or currency.

3. Options (Series 12) exercisable for ordinary shares of the Company (each Option (Series 12) will be exercisable for one ordinary share) and this in accordance with the following exercise periods: (1) on any day of trading on the TASE, from the date of their listing on the TASE through to April 1, 2021, against cash payment of an exercise price (adjusted for a dividend, bonus shares and rights) in the amount of NIS 77; and (2) from April 2, 2020 through to the exercise deadline on May 31, 2023, and this against cash payment of an exercise price (adjusted for a dividend, bonus shares and rights) in the amount of NIS 150. Options (Series 12) are not linked to any index or currency.

Regulation 24B: The Company's Shareholders Register:

For the registered shareholders of the Company see the Company's immediate report regarding the Company's equity and listed securities and changes therein dated March 29, 2021 (Ref. No. 2020-01-049596), the information therein is noted here by way of reference.

Regulation 25A: Registered address

Address:	19 Abba Eban Blvd., Herzliya
Email	leorapl@delek-group.com
Telephone:	09-8638444
Fax:	09-8854955
Website:	www.delek-group.com

Regulation 26: **Directors of the company**

	Gabriel Last	**Yitzchak Sharon Teshuva**
Position in the Company:	Chairman of the Board of Directors	Director
ID:	004787933	04340003
Date of birth:	Sept 9, 1946	July 7, 1948
Address for delivery of court documents:	19 Abba Eban Blvd., Herzliya	19 Abba Eban Blvd., Herzliya
Citizenship:	Israeli	Israeli
Member of board of directors committees:	-	-
Independent director:	No	No
External director:	No	No
If Yes, has accounting and financial expertise or professional qualifications:	-	-
If Yes, is an expert external director4	-	-
Is he an employee of the Company, its subsidiaries, affiliates or of an interested party:	Yes, employee of Delek Group Ltd.	Controlling shareholders of the Company
Commencement of office:	Sept 4, 2003	Sept 9, 2014
Education:	LL. B from Tel Aviv University; MA in Social Sciences and Mathematics from Haifa University; AMP (Advanced Management Program for executive officers) at Harvard University.	-
Occupation during past five years:	Chairman of the Company's board of directors	The controlling shareholder of public and private companies in the energy and real estate sectors
Companies in which serves as a director (other than the Company):	Chairman of the board of directors of the following companies: Delek Drilling Management (1993) Ltd.; Delek Foundation for Science, Education and Culture (external director); A director of the following companies: Delek Energy Systems Ltd.; Delek Infrastructure Ltd.; Avner Oil and Gas Ltd.; Delek Power Stations Ltd.; Delek Petroleum Ltd.; Delek Group Royalties Ltd., Delek Overriding Royalty Leviathan Ltd., and private SPC's of Delek Drilling Partnership.	-
Related to another interested party in the Company:	No	Controlling shareholder of the Company and father of Carmit Elroi, a director of the Company.
Does the Company consider him as having accounting and financial expertise for compliance with the minimum number set for the board of directors under section 92(A)(12) of the Companies Law:	No	No

[4] As the term is defined in Regulation 1 of the Companies Regulations (Regulations for Compensation and Expenses of an External Director), 2000

	Shimon Doron	Ruth Dahan Portnoy
Position in the Company:	External director:	External director.
ID:	056219181	024807927
Date of Birth:	Mar 9, 1960	Feb 1, 1970
Address for delivery of court documents:	Hagai Street, Moshav Gan Yoshiya	41 Jabotinsky St., Givatayim
Citizenship:	Israeli	Israeli
Member of board of directors committees:	Committee for reviewing the financial statements, compensations committee and audit committee	Chair of the committee for reviewing the financial statements, chair of the remunerations committee and chair of the audit committee
Independent director:	Yes.	Yes.
External director:	Yes.	Yes.
If Yes, has accounting and financial expertise or professional qualifications:	Director with professional qualifications;	Director with accounting and financial expertise
If Yes, is an expert external director[5]	No	Yes.
Is he an employee of the Company, its subsidiaries, affiliates or of an interested party:	No	No
Commencement of office:	Oct 17, 2018	Aug 25, 2020
Education:	MA Political Science in International Relations, Open University;	MBA (Finance and Accounting), Hebrew University of Jerusalem; BA in Economics, Hebrew University of Jerusalem;
Occupation during past five years:	Serves as CEO of a college under establishment in Jerusalem and is the owner of a strategic consulting firm He previously served in a senior position (equivalent to Brigadier General) at the Prime Minister's Office, served as VP of Planning and Logistics at Bar-Ilan University and as Co-CEO of the Island Hotel in Netanya	He is a financial advisor for TMF - Tailor Made Finance companies and a director of various companies.
Companies in which serves as a director (other than the Company):	No	Assuta Medical Centers, Assuta Ashdod, Mishorim Real Estate Investments Ltd. (external director), Israel Railways Ltd. (external director)
Related to another interested party in the Company:	No	No
Does the Company consider him as having accounting and financial expertise for compliance with the minimum number set for the board of directors under section 92(A)(12) of the Companies Law:	No	Yes.

[5] As the term is defined in Regulation 1 of the Companies Regulations (Regulations for Compensation and Expenses of an External Director), 2000.

	Ron Milo	Ehud Erez
Position in the Company:	Director	Director
ID:	007538408	053615845
Date of Birth:	Nov 26, 1949	Aug 14, 1955
Address for delivery of court documents:	26 King David Street, Tel Aviv	5 Aluf Kalman Magen St., Tel Aviv
Citizenship:	Israeli	Israeli, Canadian
Member of board of directors committees:	Audit Committee	Committee for reviewing the financial statements, compensations committee and audit committee
Independent director:	Yes.	No
External director:	No	No
If Yes, has accounting and financial expertise or professional qualifications:	-	Yes.
If Yes, is an expert external director[6]	-	-
Is he an employee of the Company, its subsidiaries, affiliates or of an interested party:	No	No
Commencement of office:	Apr 1, 2015	July 1, 2020
Education:	LL.B, Tel Aviv University	BA Economics and Accounting, Hebrew University in Jerusalem
Occupation during past five years:	Director in various companies	Director in various companies Previously served as Chair of the Board of Elad Group (2014 - 2016)
Companies in which serves as a director (other than the Company):	Ron Milo Management Services (2003) Ltd.; Ron Milo Holdings Ltd.	Southern Properties Capital Ltd, Extell Limited MRR Thirteen Limited, Amos Luzon Group Entrepreneurship and Energy Ltd. Sprinkel Ltd., Udi Erez Real Estate Ltd.
Related to another interested party in the Company:	No	No
Does the Company consider him as having accounting and financial expertise for compliance with the minimum number set for the board of directors under section 92(A)(12) of the Companies Law:	No	Yes.

6 As the term is defined in Regulation 1 of the Companies Regulations (Regulations for Compensation and Expenses of an External Director), 2000.

	Carmit Sharon Elroi
Position in the Company:	Director
ID:	22546832
Date of Birth:	Nov 8, 1967
Address for delivery of court documents:	18 Hashomer Street, Moshav Avihail, 472910
Citizenship:	Israeli
Member of board of directors committees:	No
Independent director:	No
External director:	No
If Yes, has accounting and financial expertise or professional qualifications:	-
If Yes, is an expert external director[7]	-
Is he/she an employee of the Company, its subsidiaries, affiliates or of an interested party:	No
Commencement of office:	Nov 28, 2012
Education:	B.A. Education and Humanities from Tel Aviv University Master of Chinese Medicine, Pacific College
Occupation during past five years:	Owner and CEO of Pharmacin Ltd. for 15 years; Baraka Or Holdings Ltd. and Likys A.D. Ltd.
Companies in which serves as a director (other than the Company):	Delek Israel Fuel Corporation Ltd.; Delek Foundation for Science, Education and Culture (external director);
Related to another interested party in the Company:	Daughter of Yitzhak Sharon (Teshuva), the controlling shareholder and a director in the Company
Does the Company consider him as having accounting and financial expertise for compliance with the minimum number set for the board of directors under section 92(A)(12) of the Companies Law:	No

(*) Until June 30, 2020 Judith Teitelman served as an external director of the Company

(**) Until June 30, 2020 Avi Harel served as a director of the Company

[7] As the term is defined in Regulation 1 of the Companies Regulations (Regulations for Compensation and Expenses of an External Director), 2000.

<u>Regulation 26A</u>: Senior officers in the Company

	Idan Wallace	Tamir Moshe Polikar	Boaz Schnitzer
ID:	033658246	059749408	024565707
Date of birth:	Jan 8, 1977	Aug 14, 1965	Nov 10, 1969
Commencement of office:	January 1, 2020 (September 1, 2015)	September 1, 2020 (August 1, 2020)	Jan 1, 2020
Position in the Company, its subsidiaries, affiliates or the controlling shareholder:	CEO of Delek Group Previously served as Deputy CEO, a director and advisor of the Group and its subsidiaries. Director of the following companies: Delek Drilling Management (1993) Ltd.; Delek Energy Systems Ltd.; Keshet Broadcasting Ltd.; the Israel News Corp. Ltd.;	Deputy CEO and CFO of Delek Group and director of Delek Group subsidiaries: Delek Drilling Management (1993) Ltd.; Delek Yam Maagan (2011) Ltd.; Delek Group Israel Holdings Ltd.; Delek Energy; Delek Power Plant Management Ltd.; Delek Petroleum Ltd.; Delek Infrastructures Ltd.; Delek Group Royalty Ltd.; Delek Property Development Ltd.; Delek Leviathan Overriding Royalty Ltd.; Ithaca Energy Ltd.; Delek Hungary Ltd.	Deputy CEO of Delek Group Ltd. and director of private subsidiaries of the controlling shareholder of the Company, as follows: Elad (GRP) Properties Ltd.; Elad Canada Inc.; Elad Canada Realty Inc. Director of international taxation of Elad Group Ltd. Director of the private company, SBE Assets and Management (2015) Ltd.
Is he/she an interested party in the Company	No	No	No
Is he/she a family member of another senior officer or of an interested party in the Company:	No	No	No
Education:	LL.B, Tel Aviv University	BA Accounting, College of Management; MBA, Heriot Watt University, Certified Public Accountant	LL.B, College of Management LL.M (International Taxation) Boston University, USA
Business experience in the past 5 years	Executive VP of Delek Group. Previously served as a director and consultant to the Group and its subsidiaries. Director of Wallace Consultants Ltd. and Wallace Investments (2018) Ltd. He previously served as CEO of Tshuva Group private companies (through Tashluz Investments & Holdings Ltd.),	Real estate developer in Israel and abroad, business advisor and director of Polikar Holdings Ltd.; Serves as a director of Galipoli Real Estate Investments Ltd.; Briza Lgyrp Ltd. and Elysee Downtown Ltd. Previously served as CEO of Aspen Group Ltd.	International taxation advisor of Delek Group and director for international taxation of Elad Group Ltd.;

(*) Until August 31, 2020 Barak Mashraki served as Deputy CEO and CFO of the Company

	Gali Gana	Leora Pratt Levin	Tamar Rosenberg
ID:	059674770	57906919	035894252
Date of birth:	June 2, 1965	October 12, 1962	December 9, 1978
Commencement of office:	January 1, 2016	April 1, 2007	November 19, 2006
Position in the Company, its subsidiaries, affiliates or the controlling shareholder:	Chief Internal Auditor of the Company and of Delek Drilling Management (1993) Ltd.	Executive VP, Chief Legal Counsel and Company Secretary Director of the following Delek Group subsidiaries: Delek Drilling Management (1993) Ltd.; Delek Energy Systems Ltd.; Delek Group Israel Holdings Ltd.; Delek Sea Maagan 2011 Ltd.; Delek Leviathan Overriding Royalty Ltd.; DKL Energy Ltd.; Delek North Sea Ltd.	CFO and Chief Accountant
Is he/she an interested party in the Company	No	No	No
Is he/she a family member of another senior officer or of an interested party in the Company:	No	No	No
Education:	CPA, MBA specializing in Accounting and MA in Public Administration and Internal Auditing, CISA, CIA, CRMA, and CRISC.	BA Political Science, Tel Aviv University, LL.B, Reading University, UK	BA in Business Administration and Accounting from the Academic College of Management and MBA specializing in financing from Tel Aviv University
Business experience in the past 5 years	A partner and CPA in Rosenblum Holtzman Accounting firm;	Executive VP of the Company; Chief Legal Counsel and Company Secretary since 2007	Chief accountant of the Company since 2006

<u>Regulation 26A</u>: Senior Officers of Subsidiaries controlled by the Company, as defined in section 37 of the Securities Law:

	Bill Dunnett
ID:	554434454 (Passport No.)
Date of Birth:	May 28, 1962
Commencement of office:	Aug 24, 2020
Position in the Company, its subsidiaries, affiliates or the controlling shareholder:	CEO and director of the subsidiary, Ithaca Energy Limited;
Is he/she an interested party in the Company	No
Is he/she a family member of another senior officer or of an interested party in the Company:	No
Education:	Certified chemical engineer, Heriot Watt University, Edenborough, Scotland
Business experience in the past 5 years	CEO of Repsol Sinopec Resources UK Ltd.

	Gilad Meirson	Joseph Abu
ID:	051892938	033840372
Date of Birth:	March 26, 1976	December 7, 1977
Commencement of office:	November 4, 2019	April 1, 2011
Position in the Company, its subsidiaries, affiliates or the controlling shareholder:	CEO and director of the subsidiary, Ithaca Energy Limited; CEO of the subsidiary, DKL Investments Limited	CEO of Delek Drilling Management (1993) Ltd.; director of private SPCs of the Partnership;
Is he/she an interested party in the Company	No	No
Is he/she a family member of another senior officer or of an interested party in the Company:	No	No
Education:	BA in Computational Biology, Bar Ilan University	LL.B, Hebrew University of Jerusalem; Attorney and member of the Israel Bar Association.
Business experience in the past 5 years	Chairman of the Board of Directors of the subsidiary, Ithaca Energy Limited; CEO of the subsidiary, DKL Investments Limited Partner in McKinsey (2012-2017); VP Operations of Theramex (2018-2019);	CEO of Delek Energy Systems Ltd. (until March 14, 2020); CEO of Avner Oil and Gas Ltd.; Chairman of the Board of Tamar Petroleum Ltd. (until March 6, 2019); director of Ithaca Energy Systems Ltd. (until March 1, 2018); of various private companies of Delek Drilling Partnership and private companies owned by him;

(*) Until September 24, 2020, Les Thomas served as CEO of the subsidiary, Ithaca Energy Limited

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<u>Regulation 27</u>: The Auditors of the Company

Kost Forer Gabbay & Kasierer– 144 Menachem Begin St., Tel-Aviv

<u>Regulation 28</u>: Amendments to the Articles of Association

On June 23, 2020 the general meeting of the Company approved an amendment to the Company's Articles of Association - adjustment of the registered share capital of the Company as set out in the immediate report for convening of the general meeting dated May 27, 2020 (Ref. No.: 2020-01-054006), and its amendment dated June 23, 2020, (Ref. No: 2019-01-077251). The information appearing therein is noted here by way of reference.

<u>Regulation 29</u>: Recommendations and resolutions of the board of directors

<u>Regulation 29(A)(1)</u>:

<u>Board of Directors resolutions regarding the distribution of a cash dividend:</u>

No dividend was distributed in the reporting year.

<u>Regulation 29(C)</u>: Resolutions adopted at a Special General Meeting

A. On February 24, 2020, the general meeting of the Company approved the terms of the office and employment of Idan Wallace in the position of CEO of the Company and all as set out in the immediate report for convening of the general meeting. For further information, see immediate reports issued by the Company on January 19, 2018 (Ref. No. 2020-01-018870) and February 28, 2018 (Ref. No: 22020-01-007620) The information appearing therein is noted here by way of reference.

B. On June 23, 2020 the general meeting of the Company approved an amendment to the Company's Articles of Association - adjustment of the registered share capital of the Company as set out in the immediate report for convening of the general meeting dated May 27, 2020 (Ref. No.: 2020-01-054006), and its amendment dated June 23, 2020, (Ref. No: 2020-01-057082) The information appearing therein is noted here by way of reference.

C. On August 25, 2020, the Company's general meeting approved the appointment of Ms. Ruth Dahan Portnoy as an external director of the Company and the Company's engagement in an insurance policy for its directors and officers. For further information, see immediate reports issued by the Company on July 20, 2020 (Ref. No. 2020-01-076914) and August 25, 2020 (Ref. No: 2020-01-093492) The information appearing therein is noted here by way of reference.

D. Subsequent to balance sheet date, on February 1, 2121, the Company's general meeting approved the revised compensations policy for the Company's officers and an amendment of the bonus mechanism for the Chairman of the Board of Directors and the CEO of the Company. For further information, see immediate reports issued by the Company on December 24, 2020 (Ref. No. 2020-01-139893); January 25, 2021 (Ref. No. 2021-01-010980) and February 1, 2020 (Ref. No.: 2021-01-013030), where the information appearing in said reports are noted here by way of reference.

E. Subsequent to balance sheet date, on March 1, 2021, the Company's general meeting approved a bonus for the Chairman of the Company's Board of Directors. For further information, see immediate reports issued by the Company on February 4, 2021 (Ref. No. 2021-01-014245) and March 1, 2021 (Ref. No: 2021-01-024876), where the information appearing in said reports are noted here by way of reference.

<u>Regulation 29A</u> - Company Resolutions

Regulation 29A(4) Exemption from insurance and indemnity for officers – valid at the date of the report:

1. Pursuant to the previous resolutions of the Company, the Company decided to grant senior officers an exemption regarding their liability for damages as a result of a breach of their fiduciary duty towards the Company, as set forth in the third section of the sixth part of the Companies Law and to indemnify them (according to and subject to the amendment adopted at the Company's extraordinary general meeting

prior to 2007). The letter of indemnification complies with Amendment 3 of the Companies Law, 1999 and the Company's articles of association. Pursuant to the letter of indemnification, as the Company's articles of association include a provision allowing it to undertake in advance to indemnify an officer, provided the undertaking is restricted to the types of events that the board of directors anticipate in view of the Company's actual actions at the time of undertaking to indemnify, in an amount or scope determined by the board of directors to be reasonable under the circumstances, all on account of any liability or expenditure that shall be authorized at that time according to the law at the time the resolution is adopted, the company also undertakes to indemnify the officer for reasonable litigation expenses, including attorneys' fees, such that may be incurred as a result of an investigation or proceedings that shall take place against the officer by any authority certified to launch an investigation or proceeding and that has ended without filing charges against the officer and without a fine being imposed in lieu of criminal proceedings or that has ended without an indictment being filed against the officer, while imposing a fine in lieu of criminal proceedings in a felony that does not warrant the proof of criminal intent.

In accordance with the new compensations policy brought for approval, the directors and officers may be eligible for letters of exemption under the Companies Law and as set out in the Company's Articles of Association, provided that for new officers who will be appointed to the Company after the date on which the policy is adopted, the letter of exemption will be state that the exemption does not apply for a decision or transaction in which the controlling shareholder or any officer of the Company (also an officer other than the one for whom the exemption is granted) has a personal interest.

2. <u>Insurance</u>:

A. On October 17, 2018, the general meeting of the Company approved the engagement with The Phoenix Insurance Co. Ltd. to insure the directors of the Company and its subsidiaries under a collective directors and officers liability insurance policy for the Company and its subsidiaries, for a period of 18 months from January 1, 2019 through June 30, 2020 (inclusive), with limit of liability of USD 150 million, at annual premium of USD 780 thousand, of which the Company's share amounts to USD 180 thousand per year.

B. On October 17, 2018 the general meeting of the Company approved extending and/or renewing the insurance policy, or alternatively if necessary, in a collective insurance policy that includes the subsidiaries and affiliates, all or some of them, from time to time, without requiring additional approval of the general meeting, with the insurer or another insurer, in Israel or abroad, so that it will apply for all the officers of the Company and/or most of its subsidiaries and affiliates, including directors and/or officers who are controlling shareholders in the Company or their relatives, at a premium and under terms as will be generally accepted at the date of the extension, renewal or replacement of the insurance policy, and in accordance with the framework terms set out in the resolution, and provided that the limit of liability of the insurance (in the collective policy) will not fall below USD 100 million and will not exceed the amount of USD 250 million per case and per period, and the annual premium for the policy will not exceed the amount of USD 1,500 thousand per year, and this with the addition of 15% per year, as of July 1, 2020. The Company's future engagements in such directors and officers liability insurance policies will be made for a number of insurance periods, provided that the aggregate of all insurance periods does not exceed three years as of July 1, 2020.

C. As the term of the previous policy ended as noted above on June 30, 2020, and in view of the dramatic adverse changes in the directors and officers liability insurance market, as will be explained below, especially in the wake of the Covid-19 pandemic crisis, in June 2020 the Company exercised its right under the previous policy to purchase runoff insurance that would cover events of professional liability for a further period of seven years applicable from July 1, 2020. Under the foregoing extension, the policy will continue to apply for claims filed during the runoff period for the first time due to events prior to the commencement of the runoff period of July 1, 2020, within the limit of liability under the previous policy, i.e., for a total amount of USD 150 million per claim and cumulatively (including the extended disclosure period of 7 years). The premium that is paid for the foregoing runoff period is USD 1,520,000.

D. As the Company was informed by its insurance advisor, the D&O liability insurance market changed dramatically at the time when the Company renewed its policy, after many insurers incurred heavy losses. In view of the numerous claims in the D&O liability insurance market and due to the significant adverse changes in the industry in general, and with regard to corporations that operate in the energy sector in particular, among others, in view of both the global and the domestic economic crisis resulting from the outbreak of the Covid-19 pandemic, at the time of the renewal of the policy, there is a genuine difficulty to purchase a new insurance policy that would cover claims filed due to events from July 1, 2020 onwards, (the “New Current Policy"), with similar terms too those of the policy that ended on June 30, 2020, and if such a new current policy could be obtained, the amount of the premium and deductible required thereunder are significantly higher than the costs and terms of the previous policy, as aforesaid.

E. On August 25, 2020, after it was approved by the Company's Compensations Committee and Board of Directors, the Company's general meeting approved the purchase of the New Current Policy, which reflects the best insurance offer that could be purchased under the circumstances at the time, with limit of liability of USD 25 million per claim and cumulatively, with the addition of reasonable legal fees, at a premium of USD 2.269 million and deductible of up to USD 750,000 per claim, and which will not apply for the officers without the Company's ability to indemnify them. Furthermore, it was decided to authorize the Company's management to purchase an increase in insurance coverage of up to an additional USD 75 million (in addition to the existing USD 25 million), in exchange for an additional premium, so that the total annual premium for the New Current Policy does not exceed USD 4 million.

F. In August 2020, the Company purchased additional insurance cover with limit of liability of USD 6 million at annual premium of USD 575 thousand.

Delek Group Ltd.

Date of Signature: **March 30, 2021**

<u>Names and titles of the signatories</u>:

Gabriel Last -– Chairman of the Board of Directors
Idan Wallace – CEO

Chapter E

Annual report for 2020 on the Effectiveness of Internal Controls for Financial Reporting and Disclosure

Delek Group Ltd.

Annual report for the year 2020 on the effectiveness of internal control for financial reporting and disclosure, pursuant to Ordinance 9B(a) of the Securities Ordinances (Periodic and Immediate Reports), 1970

Management, under the supervision of the Board of Directors of Delek Group Ltd. ("the Corporation"), is responsible for setting and maintaining an appropriate internal control for financial reporting and disclosure in the Corporation.

For this matter, the members of Management are:

1. Idan Wallace, CEO.
2. Tamir Poliker, Deputy CEO & CFO.
3. Leora Pratt Levin, Chief General Counsel
4. Tamar Rosenberg, Head of Corporate Accounting

Internal control of financial reporting and disclosure includes controls and procedures existing in the Corporation, which were planned or overseen by the CEO and the most senior financial officer or under their supervision, or by whoever fulfills those functions in practice, under the supervision of the Board of Directors of the Corporation, and were designed to provide a reasonable measure of assurance as to the reliability of the financial reporting and the preparation of the reports in accordance with the provisions of the law, and to ensure that information that the Corporation is required to disclose in the reports it publishes in accordance with the provisions of the law is collected, processed, summarized and reported on the date and in the format laid down in law.

Internal control includes, inter alia, controls and procedures planned to ensure that the information that the Corporation is required to disclose as aforesaid, is accumulated and forwarded to the Management of the Corporation, including to the CEO and the most senior financial officer or to whoever fulfills those functions in practice, in order to enable decisions to be made at the appropriate time in relation to the disclosure requirement.

Due to its structural limitations, the internal control of financial reporting and disclosure is not intended to provide absolute assurance that misstatement in or omission of information from the reports will be prevented or will be discovered.

Management, under the supervision of the Board of Directors, has carried out checks and an assessment of the internal controls on financial reporting and disclosures within the Corporation and their effectiveness.

Assessment of the effectiveness of the internal controls on financial reporting and disclosures that Management carried out under supervision of the Board included: Assessment of the risks of reporting and disclosure and determination which are the very material processes for financial reporting and disclosure and which are the applicable businesses units for assessment of the effectiveness of the internal controls, mapping and documentation of the existing controls within the Corporation, assessment of the effectiveness of the planning of the controls, analysis of existing control gaps, assessment of the effectiveness of the operation of the controls, overall assessment of the effectiveness of the internal control. The assessment model for the effectiveness of the internal controls carried out by the Corporation is based upon four components as follows: Entry Level Controls, process of preparing and closing the financial statements, general audits of IT systems (ITGC), and processes that have been identified by management as particularly material procedures for financial reporting and disclosure: Procedure for management of Corporation's cash and securities portfolio, and procedure for managing the Corporation's borrowings. The procedures that are particularly material in the consolidated financial statements that are prepared by some of the major consolidated companies, are: revenues cycle, investment in oil and gas exploration and production, insurance reserves and pending claims.

Based upon the assessment of effectiveness carried out by management under the supervision of the Board as detailed above, the Corporation's Board of Directors and management reached the conclusion that the internal controls on financial reporting and disclosures of the Corporation as of December 31, 2020 were effective.

Declaration of Executives:

(A) Declaration of the CEO in accordance with Ordinance 9B(d)(1)

Declaration of Executives
Declaration of the CEO

I, Idan Wallace declare that:

1. I have reviewed the periodic report of Delek Group Ltd. ("the Corporation") for the year 2020 ("the Reports").

2. To the best of my knowledge, the reports do not include any representations that is not correct and do not lack any representation of any vital, material fact, so that was has been presented, within the context in which they have been provided, shall not be misleading in respect of the period covered by the reports.

3. To the best of my knowledge, the financial statements and other financial information in the Reports reflect fairly, from all material aspects, the financial condition, the results of operations and the cash flows of the Corporation at the dates and for the periods to which the Reports relate.

4. I disclosed to the auditor of the Corporation, to the Board of Directors, to the Audit and the Financial Statements Committees of the Board of Directors of the Corporation, based on my latest assessment of the internal control of the financial reporting and disclosure:

   A. all the significant flaws and material weaknesses in the determination or operation of the internal control of the financial reporting and disclosure that could reasonably have an adverse effect on the ability of the Corporation to collect, process, summarize or report on financial information in a way that could cast doubt on the reliability of the financial reporting and the preparation of the financial statements in accordance with the provisions of the law; and -

   B. any deception, whether material or not material, in which the CEO or anyone directly subordinate to him is involved, or in which other employees are involved who fulfill an important function in the internal control of the financial reporting and disclosure;

5. I, alone or together with others in the Corporation:

   A. I set controls and procedures or ascertained the setting and upholding of controls and procedures under my supervision, designed to ensure the material information related to the Corporation, including its consolidated companies in their meaning in the Securities (Annual Financial Statements) Ordinances, 2010. was brought to my attention by others within the Corporation or the consolidated companies, in particular during the period in which the reports were prepared; and -

   B. I set controls and procedures or ascertained the setting and upholding of controls and procedures under my supervision, designed to reasonably ensure the reliability of the financial reporting and the preparation of the financial statements in accordance with the provisions of the law, including in accordance with accepted accounting principles;

   C. I have assessed the effectiveness of the internal controls of the financial reporting and disclosures, and in this report have presented the conclusions of the Board of Directors and Management in respect of the effectiveness of the said internal controls as of the reporting date.

Nothing in the foregoing shall derogate from my responsibility or that of anyone else in law.

March 30, 2021	Idan Wallace CEO

(B) Declaration of the most senior financial officer pursuant to Ordinance 9B(d)(2)

Declaration of Executives
Declaration of the most senior financial officer

I, Tamir Poliker, declare that:

1. I have reviewed the financial statements and other financial information of Delek Group Ltd. ("the Corporation") for the year 2020 ("the Reports").

2. To the best of my knowledge, the financial statements and other financial information do not include any representations that is not correct and do not lack any representation of any vital, material fact, so that was has been presented, within the context in which they have been provided, shall not be misleading in respect of the period covered by the reports.

3. To the best of my knowledge, the financial statements and other financial information in the Reports reflect fairly, from all material aspects, the financial condition, the results of operations and the cash flows of the Corporation at the dates and for the periods to which the Reports relate.

4. I disclosed to the auditor of the Corporation, to the Board of Directors, to the Audit and the Financial Statements Committees of the Board of Directors of the Corporation, based on my latest assessment of the internal control of the financial reporting and disclosure:

   A. all the significant flaws and material weaknesses in the determination or operation of the internal control of the financial reporting and disclosure insofar as they refer to the financial statements and other financial information that could reasonably have an adverse effect on the ability of the Corporation to collect, process, summarize or report on financial information in a way that could cast doubt on the reliability of the financial reporting and the preparation of the financial statements in accordance with the provisions of the law; and -

   B. any deception, whether material or not material, in which the CEO or anyone directly subordinate to him is involved, or in which other employees are involved who fulfill an important function in the internal control of the financial reporting and disclosure;

5. I, alone or together with others in the Corporation:

   A. set controls and procedures or ascertained the setting and upholding of controls and procedures under my supervision, designed to ensure that material information relating to the Corporation, including its subsidiaries as defined in the Securities (Annual Financial Statements) Ordinances, 2010, insofar as they are relevant to the financial statements and other financial information included in the reports, is brought to my knowledge by others in the Corporation and in the subsidiaries, particularly during the period of preparation of the Reports; and

   B. I set controls and procedures or ascertained the setting and upholding of controls and procedures under our supervision, designed to reasonably ensure the reliability of the financial reporting and the preparation of the financial statements in accordance with the provisions of the law, including in accordance with accepted accounting principles;

   C. I have assessed the effectiveness of the internal controls of the financial reporting and disclosures, insofar as it is applicable to the financial statements and other financial information included in the reports as of the reporting date.

Nothing in the foregoing shall derogate from my responsibility or that of anyone else in law.

March 30, 2021

Tamir Poliker
Deputy CEO and CFO