Delek Drilling

2020

FINANCIAL STATEMENTS

photographed by: Albatross

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Delek Drilling

2020

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Description of the Partnership business

2020

Chapter A – Description of the Partnership's Business

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This report is a translation of Delek Drilling - Limited Partnership's Hebrew-language Description of the General Development of the Partnership's Business, which is prepared solely for convenience purposes. Please note that the Hebrew version is the binding version and will prevail in any event of discrepancy.

1. Description of the General Development of the Partnership's Business[1]

1.1. Delek Drilling – Limited Partnership (the "**Partnership**") is a public limited partnership, within the meaning thereof in the Partnerships Ordinance [New Version], 5735-1975 (the "**Partnerships Ordinance**"), engaged in the exploration, development and production of natural gas, condensate and oil. The Partnership 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**") of the first part, as general partner, and Delek Drilling Trusts Ltd. as limited partner, of the second part (the "**Limited Partner**"). The Partnership was registered on July 25, 1993, under the Partnerships Ordinance.

1.2. In accordance with prospectuses released by the Partnership between the years 1993-2003, the Limited Partner issued participation units to the public which are listed for trade on the Tel Aviv Stock Exchange Ltd. ("**TASE**").

1.3. The current management of the Partnership is performed by the General Partner under the supervision of the supervisors, Fahn Kanne & Co., Accountants, together with Keidar Supervision & Management (jointly: the "**Supervisor**").

1.4. The Limited Partner serves as trustee and holds in trust for the unit holders the participation units issued thereby, which confer a right to participate in the rights of the Limited Partner in the Partnership (the "**Participation Units**" or the "**Units**").

1.5. The General Partner and the Limited Partner are subsidiaries of Delek Energy Systems Ltd. ("**Delek Energy**"), a private company wholly owned by Delek Group Ltd. ("**Delek Group**"), the controlling shareholder of which is Mr. Yitzhak Sharon (Tshuva)[2]. To the best of the Partnership's knowledge, as of the report approval date Delek Group holds, directly and indirectly (through Delek Energy and the General Partner, and through an indirect holding in Avner Oil & Gas Ltd.) approx. 54.66% of the issued unit capital.[3]

1.6. On May 17, 2017, a merger was closed between the Partnership and Avner Oil Exploration, Limited Partnership ("**Avner**" or the "**Avner Partnership**") such that all of Avner's assets and liabilities were transferred, as is, to the

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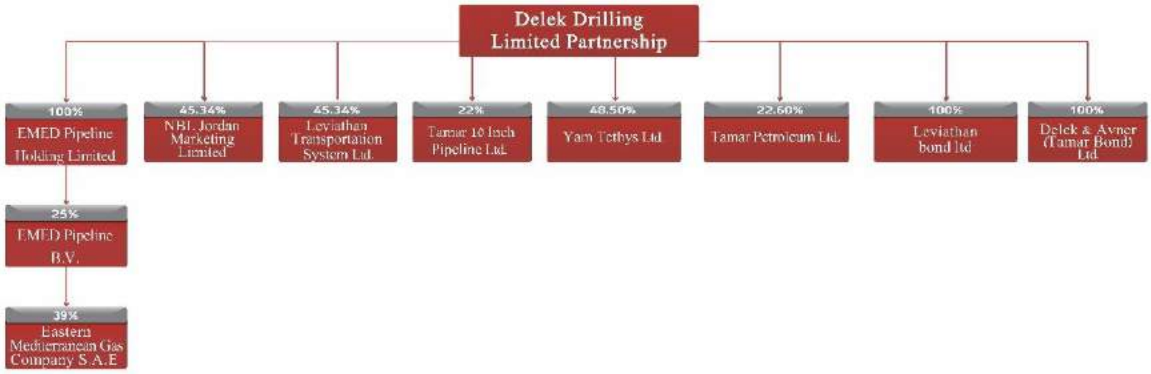
[1] For definitions of some of the professional terms included in this chapter, see the professional terms annex at the end of the chapter as well as **Annex D**, which is attached hereto.

[2] As of the report approval date, Mr. Yitzhak Sharon (Tshuva) holds approx. 49.04% of the issued capital and approx. 50.77% of the voting rights in Delek Group.

[3] To the best of the Partnership's knowledge, and in accordance with Delek Group's reports, as of the report approval date, the vast majority of the units owned by Delek Group are pledged in favor of the holders of the bonds issued by Delek Group.

Partnership. The Limited Partner issued participation units to the holders of the participation units in the Avner Partnership, and the Avner Partnership was liquidated without dissolution, and struck off from the records of the Registrar of Partnerships (the "**Merger**" or the "**Merger of the Partnerships**").

1.7. <u>The structure of principal holdings of the Partnership</u>:



1.7.1. Delek and Avner (Tamar Bond) Ltd. is a special purpose company (SPC), which was established for the purpose of the issue of bonds to the institutional market in Israel and overseas, which are secured by the Partnership's interests in the Tamar and Dalit leases. For further details, see Section 7.20.3 below.

1.7.2. Yam Tethys Ltd. is a special purpose company (SPC) incorporated by the partners in the Yam Tethys project (the "**Yam Tethys Partners**") for the purpose of receiving a license for gas transmission from the production platform of the Yam Tethys project to the terminal on the Ashdod shore (the Ashdod Onshore Terminal, AOT) (the "**Terminal**"), as mandated by the provisions of the Natural Gas Sector Law, 5760-2000 (the "**Natural Gas Sector Law**").

As of the report approval date, Yam Tethys Ltd. has no activity aside from being the holder of a construction and operation license for the gas transmission pipe, which was granted thereto by the Minister of Energy on April 29, 2002, and additional activity related to its being the holder of such license, including its being a party to various agreements in connection with the Terminal and security issues.

1.7.3. Tamar 10-Inch Pipeline Ltd. is a special purpose company (SPC) whose shareholders are the partners in the I/12 Tamar lease (the "**Tamar Lease**", the "**Tamar Project**" and the "**Tamar Partners**", respectively), which hold the shares of the company according to the rate of their holdings in the Tamar Lease. The company was established for the purpose of obtaining a license for the transmission of natural gas from the production platform of the Tamar Project to the Terminal by a 10-inch pipe, as mandated by the provisions of the Natural Gas Sector Law.

1.7.4. Leviathan Transmission System Ltd. is a special purpose company (SPC) whose shareholders are the partners in the Leviathan project (the "**Leviathan Partners**"), which hold the shares of the company according to the rate of their holdings in the I/14 Leviathan South and I/15 Leviathan North leases (the "**Leviathan South Lease**" and the "**Leviathan North Lease**", respectively. The Leviathan South and Leviathan North leases shall hereinafter be referred to collectively as: the "**Leviathan Leases**"). The company was established for the purpose of obtaining a license for the transmission of natural gas from the production platform of the Leviathan project to the northern entry point of the national transmission system of Israel Natural Gas Lines Ltd. ("**INGL**"), as mandated by the provisions of the Natural Gas Sector Law.

1.7.5. NBL Jordan Marketing Limited is a company whose shareholders are the Leviathan Partners, which hold the shares of the company according to the rate of their holdings in the Leviathan Leases. The company was established in connection with the engagement of the Leviathan Partners in a gas supply agreement with the national electric company of Jordan – The National Electric Power Company ("**NEPCO**"), whereby it will purchase the natural gas from the Leviathan Partners at the entry point to INGL's transmission system and shall sell it to NEPCO at the delivery point near the Israel-Jordan border under the same terms and conditions set forth in the said gas supply agreement (back-to-back). For further details, see Section 7.11.5(b)1 below.

1.7.6. Tamar Petroleum Ltd. ("**Tamar Petroleum**") is a public company. On July 20, 2017, upon fulfillment of all of the conditions precedent, a sale transaction was closed according to an agreement of July 2, 2017, which was signed between the Partnership and Tamar Petroleum, in the context of which the Partnership transferred to Tamar Petroleum rights at a rate of 9.25% (out of 100%) in the Tamar Lease and in the I/13 Dalit lease (the "**Dalit Lease**"), *inter alia*, in consideration for 40% of the share capital of Tamar Petroleum (after the allotment). As of the report approval date, the Partnership holds 22.6% of the equity interests and 13.42% of the voting rights in Tamar Petroleum. According to the provisions of the Gas Framework (as defined in Section 7.23.1 below) pertaining to the Partnership's obligation to sell all of its interests in the Tamar and Dalit leases, the Partnership is required to sell all of its holdings in Tamar Petroleum by December 17, 2021. For details see Section 7.23.1 below.

1.7.7. EMED Pipeline B.V. ("**EMED**") is an SPC, established for the EMG Transaction (as defined in Section 7.25.6 below), registered in the Netherlands, whose shares are held, as follows: EMED Pipeline Holding Limited, a wholly owned subsidiary (100%) of the partnership that is registered in Cyprus – 25%; Noble Energy International Ltd. ("**Noble Cyprus**") – 25%; and Sphinx EG BV, a wholly owned subsidiary (100%) of East Gas Company S.A.E., which holds, inter alia, a gas pipeline and infrastructures in Egypt (the "**Egyptian Partner**") – 50%.

1.7.8. Eastern Mediterranean Gas Company S.A.E. ("**EMG**") is a private company, registered in Egypt, which owns a subsea natural gas transport pipeline that connects between the Egyptian natural gas transmission system in the el-Arish area and the Israeli transmission system in the Ashkelon area, whose shares are held, as follows: EMED – 39%; PTT Energy Resources Company Limited ("**PTT**")[4] – 25%, Mediterranean Gas Pipeline Ltd. ("**MPGC**")[5] – 17%; Egyptian Partner – 9%, Egyptian General Petroleum Corporation ("**EGPC**")[6] – 10%. For further details see Section 7.25.6 below.

1.7.9. Leviathan Bond Ltd. is a special purpose company (SPC) which was established for the purpose of the issue of bonds to the institutional market in Israel and overseas, which are secured by the Partnership's interests in the Leviathan Leases.[7] For further details, see Section 7.20.20 below.

For further details with respect to the aforementioned companies, see Regulation 11 of Chapter D hereof.

2. Field of Business

2.1. The Partnership has holdings in petroleum assets as specified in Sections 7.2-7.8 below, and in this context, in a number of significant gas discoveries in the Mediterranean Sea region, which include, *inter alia*, the Leviathan reservoir, the Tamar reservoir and the Aphrodite reservoir which was discovered in the area of Block 12 in Cyprus ("**Aphrodite**" or "**Block 12**"). Furthermore, the Partnership is entitled to receive overriding royalties from the Karish and Tanin leases, as specified in Section 7.8 below. The Tamar reservoir, from which the piping of gas commenced in March 2013, and the Leviathan reservoir, from which the piping of gas commenced in December 2019, currently supply nearly all of the natural gas consumed by the Israeli market. The prominent customers of the partners in the Leviathan and Tamar reservoirs include the Israel Electric Corporation Ltd. (the "**IEC**"), private power plants, industrial enterprises, Jordan's national electricity company –

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[4] A public energy company partly owned by the Government of Thailand.
[5] A private company which, to the best of the Partnership's knowledge, is controlled by Evsen Group, a company headed by Dr. Ali Evsen.
[6] An Egyptian government-owned company.
[7] Delek Drilling (Leviathan Financing) Ltd. is an SPC which was established for raising the financing of the Partnership's share in the development costs of the Leviathan project. Upon completion of the issuance of the bonds by Leviathan Bond Ltd., the loans provided to the Partnership for raising the financing of the Partnership's share in the development costs of the Leviathan project as aforesaid, were fully repaid and therefore, as of the report approval date, Delek Drilling (Leviathan Financing) Ltd. is in the process of voluntary dissolution.

NEPCO, industrial enterprises in Jordan and Dolphinus Holdings Limited[8] ("**Dolphinus**") which imports gas from Israel to Egypt.

2.2. On October 5, 2020 Chevron Corporation ("**Chevron**") announced the closing of a merger between itself and Noble Energy Inc. ("**Noble Inc.**"), the parent company of Noble Energy Mediterranean Ltd. ("**Noble**"), the operator of the petroleum assets Tamar and Leviathan, and of Noble Cyprus, the operator of the Block 12 project in Cyprus. As of the report approval date, Noble Inc. is wholly owned by Chevron. Chevron is a foreign public corporation whose shares are traded on the NYSE. To the best of the Partnership's knowledge, no single shareholder holds more than 10% of Chevron's issued share capital.

2.3. As of the report approval date, the Partnership's primary 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 the volume of natural gas sales from the Partnership's assets. At the same time, the Partnership is exploring various business opportunities with characteristics similar to those where the Partnership is already active in the field of exploration, development and production of natural gas and oil.

2.4. According to the provisions of the Gas Framework (as defined in Section 7.23.1 below), the Partnership is required to transfer all of its interests in the Tamar and Dalit leases and its holdings in Tamar Petroleum by December 17, 2021. For further details see Section 7.27.1 below. For further details with respect to the Gas Framework, see Section 7.23.1 below.

2.5. During the past year, the Partnership has acted to promote a possible outline to split its assets. For further details, see Section 7.27.1 below.

2.6. In accordance with the TASE directives, the Partnership has undertaken to only carry out gas and oil exploration, development and production projects, which were defined in the Partnership Agreement or in the amendment thereto to be approved by the meeting of the Participation Unit holders. The Partnership Agreement defines the geographical areas included in the Partnership's existing petroleum assets, which are specified in Section 2.8 below[9].

[8] To the best of the Partnership's knowledge, Dolphinus is a special purpose company registered in the Cayman Islands, which engages in natural gas trade and which supplies gas to large consumers in Egypt, and primarily EGAS, an Egyptian government-owned company. In June 2020, Dolphinus endorsed the export to Egypt agreements to Blue Ocean Energy, an affiliate of Dolphinus.

[9] It is noted that in November 2017 and March 2019, the TASE Rules were amended (Chapter Q of Part Two of the Rules) regarding oil or gas exploration, development or production which are performed outside of Israel in the framework of the definition of "project" in a limited partnership that engages in oil and gas exploration, whose securities are listed on TASE. It is further noted that a listed oil and gas limited partnership will be entitled to perform additional projects that were not explicitly defined in the partnership agreement, subject to approval from the general meeting both according to the provisions of the TASE Rules (Chapter Q of Part Two of the Rules) and the provisions of the partnership agreement.
For the details of the amendment of March 2019, see https://mayafiles.tase.co.il/reports/1216001-1217000/E1216813.pdf.

2.7. It is further provided in the Partnership Agreement that the principal part of the Partnership's expenses would be "Exploration and Development Expenses", within the meaning of such term in the Income Tax Regulations (Rules for the Calculation of Tax due to the Holding and Selling of Participation Units in an Oil Exploration Partnership), 5749-1988[10] (the "**Income Tax Regulations (Participation Units**)").

2.8. For details regarding the Partnership's material petroleum assets, which include the Leviathan Leases, the Tamar and Dalit leases and Block 12 in Cyprus (the Aphrodite reservoir), see Sections 7.2 to 7.4 below.

The following table presents details with respect to the optimal evaluation (best estimate resources/2P reserves) of the quantities of the reserves, contingent resources and prospective resources attributed to these assets (in 100% terms)[11], as estimated by the independent evaluator Netherland Sewell and Associates Inc. (the "**Evaluator**" or "**NSAI**").

The resource data in the following table do not include resources attributed to the Tamar South West reservoir, discovered in the area of the Tamar Lease ("**Tamar SW**"), which extend into the area of the Eran/353 license (the "**Eran License**"). For further details on the Eran License and the mediation arrangement regarding the Eran License and the Tamar SW License, see Section 7.9.2 below.

The Partnership's holding rate in the Tamar and Dalit leases as presented in the table below (22.0%) does not include a holding of 22.6% in the shares of Tamar Petroleum.

In addition to the above assets, the Partnership has rights in additional petroleum assets which, as of the date of approval of the report, are classified as negligible petroleum assets, as follows:

- The exploration licenses 405/"New Ofek" and 406/"New Yahel" (the "**New Ofek License**" and the "**New Yahel License**", respectively);
- Rights to receive royalties from the I/16 "Tanin" and I/17 "Karish" leases (the "**Tanin Lease**" and the "**Karish Lease**", respectively);
- Yam Tethys project in leases I/7 "Noa" and I/10 "Ashkelon" (the "**Noa Lease**" and the "**Ashkelon Lease**", respectively).

For details on these petroleum assets, see Sections 7.5-7.8 below.

For details on petroleum assets, the activity in which has been terminated, see Section 7.9 below.

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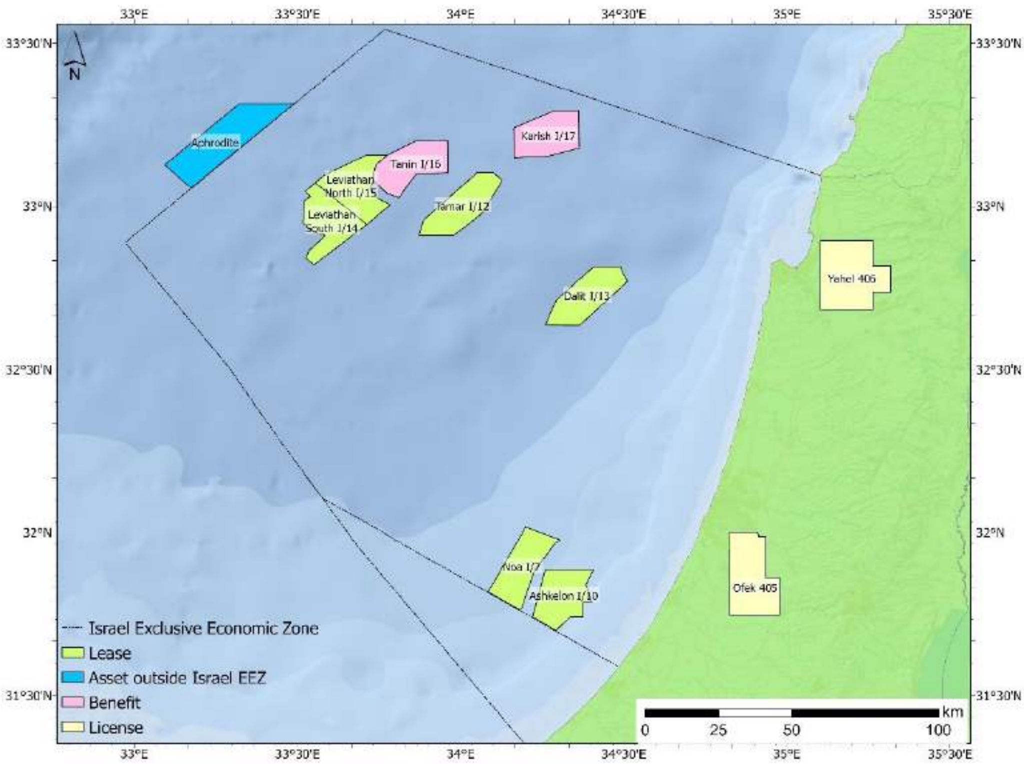
[10] It is noted that the said regulations were effective until June 30, 2015, and as of the report approval date, have not yet been extended. It is further noted that on October 12, 2020, the Draft Income Tax Regulations (Rules for the Calculation of Tax due to the Holding and Sale of Participation Units in Oil Exploration Partnerships) (Amendment), 5781-2020 were published for public comment. For further details in this regard, see Section 7.21.2 below.

[11] With respect to all assets for which reserve and/or resource quantity evaluation data are presented, the data are as of December 31, 2020.

Petroleum assets in which the Partnership has a direct and indirect holding														
Name of Project	Name of Petroleum Assets	Type of Interest	Rate of Partnership's Interests in the Petroleum Assets	Reservoirs Discovered in the Area of the Petroleum Asset/s	Optimal Evaluation (2U) of the Total Quantity of the Prospective Resources[12] (100%)			Optimal Evaluation (2C) of the Quantity of Contingent Resources (100%)			Optimal Evaluation (2P) of the Total Quantity of Reserves (100%)		
					Natural Gas BCF	Conde-nsate Million barrels	Oil Million barrels	Natural Gas BCF	Conde-nsate Million barrels	Oil Million barrels	Natural Gas BCF	Conde-nsate Million barrels	Oil Million barrels
Leviathan	Leviathan Leases	Lease	45.34%	Leviathan	-	-	-	9,580.9	21.1	-	13,087.6	28.8	-
Deep Leviathan	Leviathan Leases	Lease	45.34%	Leviathan	390.2	-	379.2	-	-	-	-	-	-
Tamar	Tamar Lease	Lease	22%	Tamar and Tamar SW	-	-	-	-	-	-	10,481.2	13.6	-
Dalit	Dalit Lease	Lease	22%	Dalit	267.6	-	-	270.7	-	-	-	-	-
Block 12 in Cyprus	Block 12	Production sharing	30%	Aphrodite	912.6	1.9	-	3,476.7	7.6	-	-	-	-

[12] The prospective resources stated below are located in several fault blocks and/or various prospects, the chances of the presence of which vary.

<u>The following map shows the Partnership's petroleum assets, as of the report approval date</u>



3. Investments in the Partnership's Capital and Transactions in Participation Units

For details on changes in interested parties' holdings in the Partnership that were made following a full exchange tender offer made by the Delek Group to purchase shares of Delek Energy, in consideration, *inter alia*, for participation units of the Partnership, see immediate reports of the Partnership dated October 9, 2018, October 15, 2018 and February 18, 2019 (Ref.: 2018-01-090619, 2018-01-092839 and 2019-01-015375, respectively).

In Q1/2020 Delek Group sold Participation Units. For details on the said transactions, see the Partnership's immediate reports of March 15, 2020, March 25, 2020 and March 29, 2020 (Ref. nos. 2020-01-021130, 2020-01-024864, 2020-01-029802 and 2020-01-031272, respectively).

4. Distribution of Profits

4.1. In the period from January 1, 2019 to December 31, 2020, the Partnership declared profit distributions (as defined in the Partnership Agreement), as specified below:

Declaration Date	Distribution Date	Distribution Amount per Participation Unit	Total Distribution Amount	Immediate Report
August 13, 2019	September 5, 2019	$0.12779	$150 million	Ref.: 2019-01-069840

Declaration Date	Distribution Date	Distribution Amount per Participation Unit	Total Distribution Amount	Immediate Report
November 17, 2020	December 7, 2020	$0.05537	$65 million	Ref.: 2020-01-115519

4.1. For details on the provisions of Section 19 of the Taxation of Profits from Natural Resources Law, 5771-2011 (the "**Taxation of Profits from Natural Resources Law**") regarding the payment of the tax liability that applies to holders of the Participation Units, including the balancing payments, see Section 7.21.3 below.

4.2. As of December 31, 2020, the Partnership has profits available for distribution in the amount of approx. 821 million U.S. Dollars ("**Dollars**" or "**$**").

4.3. Other than restrictions set forth in financing agreements, as specified in Section 7.20 below, and restrictions deriving from the provisions of Section 19 of the Taxation of Profits from Natural Resources Law, as specified in Section 7.21.3 below, as of the report approval date, there are no external restrictions that may affect the Partnership's ability to distribute profits in the future.

4.4. <u>The provisions of the Partnership Agreement regarding a profit distribution and resolutions of general meetings thereon</u>

4.4.1. The Partnership Agreement provides that all of the Partnership's profits, which are distributable, by the Partnership under law, net of amounts (which were not taken into account for the purpose of determination of the profits) required for the Partnership, as per the discretion of the General Partner, for the purpose of or in connection with the Partnership's existing undertakings, including the repayment of loans, and including amounts which are required, in the opinion of the General Partner, in order to meet unforeseeable expenses, the amount of which shall not exceed $250,000 (in this section: the "**Profits**"), will be distributed to the partners in the Partnership according to their rights.

4.4.2. Once a year, on or about the end of the year, the General Partner, in consultation with the Partnership's accountants, will perform an estimation of the Partnership's annual taxable income. Based on such estimation, the General Partner will determine the amount for first distribution (the "**First Distribution Amount**"). The First Distribution Amount will be published by the General Partner before the year-end and thereafter distributed to the partners (as being at the year-end). The balance of the Profits remaining for distribution (if any) due to the same year will be determined by the General Partner and published shortly after the release of the Partnership's audited financial statements for the same year (the "**Second Distribution**"). The Partnership Agreement clarifies that in the event that after the Second Distribution it transpires, following a change of circumstances, that additional amounts may be distributed for the same year, the General Partner may perform additional distributions for the same year, and the General Partner will be obligated to do so if the additional distributable amounts exceed $3 million.

4.4.3. Calculation of the Profits will always be made for the year ending on December 31. Notwithstanding the aforesaid, no amounts will be distributed if receipt thereof by the Limited Partner is deemed a withdrawal of its investment or part thereof, within the meaning thereof in Section 63(b) of the Partnerships Ordinance. In any event of doubt as to whether the distribution of any amounts to the Limited Partner is deemed a withdrawal of its investment or part thereof as aforesaid, the distribution will not be performed, unless the Supervisor consents thereto.

4.4.4. In accordance with the resolution of a meeting of the Participation Unit holders on April 8, 2010, the Partnership Agreement was amended, such that the General Partner may refrain from the distribution of profits, insofar as required, if required at all, for the purpose of participation in the development and production work in the Tamar and Dalit leases, which shall be approved by the General Partner, from time to time, according to the joint operating agreement which applies to such leases.

4.4.5. On December 30, 2013, a meeting of the Participation Unit holders was held, in which it was resolved, *inter alia*, to approve refraining from distribution of profits (within the meaning thereof in the Partnership Agreement), for the purpose of investment thereof in the development of the Leviathan reservoir according to the work plan and budgets approved and/or to be approved under the joint operating agreements that apply to the Leviathan Leases, and also to approve use of the surplus cash accumulated and to be accumulated by December 31, 2014, for the purpose of investment thereof in activities of exploration and evaluation in the Leviathan Leases and in Block 12 which is situated in the EEZ of Cyprus, according to a work plan and budgets approved and/or to be approved under the joint operating agreements that apply to the aforesaid petroleum assets.

4.4.6. On July 1, 2018, a meeting of the Participation Unit holders was held, in which it was resolved to approve refraining from distribution of profits (within the meaning thereof in the Partnership Agreement), for the purpose of investing the same in the purchase of rights in EMG only, in order to enable engagement with EMG in connection with the use of the existing gas pipeline between Israel and Egypt and the facilities owned thereby for the purpose of piping of natural gas only. For details, see the Partnership's immediate reports as of June 11, 2018, June 28, 2018 and July 1, 2018 (Ref.: 2018-01-049728, 2018-01-062350, and 2018-01-063043, respectively), the details of which for the purpose of this resolution are incorporated herein by reference. For details on the EMG Transaction (as defined below), see Section 7.25.6 below.

4.4.7. On May 16, 2019, a meeting of the unit holders was held at which it was resolved, *inter alia*, to give approval to the General Partner to refrain from the distribution of profits (as defined in Section 9.4 of the Partnership Agreement) for the purpose of their investment in oil and/or gas exploration and the production thereof in the Royee[13], New Ofek and New Yahel licenses. For details see the Partnership's immediate reports dated March 31, 2019 and May 16, 2019 (Ref.: 2019-01-028755 and 2019-01-042057, respectively), the information in which is incorporated herein by reference.

5. Financial Information regarding the Partnership's field of business

5.1. For figures with respect to revenues, costs, profit from ordinary activities in the field of business, see the statements of comprehensive income included in the financial statements (Chapter C hereof).

5.2. For details with respect to the total assets and liabilities of the Partnership as of December 31, 2020 and December 31, 2019, see the Statements of Financial Position included in the financial statements (Chapter C hereof).

5.3. For explanations with respect to the aforesaid financial data, see Part One of the board of directors' report (Chapter B hereof).

6. General Environment and the Effect of External Factors

6.1. The Petroleum Law, 5712-1952 (the "**Petroleum Law**") governs the regulation in the sector of oil and natural gas exploration and production in Israel and prescribes, *inter alia*, that oil and gas exploration activities in Israel can be conducted in geographical areas in which the exploring entity was granted a gas and petroleum right under the Petroleum Law. The Natural Gas Sector Law mainly governs the issue of transmission, distribution, marketing and storage of natural gas and/or liquefied natural gas (LNG) within the State of Israel. In addition, the Taxation of Profits from Natural Resources Law regulates, *inter alia,* issues of tax, petroleum profit levy and payment of royalties to the State. For further details with respect to the Petroleum Law, the Natural Gas Sector Law and the Taxation of

[13] As of the report approval date, the Partnership's operation in the Royee license has terminated, for further details see Section 7.9.1 below.

Profits from Natural Resources Law, see Sections 7.23.3(a) and 7.23.3(d) below, respectively.

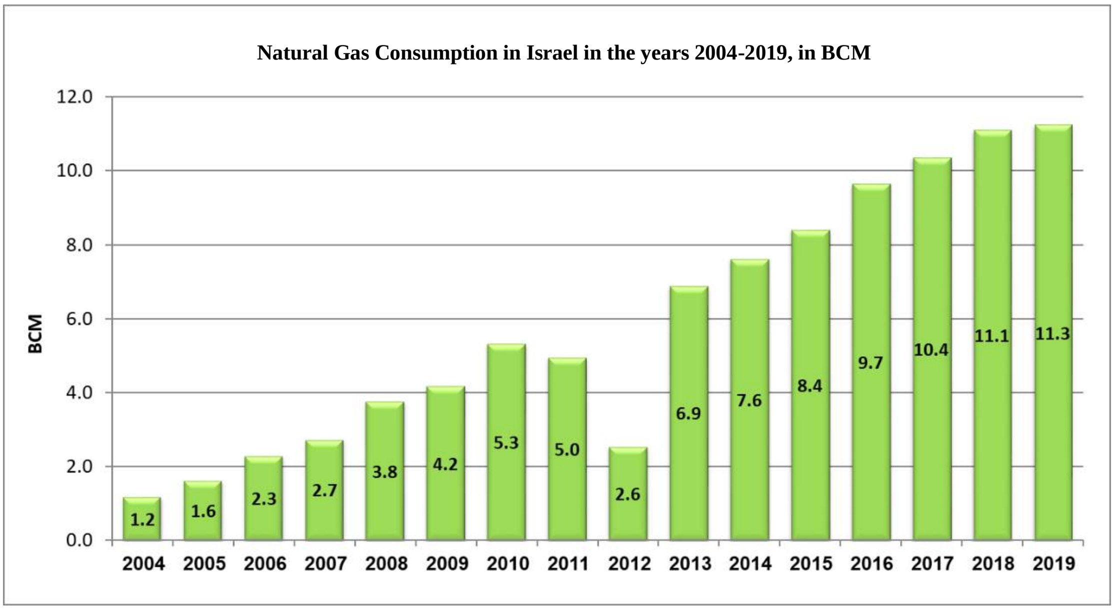
6.2. The economic merit of investments in the exploration for and development of natural gas reservoirs is greatly affected by oil and gas prices in the world, *inter alia* by LNG prices, by the demand for natural gas in the global, regional and domestic markets and by the ability to export natural gas (whether by pipes, in compressed form or in liquid form), which requires, *inter alia*, gas resources of considerable volumes and engagements in long term agreements for the sale of natural gas in substantial amounts, to justify the large investments required for construction of the appropriate infrastructures and/or the payments in respect of usage fees for preexisting infrastructures. In addition, the amount of the payments to the State has a material impact on the economic merit of investments in oil and gas projects.

6.3. The development of the natural gas sector in Israel began in 1999-2000 upon the discovery of the Noa reservoir in the Noa Lease and the Mari B reservoir in the Ashkelon Lease. The overall consumption of natural gas in Israel has increased concurrently with the progress in the construction of the transmission infrastructure of INGL and the connection of consumers (including power plants of the IEC and private power plants) to the transmission system and of smaller consumers to the distribution network.

6.4. In the past two decades, the natural gas sector in Israel has been undergoing significant changes (which include, *inter alia*, regulatory, economic, commercial and environmental changes). Within a few years, natural gas has become the primary component in the Israeli economy in the range of fuels for electricity production and a significant energy source for industry in Israel. The natural gas resources that have been discovered in Israel can provide for all of Israel's gas needs in the next decades and for most of its energy needs, thereby substantially reducing the State of Israel's dependence on foreign energy sources, as well as enabling export of natural gas in material quantities to countries in the region, and chiefly to Egypt and Jordan.

6.5. According to the data of the Ministry of Energy[14], the scope of use of natural gas in Israel increased from approx. 7.6 BCM in 2014 to approx. 11.3 BCM in 2019, where in 2020, it is estimated by the Partnership at approx. 12 BCM, as specified in the graph below:

[14] Source of data: The Ministry of Energy, Natural Gas Authority, Review of the Developments in the Natural Gas Sector – 2019 summary, https://www.gov.il/BlobFolder/reports/ng_2019/he/ng_2019.pdf.



2017 saw the commencement of natural gas export from the Tamar reservoir to Jordan for the first time, at a volume of approx. 0.07 BCM, which increased in the following years to approx. 0.14 BCM in 2018, to approx. 0.22 BCM in 2019 and to approx. 0.23 BCM in 2020. In addition, from July 2020, export of natural gas began from the Tamar reservoir to Egypt, which totaled approx. 0.25 BCM in 2020.

6.6. December 31, 2019 saw the commencement of natural gas flow from the Leviathan reservoir to the domestic market, and January 1, 2020 and January 15, 2020 saw the commencement of natural gas flow from the Leviathan reservoir to Jordan and to Egypt, respectively. In 2020, approx. 3.5 BCM of natural gas was supplied from the Leviathan reservoir to the domestic market, and approx. 1.9 BCM and approx. 1.9 BCM to Jordan and to Egypt, respectively.

6.7. In the Partnership's estimation, by 2040, natural gas consumption in Israel is expected to double, *inter alia*, given the connection of additional gas suppliers to the national transmission system, the Government's policy with regard to the increase of use of natural gas for electricity production and the gradual discontinuation of electricity production via polluting coal-fired power plants by the end of 2025 through, *inter alia*, the closedown of 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 uses in some transportation sectors (such as conversion of buses and heavy vehicles to natural gas use), accessibility to natural gas for additional industrial enterprises throughout Israel, *inter alia*, through a government-sponsored program to supports companies that received a government franchise to lay down a distribution pipeline for the purpose of upgrading the distribution systems, implementation of the use of natural gas in additional segments, such as housing, services, etc., external increase in the scope of demand for electricity (*inter alia,* in view of the expedited introduction of electric vehicles, the railway electrification, the construction of additional facilities for seawater desalination, and more), which accordingly increases the demand for natural gas, development and tapping of industries based on natural gas as feedstock (such as development of petrochemical plants that use natural gas), and policy actions taken in favor of the matter, all over and above the natural increase in demand for natural gas and for electricity in the Israeli economy due to population growth and an increased standard of living. It is noted that the said increase in the demand for natural gas is expected to moderate against the backdrop of the government resolution on “Promotion of renewable energy in the electricity sector and amendment of government resolutions” of October 25, 2020. For details, see Section 7.23.5(f) below. With respect to the decision of the Minister of Energy to reduce the use of coal and the reform at the IEC and in the electricity sector, and the Minister of Energy’s plan to save Israel from the consequences deriving from the use of polluting energy, see Sections 7.23.5(d), and 7.23.5(e) below, respectively. With respect to orders in relation to an increase of the excise tax on coal and on CNG, see Section 7.23.5(h) below.

6.8. An additional operation of the Partnership’s is conducted in Cyprus – for a description of the general environment and the competition in the market in Cyprus, see Section 7.14.4(b) below.

6.9. <u>The spread of Covid-19 and the possible impact thereof on the Partnership’s business</u>

At the end of 2019 and during Q1/2020, Covid-19 began spreading through China and subsequently throughout the world, and in March 2020 it was declared a global pandemic by the World Health Organization (the “**Covid-19 Crisis**”).

During the H1/2020, extremely sharp declines were recorded in the international markets in oil and natural gas prices, which may, in the Partnership’s estimation, be attributed to the Covid-19 Crisis, as well as to other causes and reasons which affect the supply and demand of energy products. However, towards the end of 2020 and in the first months of 2021, a recovery is felt in the prices of energy products worldwide, including oil and LNG prices.

In addition, in H1/2020 and mainly during Q2, stagnation in the demand for natural gas has been recorded in the domestic market compared with the same period last year, mainly due to the effect of the Covid-19 crisis on the demand for electricity in these markets as a result of closures and restrictions on economic activity. It is noted that even though the Covid-19 crisis continued, an increase in the demand for natural gas was recorded in H2/2020 compared with the same period last year.

As of the report approval date, it is difficult to estimate how the Covid-

19 Crisis will continue to develop in the coming years, what the extent of its impact on the global economy will be and what will be its impact on the demand and sales from the Leviathan and Tamar reservoirs in the coming years. In these circumstances, the Covid-19 Crisis constitutes a global macroeconomic risk that creates uncertainty as to the future economic activity in the world and the expected effects on financial markets, interest rate margins, currency exchange rates and commodity prices in the energy sector and may adversely affect many industries including the energy sector in which the Partnership operates.

For further details in this regard, see the paragraph "Factors affecting the price of and demand for natural gas and other energy products" in Section 7.1.3(b) below.

As part of their Covid-19 strategy, the Tamar Partners, the Leviathan Partners and the partners in Block 12 in Cyprus worked to streamline and reduce operating budgets for 2020 and postpone planned investment budgets to later years. Accordingly, the partners in the said projects approved updated budgets for 2020, such that the actual overall reduction amounted to some $170 million (100%; Partnership's share approx. $56 million). The Partnership is continuing to work with its partners in the said projects to expand the streamlining plans into the coming years.

Furthermore, as a result of the spread of the Covid-19 Crisis, many countries, including Israel, are taking extreme measures to prevent the virus from spreading, such as restrictions on civilian movement and gatherings, transport restrictions on passengers and goods, closure of international borders, and other suchlike. Beyond the negative impact of these measures on local and global economic growth, the restrictions and actions taken and that will be taken by Israel and other countries in coping with the Covid-19 Crisis may have a material adverse effect on the Partnership's work plans. As a result of these measures, delays may be caused in the entry of foreign experts and in the supply of designated equipment to Israel due to restrictions that apply to civilian movement between sites and countries, and restrictions on production or shipping that apply in the various countries, which may, *inter alia*, disrupt the regular production activity, the work plans of the operator and also impose unexpected additional costs. In this context, it is noted that Noble, which operates the Tamar and Leviathan projects, in coordination with the Petroleum Commissioner and the Ministry of Health, has put together an action plan for dealing with the Covid-19 Crisis, *inter alia*, with the aim of ensuring, insofar as possible, that the operator's workforce will be able to get to the offshore and onshore facilities of the projects and continue in the performance of essential activities in such facilities. As of the report approval date, the Covid-19 Crisis has not had a material adverse effect on the operation system in the Tamar and Leviathan projects. However, since there is uncertainty as to the manner in which the Covid-19 Crisis will develop, there is a risk that despite the prevention measures being taken by the partners in the projects, the operation of the reservoirs will be impacted.

Caution concerning forward-looking information – The Partnership's assessments regarding the possible repercussions of Covid-19 constitute forward-looking information, as defined in Section 32A of the Securities Law, 5728-1968 (the "Securities Law"). Such information is based, *inter alia*, on the Partnership's assessments and estimates as of the date of this report and on reports published in Israel and around the world on this issue and the instructions of the relevant authorities, the materialization of which, in whole or in part, is uncertain and not in the Partnership's control.

6.10. The principal external factors that affect this sector are:

6.10.1. Fluctuations in linkage components in the formulas of natural gas prices

The gas prices stated in the agreements for the sale of natural gas from the Tamar and Leviathan projects are based on various pricing formulas including, *inter alia* linkage to the Brent barrel price, linkage to the electricity production tariff as determined from time to time by the Public Utility Authority-Electricity (the "**Electricity Production Tariff**"), linkage to the U.S. CPI, and linkage to the Shekel/Dollar exchange rate (jointly: the "**Linkage Components**")[15]. It is noted that some of the natural gas sale agreements include a floor price and some include a fixed price, and therefore the Partnership's exposure to fluctuations in the Linkage Components in such agreements is hedged by a bottom threshold.

A change in any of the aforesaid Linkage Components may affect the economic merit of development or expansion of existing and/or new reservoirs discovered and/or to be discovered in the future (if any) by the Partnership and the scope of production therefrom, and consequently the Partnership's decisions in connection with the foregoing.

For details regarding the sensitivity analyses performed by the Partnership on the main Linkage Components of the gas prices according to the agreements for the sale of gas in which the Tamar Partners engaged (the U.S. CPI and the Electricity Production Tariff), see Section 7.3.11(a)5 below.

[15] It is noted that in addition to the effect of the changes in the Brent barrel price, the Partnership's business is also indirectly affected by the prices of natural gas and other alternative energy products which are determined on the international markets. For further details, see Section 7.1.3 below.

6.10.2. <u>Regulation</u>

Exploration, development and production of oil and natural gas are subject to the regulation in the countries within which the activity is conducted. The sector of exploration, development and production of oil and natural gas in Israel is subject to extensive regulation with respect to petroleum assets (including rules for granting, transferring and pledging the same), conditions for development, production and supply (including the construction of transmission and distribution and consumer connection infrastructures), royalties, taxation, environmental regulation, restrictive trade practices and so forth. Following the gas discoveries which were made by the Partnership and its partners in the various petroleum assets, in the State of Israel's EEZ, there has been a significant increase in the extent of regulation of the energy sector in Israel in general and in connection with the natural gas discoveries in particular, including: the enactment of the Taxation of Profits from Natural Resources Law, the Government's decisions regarding adoption of recommendations of the Committees for Examination of the Government Policy on the Natural Gas Sector (collectively: the "**Government Resolution on Export**"), the declaration by the Competition Commissioner (the "**Competition Commissioner**") of the Partnership together with the other Tamar Partners as monopoly holders in natural gas supply to Israel, the release of various directives by the Petroleum Commissioner at the Ministry of Energy (the "**Petroleum Commissioner**") (for further details, see Section 7.23.4 below), the Government Resolution on the Gas Framework as specified in Section 7.23.1(c)6 below, the national outline plan on the reception and processing of natural gas, etc. ("**NOP 37/H**"), and directives on the method of calculation of the royalty value at the wellhead with respect to offshore petroleum interests, as specified in Section 7.23.4(b) below.

For details with respect to restrictions and supervision over the activities of exploration, development and production of natural gas and/or oil in Israel and in Cyprus, see in Section 7.23 below.

6.10.3. <u>Supply and demand conditions</u>

For details on the supply and demand in the international markets and in the local market, see Sections 7.1.3(b) and 7.12.2(b)(2) below.

7. <u>Description of the Partnership's Business per field of business</u>

7.1. <u>General information about the field of business</u>

7.1.1. <u>Structure of the field of business and changes occurring therein</u>

The operation of exploration, development and production of oil and natural gas is complex and dynamic, involving substantial costs and evident uncertainty with respect to costs, timetables, the presence of oil or natural gas and the ability to produce them while protecting the environment and maintaining cost effectiveness. As a result thereof, despite considerable investments, the exploration activities, including the exploration and appraisal drilling often does not accomplish positive results and do not generate any revenues and may lead to the loss of most or all of the investment in a relatively short time.

Activities of exploration, development and production of oil and natural gas are usually conducted in the framework of joint ventures between several partners who sign a joint operating agreement (JOA), whereby one of the partners is appointed as the operator of the joint venture (for a description of a joint operating agreement, see, for example, an operating agreement that applies to the Tamar Project, which is described in Section 7.25.7 below).

A typical process of exploration, development and production of oil and natural gas in any area may include, *inter alia*, the following stages:

(a) Initial analysis of existing geological and geophysical data, for the selection of areas presenting a potential for oil and natural gas exploration.

(b) Formulation of an initial geological model (Play).

(c) Performance of various geophysical surveys, including seismic surveys, which assist in the location of geological structures that may contain oil and/or natural gas (Leads) and data processing and interpretation.

(d) Examination of the Leads and preparation of prospects fit for test drilling therefrom.

(e) Decision to perform test drilling and performance of activities in preparation for the drilling.

(f) Engagement with contractors for the performance of the drilling and for receipt of related services.

(g) Performance of the test drilling, including logs and additional tests.

(h) Performance of production tests (, to the extent justified by the findings of the drilling).

(i) Analysis of the results of the drilling and, in the event of a finding, based on an initial evaluation of the features of the reservoir and the amount of oil and/or natural gas, an economic (including a market assessment) and fiscal analysis and an initial evaluation of the development format and cost. There may be additional seismic surveys and/or appraisal wells, as necessary, for the purpose of formulating a better estimate of the features of the reservoir and the amount of oil and/or natural gas present therein.

(j) Examination of the alternatives for commercialization of the oil and/or natural gas, identification of the target markets and examination thereof, formulation of a development plan and preparation of a financial plan for the project.

(k) A final analysis of the data and a final investment decision (FID).

(l) The projects for development of natural gas findings require, over and above engineering feasibility, also the signing of binding long-term supply agreements for appropriate quantities and prices with customers that have the financial ability that allows for obtaining project financing.

(m) Development of the reservoir, including the performance of production drilling, layout of transmission pipeline, construction of treatment facilities and so forth.

(n) Production from the reservoir, including operation and ongoing maintenance, and performance of additional development work in the purpose of preserving and/or increasing the production volume.

(o) When the reservoir is depleted, and after weighing various technical, economic and regulatory parameters – plugging the wells, abandoning the facilities and the area of the lease, in accordance with the local accepted standards.

Due to the various characteristics and data of each and every project, the stages specified above are not necessarily exhaustive of all of the stages of the exploration, development, production and abandonment process in a specific project, which, due to the quality and nature thereof, may only include some of the aforesaid stages and/or additional stages and/or stages in a different order.

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

It is noted that the commerciality of oil and/or natural gas findings is complex and dependent upon numerous and various factors. In this context, there are material differences between an offshore finding, the development of which requires financial input and use of unique technologies, such as drilling at a considerable water depth or laying subsea facilities and pipelines which are able to operate at a high level of reliability in the sea depths, and an onshore discovery, whose development costs may be substantially lower. In addition, the financial, logistical and technical inputs required to develop a natural gas reservoir, including for building 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 immeasurably more significant relative to those required for development and production from a natural gas reservoir which is designated solely for the local domestic market. An additional key parameter is the demand and the price at the target markets. There is great difficulty in developing a project of significant scope when the demand and prices of natural gas do not allow the raising of project finance. Furthermore, there are substantial technological, marketing and financial differences between oil reservoirs and natural gas reservoirs. For example, the economic merit of a natural gas reservoir mostly derives from the ability to market it to a guaranteed attractive target over the course of years, due to the fact that unlike oil, natural gas is not a commodity which is sold for similar prices all around the world and transportation thereof to the target markets may be complicated and entail liquefaction or compression. Moreover, the commerciality of an oil reservoir is highly impacted by global oil prices, thus, for example, a reservoir which is not commercial when the price of an oil barrel is X Dollars, may become commercial when the price of an oil barrel rises to 1.5X Dollars and vice versa. In light of the aforesaid, naturally, oil and/or natural gas reservoirs, which are not commercial under certain market conditions, may become, upon the occurrence of material changes in the regulation and market conditions, commercial reservoirs, and vice versa.

7.1.2. <u>Restrictions, legislation, standardization, directives and special constraints applicable to the field of business</u>

For details, see Section 7.23 below.

7.1.3. <u>Developments in markets or changes in customer characteristics</u>

(a) As of the report approval date, the Partnership sells natural gas from the Tamar and Leviathan projects to various customers in the domestic and regional market, the most important of which being the IEC, NEPCO in Jordan, and Dolphinus in Egypt. For a description of the Partnership's agreements with its customers, see Sections 7.11.4 and 7.11.5 below. In addition, the Partnership sells condensate, as specified in Section 7.11.6 below.

At the same time, and in light of the significant volume of resources discovered off the shores of the State of Israel, mainly in the Tamar and Leviathan natural gas reservoirs, the Partnership is acting to identify additional markets and customers, in the domestic market and in neighboring countries and/or markets in Europe and in Asia, subject to restrictions on gas export, as specified in Section 7.23.1(c)2 below. The Partnership is also promoting use of infrastructures now in existence and/or that will exist in the foreseeable future and/or that will be built especially for natural gas export purposes including additional ways to export the natural gas, including by way of the liquefaction (LNG) and/or compression (CNG) thereof. For further details in this matter, see Sections 7.11.5 and 7.12.2(b) below.

(b) <u>Factors affecting the price of and demand for natural gas and other energy products</u>

The demand for energy in general and natural gas in particular depends on a number of key factors, including energy prices, GDP (gross domestic product) growth rate, 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 the Israeli economy, through, *inter alia*, encouraging development of energy sources that serve as alternatives to natural gas, such as renewable energies; energy storage measures; the rate of entry of electric vehicles; the rate of connection of plants to the natural gas system; construction of new natural gas-powered power plants and the rate of conversion of coal-fired power plants to natural gas use.

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 gas sales and the sale prices of natural gas, both under existing agreements and under future agreements, such as agreements for natural gas sale to liquefaction facilities and/or LNG sale agreements, thereby affecting the economic viability of the promotion of new projects that depend on the LNG market or of the expansion of existing projects. Moreover, low LNG prices in international markets may lead to increased LNG import into Israel and/or into the regional markets, reducing the demand for natural gas produced in Israel in the markets relevant to the Partnership and reducing the Partnership's revenues from the Tamar and Leviathan reservoirs. Thus, high LNG prices reduce the import of LNG into Israel and/or the regional markets, and increase the demand for natural gas that is produced in Israel.

In recent years, there has been a significant increase in the capacity to produce LNG, *inter alia* due to the operation of new liquefaction facilities, or expansion of existing facilities, such as liquefaction facilities in the U.S., Qatar, Russia (in the Arctic Circle) and Australia. However, on the demand side there has been a significant slowdown, *inter alia* as a result of the Covid-19 Crisis and the accumulation of natural gas stock in natural gas storage facilities. Such excess supply over demand caused, in these years, a drop 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 which the LNG surpluses were directed.

During 2020, sharp fluctuations were recorded in oil and natural gas prices in the international markets. In the Partnership's estimation, such price fluctuations should be attributed to a combination of several factors, including: (a) A rise in the supply and a decrease in the demand for natural gas (including LNG), *inter alia*, due to the introduction of new liquefaction facilities and due to weather conditions, as specified above; (b) A significant decrease in the demand for energy products due to the spread of the Covid-19 Crisis, as specified in Section 6.9 above; (c) Global macroeconomic factors such as quantitative expansion plans, fluctuations in global exchange rates, etc.; and (d) the U.S.-China trade war and the lack of agreement between oil producing countries on the imposition of coordinated restrictions on global oil production volumes for the purpose of balancing and increasing oil prices.

It is noted that the aforesaid decrease in prices and the excess supply of LNG in the world 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 details, see Section 7.14.2 below.

For further details regarding projects of the Partnership for increasing the demand for natural gas, see Section 7.27.7 below.

As of the report approval date, a recovery in the energy prices has been recorded in the international markets, and they have returned to price levels similar to those existing prior to the outbreak of the Covid-19 Crisis.

7.1.4. Material technological changes

The last decades saw technological changes in the field of oil and natural gas exploration, development and production, both in the area of information collection and analysis and in the drilling and production methods. These changes have improved the quality of the data available to oil and natural gas explorers and have allowed for more advanced identification of potential oil and natural gas reservoirs, and therefore may also reduce the risks of drilling. Furthermore, the technological improvements have increased the efficiency of the drilling and production work and also presently allow the performance of activities in rougher conditions than before, including at significant water depths. Accordingly, corporations exploring for oil and natural gas, are able to invest exploration efforts in areas where drillings were not feasible in the past, or were feasible but at very high costs and at greater risks. The Partnership and the operators in the various projects in which the Partnership is a partner strive to use the best available technologies in all of the operation segments. Thus, for example, until 2020 significant resources were invested in the reprocessing of seismic surveys by means of innovative technologies, in order to improve the database, update the maps of the reservoirs and the assessment of their characterizing parameters, and thereby accordingly update the volume of resources therein. 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 the facilities' safety and reduce their effect on the environment.

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

7.1.5. Critical success factors in the field of business

(a) Identification and receipt of exploration rights (purchase or farm-in) in areas presenting a potential for commercial finding.

(b) Financial abilities and ability to raise considerable financial resources.

(c) Use of advanced technologies, e.g., 3D seismic surveys and advanced information processing for the identification and preparation of prospects for drilling, for improvement of the evaluation of drilling results and for the formulation of a development plan.

(d) Joining forces with highly knowledgeable and experienced entities which operate in the sector for the purpose of performing complex development plans and/or drillings, while being assisted by the professional knowledge possessed thereby and the contribution thereof to the considerable financial investments.

(e) Success of the exploration activity.

(f) In the event of a natural gas find, engagement in agreements for the sale of gas in the appropriate quantities and for the appropriate prices.

(g) Existence of engineering, geological, financial and commercial knowledge, experience and ability to manage exploration, development and production projects at considerable financial scopes, including the construction of production and export infrastructures.

7.1.6. Changes in the suppliers and raw materials layout

For details, see Section 7.17 below.

7.1.7. Barriers to entry and exit

The main barriers to entry to the field of business are the need for permits and licenses for the performance of oil and natural gas exploration, development and production, compliance with the requirements of law and regulation, including the directives and criteria determined by the Petroleum Commissioner (and, in Cyprus – directives and criteria prescribed by legislation and arrangements under the Production Sharing Contract, as described in Section 7.4.3(j) below), the ability to transfer and/or purchase interests in petroleum assets, including as pertains to demonstration of the applicant's financial soundness and the operator's technical ability for the purpose of receipt thereof, and the existence of the financial and technical ability to make large-scale investments of billions of Dollars characterized by a relatively high level of risk, which are entailed by the performance of the exploration, development and production activities.

The significant barriers to exit in the field of business in Israel are mainly undertakings under long-term gas supply agreements in which the Partnership has engaged. In addition, both in Israel and in Cyprus, there is a duty to plug and abandon wells and to decommission production facilities before abandoning lease areas, as specified in the lease deeds, the production sharing contract in Cyprus and the provisions of the law regarding the abandonment of offshore oil and gas wells.

It is noted that, as concerns exit from existing projects by way of partial or full sale, there may be exit barriers that derive from the regulatory requirements that will apply to the purchaser, and from the substantial financial scale of such sale.

7.1.8. Substitutes for the products of the field of business

Natural gas is mainly used for electricity production and is sold in Israel and in the region mainly to electricity producers and industrial customers. In general, the alternatives to natural gas use are other fuels, the main ones of which are: diesel oil, fuel oil, coal, LPG, LNG, petcoke, as well as energy from renewable sources, such as solar energy, wind energy and so forth, including renewable energy that may be produced in excess of market demand and stored in storage facilities for use when the energy source is unavailable (for example during night hours when it is not possible to produce energy from solar sources). Each of the aforesaid interchangeable fuels and the alternative energy production methods has advantages and disadvantages and they are subject to volatility of prices, availability, technical constraints, availability of land and more. The switch from using one type of energy to using another type of energy usually involves large investments. The principal advantages of natural gas compared with coal and liquid fossil fuels, are the fact that the energy efficiency of power plants operated by natural gas is significantly higher than that of power plants operated by coal and fuel oil, and the fact that the emission of particles and nitrogen and sulfur oxides from the combustion of natural gas is significantly lower than that of coal and fuel oil. For details with respect to the Minister of Energy's announcement of the date of discontinuation of the use of coal in the State of Israel being brought forward to 2025 instead of 2030, and with respect to an update of the interim target for the production of electricity from renewable energies, which will be 20% by the end of 2025, see Sections 7.23.5(d) and 7.23.5(e) below, respectively.

7.1.9. Structure of competition in the field of business

For details, see Section 7.14 below.

Following are details regarding the Partnership's petroleum assets:

7.2. Leviathan project

7.2.1. General

General Details with respect to the Petroleum Asset	
Name of the petroleum assets:	Leviathan North Leviathan South
Location:	Offshore assets situated approx. 130-140 km west of the shores of Haifa.
Area:	The overall area of the two leases combined is approx. 500 km^2.
Type of petroleum asset and description of the activities permitted for such type:	Lease; Permitted activities under the Petroleum Law – exploration and production.
Original granting date of the petroleum asset:	March 27, 2014
Original expiration date of the petroleum asset:	February 13, 2044
Dates on which an extension of the term of the petroleum asset was decided:	-
Current expiration date of the petroleum asset:	February 13, 2044
Note on whether there is an additional option to extend the term of the petroleum asset; if such option exists – the optional extension term should be noted:	Subject to the Petroleum Law, it may be extended by another 20 years.
The name of the operator:	Noble
The names of the direct partners in the petroleum asset and their direct share in the petroleum asset, and, to the best of the Partnership's knowledge, the names of the controlling shareholders of such partners:	▪ The Partnership (45.34%). ▪ Noble (39.66%). ▪ Ratio Oil Exploration (1992) – Limited Partnership ("**Ratio**") (15%). To the best of the Partnership's knowledge, the general partner of Ratio, Ratio Oil Explorations Ltd., is a company co-owned by D.L.I.N. Ltd. ("**D.L.I.N.**") (34%), Hiram Landau Ltd. ("**Hiram**") (34%), Eitan Aizenberg Ltd. ("**Aizenberg**") (8.5%), Eyal Zafriri (4.3%), Edo Porat (1.4%), Asher Porat (1.4%), Daniel Soldin (1.4%) and Adv. Boaz Ben-Zur and Adv. Robi Behar in trust for Mr. 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 whose shares are held by the administrators of the estate of the late Yeshayahu Landau (Mr. Landau OBM left his shares in Hiram to his children Yigal Landau, Yuval Landau and Shlomit Landau, in equal shares). Aizenberg is a private company controlled by Eitan Aizenberg[16].

[16] As of the report approval date, the holdings of all of the interested parties in Ratio (apart from the holdings of institutional bodies, mutual funds and provident funds) are under 22%.

General Details with respect to the Partnership's Share in the Petroleum Asset	
For a holding in a purchased petroleum asset – the purchase date:	-
Description of the nature and manner of the Partnership's holding in the petroleum asset:	The Partnership directly holds 45.34% of each of the Leviathan Leases.
The actual share in the revenues from the petroleum asset attributable to the holders of the equity interests of the Partnership:	Before investment recovery – 37.63%. After investment recovery – 35.37%.
The total share of the holders of the equity interests of the Partnership in the aggregate investment in the petroleum asset during the five years preceding the last day of the year of the report (whether recognized as an expense or as an asset in the financial statements):	Approx. $1,634,168 thousand[17].

7.2.2. The principal terms and conditions of the Leviathan Leases

(a) The terms and conditions of the Leviathan North and Leviathan South leases are principally identical. The description presented below relates to the main subjects in the Leviathan South lease (in this Section: the "**Lease**"), and where there is a material difference in relation to the Leviathan North lease, it is stated.

(b) The Operator's actions will be binding on the lease holder and notices from the Petroleum Commissioner or anyone on his behalf to the Operator will be binding on the lease holder. Nothing in the provisions of this section shall derogate from the undertakings and liability of each of the Leviathan Partners to act in accordance with the provisions of the lease and the provisions of any law, jointly and severally.

(c) The lease holder will only replace the Operator with approval in advance and in writing by the Petroleum Commissioner.

(d) Scope of the lease

1. The lease holder will have the exclusive right to explore and produce oil and natural gas in the lease area alone, throughout the entire term of the lease, as aforesaid,

[17] The costs in the table reflect the Partnership's post-Merger holding in the Leviathan Leases, i.e., 45.34%, and exclude the costs of construction of the Israeli transmission system up to the Israel-Jordan border, as specified in Section 7.12.2(b)3.a below, costs in respect of Leviathan's Participation (as defined in Section 7.25.6(c) below) and additional expansion costs of the gas flow capacity to Egypt through the construction of the Combined Section (as specified in Section 7.23.5(d) and the EMG pipeline (as specified in Section 7.25.5 (a)).

subject to the other provisions of the lease deed and to any law.

2. The lease holder, at its sole responsibility, will plan, finance, construct and operate the production system and will maintain it for the purpose of its ongoing operation, all through the Operator, contractors, planners and consultants who have a high level of knowledge and vast 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.

(e) Term of the lease

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

(f) Sale to consumers in Israel and export

1. The lease holder will not unreasonably refuse to supply oil and natural gas to consumers in Israel.

   The export of gas from the lease will require written approval from the Petroleum Commissioner with the approval of the Minister of Energy (in this Section: the "**Export Approval**") in accordance with the government resolution as detailed in Section 7.23.1(c)2 below. Note that export will not be allowed in practice unless, following the execution of the development program, a quantity of 500 BCM will be available to the domestic market in accordance with the provisions of the foregoing government resolution. Similarly, export will not be allowed in a manner that harms the lease holder's ability to supply and to pipe, from the Leviathan field to the national transmission system, an amount of at least 1.05 MCM of gas per hour (from the areas leased to Leviathan together). In any event, the actual export will not begin prior to the date of commencement of the piping to the transmission system.

2. Despite the aforementioned provisions, the Petroleum Commissioner may consider decreasing the amount that the lease holder is required to supply and pipe from the Leviathan field to the national transmission system as aforesaid, if there is, *inter alia*, another lease holder that will receive a lease following March 27, 2014, that will

pipe or is expected to pipe gas to the national transmission system, according to a reasonable timetable.

3. In case of a shortage of natural gas in Israel, the lease holder will give preference to the needs of the local economy, in relation to its supply capacity which is not subject to sale undertakings under a contract thereof, valid at the time. The quantity that will be supplied, as aforesaid, to the local economy will be considered part of the quantity designated for the local economy according to the foregoing government resolution, and will not diminish the quantity permitted for export according to the Export Approval, to the extent it is given.

(g) <u>Construction of facilities and adjustment of the capacity to the needs of the local economy</u>

1. The planning and set up of the production system and transmission system to the shore, in the framework of the development program, will be performed so as to allow the supply and piping of gas to the national transmission system in an amount of at least 1.4 MCM per hour (approx. 12 BCM per year) from the areas of the Leviathan Leases jointly.

2. The lease holder may, subject to receiving written approval from the Petroleum Commissioner and the Director General of the Natural Gas Authority, as applicable, increase the capacity of the production system and the transmission system to the supplier, and add facilities and wells, in a manner that will allow for the piping of quantities of gas exceeding those stated in Subsection (1) above to the national transmission system.

3. The Petroleum Commissioner may demand that the lease holder, if necessary due to special circumstances, adds facilities and wells, and another entrance point to the production system and transmission system, in a manner that allows for the safe, reliable, and effective piping of quantities of gas, that exceed those aforementioned, to consumers in Israel; the demand, as aforesaid, will be made only if special circumstances exist, and while weighing and balancing all the relevant considerations, amongst them considerations of economic merit, and if the Petroleum Commissioner finds that the addition has no economic merit for the lease holder, only upon finding a solution thereto. If the Petroleum Commissioner demands, as aforesaid, the

lease holder will prepare an addition to the development plan and submit it for his approval within the period determined by the Petroleum Commissioner in his demand.

(h) <u>The commercial production</u>

1. Commercial production from the lease area will be conducted under the following principles:

   a. Production will be carried out with proper diligence, without waste, without creating a risk, and in a manner that does not constitute any harm to the features of the gas reservoir situated in the Leviathan field.

   b. The production from each well will be performed in a manner so as not to exceed the maximum effective output; the Petroleum Commissioner may instruct the lease holder, from time to time, of the maximum output, taking into account the data from the gas reservoirs located on the Leviathan field, and the characteristics thereof.

   c. The lease holder will maintain the quality of the gas piped by him to the national transmission system in accordance with the gas specification, as will be determined.

2. The lease holder will perform commercial production in accordance with the provisions of the authorized authorities and any law, and in accordance with the provisions of any license, permit, approval etc. required as such according to any law.

3. The lease holder will only commence commercial production and will only commence natural gas flow into the transmission system to the supplier, after the submission of an application for approval of the operation to the Petroleum Commissioner, and the approval of the application by him.

4. At the end of every year (at least 30 days prior to the end of the calendar year), the lease holder will submit to the Petroleum Commissioner a detailed work plan describing the work that he intends to perform in the following year with regards to the lease for the purpose of the production and compliance with the provisions of the lease deed, a projection of the costs for performing the activities in the aforementioned work plan, and a forecast of the production rate in the following year.

5. The lease holder shall notify the Petroleum Commissioner of the dates on which it intends to begin construction of additional facilities in order to fulfill the provisions of the lease deed.

(i) The supervision companies

The planning of the production system, the production of its components, its construction and operation will be carried out under the supervision of supervision companies with training and experience in supervising planning, production, construction or operation, as applicable, of maritime production systems, subject to the approval of the Petroleum Commissioner.

(j) The development plan

1. The lease holder will prepare and submit the development plan that it proposes for the Leviathan field to the Petroleum Commissioner for approval.

2. The lease holder will include in the development plan a detailed timetable for executing the development plan regarding the production system for the local economy, according to which the commercial production and the piping of gas to the transmission system will begin 48 months from the date of the provision of the lease deed.

3. The lease holder may submit to the Petroleum Commissioner a reasoned and detailed request to postpone or update the timetable determined in the development plan, as aforesaid. The Petroleum Commissioner will postpone or update the timetable, as requested or otherwise, as he sees fit under the circumstances, if convinced that the lease holder acted with appropriate diligence as required for keeping up with the timetable, and the delay in the timetable does not derive from an act or omission of the lease holder, or from an event the results of which the lease holder could, had he acted with the appropriate diligence, have prevented or limited or mitigated.

(k) Change of conditions in the lease deeds

If a layer is discovered on the area of the lease, from which crude oil can be produced in commercial quantities, the Petroleum Commissioner will add chapters to the lease deed that will include all that is necessary to adapt it to what is required for the production of crude oil, its processing and transmission; the lease holder will not produce oil from the leased territory, unless the aforesaid chapters are added, and in accordance with their provisions.

(l) Revocation or restriction of the lease

The lease will be terminated upon the end of the term of the lease, upon expiration thereof under Section 29 of the Petroleum Law, upon revocation thereof under Section 55 of the Petroleum Law, or upon the occurrence of either of the conditions specified below:

1. The lease holder shall have materially deviated from a material provision of the lease deed or from the instructions of the Petroleum Commissioner by virtue of the lease deed.

2. The guarantee (as detailed in Section 7.2.2(n) below) or a part thereof shall have been forfeited and the lease holder shall not have supplemented the amount of the guarantee as required under the provisions of the lease deed.

(m) Decommissioning plan

1. 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 will be reduced to less than 125 BCM, the lease holder will submit a detailed plan for the decommissioning of the facilities, and an estimate of the decommissioning costs (the "**Decommissioning Plan**") to the Petroleum Commissioner for approval. If the lease holder does not submit the foregoing Decommissioning Plan on time, or the Petroleum Commissioner finds that the Decommissioning Plan that was submitted is not suitable for approval, and the parties did not succeed in agreeing on a Decommissioning Plan, the Petroleum Commissioner will determine the Decommissioning Plan in accordance with the accepted international standards.

2. On the date of approval of the Decommissioning Plan by the Petroleum Commissioner, the Petroleum Commissioner will determine a plan for the lease holder according to which the lease holder will provide collateral or a deposit into an "abandonment fund", on the dates, in the format and according to the accrual method, as instructed by the Petroleum Commissioner, with the aim of ensuring that the lease holder will have the means required for executing the Decommissioning Plan.

3. The lease holder will provide notice of his intention to abandon a well, to the Petroleum Commissioner, at least 3 months prior to the date on which he requests to perform the act, and it will not be executed until after receiving written approval from the Petroleum Commissioner.

(n) Guarantees[18]

1. For the purpose of ensuring compliance with the provisions of the lease deed and any approval provided by the Petroleum Commissioner according to the lease deed (in this Section: "**Letters of Approval**"), for ensuring the payments from the lease holders to the State according to any law, and as a condition for the provision of a lease deed, the lease holder will provide an autonomous, unconditional and irrevocable bank guarantee in favor of the State of Israel in the amount of $50 million for each of the Leviathan Leases (and in total $100 million, while the Partnership's share is approx. $45 million) in accordance with timetables determined in advance (in this section: the "**Guarantee**"). As of the report approval date, each one of the holders of the Leviathan Leases has provided its share in the said Guarantee.

2. The Guarantee will be valid throughout the lease period and will continue to remain valid also following the expiration of the lease so long as the Petroleum Commissioner shall not have given notice that there is no need therefor, and subject to the provisions of the Petroleum Law.

3. The Guarantee will serve to ensure compliance with the provisions of the lease deed and the Letters of Approval by the lease holder, to ensure payments due according to any law by the lease holder to the State for compensation and indemnification of the State and any authority thereof, for any damage, payment, loss, or expense incurred thereby, directly or indirectly, following non-compliance with the provisions of the lease deed or Letters of Approval, on time and in full, or following the revocation of a condition in the lease, its limitation or its suspension or following any action or omission of the lease holder in connection with the lease and the compliance with the conditions of the lease deed, and ensuring the payment of pecuniary

[18] Such a guarantee will be provided for each of the Leviathan Leases separately, but each one of them will be used for both leases, as aforesaid.

sanctions if imposed on the lease holder according to any law.

4. The Petroleum Commissioner may forfeit the Guarantee, in full or part, in any of the cases detailed below:

   a. The lease holder did not carry out the development plan approved by the Petroleum Commissioner and according to the conditions determined in the approval, or did not set up the production system facilities, or did not begin the commercial production or the piping to the transmission system to the supplier on the dates determined therefor according to the lease deed or Letters of Approval.

   b. A safety or environmental malfunction occurred as a result of the lease holder's operations, and the lease holder did not repair the malfunction or its results according to the instructions of the Petroleum Commissioner and any law.

   c. With regards to the Leviathan North lease alone – the lease holder violated a term set by the Petroleum Commissioner in connection with the abandonment of the "Leviathan 2" well or did not execute in the optimal manner, the Abandonment Plan related to the foregoing well.

   d. The lease holder did not execute the abandonment in accordance with the Decommissioning Plan.

   e. A claim or demand is filed against the State for payment of compensation for damage caused due to a violation of any condition of the lease deed or the Letters of Approval, due to the deficient performance of the provisions of the lease deed or the Letters of Approval, or due to the revocation of the lease deed, and also if the State incurs expenses as a result of such claim or demand. Forfeiture of the Guarantee for the purpose of covering the amount of such claim will only be made after a judgment on such claim (including an arbitrator's award) becomes final and conclusive, and according to amounts ruled against the State in such judgment (and in the event of a settlement – subject to approval thereof by the lease holder, which approval shall not be unreasonably withheld) and subject to the lease holder being given the opportunity to join as a party to the proceeding;

f. The State incurs expenses or damage as a result of the revocation of the lease;

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

h. The lease holder did not comply with one of the provisions relating to insurance as determined in the lease deed or imposed on him according to any law.

i. The lease holder violated instructions given to him by a representation of the IDF on any security matter related to the production system.

j. The lease holder did not comply with the provisions in the lease deed relating to the Guarantee.

k. The lease holder materially breached another condition in the lease deed or the Letters of Approval or the instructions given him by the Commissioner according thereto.

5. If the Petroleum Commissioner finds that *prima facie* grounds are established for forfeiture, the Petroleum Commissioner shall give the lease holder notice thereof and enable him to respond in relation to the prima facie grounds and the possibility of forfeiture, within 7 days of receiving the cease-and-desist letter, unless under the circumstances waiting is not possible; If the Petroleum Commissioner decided, after weighing the lease holders response, if any, that there is room for forfeiture, a notice will be sent to the lease holder detailing the breach, the explanations for the forfeiture, and the amount of the forfeiture; the Petroleum Commissioner may contact the bank and demand the forfeiture commencing from the end of the 7 days from the day the notice was delivered, unless prior to that, the lease holder paid the amount determined in the notice.

6. Notwithstanding the provisions in Subsection (6) above, if the prima facie grounds for forfeiture is an act or omission that may be remedied, the Petroleum Commissioner may notify the lease holder that his request to the bank will be made if within a determined period the lease holder does not remedy the act or omission, and the stated period will pass without the lease holder remedying the act or omission to the satisfaction of the Petroleum Commissioner.

7. If the Guarantee or any part thereof is forfeited, the lease holder will provide a new guarantee, or supplement the balance thereof up to the amount of the Guarantee, as it is intended to be at such time, immediately upon receipt of the Petroleum Commissioner's demand.

8. Neither the authority to forfeit nor the forfeiture derogates from the State's right to claim from the lease holder payment of damage which it owes according to the lease deed, or 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.

(o) The lease deeds include additional provisions, including on the following subjects: security arrangements, conditions for operation of the facilities and dealing with malfunctions, tests, reporting and supervision; provision of services to other lease holders, provisions relating to environment protection, safety; limitations on the transfer or pledge on the lease deed and assets of the production system; liability, indemnification and insurance.

7.2.3. Compliance with the conditions of the work plan in the Leviathan project

Over and above the terms and conditions of Leviathan's lease deeds as specified in Section 7.2.2 above, no binding work plan in the Leviathan project was determined.

7.2.4. Actual and planned work plan for the Leviathan project

Below is a concise description of the main activities actually carried out in the Leviathan project between January 1, 2018 and the report approval date, as well as a concise description of planned activities in the aforesaid project:

Leviathan Leases			
Period	**Concise Description of Activities Actually Performed for the Period or of the Planned Work Plan**	**Total Estimated Budget for Activity at the Petroleum Asset Level (Dollars in thousands)[19]**	**Amount of Actual Participation in the Budget by the Holders of the Equity Interests of the Partnership (Dollars in thousands)[20]**
2018[21]	• Completion of drilling of Leviathan 3 and Leviathan 7 wells, and completion of Leviathan 3, 4, 5 and 7 wells.[22] Continuation of Phase 1A for the development of the Leviathan reservoir. For further details, see Section 7.2.5(a)3 below.	Approx. 1,521,955	Approx. 690,054
	• Performance of monitoring activities, in the area of the Leviathan 2 well, in coordination with the Ministry of Energy and the Ministry of Environmental Protection, with the aim of ensuring the continued rehabilitation of the environment.	Approx. 25	Approx. 11
	• Continuation of the project for the reprocessing of seismic surveys, *inter alia*, in relation to a deep-target exploration well in the Leviathan Leases.	Approx. 2,603	Approx. 1,180
	• Continued update of the geological model and flow model, *inter alia*, according to the well data.		
2019[23]	• Completion of Phase 1A for the development of the Leviathan reservoir and commencement of gas piping therefrom.	Approx. 1,020,169	Approx. 462,545
	• Completion of the project for the reprocessing of seismic surveys and commencement of the work of interpretation of the results, *inter alia*, in relation to a deep-target exploration well in the Leviathan Leases.	Approx. 2,093	Approx. 949
	• Examination of various alternatives for the export of natural gas through a subsea pipeline and/or liquefaction, including an FLNG, *inter alia*, through an engagement for the receipt of engineering services for	Approx. 1,341	Approx. 608

[19] The amounts for 2018-2020 are amounts actually expended and audited in the framework of the financial statements.
[20] The costs in the table reflect the Partnership's holding in the Leviathan Leases following the Merger, namely 45.34%.
[21] The costs specified in 2018 do not include a budget update (decrease) in the sum of approx. $211 thousand (in 100% terms) (the Partnership's share is approx. $96 thousand), costs of abandonment of the reservoir including expenses in respect thereof, G&A and insurance costs, and costs in respect of construction of the Israeli transmission system up to the Israel-Jordan border, as specified in Section 7.12.2(b)3.a below.
[22] The said budget is included in the total budget of the development of Phase 1A, as described in Section 7.2.5(a)3 below.
[23] The costs specified in 2019 do not include abandonment costs attributed to the asset on the books, G&A and insurance costs, costs in respect of construction of the Israeli transmission system up to the Israel-Jordan border, as specified in Section 7.12.2(b)3.a below, costs in respect of Leviathan's Participation (as defined in Section 7.25.6(c) below) and costs in relation to the EMG transaction.

Leviathan Leases			
Period	**Concise Description of Activities Actually Performed for the Period or of the Planned Work Plan**	**Total Estimated Budget for Activity at the Petroleum Asset Level (Dollars in thousands)[19]**	**Amount of Actual Participation in the Budget by the Holders of the Equity Interests of the Partnership (Dollars in thousands)[20]**
	the performance of FEED and technical design. • Performance of monitoring activities in the area of the Leviathan 2 well, with the aim of ensuring the continued rehabilitation of the environment. As of the report approval date, it appears that the 2012 plugging of the well is effective, that there is no evidence of flow therefrom, and that the environment is recovering gradually and continuously. • Continued update of the geological model and flow model, *inter alia* according to the well data.	Approx. 220	Approx. 98
2020[24, 25]	• Costs in connection with completion of Phase 1A of the development of the Leviathan reservoir, including promotion of the running-in of all of the systems on the platform (including the turbo expanders[26]) and completion of construction of the onshore condensate system, including completion of the Hagit site. • Commencement of production from the Leviathan reservoir, ongoing operation and maintenance[27]. • Examination of various alternatives for natural gas export via a subsea pipeline and/or liquefaction (including an FLNG), *inter alia* through an engagement for receipt of engineering services for the performance of FEED and technical design. • Examination of alternatives and performance of FEED for an additional increase of the piping capacity in the EMG system, including the installation of a second compressor. • Performance of monitoring activities in the vicinity of the Leviathan 2 well, with	Approx. 94,872 Approx. 2,052 Approx. 15	Approx. 43,015 Approx. 930 Approx. 7

[24] The costs and operations specified in 2020 do not include costs borne by the Partnership in connection with expansion of the gas flow capacity to Egypt via the EMG pipeline in the sum of approx. $38.7 million (100%, the Partnership's share approx. $17.5 million).
[25] The budgets specified for 2020 do not include costs in connection with the construction of the Combined Section (as defined in Section 7.23.3(h)1 below), the continued expansion of the flow capacity to Egypt and the costs of abandonment of the reservoir, including the expenses in respect of G&A [and] insurance costs.
[26] For details regarding turbo expanders, which were intended to allow an increase in the gas flow capacity from the Leviathan project to INGL's transmission system, see Section 7.2.5(b) below.
[27] During November 2020, maintenance work was carried out on the Leviathan platform for five days, during which the gas flow from the Leviathan platform was halted.

Leviathan Leases			
Period	**Concise Description of Activities Actually Performed for the Period or of the Planned Work Plan**	**Total Estimated Budget for Activity at the Petroleum Asset Level (Dollars in thousands)[19]**	**Amount of Actual Participation in the Budget by the Holders of the Equity Interests of the Partnership (Dollars in thousands)[20]**
	the aim of ensuring the continued rehabilitation of the environment. • Continued update of the geological model and the flow model, *inter alia* according to the production data and well data, and planning and preparations for drilling wells and additional completions, insofar as required. • Promotion of formulation of a deep target prospect in the Leviathan Leases and examination of the advisability of conducting an additional seismic survey for the purpose of improving the existing data, in order to substantiate the making of a decision on an exploration drilling to the new targets.	Approx. 99	Approx. 45
2021[28]	• Continued production from the Leviathan reservoir, ongoing operation and maintenance. • Completion of the running-in of all of the systems on the platform (including the turbo expanders). Improving the production system, adding environmental systems in accordance with regulatory requirements, upgrading the valve system, upgrading the sanitary waste treatment system in accordance with regulatory requirements. • Activation of the on-shore condensate system, including the completion of the Hagit site. • Formulation of a deep target prospect in the Leviathan Leases. In this context, it is noted that the Partnership is exploring the possibility of bringing in a strategic partner with relevant experience and knowledge in specification, drilling and development of the exploration targets identified in the area of the lease (and specifically a carbonate buildup target). • Continued update of the geological model and the flow model, *inter alia* according to the production data and well data, and planning and preparations for drilling wells and additional completions, insofar as required.	Approx. 48,900	Approx. 22,171

[28] The costs and operations specified in the years 2021 and 2022 do not include planned costs of the Partnership in connection with an additional expansion of the gas flow capacity to Egypt through the construction of the Combined Section (as defined in section 7.23.5(d) below) and the EMG pipeline (as defined in Section 5.25.7(a) below in the amount of approx. $92.5 million and approx. $27.5 million, respectively (100%, the Partnership's share approx. $42 million and approx. $12.5 million, respectively).

Leviathan Leases			
Period	**Concise Description of Activities Actually Performed for the Period or of the Planned Work Plan**	**Total Estimated Budget for Activity at the Petroleum Asset Level (Dollars in thousands)[19]**	**Amount of Actual Participation in the Budget by the Holders of the Equity Interests of the Partnership (Dollars in thousands)[20]**
	• Examination of the development of Phase 1B for the development of the Leviathan reservoir and/or other development alternatives, insofar as required. • Formulation of an alternative for the export of natural gas via a subsea pipeline and/or liquefaction (including via an FLNG), *inter alia* through an engagement for receipt of engineering services for the performance of FEED and detailed technical design. • Performance of monitoring activities in the vicinity of the Leviathan 2 well, with the aim of ensuring the continued rehabilitation of the environment. • Examination of alternatives for the export of condensate, performance of FEED, detailed technical design, preparation for procurement and performance.	Approx. 20,800 Approx. 3,750 Approx. 10,500	Approx. 9,431 Approx. 1,700 Approx. 4,761
2022	• Continued production from the Leviathan reservoir, ongoing operation and maintenance. • Continued improvement of the production system on the Leviathan platform, and improvement of environmental systems, in accordance with regulatory requirements. • Formulation of a deep target prospect in the Leviathan Leases. In this context, it is noted that the Partnership is exploring the possibility of bringing in a strategic partner with relevant experience and knowledge in specification, drilling and development of the exploration targets identified in the area of the lease (and specifically a carbonate buildup target). • Continued update of the geological model and the flow model, *inter alia* according to the production data and well data, and planning and preparations for drilling wells and additional completions, insofar as required. • Continued examination of development of Phase 1B for the development of the Leviathan reservoir and/or other development alternatives, insofar as required. • Performance of monitoring activities in the vicinity of the Leviathan 2 well, with the aim of ensuring the continued rehabilitation of the environment. • Promotion of an alternative for the export of natural gas via a subsea pipeline and/or liquefaction (including an FLNG), *inter alia* through the performance of		

Leviathan Leases			
Period	**Concise Description of Activities Actually Performed for the Period or of the Planned Work Plan**	**Total Estimated Budget for Activity at the Petroleum Asset Level (Dollars in thousands)[19]**	**Amount of Actual Participation in the Budget by the Holders of the Equity Interests of the Partnership (Dollars in thousands)[20]**
	FEED, detailed technical design and preparations for performance. • Formulation and development of the alternative chosen for the export of condensate. Performance of FEED, detailed technical design, performance of procurement and preparations for performance.	Approx. 35,000	Approx. 15,869
2023 forth	• Continued production from the Leviathan reservoir, ongoing operation and maintenance. • Formulation of a deep target prospect in the Leviathan Leases. In this context, it is noted that the Partnership is exploring the possibility of bringing in a strategic partner with relevant experience and knowledge in specification, drilling and development of the exploration targets identified in the area of the lease (and specifically a carbonate buildup target). • Continued update of the geological model and the flow model, *inter alia* according to the production data and well data, and planning and preparations for drilling wells and additional completions, insofar as required. • Continued examination of development of Phase 1B for the development of the Leviathan reservoir and/or other development alternatives, insofar as required. • Continued promotion of the alternative for the export of natural gas via a subsea pipeline and/or liquefaction (including an FLNG), *inter alia* through continued detailed technical design and construction of the facilities. • Completion of the development of the alternative for the export of condensate and operation thereof.	Approx. 24,500	Approx. 11,108

7.2.5. Plan for development of the Leviathan reservoir

On June 2, 2016, the Leviathan field development plan was approved by the Petroleum Commissioner. In the approval letter, the Petroleum Commissioner stated that according to the opinion of an international company that had been provided to his office, the total estimated recoverable quantity of natural gas, based on the submitted development plan, is approx. 17.6 TCF. The Petroleum Commissioner further noted that upon receipt of additional data regarding the reservoir, particularly from the Leviathan-5 well, and upon receipt of data that shall be received during the production from the field, the recoverable quantity will be revised, *inter alia*, for the purpose of export permit calculations, insofar as required. It is noted that the Operator of the Leviathan project has transferred and transfers to the Petroleum Commissioner a full database, which is updated from time to time, which includes, *inter alia*, the data of the Leviathan 3, 4, 5 and 7 wells and completions, the results of the reprocessing of seismic surveys, updated flow models and geological models and production data. It is noted that the resource evaluation in the said opinion materially differs from the resource evaluation provided to the Leviathan Partners by NSAI as specified in Section 7.2.10 below. As of the report approval date, the Partnership, together with the other Leviathan Partners, is continuing to hold discussions with the Ministry of Energy with respect to the possibility of updating the evaluation of the resources in the Leviathan reservoir. Nevertheless, it is emphasized that for the current export agreements, export licenses have been granted for the entire quantity in the agreements. In addition, in the Partnership's estimation, and given the Government's policy with respect to natural gas export, the quantity recoverable according to the Petroleum Commissioner is also sufficient for implementation of the Leviathan Development Plan as specified in this section below.

On February 23, 2017, the Leviathan Partners adopted a final investment decision (FID) for the development of Phase 1A of the Development Plan for the Leviathan reservoir, at a capacity of approx. 12 BCM per year, with a budget of approx. $3.75 billion (for 100% of the interests in the Leviathan reservoir). During the development period, the Phase 1A development budget, as estimated when approved, decreased by approx. $217 million in total (100%), and therefore the total Phase 1A development cost amounted to approx. $3.5 billion (100%). After a running-in period, on December 31, 2019, the piping of natural gas from the Leviathan reservoir commenced; on January 1, 2020 the sale of natural gas to Jordan under the NEPCO agreement (specified in Section 7.11.5(b)1 below) commenced; and on January 15, 2020, the piping of natural gas from the reservoir to Egypt commenced under the Dolphinus agreement (specified in Section 7.11.5(b)2 below). For details on the gradual ramp-up of the Leviathan reservoir production capacity, see Section 7.16.1(a) below.

(a) The plan for full development of Leviathan reservoir (Phase 1A and Phase 1B) includes the supply of natural gas to the domestic market and for export and the supply of condensate to the domestic market (in this section: the

"**Development Plan**" or the "**Plan**"), the main provisions of which are as follows:

1. Eight production wells at the first stage (four of which have been drilled and completed for production in Phase 1A) will be connected by a subsea pipeline to a permanent platform (in this section: the "**Platform**"), which is located offshore (in the territorial waters of Israel) in accordance with the provisions of NOP 37/H and on which all gas and condensate treatment systems have been installed. Gas flows from the Platform to the northern onshore entry point of the national transmission system of INGL as defined in NOP 37/H (the "**INGL Connection Point**"). Condensate is also piped to the shore via a separate pipeline parallel to the gas pipeline, and is connected to an existing fuel pipeline of Europe Asia Pipeline Co. ("**EAPC**") that leads to the tank farm of Petroleum & Energy Infrastructures Ltd. ("**PEI**") and from there to the Oil Refineries Ltd. ("**ORL**"). Furthermore, a pipeline to the Hagit site has been laid and facilities have been set up therein for storage and unloading of the condensate, for the purpose of providing backup in the event that piping condensate to ORL is impossible[29]. Setup of the condensate storage system at the Hagit site has been completed and the permits required for the operation thereof have been received. For further details regarding the approval of NOP 37/H and the provisions thereof as aforesaid, see Section 7.23.5(j) below. For details with respect to the production system of the Leviathan project, see Section 7.16.1 below.

2. The production system includes: the production wells, the subsea production system, the production and processing platform, the system for transmission to the shore and the related onshore facilities (in this section jointly: the "**Production System**") and it is intended to supply approx. 21 BCM per year after completion of Phase 1A and Phase 1B of the Development Plan, as shall be specified below. The gas to be supplied at the INGL Connection Point is designated for the local market and neighboring countries.

3. The Development Plan is implemented in two phases, according to the maturity of the relevant markets, as specified below:

[29] In the context of the laying of the pipeline to the Hagit site, the Partnership provided a guarantee in the sum of approx. ILS 2.3 million in favor of the Israel Land Authority (ILA).

a. <u>Phase 1A</u> – includes, at the first stage, four subsea production wells, a subsea production system that connects the production wells to the Platform, a system for transmission to the shore and related onshore facilities. At this point, the reservoir's gas production capacity is at approx. 12 BCM per year. On December 31, 2019, natural gas and condensate piping in the context of the development of Phase 1A has commenced. The cost invested in the development of Phase 1A, as of December 31, 2020, totals approx. $3.6 billion (100%).

b. <u>Phase 1B</u> – expected to include, at the first stage, four additional production wells, related subsea systems and expansion of the Platform's processing facilities to increase the system's total gas production capacity by approx. 9 additional BCM per year (to a total of approx. 21 BCM per year), with an estimated budget of approx. $1.5-2 billion (in relation to 100% of the interests in the Leviathan project).

As of the report approval date, the Leviathan Partners have not yet adopted a final investment decision (FID) for the development of Phase 1B.

4. It is noted that additional production wells will be required during the life of the project to enable production of the required volume.

(b) As of the report approval date, and in accordance with the Development Plan, the gas supply capacity from the Leviathan project to INGL's transmission system is approx. 1.2 BCF per day at maximum production. Upon completion of the running-in of all of the systems on the platform, and mainly the operation of the turbo expander system, the ability to increase the maximum daily supply capacity will be examined, upon the fulfillment of specific conditions, over and above 1.2 BCF. The Leviathan project's up-time in 2020 was approx. 98.5%.

(c) As of the date of approval of this report, the Leviathan Partners are considering various alternatives for increasing the volume of production from the Leviathan reservoir (beyond Phase 1A and concurrently with the examination of Phase 1B), based on the existing facilities, and are acting to update the development plan, so as to allow for an increase of the production capacity up to approx. 24 BCM per year, and all according to estimates that are updated from time to time with respect to the current and projected demand in the local market and regional and global target markets, and *inter alia*, the following alternatives are considered:

1. Increase of the production capacity of Phase 1A from 12 BCM per year to 16 BCM per year by means of adding two production wells and related subsea infrastructures at the first stage and immaterial changes in the Platform. This alternative will allow for maximum utilization of the processing infrastructures installed on the Leviathan platform as part of Phase 1A, and the estimated cost in respect thereof is approx. $875 million (for 100% of the interests in the Leviathan project).

2. Increase of the production capacity from 16 BCM per year to 24 BCM per year (subject to implementation of the first alternative described above), *inter alia*, by means of adding, at the first stage, four production wells and related subsea infrastructures, over and above those of the first alternative described above, adding a fourth pipe from the field to the Platform, and expansion of the processing facilities on the Platform with an estimated budget of $1.5-2 billion (for 100% of the interests in the Leviathan project). This alternative will allow for the supply of additional quantities of gas for export, insofar as required, including to the liquefaction facilities situated in Egypt and/or for the supply of gas to a floating liquefaction facility (FLNG); on this issue, see Section 7.12.2(b)3.b below. For details with respect to engagement by the Partnership, jointly with its partners in the Leviathan project, in interim agreements with FLNG services and technology providers, see Section 7.12.2(c) below.

For the purpose of examination of the various expansion options, the Leviathan Partners have approved an engineering design (FEED) budget, as specified in Section 7.2.4 above.

Caution concerning forward-looking information – The above estimates in relation to the expected production capacity of the Leviathan reservoir, the amount of the budget and the timetables for additional development phases of the Leviathan reservoir, as set forth above, constitute forward-looking information within the meaning thereof in Section 32A of the Securities Law. Such information is based on estimates by the Partnership and the Operator in the Leviathan reservoir, based on a range of factors, including the Development Plan and the timetables for implementation thereof, receipt of regulatory approvals, estimated data of availability of equipment, services and costs as well as past experience. The estimates in this report may not materialize or may materialize in a

materially different manner if changes and/or delays occur in the range of factors as specified above, and if the estimates received change, the market conditions change and/or due to a gamut of regulatory and/or geopolitical changes and/or due to operating and technical conditions in the Leviathan reservoir and/or due to unexpected factors relating to the exploration, production and marketing of oil and natural gas and/or as a result of the progress of development of the Leviathan reservoir until completion thereof.

7.2.6. The actual participation rate in the expenses and revenues under the Leviathan Leases

Participation Rate	Percentage Pre Investment-Recovery	Percentage Post Investment-Recovery	Rate grossed-up to 100% Pre Investment-Recovery	Rate grossed-up to 100% Post Investment-Recovery	Explanations
The rate actually attributed to the holders of the equity interests of the Partnership in the petroleum asset	45.34%	45.34%	100%	100%	See description of chain of holdings in Section 7.2.1 above.
The rate actually attributed to the holders of the equity interests of the Partnership in the **revenues** from the petroleum asset	37.63%	35.37%	83.00%	78.00%	See calculation in Section 7.2.7 below.
The actual participation rate of the holders of the equity interests of the Partnership in the **expenses** involved in the exploration, development and production activity at the petroleum asset.	45.79%-47.15%	45.79%-47.15%	101%-104%	101%-104%	See calculation in Section 7.2.8 below.

7.2.7. Participation rate of the holders of the equity interests of the Partnership in the revenues from the Leviathan Leases

Item	**Percentage Pre Investment-Recovery**	**Percentage Post Investment-Recovery**	**Concise Explanation as to How Royalties or Payments are Calculated**
Projected annual revenues of petroleum asset	100%	100%	
Specification of the royalties or payment (deriving from revenues post-finding) at the petroleum asset level:			
The State	(12.50%)	(12.50%)	As prescribed by the Petroleum Law, royalties are calculated according to market value at the wellhead. The actual royalty rate may be lower, as a result of the deduction of expenses in respect of the systems of gas processing and transmission up to the onshore gas delivery point. For further details, including with respect to the publication of directives on the method of calculation of the royalty value at the wellhead with respect to offshore petroleum interests, see Section 7.23.4(b) below.
Adjusted revenues at the petroleum asset level	87.5%	87.5%	
Share in the adjusted revenues deriving from the petroleum asset attributable to the holders of the equity interests of the Partnership (indirect holdings)	45.34%	45.34%	
Total share of the holders of the equity interests of the Partnership in the actual amount of revenues, at the petroleum asset level (and before other payments at the Partnership level)	39.67%	39.67%	
Specification of royalties or payments (deriving from revenues post-finding) in connection with the petroleum asset at the Partnership level (the following percentage will be calculated according to the rate of the holders of the equity interests of the Partnership in the petroleum asset)			
The rate of the holders of the equity interests of the Partnership in payment to related and third parties	(2.04%)	(4.30%)	Overriding royalty in respect of the Partnership's share at a 4.5% rate Pre Investment-Recovery and at a 9.5% rate Post Investment-Recovery calculated according to market value at the wellhead[30]. The said rate was calculated according to the principles under which the State's royalties in respect of the project are calculated, and therefore such rate may change, insofar as the

[30] The parties entitled to royalties are a wholly-owned subsidiary of Delek Energy and others which are not related parties.

Item	Percentage Pre Investment-Recovery	Percentage Post Investment-Recovery	Concise Explanation as to How Royalties or Payments are Calculated
			method of calculation of the State's royalties changes. For further details with respect to the method of calculation of the royalty rate, see Section 7.25.10 below.
Actual rate in revenues from the petroleum asset attributable to the holders of the equity interests of the Partnership	37.63%	35.37%	

7.2.8. Participation rate of the holders of the equity interests of the Partnership in the exploration, development and production expenses in the Leviathan Leases

Item	Percentage	Summary explanation of how the royalties or payments are calculated
Theoretical expenses within the framework of a petroleum asset (without the said royalties)	100%	
Specification of the payments (derived from the expenses) at the petroleum asset level:		
The Operator	1%-4%	Including a rate of 1% for the indirect expenses of the Operator out of the total direct expenses in relation to development and production activities, subject to certain exclusions, such as marketing activity. A rate of 1%-4% for exploration expenses, with the rate of payment to the Operator decreasing upon an increase in the exploration expenses. Such sums are for payment of the Operator's indirect expenses and are in addition to the reimbursement of direct expenses paid thereto.
Total actual expense rate on the petroleum asset level	101%	
The share of the holders of equity interests of the Partnership in the petroleum asset expenses (indirect holdings)	45.34%	
Total actual share of the holders of the equity interests of the Partnership, in the expenses, on the petroleum asset level (and prior to other payments on the Partnership level)	45.15%-47.79%	
Specification of payments (derived from the expenses) in respect of the petroleum asset and at the Partnership level (the following percentage will be calculated according to the share of the holders of the equity interests of the Partnership in the petroleum asset):		
The rate actually attributed to the holders of the equity interests of the Partnership in expenses involved in the exploration, development and production activity at the petroleum	45.15%-47.79%	The Partnership pays management fees to the General Partner, which comprise a fixed amount and a variable amount that is calculated as a rate of the exploration expenses upon fulfillment of certain conditions (for details see Section (b)7 of Regulation

Item	Percentage	Summary explanation of how the royalties or payments are calculated
asset.		21 in Chapter D of this report). Such amounts were not taken into account in this table.

7.2.9. Fees and payments paid during exploration activity at the petroleum asset (in Dollars in thousands)

Item	Total share of the holders of the equity interests of the Partnership in the investment in the petroleum asset in this period (including costs for which no payments are made to the Operator)	Out of which, the share of the holders of the equity interests of the Partnership in payments to the General Partner	Out of which, the share of the holders of the equity interests of the Partnership in payments to the Operator (in addition to the reimbursement of its direct expenses)
Budget actually invested in 2018	Approx. 703,224	-	Approx. 6,865
Budget actually invested in 2019	Approx. 567,259	-	Approx. 4,597
Budget actually invested in 2020	Approx. 101,468	-	Approx. 964

7.2.10. Reserves, contingent resources and prospective resources in the Leviathan Leases

For details regarding resources, reserves and contingent resources in the area of the Leviathan Leases and the discounted cash flow that derives from the reserves and from part of the contingent resources in the Leviathan Leases as of December 31, 2020, see the Partnership's immediate report of March 10, 2021 (Ref. no.: 2021-01-030942), the information included in which is hereby presented by way of reference. As of the report approval date, no change has occurred in the above details. Attached hereto as **Annex A** is NSAI's consent to the inclusion of the said report herein by way of reference, and a letter of lack of material changes from NSAI in the Leviathan Leases.

For details regarding prospective resources in the area of the Leviathan Leases as of December 31, 2019, see Section 7.2.10 of the 2019 periodic report as released on March 30, 2020 (Ref. no.: 2020-01-032010). As of December 31, 2020, no change has occurred in the above details. Attached hereto as **Annex A** is NSAI's consent to the inclusion of the said report herein, including by way of reference, and a letter of lack of material changes from NSAI in the Leviathan Leases.

7.3. The Tamar and Dalit project

7.3.1. General

The Tamar Lease	
General Details with respect to the Petroleum Asset	
Name of the petroleum asset:	Tamar Lease
Location:	An offshore asset approx. 90 km west of the shores of Haifa, at a water depth of 1,670 meters.
Area:	Approx. 250 km^2.
Type of petroleum asset and description of the activities permitted for such type:	Lease; Permitted activities under the Petroleum Law – exploration and production.
Original granting date of the petroleum asset:	December 2, 2009
Original expiration date of the petroleum asset:	December 1, 2038
Dates on which an extension of the term of the petroleum asset was decided:	-
Current expiration date of the petroleum asset:	December 1, 2038
Note on whether there is an additional option to extend the term of the petroleum asset; if such option exists – the optional extension term should be noted:	Subject to the Petroleum Law, by 20 additional years.
The name of the operator:	Noble
The names of the direct partners in the petroleum asset and their direct share in the petroleum asset, and, to the best of the Partnership's knowledge, the names of the controlling shareholders of such partners:	▪ Isramco (28.75%). To the best of the Partnership's knowledge, the general partner of Isramco, Isramco Oil & Gas Ltd., is a private company indirectly controlled by Naphtha Israel Petroleum Corp. Ltd., a public company which, to the best of the Partnership's knowledge, is indirectly controlled by Mr. Haim Tsuff. ▪ Noble (25%). ▪ The Partnership (22%). ▪ Tamar Petroleum (16.75%). ▪ Dor Gas Exploration, Limited Partnership ("**Dor**") (4%). To the best knowledge of the Partnership, the general partner of Dor Exploration is Alon Gas Exploration Management Ltd., a private company controlled by Alon Natural Gas Exploration Ltd., which is a public company, the controlling shareholder of which is "Alon" Israeli Fuel Company Ltd., which is a private company. ▪ Everest Infrastructures, Limited Partnership ("**Everest**") 3.5%. To the best of the Partnership's knowledge, Everest is a limited partnership, in which Harel Insurance Co. Ltd. and other institutional bodies owned thereby are partners, as well as partners from the Israel Infrastructure Fund group.

The Tamar Lease	
General Details with respect to the Partnership's Share in the Petroleum Asset	
For a holding in a purchased petroleum asset – the purchase date:	The interests in the lease were granted to the Partnership on December 2, 2009, following the Tamar natural gas discovery which was made in 2009 in the area of the 309/Matan license.
Description of the nature and manner of the	The Partnership holds 22% of the lease.

Partnership's holding in the petroleum asset:	
The actual share in the revenues from the petroleum asset attributable to the holders of the equity interests of the Partnership:	17.0676% (this figure is after the Investment Recovery Date)[31].
The total share of the holders of the equity interests of the Partnership in the aggregate investment in the petroleum asset during the five years preceding the last day of the year of the report (whether recognized as an expense or as an asset in the financial statements):	Approx. $243,111 thousand[32].

The Dalit Lease	
General Details with respect to the Petroleum Asset	
Name of the petroleum assets:	I/13 Dalit lease[33]
Location:	An offshore asset approx. 50 km west of the shores of Haifa.
Area:	Approx. 250 km^2.
Type of petroleum asset and description of the activities permitted for such type:	Lease; Permitted activities under the Petroleum Law – exploration and production.
Original granting date of the petroleum asset:	December 2, 2009
Original expiration date of the petroleum asset:	December 1, 2038
Dates on which an extension of the term of the petroleum asset was decided:	-
Current expiration date of the petroleum asset:	December 1, 2038
Note on whether there is an additional option to extend the term of the petroleum asset; if such option exists – the optional extension term should be noted:	Subject to the Petroleum Law, by 20 additional years.
The name of the operator:	Noble
The names of the direct partners in the petroleum asset and their direct share in the petroleum asset, and, to the best of the Partnership's knowledge, the names of the controlling shareholders of such partners:	▪ Isramco (28.75%). ▪ Noble (25%). ▪ The Partnership (22%). ▪ Tamar Petroleum (16.75%). ▪ Dor (4%). ▪ Everest (3.5%)

The Dalit Lease	
General Details with respect to the Partnership's Share in the Petroleum Asset	
For a holding in a purchased petroleum asset – the purchase date:	The interests in the lease were granted to the Partnership on December 2, 2009, following the Dalit natural gas discovery which was made in 2009 in the area of the 308/Michal license.
Description of the nature and manner of the Partnership's holding in the petroleum asset:	The Partnership holds 22% of the Lease.
The actual share in the revenues from the petroleum asset attributable to the holders of	Pre Investment-Recovery – 18.1676%. Post Investment-Recovery – 17.0676%.

[31] For further details regarding the investment recovery date in the Tamar Project, see Sections 7.25.10 and 7.26.6 below.
[32] The costs in the table reflect the Partnership's direct and indirect holdings in the Tamar Lease at the rate of 25.7855% until December 31, 2018; and only the Partnership's direct holdings in the Tamar Lease at the rate of 22% from January 1, 2019.
[33] The Dalit gas reservoir was discovered in the area of the Dalit Lease in 2009.

the equity interests of the Partnership:	
The total share of the holders of the equity interests of the Partnership in the aggregate investment in the petroleum asset during the five years preceding the last day of the year of the report (whether recognized as an expense or as an asset in the financial statements):	Approx. $72 thousand[34].

7.3.2. The principal terms and conditions of the Tamar and Dalit lease deeds

(a) The terms and conditions of the Tamar and Dalit leases (in this section: the "**Leases**") are for the most part identical. The description set forth below pertains to the main issues in the Tamar and Dalit leases.

(b) The facilities of the production system and the transmission system (in this section: the "**Facilities**") will be constructed and operated through Noble (in this section: the "**Operator**"), which shall manage the activities required under the lease deed and under the Petroleum Law on behalf of the lease holder. The Operator's actions will be binding on the lease holder and notices from the Petroleum Commissioner or anyone on his behalf to the Operator will be binding on the lease holder. Nothing in the provisions of this section shall derogate from the undertakings and liability of each of the Tamar Partners to act in accordance with the provisions of the lease deed and the provisions of any law, jointly and severally.

(c) The lease holder will only replace the Operator with a company approved in advance and in writing by the Petroleum Commissioner.

(d) Scope of the lease

1. The lease holder will have the exclusive right to explore and produce oil and natural gas in the lease area only, throughout the entire term of the lease, subject to the other provisions of the lease deed and to any law.

2. At the lease holder's sole responsibility, the lease holder will plan, finance, construct and operate the lease holder's production system and the transmission system and will maintain them for the purpose of their ongoing operation, all through the Operator, contractors,

[34] The costs in the table reflect the Partnership's direct and indirect holdings in the Dalit Lease at the rate of 25.7855% until December 31, 2018; and only the Partnership's direct holdings in the Dalit Lease at the rate of 22% from January 1, 2019. The costs in the table do not include a budget update (decrease) in the sum of approx. $462 thousand, as done in previous years.

planners and consultants who have knowledge and experience in their fields, in such manner so as to enable the regular, proper and safe supply of oil and natural gas from the reservoir.

(e) Term of the Lease

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

2. The Term of the Lease will be divided into two sub-terms:

   Development period – the period during which the lease holder performs all of the activities for the purpose of reaching the commercial production stage, including development drillings, and constructs the lease holder's production system and transmission system, subject to the provisions of the lease deed.

   Commercial production period – the period from the end of the development period until the end of the term of the lease, during which the lease holder carries out commercial production from the lease area, subject to the provisions of the lease deed and any law.

3. If the Term of the Lease ends or the lease is revoked in accordance with the provisions of the Petroleum Law, *inter alia* Section 29 of the Petroleum Law, or according to the provisions of the lease deed, the right of the lease holder to act by virtue of the lease deed will expire.

(f) Sale to consumers in Israel

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

(g) Construction of facilities

1. The lease holder will only construct the production system after the Petroleum Commissioner shall have granted the lease holder a construction approval and subject to the terms and conditions of the approval.

2. The lease holder will construct the production system and the transmission system in a manner enabling a total commercial production capacity from the area of

the Tamar Lease and the area of the Dalit Lease, of no less than 7 billion standard cubic meters of natural gas in the year commencing on the beginning of the commercial production period, subject to approval of the northern terminal[35].

3. Insofar as there is financial justification therefor, the lease holder may, subject to receipt of approval from the Petroleum Commissioner and the Director of the Natural Gas Authority who was appointed pursuant to the Natural Gas Sector Law, increase the capacity of the lease holder's production system and transmission system and add facilities and wells thereto, including the construction of a pipe to an additional terminal, in a manner enabling the flow of larger quantities of natural gas, reliably and efficiently, to consumers in Israel.

(h) Supervision company

The planning and construction of the production system will be made under the supervision of companies experienced in supervising the planning or construction of production systems, which the lease holder will engage with, subject to approval by the Petroleum Commissioner. In accordance with the aforesaid, supervising companies were chosen to accompany the planning of the production system and its construction, which were approved by the Petroleum Commissioner.

(i) Commercial production

1. Commercial production from the lease area will be conducted under the following principles:

    a. Production will be carried out with proper diligence, without waste, in a manner that does not constitute any harm to the features of the reservoir situated in the lease area.

    b. Production will be carried out in accordance with the minimum output and maximum output to be approved by the Petroleum Commissioner, from time to time, considering the data and features of the reservoir.

    c. The lease holder will be required to maintain the quality of the gas piped thereby into the national

[35] Production is performed via a platform constructed opposite the shores of Ashkelon and via the Terminal.

transmission system, in accordance with the gas specification to be determined.

2. The lease holder will perform commercial production with proper diligence, in accordance with the instructions of the competent authorities and with any law, and in accordance with the provisions of any license, permit and so forth, which are required for such purpose under any law.

3. The lease holder will only commence commercial production and will only commence natural gas flow into the lease holder's transmission system after the submission of an application for approval of the operation to the Petroleum Commissioner and approval of the application by the Petroleum Commissioner.

4. At the end of each year (at least 30 days prior to the end of each calendar year), the lease holder will submit to the Petroleum Commissioner a detailed annual work plan and a cost forecast for the performance of the activities in the plan, and a production rate forecast for the following year.

5. The lease holder will notify the Petroleum Commissioner of the dates on which it intends to commence construction of additional facilities in order to comply with the provisions of the lease deed.

(j) Natural gas storage

1. The Petroleum Commissioner may instruct the lease holder with respect to activities for the transfer of natural gas, for the purpose of gas storage, from the reservoir to permitted reservoirs, insofar as compliance with such instructions does not impose any costs on the lease holder due to transmission, insertion, storage and removal of the gas, and compliance with the instructions does not harm the reservoir. Royalty due to the stored natural gas will apply at the time of removal of the gas from the storage reservoir, rather than at the time of its production from the reservoir.

2. If the lease holder, on its own initiative, requests to store gas in permitted storage reservoirs, it shall be done at the expense of the lease holder and in accordance with the provisions of any law and the criteria, if any.

(k) Revocation or restriction of the lease

The lease will be terminated upon the end of the term of the lease, upon expiration thereof under Section 29 of the Petroleum Law, upon revocation thereof under Section 5 of the Petroleum Law, or upon the occurrence of either of the conditions specified below:

1. The lease holder shall have materially deviated from a material provision of the lease deed or from the instructions of the Petroleum Commissioner by virtue of the lease deed.

2. The guarantee or a part thereof shall have been forfeited and the lease holder shall not have supplemented the amount of the guarantee as required under the provisions of the lease deed.

(l) Abandonment plan

1. Within 30 months of the date of commencement of the production period, the lease holder will submit for approval by the Petroleum Commissioner, a general plan for abandonment of the production system's facilities and for the sealing of wells, when use thereof ends, whether during the term of the lease or thereafter (the "**General Abandonment Plan**"). It is noted in this context that the General Abandonment Plan was submitted for approval by the Petroleum Commissioner on September 30, 2015.

2. No later than the date on which the lease holder produces one hundred and seventy billion cubic meters of gas from the lease area, the lease holder will submit for approval by the Petroleum Commissioner a detailed plan for decommissioning of the facilities, in accordance with the provisions of the General Abandonment Plan (the "**Abandonment Plan**"), which was approved by the Petroleum Commissioner, as well as an estimate of the decommissioning costs. If the lease holder does not timely submit an abandonment plan, or if the Petroleum Commissioner finds that the Abandonment Plan that was submitted does not merit approval, and the Petroleum Commissioner and lease holder do not reach an agreement with respect to an abandonment plan, the Petroleum Commissioner will determine the Abandonment Plan.

3. On the date of approval of the Abandonment Plan by the Petroleum Commissioner, the Petroleum Commissioner will set out a plan for the lease holder,

whereby the lease holder will provide collateral or deposit into an "abandonment fund" on the dates, in the format and under the accrual method as ordered by him, with the purpose of ensuring that the lease holder has the means required to carry out the Abandonment Plan.

4. The lease holder shall notify the Petroleum Commissioner of its wish to seal a single well at least three months before performance thereof. The notice to be submitted shall include an explanation of the need to seal the well and the sealing plan. Sealing of the well requires prior approval by the Petroleum Commissioner.

(m) Guarantees

The lease deed prescribes provisions for the furnishing of an irrevocable unconditional autonomous bank guarantee by the lease holders, in order to secure compliance with the terms and conditions of the lease deed, the term thereof and causes for forfeiture of the guarantee. For details regarding the guarantee furnished as aforesaid for securing compliance with the terms and conditions of the lease deed and the directives of the Petroleum Commissioner, see Section 7.23.4(a) below.

(n) Furthermore, the lease deed includes additional provisions, which address, *inter alia*, conditions for operation of the Facilities, safety, the handling of malfunctions, reports and supervision, liability, insurance and indemnification.

(o) In addition, in the context of a permit for operation of the production system from the Tamar Lease, enhanced duties were imposed on the lease holder in relation to the operation of the production system due to the importance of gas production for Israel.

7.3.3. Compliance with the conditions of the work plan for the Tamar Project[36]

No binding work plan has been set for the Tamar Project, beyond the provisions of the Tamar and Dalit lease deeds as specified in Section 7.3.2 above.

[36] As of the report approval date, a detailed work plan has been submitted with respect to the Tamar Lease only.

7.3.4. Work plan for the Tamar Project – actual and planned[37]

(a) Below is a concise description of the main activities actually carried out in the Tamar Project between January 1, 2018 and the report approval date, as well as a concise description of planned activities:

The Tamar Lease[38,39]			
Period	**Concise Description of Activities Actually Performed for the Period or of the Planned Work Plan**	**Total Estimated Budget for Activity at the Petroleum Asset Level (Dollars in thousands)[40]**	**Amount of Actual Participation in the Budget by the Holders of the Equity Interests of the Partnership (Dollars in thousands)[41]**
2018	• Continued production from the Tamar Project, ongoing operation and maintenance. • Continuation of project for installation of systems for the reduction of emissions from the Tamar Platform. • Continued upgrade and improvement of the production system on the Tamar Platform and at the Terminal, including improvement of the operating systems, and upgrade of the stainless steel pipeline for the prevention of corrosion. • Continued update of the geological model and the flow model, *inter alia*, according to the production and well data, and planning and preparations for additional completions and drilling of wells. • Mapping out and definition of additional prospects, including a deep target prospect in the area of the lease. • Continued project of reprocessing of seismic surveys.	Approx. 28,894 Approx. 24,845[42]	Approx. 7,450 Approx. 6,409
2019[43]	• Continued production from the Tamar Project,		

[37] The costs specified in 2018-2020 in the work plan below do not include current operating and maintenance costs and abandonment costs of the Tamar Project, which were included in Section 7.3.10 below.

[38] The costs specified in this table do not include abandonment costs attributed to the asset on the books, insurance, operating and G&A costs. Access and participation fee for the gas transmission and ensuring capacity in the EMG pipeline as specified in Section 7.25.6 below, and costs in connection with the construction of the Combined Section, as specified in Section 7.23.3(h)1 below.

[39] The costs in the table reflect the Partnership's direct and indirect holdings in the Tamar Lease at the rate of 25.7855% until December 31, 2018; and only the Partnership’s direct holdings in the Tamar Lease at the rate of 22% from January 1, 2019.

[40] The amounts for 2018-2020 are amounts actually expended and audited in the framework of the financial statements.

[41] The costs in the table reflect the Partnership's direct and indirect holdings in the Tamar Lease at the rate of 25.7855%. until December 31, 2018; and only the direct holdings of the Partnership in the Tamar Lease at the rate of 22% from January 1, 2019.

[42] The costs specified do not include a decrease in the amount of the investments in the sum of approx. $33.6 million (100%) (the Partnership’s share is approx. $8.7 million). The decrease derives, *inter alia*, from the sale of drilling equipment, pipeline depreciation and a decrease in the investment in the Tamar SW well.

[43] The costs specified for 2019 do not include abandonment costs attributed to the asset on the books, and costs in respect of Tamar’s Participation fee in the sum of approx. $50 million (as defined in Section 7.25.6(c) below).

The Tamar Lease[38,39]			
Period	**Concise Description of Activities Actually Performed for the Period or of the Planned Work Plan**	**Total Estimated Budget for Activity at the Petroleum Asset Level (Dollars in thousands)[40]**	**Amount of Actual Participation in the Budget by the Holders of the Equity Interests of the Partnership (Dollars in thousands)[41]**
	ongoing operation and maintenance. • Completion of project for installation of systems for the reduction and monitoring of emissions from the Tamar Platform into the air. • Completion of seismic survey reprocessing project, and commencement of interpretation of the processed surveys. • Continued update of the geological model and the flow model, *inter alia*, according to the production and well data, and planning and preparations for additional completions and drilling of wells. • Continued improvement of the production system on the Tamar Platform and at the Terminal, including improvement of the operating systems, addition of structures, upgrade of the stainless steel pipeline for the prevention of corrosion, dyeing of equipment and pipeline and continued upgrade of the valve system. • Purchase of equipment and pipeline for the purpose of developing the Tamar SW reservoir.	Approx. 12,479 Approx. 19,501[44] Approx. 53,463	Approx. 3,217 Approx. 5,028 Approx. 13,786
2020[45,46]	• Continued production from the Tamar Project, ongoing operation and maintenance. • Laying of subsea infrastructures required for connection of the Tamar SW well to the subsea production system in the Tamar field. For further details, see Section (d) below. • • Operations related to compliance with regulatory requirements and in connection with emission permits, discharge and toxins, monitoring of the marine and air environment. • Continued upgrade and improvement of the production system on the Tamar platform and at the Terminal, including the acquisition of land rights in the Terminal, improvement of the operating systems and upgrade of the stainless steel piping for the prevention of corrosion, dyeing of equipment and pipeline and examination of the upgrade of MEG treatment systems. • Continued update of the geological model and the flow model, *inter alia*, based on the data of the seismic survey reprocessing completed in 2019, and according to the production and well data, and planning and preparations for additional	Approx. 31,833 Approx. 2,465 Approx. 8,941	Approx. 7,003 Approx. 542 Approx. 1,967

[44] The costs specified for 2019 do not include a budget update of approx. $4.9 million (100%) (the Partnership's share is approx. $1.3 million).

[45] The costs specified do not include a decrease in the scope of investments in the sum of approx. $8.9 million (100%) (the Partnership's share approx. $1.9 million). The decrease derives from the sale of equipment.

[46] The costs and operations specified for 2020 do not include costs borne by the Partnership in connection with the expansion of the gas flow capability to Egypt through EMG pipeline in the sum of approx. $22.2 million (100%, the Partnership's share approx. $4.4 million).

The Tamar Lease[38,39]			
Period	**Concise Description of Activities Actually Performed for the Period or of the Planned Work Plan**	**Total Estimated Budget for Activity at the Petroleum Asset Level (Dollars in thousands)[40]**	**Amount of Actual Participation in the Budget by the Holders of the Equity Interests of the Partnership (Dollars in thousands)[41]**
	completions and drilling of wells. • Mapping out and definition of additional prospects, including a deep target prospect in the area of the lease. • Examination of alternatives and performance of FEED for the MEG regeneration facility.		
2021[47,48]	• Continued production from the Tamar Project, ongoing operation and maintenance[49]. • Continued upgrade and improvement of the production system on the Tamar Platform and at the Terminal, including improvement of the operating systems, improvement of structures, addition of environmental systems for emission reduction and monitoring, upgrade of the stainless steel pipeline for the prevention of corrosion, dyeing of equipment and pipeline, and continued upgrade of the valve system.	Approx. 14,070	Approx. 3,095
	• Mapping out and definition of additional prospects, including a deep target prospect in the area of the lease. • Completion of the FEED for the MEG regeneration facility. Continuation of detailed planning and preparations for performance. • Coverage of a section of the subsea piping layout. • Continued examination of other development alternatives, including the laying of a third pipeline from the Tamar field to the platform, insofar as required.	Approx. 5,000 Approx. 6,000 Approx. 750	Approx. 1,110 Approx. 1,320 Approx. 165
2022 forth	• Since in accordance with the provisions of the Gas Framework, the Partnership is required to sell its holdings in the project by December 2021, the work plan from 2022 forth, was not included.		

[47] The costs and operations specified for 2021 forth, do not include planned costs of the Partnership in connection with an additional expansion of the gas flow capability to Egypt through the construction of the Combined Section (as defined in Section 7.23.3(h)1 below) and EMG pipeline (as defined in Section 7.25.6(a) below) in the sum of approx. $41.5 million and approx. $12.5 million, respectively (100%, the Partnership's share approx. $10.5 million and approx. 3 million, respectively).
[48] The amounts specified below are nominal amounts. In addition, the table below does not include actions of abandonment of the reservoir, including expenses in respect thereof.
[49] For details regarding operation costs in the Tamar Project that are attributed to the Partnership, see the discounted cash flow figures that are attributed to the Partnership's share from the reserves in the Tamar Project, as specified in Section 7.3.11(a)3 below.

he Dalit Lease			
Period	**Concise Description of Activities Actually Performed for the Period or of the Planned Work Plan**	**Total Estimated Budget for Activity at the Petroleum Asset Level (Dollars in thousands)**	**Amount of Actual Participation in the Budget by the Holders of the Equity Interests of the Partnership (Dollars in thousands)**
2018	• Examination of development alternatives, considering the development plans of the adjacent reservoirs and the production data from the Tamar reservoir. • Update of mapping and analysis of the Dalit reservoir, based on the seismic survey as aforesaid and on data from adjacent reservoirs, including the production data from the Tamar reservoir. • Mapping out and definition of additional prospects in the area of the lease, including a deep target prospect in the area of the lease.		
2019	• Examination of development alternatives, considering the development plans of the adjacent reservoirs and the production data from the Tamar reservoir. • Update of specification of the Dalit reservoir, based on the seismic survey as aforesaid and on data from adjacent reservoirs, including the production data from the Tamar reservoir. • Specification of deep prospects in the area of the lease.		
2020	• Examination of development alternatives, considering the development plans of the adjacent reservoirs and the production data from the Tamar reservoir. • Update of mapping and analysis of the Dalit reservoir, based on the seismic survey as aforesaid and on data from adjacent reservoirs, including the production data from the Tamar reservoir.		
2021	• Examination of development alternatives, considering the development plans of the adjacent reservoirs and the production data from the Tamar reservoir. • Update of mapping and analysis of the Dalit reservoir, based on the seismic survey as aforesaid and on data from adjacent reservoirs, including the production data from the Tamar reservoir. • Mapping out and definition of additional prospects in the area of the lease, including deep prospects in the area of the lease.		
2022 forth	• Since in accordance with the provisions of the Gas Framework, the Partnership is required to sell its holdings in the project by December 2021, the work plan from 2022 forth, was not included.		

(b) Development plan for the Tamar Project[50]

The Tamar Project's production system includes six subsea production wells, a subsea production system that connects the production wells and the processing and production platform (in this section: the "**Platform**"), on which Platform most of the processing of natural gas takes place, a system for the transmission of gas and condensate from the Platform to the shore and the Terminal, wherein final processing of the natural gas takes place and wherefrom the natural gas is piped into INGL's national transmission system, whereas condensate is piped through a designated pipe to the nearby Paz Ashdod Refinery (PAR).

On August 29, 2016, the Minister of Energy granted the Tamar Partners[51] a license for the operation of a 10-inch pipe, which had originally been designated for the transmission of condensate from the Platform, for natural gas transfer, to increase the gas supply capacity.

The maximum capacity of gas supply from the Tamar Project to the INGL transmission system is approx. 1.1 BCF per day. For details regarding the average daily production in the past two years, see Footnote 74 below.

Since commencement of its commercial operation, the production system of the Tamar Project has had very high operational availability with over 99% Up-time.

For a detailed description of the production system of the Tamar Project, see Section 0 below.

The total cost invested in the Tamar Project, as described above, as of December 31, 2020, is approx. $4.6 billion (100%) (including exploration costs, and excluding retirement and abandonment costs, exploration costs in respect of the Dalit Lease and Tamar's Participation (as defined in Section 7.25.6(c) below)).

(c) Examination of the possible expansion of the supply capacity of the Tamar Project

The overall supply capacity of the Tamar facilities is currently limited to the flow capacity of the Double Piping (as defined in Section 7.16 below). The Tamar Partners

[50] The development plan for the Tamar reservoir, which was submitted to the Petroleum Commissioner by the operator on behalf of the partners in the Tamar and Dalit leases, addressed, *inter alia*, the development of the Dalit Lease.
[51] The license was granted to Tamar 10 Inch which is held by the Tamar Partners, according to their rate of holding in the Tamar Lease.

examine, from time to time, options for expansion of the supply capacity of the Tamar Project, insofar as required, according to the scope of forecasted demand in the domestic market and for export.

Expansion of the supply capacity may include, *inter alia*, completion of the development of the Tamar SW reservoir and/or the drilling and/or completion of additional production wells, which will be connected to the existing subsea production system, as well as the laying of an additional third supply pipe from the Tamar field to the Tamar and/or Mari B platforms. In addition, the need for and manner of the upgrade required for the Tamar platform and for the Terminal, are being examined. On this matter, also see Section 7.3.11(a)3 below.

(d) The Tamar SW reservoir

As specified below, 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 Petroleum Commissioner in January 2019, considering the provisions of the Gas Framework specified in Section 7.23.1(c)3 below, the Tamar SW reservoir will be developed by converting the discovery well into a production well and connecting it to the subsea facilities of the Tamar Project. The cost of development of the Tamar SW reservoir has been partly approved by the Tamar Partners, and accordingly equipment has been purchased and various actions have been performed in connection with development of the reservoir, including the laying of a subsea pipeline between the Tamar SW reservoir and the manifold, which was completed in 2020.

For further details with respect to the work plans and the budget for completion and development of the Tamar SW reservoir, see the table in Section 7.3.4(a) above.

For details with respect to the mediation arrangement in the context of which it was agreed to divide the Tamar SW reservoir between the Tamar Lease (78%) and the Eran License (22%), see Section 7.9.2 below. Note that as of the report approval date, the Tamar Partners and the relevant State representatives are continuing to act to formulate the required agreements in order to implement the mediation arrangement, as aforesaid, but there is no certainty that such agreements will be reached, which will allow commencement of the development of the reservoir, in the near future.

<u>Repercussions of the Covid-19 Crisis</u>

As specified in Section 6.9 above, due to the Covid-19 Crisis there is, on the report approval date, significant and unusual uncertainty as to the possible repercussions of the crisis in and after 2021 for the global economy in general, and energy prices in particular, as well as its possible effect on the availability of the professional manpower needed to operate and upgrade the production facilities. Therefore, insofar as the Covid-19 Crisis continues or worsens, material changes may occur to the work plan and/or time tables specified above.

Caution concerning forward-looking information – The Partnership's aforesaid estimations with respect to the planned activities, costs, timetables and actual performance of the planned activities, including the possible expansion of the supply capacity and production rates of the Tamar Project, constitute forward-looking information within the meaning thereof in Section 32A of the Securities Law, which is based on the estimations of the General Partner of the Partnership with respect to the planned activities, costs, timetables and actual performance of the planned activities and the production rates, which are all based on estimations that the General Partner of the Partnership received from the Operator. In actuality, the planned activities, costs, timetables and production rates may materially differ from the aforesaid estimations and are contingent, *inter alia*, on adoption of the fitting decisions by the Tamar Partners, receipt of the approvals required pursuant to any law, completion of the detailed planning of the components of the activities, receipt of proposals from contractors, changes in the global raw materials and suppliers market , in the applicable regulation, in technical abilities and in economic merit.

7.3.5. Actual participation rate in the expenses and revenues of the Tamar Project[52] (the figures in the table are after the Investment Recovery Date)

Participation Rate	**Percentage**	**Rate Grossed-Up to 100%**	**Explanations**
Actual rate in the petroleum asset attributable to the holders of the equity interests of the Partnership.	22%	100%	See the description of the chain of holdings in Section 7.3 above.
Actual rate in the **revenues** from the petroleum asset attributable to the holders of the equity interests of the Partnership.	17.0676%	77.58%	See the calculation in Section 7.3.7 below.
Actual participation rate in the **expenses** involved in exploration, development or production activities in the petroleum asset attributable to the holders of the equity interests of the Partnership.	22.22%	101%	See the calculation in Section 7.3.9 below.

7.3.6. Actual participation rate in the expenses and revenues of the Dalit Lease

Participation Rate	**Percentage Pre Investment-Recovery**	**Percentage Post Investment - Recovery**	**Rate Grossed-Up to 100% Pre Investment-Recovery**	**Rate Grossed-Up to 100% Post Investment-Recovery**	**Explanations**
Actual rate in the petroleum asset attributable to the holders of the equity interests of the Partnership.	22%	22%	100%	100%	See the description of the chain of holdings in Section 7.3 above.
Actual rate in the **revenues** from the petroleum asset attributable to the holders of the equity interests of the Partnership.	18.1676%	17.0676%	82.58%	77.58%	See the calculation in Section 7.3.8 below.

[52] This table and the notes to this table do not include the Partnership's holdings in the Tamar Petroleum shares and do not refer to the resources from the Tamar SW reservoir which are located in the area of the Eran License. For further details on the Eran License and the mediation arrangement regarding the Eran License and the Tamar SW reservoir, see Section 7.9.2 below.

Actual participation rate in the **expenses** involved in exploration, development or production activities in the petroleum asset attributable to the holders of the equity interests of the Partnership.	22.22%	22.22%	101%	101%	See the calculation in Section 7.3.9 below.

7.3.7. Participation rate of holders of the equity interests of the Partnership in revenues from the Tamar Project (the figures in the table are after the Investment Recovery Date)

Item	**Percentage**	**Concise Explanation as to How Royalties or Payments are Calculated**
Projected annual revenues of petroleum asset	100%	
Specification of the royalties or payment (deriving from revenues post-finding) at the petroleum asset level:		
The State	(12.50%)	In accordance with the Petroleum Law, the royalties are calculated according to market value at the wellhead. The actual royalty rate is lower, as a result of the deduction of expenses in respect of the systems for gas processing and transmission from the wellhead to the onshore gas delivery point. For further details, including with respect to the publication of directives for the method of calculation of the royalty value at the wellhead for offshore petroleum interests and instructions of the Petroleum Commissioner regarding calculation of the royalty value at the wellhead – Tamar Lease, see Section 7.23.4(b) below.
Adjusted revenues at the petroleum asset level	87.50%	
Share in the adjusted revenues deriving from the petroleum asset attributable to the holders of the equity interests of the Partnership (indirect holdings)	22%	
Total share of the holders of the equity interests of the Partnership in the actual amount of revenues, at the petroleum asset level (and before other payments at the Partnership level)	19.25%	
Specification of royalties or payments (deriving from revenues post-finding) in connection with the petroleum asset at the Partnership level (the following percentage will be calculated		

Item	Percentage	Concise Explanation as to How Royalties or Payments are Calculated
according to the rate of the holders of the equity interests of the Partnership in the petroleum asset):		
Rate of the holders of the equity interests of the Partnership in payment to related and third parties	(2.09%)	Overriding royalty in respect of the Partnership's share at a rate of 9.5% Post-Investment-Recovery is calculated according to market value at the wellhead[53]. Calculation of the aforesaid rate is made according to the principles by which the State's royalties in the Tamar Project are calculated, and therefore such rate may change, insofar as the method of calculation of the State's royalties changes. For further details with respect to the method of calculation of the royalty rate, see Section 7.25.10 below.
Rate of the holders of the equity interests of the Partnership in the payment to Dor Chemicals Ltd.[54]	(0.0924%)	Overriding royalty at the rate of 6% in respect of 2.5% (out of 100%) of the interests in the petroleum asset is paid to the royalty holder, after deduction of the royalty to the State, and calculated according to market value at the wellhead. Calculation of the aforesaid rate is made according to the principles by which the State's royalties in the Tamar Project are calculated, and therefore such rate may change insofar as the method of calculation of the State's royalties changes. For further details regarding the manner of calculating the rate of the royalties, see Section 7.25.10 below.
Actual rate in revenues from the petroleum asset attributable to the holders of the equity interests of the Partnership	17.0676%	

7.3.8. Participation rate of the holders of the equity interests of the Partnership in revenues from the Dalit Lease

Item	Pre Investment-Recovery	Post Investment-Recovery	Concise Explanation as to How Royalties or Payments are Calculated
Projected annual revenues of petroleum asset.	100%	100%	

[53] The parties entitled to royalties are not related parties. For further details, see Section 7.25.10 below.
[54] On January 21, 2007, the Partnership and Avner entered into an agreement with Dor Chemicals Ltd. for the purchase of 2.5% (out of 100%) of the interests in the Michal and Matan licenses (in whose stead the Tamar and Dalit leases were granted, respectively). In consideration for the sale of the interests as aforesaid, Dor Chemicals Ltd. is entitled to an overriding royalty as specified in the table. The figures presented in the above tables refer to a royalty after the sale of the interests to Tamar Petroleum, as described in Section 1.7.6 above.

Item	**Pre Investment-Recovery**	**Post Investment-Recovery**	**Concise Explanation as to How Royalties or Payments are Calculated**
Specification of the royalties or payment (deriving from revenues post-finding) at the petroleum asset level:			
The State	(12.50%)	(12.50%)	In accordance with the Petroleum Law, the royalties are calculated according to market value at the wellhead. The actual royalty rate is lower, as a result of the deduction of expenses in respect of the systems for gas processing and transmission from the wellhead to the onshore gas delivery point. For further details, including with respect to the publication of directives on the method of calculation of the royalty value at the wellhead for offshore petroleum interests and instructions of the Petroleum Commissioner regarding calculation of the royalty value at the wellhead – Tamar Lease, see Section 7.23.4(b) below.
Adjusted revenues at the petroleum asset level	87.50%	87.50%	
Share in the adjusted revenues deriving from the petroleum asset attributable to the holders of the equity interests of the Partnership (indirect holdings)	25.7855%	22%	
Total share of the holders of the equity interests of the Partnership in the actual amount of revenues, at the petroleum asset level (and before other payments at the Partnership level)	19.25%	19.25%	
Specification of royalties or payments (deriving from revenues post-finding) in connection with the petroleum asset at the Partnership level (the following percentage will be calculated according to the rate of the holders of the equity interests of the Partnership in the petroleum asset):			

Item	**Pre Investment-Recovery**	**Post Investment-Recovery**	**Concise Explanation as to How Royalties or Payments are Calculated**
Rate of the holders of the equity interests of the Partnership in payment to related and third parties	(0.99%)	(2.09%)	Overriding royalty in respect of the Partnership's share at a rate of 4.5% Pre-Investment-Recovery and at a rate of 9.5% Post-Investment-Recovery, calculated according to market value at the wellhead[55]. Calculation of the aforesaid rate is made according to the principles by which the State's royalties in the Tamar Project are calculated, and therefore such rate may change, insofar as the method of calculation of the State's royalties changes. For further details with respect to the method of calculation of the royalty rate, see Section 7.25.10 below.
Rate of the holders of the equity interests of the Partnership in the payment to Dor Chemicals Ltd.	(0.0924%)	(0.0924%)	Overriding royalty at the rate of 6% in respect of 2.5% (out of 100%) of the interests in the petroleum asset is paid to the royalty holder, after deduction of the royalty to the State and calculated according to market value at the wellhead. Calculation of the aforesaid rate is made according to the principles by which the State's royalties in the Tamar Project are calculated, and therefore such rate may change, insofar as the method of calculation of the State's royalties changes. For further details with respect to the method of calculation of the royalty rate, see Section 7.25.10 below.
Actual rate in revenues from the petroleum asset attributable to the holders of the equity interests of the Partnership.	18.1676%	17.0676%	

[55] The parties entitled to royalties are not related parties. For further details, see Section 7.25.10 below.

7.3.9. Participation rate of the holders of the equity interests of the Partnership in the exploration, development and production expenses of the Tamar Project and Dalit Lease

Item	**Percentage**	**Concise Explanation as to How Royalties or Payment are Calculated**
Theoretical expenses of the petroleum asset (without the aforesaid royalties)	100%	
Specification of the payments (derived from the expenses) at the petroleum asset level:		
The Operator	1%	For further details, see the description of the Joint Operating Agreement in Section 7.25.7(b) below.
Total actual expense rate at the petroleum asset level	101%	
Rate of the holders of the equity interests of the Partnership in the expenses of the petroleum asset (indirect holdings)	22%	
Total actual rate of the holders of the equity interests of the Partnership in the expenses, at the petroleum asset level (before other payments at the Partnership level)	22.22%	
Specification of payments (derived from the expenses) in connection with the petroleum asset and at the Partnership level (the following percentage will be calculated according to the rate of the holders of the equity interests of the Partnership in the petroleum asset):		
Actual rate in the expenses involved in exploration, development and production activities in the petroleum asset, attributable to the holders of the equity interests of the Partnership	22.22%	The Partnership pays management fees to the General Partner, which are comprised of a fixed amount and a variable amount that is calculated as a rate of the exploration expenses upon fulfillment of certain conditions (for details see Section (b)7 of Regulation 21 in Chapter D of this report). Such amounts were not taken into account in this table.

7.3.10. Fees and payments paid during the exploration, development and production activities in the petroleum asset (Dollars in thousands)[56]

The Tamar Lease			
Item	**Total Rate of the Holders of the Equity Interests of the Partnership in the Investment in the Petroleum Asset in this Period (including costs for which no payments are made to the Operator)**	**Out of which, the Share of the Holders of the Equity Interests of the Partnership in Payments to the General Partner**	**Out of which, the Share of the Holders of the Equity Interests of the Partnership in Payments to the Operator (beyond the reimbursement of its direct expenses)**
Budget actually invested in 2018	Approx. 41,250	-	Approx. 410
Budget actually invested in 2019	Approx. 55,040	-	Approx. 570
Budget actually invested in 2020	Approx. 26,885	-	Approx. 261

The Dalit Lease			
Item	**Total Rate of the Holders of the Equity Interests of the Partnership in the Investment in the Petroleum Asset in this Period (including costs for which no payments are made to the Operator)**	**Out of which, the Share of the Holders of the Equity Interests of the Partnership in Payments to the General Partner**	**Out of which, the Share of the Holders of the Equity Interests of the Partnership in Payments to the Operator (beyond the reimbursement of its direct expenses)**
Budget actually invested in 2018	-	-	-
Budget actually invested in 2019	-	-	-
Budget actually invested in 2020	-	-	-

[56] The costs in the table reflect the Partnership's direct and indirect holdings in the Tamar and Dalit Leases (at the rate of 25.7855%) until December 31, 2018; and only the Partnership's direct holdings in the Tamar and Dalit Leases (at the rate of 22%) from January 1, 2019.

7.3.11. Reserves, contingent resources and prospective resources in the Tamar Project

(a) Reserves in the Tamar Lease

1. Quantity data

According to a report received by the Partnership from NSAI, which was prepared in accordance with the rules of the Petroleum Resources Management System (SPE-PRMS), as of December 31, 2020 (in this section: the "**Reserves Report**"), the natural gas and condensate reserves at the Tamar Project (which includes, as aforesaid, the Tamar and Tamar SW reservoirs[57]), are as specified below[58]:

[57] The reserves in the Tamar SW reservoir specified below, do not include the reserves in the part of the reservoir that overflows into the area of the Eran license. For further details regarding the Eran license and the mediation arrangement regarding the Eran license and the Tamar SW reservoir, see Section 7.9.2 below.
[58] The amounts in the table may not add up due to rounding off differences.

Reserves Category	Total (100%) in the Petroleum Asset (gross)						Total (Tamar and Tamar SW Reservoirs) Part Attributable to the Holders of the Equity Interests of the Partnership (Net)[59]	
	The Tamar Reservoir		The Tamar SW Reservoir		Total (Tamar and Tamar SW Reservoirs)			
	Natural Gas BCF	Condensate Million Barrels	Natural Gas BCF	Condensate Million Barrels	Natural Gas BCF	Condensate Million Barrels	Natural Gas BCF	Condensate Million Barrels
Proved Reserves 1P	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 2P Reserves (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 3P Reserves (Proved + Probable + Possible Reserves)	11,891.7	15.5	1,057.8	1.4	12,949.5	16.8	2,210.2	2.9

Caution – Possible reserves are the additional reserves which are not expected to be produced at the same degree as the probable reserves. There is a 10% chance that the quantities actually produced are equal to or higher than the quantity of proved reserves, with the addition of the quantity of probable reserves and with the addition of the quantity of possible reserves.

[59] The Reserves Report does not state the Partnership's net share, but rather the Partnership's gross share. The Partnership's share in the table above is after payment of royalties to the State and third parties, based on the assumption that the rate of the royalty to the State is 12.5% (at the wellhead), and the rate of the royalty to third parties is 9.92% (at the wellhead). The part attributed to the holders of the Partnership's equity interests was calculated according to the Partnership's direct holdings in the Tamar Project (22%). For details regarding the date of recovery of the investment in the Tamar Project, see Sections 7.25.10 and 7.26.6 below.

2. In the Reserves Report, NSAI noted that the maturity stage of the project to which the reserves belong, is on production. NSAI also noted, among other things, several assumptions and reservations, including that: (a) as is common practice in reserve evaluation under the rules of SPE-PRMS, the estimations are not adjusted to risks; (b) NSAI did not visit the oil field and did not examine the mechanical operation of the facilities and wells or their condition; (c) NSAI did not examine possible exposure stemming from environmental protection issues. However, NSAI noted that, as of the date of the Reserves Report, it is not aware of a possible liability pertaining to environmental protection issues, which might materially affect the estimated quantity of reserves in the Reserves Report or the commerciality thereof, and therefore did not include in the Reserves Report costs that might stem from such liability (d) NSAI assumed that the reservoirs are developed according to the development plans that will be reasonably operated, that no regulation will be applied which affects the ability of the petroleum rights holder to produce the reserves and that its forecasts with respect to future production will be similar to the actual functioning of the reservoirs.

Caution concerning forward-looking information – NSAI's estimations with respect to the quantities of natural gas and condensate in the Tamar and Tamar SW reservoirs constitute forward-looking information within the meaning thereof in Section 32A of the Securities Law. The aforesaid estimations are based, *inter alia*, on geological, geophysical, engineering and other information, which has been received from the wells and from the Operator of the Tamar Project, and are merely conjectures and assessments by NSAI, with respect to which there is no certainty. The actual quantities of natural gas and/or condensate to be produced may differ from the aforesaid conjectures and assessments, as a result, *inter alia*, of operational and technical conditions and/or regulatory changes and/or conditions of supply and demand in the natural gas and/or condensate market and/or commercial conditions and/or as a result of the actual performance of the reservoirs. The aforesaid conjectures and assessments may be updated insofar as additional information accumulates and/or as a result of a gamut of factors related to oil and natural gas exploration and production projects, including as a result of the continued production from the Tamar Project.

3. Discounted cash flow figures

The discounted cash flow figures are based on various estimates and assumptions provided by the Partnership to NSAI, mainly as specified below:

(a) Projected sales volumes: the assumptions in the cash flow with respect to the natural gas quantities that shall be sold by the Partnership from the Tamar Project are based on: (i) the production capacity of the Tamar Project[60] . It is noted that the actual production rate for each one 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 in relation to the production rate of the wells; (ii) the Partnership's assumptions with respect to natural gas quantities that shall be sold to customers of the Partnership under the existing agreements entered into by the Partnership, including the agreement for the export of natural gas to Egypt that was signed with Dolphinus (for details see Section 7.11.5(b)(2) below) considering, *inter alia*, the forecasts which were used by the Partnership with respect to the Brent price and the possible impact thereof on the quantities sold to Egypt, and the agreement for the supply of natural gas to the IEC (for details see Sections 7.11.4(a)4 and 7.11.4(a)6 (collectively: the "**Existing Agreements**"); (iii) additional quantities of natural gas which, in the Partnership's estimation, shall be sold in the domestic market in Israel, based, *inter alia*, on negotiations for the sale of natural gas from the Tamar Project, a forecast of demand for natural gas in the domestic market in Israel, which was prepared by outside consultants (BDO Consulting Group, "**BDO**")[61] , and in relation to an estimate of the expected supply from other gas sources and mainly from the Leviathan

[60] The current maximum gas supply capacity from the Tamar Project to the transmission system of INGL, as of the report approval date, is approx. 1.1 BCF per day.

[61] The forecast of the demand for natural gas in the domestic market for the coming years on which the Partnership relied, is as follows (BCM): 2021 – approx. 13.1; 2022 – approx. 15; 2023 – approx. 15.6; 2024 – approx. 16.6; 2025 – approx. 17.9. The aforesaid forecast of the demand is primarily based on a forecast of demand for electricity, which is affected, *inter alia*, by the growth forecasts in Israel and by the COVID-19 Crisis, and also based on the mix of energy sources that will be used in the electricity production that is affected by government policy regarding the reduction of the use of coal as a source of electricity production until its complete cessation and regarding the use of renewable energies as a source of electricity production. The demand forecast is forward-looking information, which there is no certainty will materialize, in whole or in part, and it may materialize in a materially different manner, due to various factors, *inter alia*, the method of the continued spread of the COVID-19 pandemic and its impact on local and global economies, the development of growth in the Israeli economy, the climatic conditions in Israel, the rate of cessation of use of coal as a source of electricity production, the rate of entry of renewable energies as a source of electricity production, the rate of entry of electric vehicles into the Israeli market and government policy in other areas which directly or indirectly pertain to the increase in natural gas demand.

Project and from the Karish and Tanin reservoirs[62]; and (iv) additional quantities of natural gas which, in the Partnership's estimation, will be sold in the regional markets[63].

(b) The sale prices of natural gas and condensate: the assumptions in the cash flow with respect to the prices of the natural gas that shall be sold from the Tamar Project are based, *inter alia*, on a weighted average of the gas prices stated in the Existing Agreements according to the price formulas set forth therein, and on the Partnership's assumptions with respect to the prices that shall be determined in future agreements, based, *inter alia*, on a breakdown of the forecast of the demand in the domestic market in the cash flow years, as estimated by BDO, and on the Partnership's estimate of the expected supply.

The price formulas determined in the Existing Agreements include, *inter alia*, linkage to the Electricity Production Tariff[64], the U.S. CPI and the Brent oil barrel price (the "**Brent Price**"). The assumptions with respect to the linkage components are based on data and forecasts received from BDO as specified below:

(1) The U.S. CPI – annual growth was assumed at an average rate of approx. 2% per year;
(2) Brent barrel price – was based on an average of long-term forecasts of the following four bodies[65]: the World Bank, the U.S. Department of Energy, IHS Global Insights and Wood Mackenzie. Accordingly, an assumption was made in the cash flow of a price of approx. \$52 per Brent barrel in 2021, which rises to approx. \$68 per barrel in 2025, and to a fixed barrel price of approx. \$86 per barrel from 2030 until the end of the cash flow period.
(3) Electricity Production Tariff – a forecast which is based, *inter alia*, on the ILS to dollar exchange rate and on a

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[62] For details regarding the natural gas sales forecast from the Leviathan Project, see the Partnership's immediate report of March 10, 2021 (Ref. no.: 2021-01-030942). In the discounted cash flow, it was assumed that sales of natural gas to the domestic market in Israel from the Karish and Tanin project will begin in Q1/2022.

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

[64] The electricity production tariff is a tariff regulated by the PUA-E, and reflects the costs of the IEC's electricity production segment, including the IEC's fuel cost, capital and operating costs associated with the production segment and the cost of purchasing electricity from independent power producers.

[65] To the best of the Partnership's knowledge, the frequency of updating the Brent Price forecast by the four aforesaid bodies is as follows: the World Bank - twice a year; the U.S. Department of Energy – short-term forecast – every month, long-term forecast – twice a year; Wood Mackenzie - every six months; IHS Global Insights – every month.

forecast of the cost of the fuels which is based on the gas price to the IEC.

It is noted that the sale prices may change, *inter alia*, due to changes in indices on which the linkages in the gas supply agreements are based as aforesaid, due to commercial and competitive considerations and due to price adjustment mechanisms as determined in the agreement with the IEC[66], and in the Export to Egypt Agreement[67]. In the cash flow it was assumed that a price reduction will be made in the agreement with the IEC at the rate of 25% on the first adjustment date (i.e. on July 1, 2021), and at the rate of 10% on the second adjustment date (i.e. on July 1, 2024). Such price reductions were incorporated into the electricity production tariff forecast. It is further noted that no price change as a result of the class certification motion filed by a consumer of the IEC against the partners in the Tamar Project, as specified in Section 7.27.1 below, was taken into account. In the estimation of the Partnership's legal counsel, the chances of the certification motion being granted are lower than 50%. As aforesaid, at this stage, the parties are currently at the stage of the class certification motion. Insofar as a final and non-appealable decision is issued in the context of acceptance of the said class action (i.e. after the class certification motion is granted (if granted) and a non-appealable decision is issued on the class action on the merits (if issued)) against the owners of the rights in the Tamar venture, this may have an adverse effect on the Partnership's business, including on the discounted cash flow figures and on the prices at which the Partnership shall sell natural gas to its customers, the extent of which will be derived from the outcome of the action.

The assumptions in the cash flow with respect to the sale prices of condensate are based on the Brent Crude prices, which are adjusted to differences in quality, transmission costs and the price at which condensate is sold in the region. For details regarding the agreement for the supply of condensate from the Tamar Project, see Section 7.12.6(a) below.

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[66] The agreement with the IEC determined two dates on which each party may request a price adjustment in accordance with the mechanism set forth in the agreement. For details see Section 7.12.4(a)(4)(h) below.

[67] The Export to Egypt Agreement includes a mechanism for updating the price at a rate of up to 10% (addition or reduction) after the fifth year and after the tenth year of the Agreement subject to certain conditions set forth in the Agreement. It is noted that no price update was assumed on such dates.

(c) The operation costs that were taken into account are costs that were provided to NSAI by the Partnership based, *inter alia*, on information supplied from the Operator. These costs include direct costs at the project level, insurance costs, production well maintenance costs, transmission costs to the point of delivery, as set forth in the Export to Egypt Agreement and estimated overhead and general and administrative expenses of the Operator, which may be directly attributed to the project and jointly constitute the operation costs of the project. The operation costs in the cash flow are not adjusted to inflation changes. NSAI confirmed that the operation costs that were provided by the Partnership are reasonable based, *inter alia* on knowledge that NSAI has from similar projects.

(d) The capital expenditures that were taken into account in the cash flow are expenditures approved by the Partnership and an estimate of future capital expenditures not yet approved by the Partnership, that shall be incurred in the course of the production for the purpose of preserving and expanding the production capacity, including, *inter alia*, the drilling and connection of new development wells, the laying of additional infrastructure and additional production equipment, expenses for engineering work, participation in the costs of construction of the natural gas transmission infrastructure[68], and indirect costs paid to the Operator. The capital expenditures in the cash flow are not adjusted to inflation changes. NSAI confirmed that the capital expenditures that were provided by the Partnership are reasonable based, *inter alia* on the development plan for the Tamar Project and on knowledge that NSAI has from similar projects.

(e) Abandonment costs that were taken into account in the cash flow are costs that were provided to NSAI by the Partnership in accordance with its estimates based, *inter alia*, on outside experts with respect to the cost of abandonment of the wells, the platform and the production facilities. These costs do not take into account the salvage value of the Tamar Lease and the facilities in the Tamar Project and are not adjusted to inflation changes.

(f) The calculation of the discounted cash flow took into account the Partnership’s estimate whereby the effective rate of the State’s royalties is 11.5%, and the effective rate of the royalties

[68]In order to increase the possible flow capacity via the EMG pipeline, expansion of the supply capacity in the INGL system is required, as well as in the EMG systems in Israel and Egypt, for details see Section 7.13.2(b)(2)(b) below.

that shall be paid to third parties is 9.13% (with respect to the Partnership's direct holdings in the Tamar Project). The actual rate of the said royalties is not final and may change. For further details on the matter, see Sections 7.24.3(b) and 7.26.9(b) below.

(g) The tax payments and the rates of tax which were taken into account in the discounted cash flow were calculated from the perspective of a company that holds the participation units of the Partnership from the date of commencement of the project. The tax calculations took into account the corporate tax rate pursuant to law. It is noted that the tax payments that shall actually be made in the future by the Partnership on account of the tax for which the holders of the participation units of the Partnership are liable in each one of the relevant tax years, according to the provisions of the Taxation of Profits from Natural Resources Law, may be materially different. The depreciation expenses for tax purposes were calculated pursuant to the depreciation rates set forth in the law.

(h) The calculation of the discounted cash flow takes into account the petroleum profit levy (in this section: the "**Levy**") that shall apply to the Partnership pursuant to the provisions of the law. It should be emphasized that the Levy calculations were made, *inter alia*, according to the definitions, the formulas and the mechanisms defined in the law, as understood and interpreted by the Partnership, and which were expressed in the Levy reports of the Tamar venture which were filed with the Tax Authority. However, in view of the novelty of the Law and the complexity of the calculation formulas and the various mechanisms defined therein, there is no assurance that this interpretation of the method of calculation of the Levy will be the same as that which shall be adopted by the tax authorities and/or the same as the interpretation of the law by the court. It is noted that as of the report approval date, several interpretation disputes are being heard with respect to the implementation of the law in the Levy reports of the Tamar venture vis-à-vis the Tax Authority, under administrative objection and appeal proceedings as set forth in the law. The issues to which these disputes pertain have not yet been addressed in Israeli case law[69]. The Levy calculations were made according to the transitional provisions set forth in the law with respect to a venture, the date of commencement of

[69] If and to the extent that the position of the Tax Authority in the aforesaid disputes is accepted, the Partnership estimates that no material effect is expected on the value of the discounted cash flow.

commercial production in respect of which occurred from the date of commencement of the law until January 1, 2014. In addition, the calculation was made in dollars according to the choice of the holders of rights in the venture, pursuant to Section 13(b) of the law, and is based, *inter alia*, on the following assumptions: all of the payments which are attributed to the venture (the production costs, the investments, the royalties, etc.) will be recognized by the tax authorities for the purpose of the Levy calculation; for the purpose of calculation of the income attributed to the venture, the actual sale prices of the natural gas shall be taken into account.

(i) The calculation of the discounted cash flow took into account expenses and investments actually paid and expected to be paid by the Partnership from July 1, 2021, and income deriving from sales of natural gas and condensate that were produced and are expected to be produced from January 1, 2021.

(j) Income from natural gas and condensate sales that shall be made in a certain year was taken into account in the same year, regardless of the actual payment date.

<u>It is noted that the discounted cash flow was updated relative to the discounted cash flow as of June 30, 2020, for the following main reasons:</u>

(1) Update of forecasts of the volume that shall be sold, mainly due to the Partnership's assumptions regarding the deferral of the date of commencement of production from the Karish, Karish North and Tanin reservoirs and the increase in the annual volume of sales from these reservoirs.

(2) Update of the operating costs and investments made until December 31, 2020, in accordance with the actual investments. Forecasts of the future investments and operating costs were also updated in accordance with the Partnership's estimate, based, *inter alia*, on the production profile and on updated estimates received from the Operator, and which were updated, *inter alia*, in view of the expected streamlining and reduction of the operating budgets.

(3) Update of the quantities of gas and condensate produced and sold during H2/2020, in accordance with actual figures.

(4) In the discounted cash flow as of June 30, 2020, data was given which is attributed to the Partnership's direct and indirect share (through its holding at a rate of 22.6% in Tamar Petroleum)

from the reserves of the Tamar Project (i.e. 25.7855%) whereas in the updated discounted cash flow, data was given which is attributed only to the Partnership's direct share (22%).

In accordance with various assumptions, the principal amount which assumptions are specified above, the following table shows the estimated discounted cash flow as of December 31, 2020 in thousands of dollars (after levy and income tax), attributed to the Partnership's share (directly 22%), from the reserves in the Tamar Project, for each of the reserve categories specified above[70]:

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

Total discounted cash flow from 1P (proved) reserves as of December 31, 2020 (in dollars in thousands in relation to the Partnership's share)																	
Cash flow components																	
Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Gas sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Develop-ment costs	Abandon-ment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Taxes		Total discounted cash flow after tax					
										Levy	Income Tax	Discounted at 0%	Discounted at 5%	Discounted at 7.5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2021	395	8.60	299,712	61,833	-	32,112	14,570	-	191,197	45,805	29,620	115,772	112,982	111,660	110,384	107,958	105,685
31.12.2022	421	9.16	337,784	69,688	-	29,068	6,172	-	232,856	71,022	31,676	130,158	120,973	116,778	112,819	105,542	99,015
31.12.2023	419	9.13	344,590	71,092	-	28,928	47,436	-	197,135	70,617	35,319	91,199	80,726	76,115	71,863	64,305	57,814
31.12.2024	436	9.49	357,417	73,738	-	28,879	68,603	-	186,197	74,426	35,193	76,578	64,557	59,453	54,857	46,953	40,455
31.12.2025	475	10.35	392,114	80,896	-	29,019	-	-	282,199	127,250	27,801	127,148	102,084	91,827	82,802	67,791	55,975
31.12.2026	488	10.62	412,572	85,117	-	29,068	-	-	298,387	139,645	29,592	129,149	98,753	86,765	76,460	59,876	47,380
31.12.2027	501	10.91	429,558	88,621	-	29,108	-	-	311,829	145,936	32,630	133,262	97,046	83,282	71,723	53,724	40,741
31.12.2028	505	11.00	440,918	90,965	-	29,609	35,019	-	285,325	133,532	37,888	113,905	78,999	66,218	55,731	39,931	29,019
31.12.2029	526	11.46	464,557	95,842	-	29,700	7,849	-	331,167	154,986	36,796	139,385	92,068	75,378	61,998	42,490	29,592
31.12.2030	535	11.65	476,544	98,315	-	29,746	-	-	348,483	163,090	37,065	148,328	93,309	74,618	59,978	39,318	26,242
31.12.2031	535	11.65	476,800	98,368	-	29,747	-	-	348,686	163,185	37,331	148,169	88,771	69,338	54,467	34,153	21,845
31.12.2032	535	11.65	474,918	97,979	-	29,740	-	-	347,199	162,489	37,250	147,459	84,139	64,191	49,278	29,556	18,117
31.12.2033	535	11.65	474,888	97,973	-	29,739	22,385	-	324,790	152,002	39,751	133,037	72,295	53,872	40,417	23,187	13,621
31.12.2034	535	11.65	475,086	98,014	-	29,740	42,867	-	304,465	142,490	43,614	118,361	61,257	44,586	32,689	17,939	10,099
31.12.2035	535	11.65	465,155	95,965	-	29,702	-	-	339,488	158,880	39,024	141,584	69,786	49,612	35,548	18,659	10,067

Total discounted cash flow from 1P (proved) reserves as of December 31, 2020 (in dollars in thousands in relation to the Partnership's share)

Cash flow components

Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Gas sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Develop-ment costs	Abandon-ment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Taxes: Levy	Taxes: Income Tax	Total discounted cash flow after tax: Discounted at 0%	Discounted at 5%	Discounted at 7.5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2036	494	10.77	430,185	88,751	-	29,567	-	-	311,867	145,954	35,644	130,269	61,151	42,463	29,734	14,929	7,718
31.12.2037	366	7.98	317,820	65,569	-	29,135	-	-	223,116	104,418	24,785	93,913	41,986	28,476	19,487	9,359	4,637
31.12.2038	286	6.24	248,653	51,299	-	28,869	-	-	168,485	78,851	18,100	71,534	30,458	20,177	13,494	6,199	2,943
31.12.2039	236	5.13	204,519	42,194	-	28,699	-	-	133,626	62,537	14,669	56,420	22,879	14,804	9,675	4,251	1,935
31.12.2040	200	4.35	173,522	35,799	-	28,580	-	-	109,143	51,079	11,854	46,210	17,846	11,279	7,204	3,028	1,320
31.12.2041	174	3.78	150,734	31,098	-	28,493	-	-	91,144	42,655	9,652	38,837	14,284	8,818	5,504	2,213	925
31.12.2042	153	3.33	132,745	27,386	-	28,423	-	-	76,935	36,006	7,913	33,016	11,565	6,973	4,254	1,636	655
31.12.2043	135	2.93	116,760	24,089	-	28,362	-	-	64,310	30,097	6,368	27,845	9,289	5,471	3,261	1,200	460
31.12.2044	118	2.58	102,778	21,204	-	28,308	-	-	53,266	24,929	5,532	22,806	7,246	4,168	2,428	854	314
31.12.2045	104	2.27	90,398	18,650	-	28,261	-	-	43,488	20,352	5,321	17,814	5,391	3,029	1,724	580	205
31.12.2046	91	1.99	79,221	16,344	-	28,218	-	-	34,660	16,221	4,241	14,198	4,092	2,245	1,249	402	136
31.12.2047	81	1.76	70,041	14,450	-	28,182	-	-	27,409	12,827	3,060	11,521	3,162	1,695	922	284	92
31.12.2048	71	1.54	61,266	12,640	-	28,148	-	-	20,478	9,584	2,212	8,682	2,269	1,188	631	186	58
31.12.2049	62	1.36	54,087	11,158	-	28,121	-	17,946	(3,139)	-	3,112	(6,251)	(1,556)	(796)	(413)	(116)	(35)
31.12.2050	55	1.20	47,707	9,842	-	28,096	-	17,946	(8,177)	-	1,953	(10,131)	(2,402)	(1,200)	(609)	(164)	(47)

Total discounted cash flow from 1P (proved) reserves as of December 31, 2020 (in dollars in thousands in relation to the Partnership's share)																	
Cash flow components																	
Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Gas sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Develop-ment costs	Abandon-ment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Taxes		Total discounted cash flow after tax					
										Levy	Income Tax	Discounted at 0%	Discounted at 5%	Discounted at 7.5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2051	44	0.95	37,811	7,801	-	28,058	-	17,946	(15,994)	-	156	(16,149)	(3,646)	(1,779)	(882)	(227)	(62)
31.12.2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**10,044**	**219**	**8,640,862**	**1,782,680**	**-**	**899,426**	**244,899**	**53,837**	**5,660,019**	**2,540,864**	**685,125**	**2,434,030**	**1,541,758**	**1,270,707**	**1,068,681**	**795,994**	**626,921**

Total discounted cash flow from probable reserves as of December 31, 2020 (in dollars in thousands in relation to the Partnership's share)																	
Cash flow components																	
Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Gas sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Develop-ment costs	Abandon-ment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Taxes		Total discounted cash flow after tax					
										Levy	Income Tax	Discounted at 0%	Discounted at 5%	Discounted at 7.5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2021	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2022	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2023	-	-	-	-	-	-	(41,881)	-	41,881	16,626	(3,824)	29,079	25,739	24,269	22,913	20,504	18,434
31.12.2024	-	-	-	-	-	-	(68,603)	-	68,603	32,701	(5,604)	41,506	34,990	32,224	29,733	25,449	21,927
31.12.2025	-	-	-	-	-	-	68,603	-	(68,603)	(28,589)	10,076	(50,089)	(40,215)	(36,175)	(32,619)	(26,706)	(22,051)
31.12.2026	-	-	-	-	-	-	41,881	-	(41,881)	(19,600)	6,425	(28,706)	(21,950)	(19,285)	(16,994)	(13,308)	(10,531)
31.12.2027	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2028	-	-	-	-	-	-	(35,019)	-	35,019	16,389	(3,769)	22,399	15,535	13,022	10,959	7,852	5,707
31.12.2029	-	-	-	-	-	-	(7,849)	-	7,849	3,673	(10)	4,186	2,765	2,264	1,862	1,276	889
31.12.2030	-	-	-	-	-	-	-	-	-	-	1,015	(1,015)	(638)	(511)	(410)	(269)	(180)
31.12.2031	-	-	-	-	-	-	-	-	-	-	1,015	(1,015)	(608)	(475)	(373)	(234)	(150)
31.12.2032	-	-	-	-	-	-	-	-	-	-	1,015	(1,015)	(579)	(442)	(339)	(203)	(125)
31.12.2033	-	-	-	-	-	-	(22,385)	-	22,385	10,476	(1,395)	13,303	7,229	5,387	4,042	2,319	1,362
31.12.2034	-	-	-	-	-	-	(42,867)	-	42,867	20,062	(5,001)	27,807	14,391	10,475	7,680	4,214	2,372

Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Gas sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Develop-ment costs	Abandon-ment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Taxes: Levy	Taxes: Income Tax	Total discounted cash flow after tax: Discounted at 0%	Discounted at 5%	Discounted at 7.5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
Total discounted cash flow from probable reserves as of December 31, 2020 (in dollars in thousands in relation to the Partnership's share)																	
Cash flow components																	
31.12.2035	-	-	-	-	-	-	7,849	-	(7,849)	(3,673)	(139)	(4,036)	(1,989)	(1,414)	(1,013)	(532)	(287)
31.12.2036	40	0.88	35,147	7,251	-	135	35,019	-	(7,258)	(3,397)	7,584	(11,446)	(5,373)	(3,731)	(2,612)	(1,312)	(678)
31.12.2037	168	3.67	146,149	30,152	-	562	22,385	-	93,050	43,548	18,035	31,468	14,068	9,542	6,530	3,136	1,554
31.12.2038	248	5.41	215,562	44,472	-	829	42,867	-	127,394	59,620	26,433	41,340	17,602	11,661	7,798	3,582	1,701
31.12.2039	299	6.52	259,917	53,623	-	1,000	-	-	205,295	96,078	24,285	84,931	34,440	22,285	14,565	6,400	2,912
31.12.2040	335	7.30	291,181	60,073	-	1,120	42,867	-	187,121	87,573	31,741	67,808	26,187	16,551	10,571	4,443	1,938
31.12.2041	361	7.87	313,813	64,742	-	1,207	-	-	247,864	116,000	28,328	103,536	38,081	23,508	14,674	5,899	2,465
31.12.2042	361	7.86	313,310	64,639	-	1,205	-	-	247,467	115,815	28,279	103,373	36,211	21,834	13,319	5,122	2,051
31.12.2043	311	6.78	270,174	55,739	-	1,039	-	-	213,396	99,869	24,110	89,416	29,830	17,568	10,473	3,852	1,479
31.12.2044	266	5.80	231,049	47,667	-	889	-	-	182,493	85,407	19,814	77,272	24,551	14,123	8,228	2,895	1,065
31.12.2045	228	4.97	197,921	40,833	-	761	-	-	156,327	73,161	15,626	67,539	20,437	11,483	6,538	2,200	776
31.12.2046	196	4.26	169,589	34,988	-	652	-	-	133,949	62,688	13,069	58,192	16,770	9,203	5,121	1,648	557
31.12.2047	167	3.63	144,461	29,803	-	556	-	-	114,101	53,399	11,768	48,934	13,431	7,199	3,915	1,205	390
31.12.2048	143	3.12	124,123	25,608	-	477	-	-	98,038	45,882	10,317	41,839	10,936	5,726	3,043	896	278

Total discounted cash flow from probable reserves as of December 31, 2020 (in dollars in thousands in relation to the Partnership's share)																	
Cash flow components																	
Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Gas sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Develop-ment costs	Abandon-ment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Taxes		Total discounted cash flow after tax					
										Levy	Income Tax	Discounted at 0%	Discounted at 5%	Discounted at 7.5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2049	122	2.66	105,787	21,825	-	407	-	(17,946)	101,501	46,034	7,497	47,970	11,942	6,107	3,172	893	266
31.12.2050	104	2.27	90,246	18,619	-	347	-	(17,946)	89,227	37,931	6,538	44,758	10,612	5,301	2,690	725	207
31.12.2051	94	2.05	81,417	16,797	-	313	-	1,063	63,243	22,113	9,558	31,573	7,129	3,478	1,725	445	121
31.12.2052	119	2.59	102,899	21,229	-	28,309	-	19,009	34,352	16,077	8,135	10,140	2,181	1,039	504	124	32
31.12.2053	17	0.38	14,901	3,074	-	27,970	-	19,009	(35,152)	-	-	(35,152)	(7,199)	(3,351)	(1,587)	(374)	(94)
31.12.2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**3,582**	**78**	**3,107,646**	**641,133**	**-**	**67,779**	**42,867**	**3,190**	**2,352,678**	**1,105,862**	**290,921**	**955,895**	**336,507**	**208,864**	**134,104**	**62,141**	**34,387**

Total discounted cash flow from 2P (proved + probable) reserves as of December 31, 2020 (in dollars in thousands in relation to the Partnership's share)																	
Cash flow components																	
Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Gas sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Develop-ment costs	Abandon-ment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Taxes		Total discounted cash flow after tax					
										Levy	Income Tax	Discounted at 0%	Discounted at 5%	Discounted at 7.5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2021	395	8.60	299,712	61,833	-	32,112	14,570	-	191,197	45,805	29,620	115,772	112,982	111,660	110,384	107,958	105,685
31.12.2022	421	9.16	337,784	69,688	-	29,068	6,172	-	232,856	71,022	31,676	130,158	120,973	116,778	112,819	105,542	99,015
31.12.2023	419	9.13	344,590	71,092	-	28,928	5,555	-	239,016	87,243	31,495	120,277	106,466	100,384	94,777	84,808	76,248
31.12.2024	436	9.49	357,417	73,738	-	28,879	-	-	254,800	107,127	29,589	118,084	99,547	91,677	84,590	72,402	62,382
31.12.2025	475	10.35	392,114	80,896	-	29,019	68,603	-	213,596	98,661	37,876	77,059	61,869	55,653	50,183	41,085	33,924
31.12.2026	488	10.62	412,572	85,117	-	29,068	41,881	-	256,506	120,045	36,017	100,444	76,804	67,480	59,465	46,568	36,849
31.12.2027	501	10.91	429,558	88,621	-	29,108	-	-	311,829	145,936	32,630	133,262	97,046	83,282	71,723	53,724	40,741
31.12.2028	505	11.00	440,918	90,965	-	29,609	-	-	320,344	149,921	34,119	136,304	94,534	79,240	66,691	47,783	34,726
31.12.2029	526	11.46	464,557	95,842	-	29,700	-	-	339,015	158,659	36,786	143,571	94,832	77,641	63,860	43,766	30,481
31.12.2030	535	11.65	476,544	98,315	-	29,746	-	-	348,483	163,090	38,080	147,313	92,671	74,107	59,568	39,049	26,063
31.12.2031	535	11.65	476,800	98,368	-	29,747	-	-	348,686	163,185	38,346	147,154	88,163	68,863	54,094	33,919	21,696
31.12.2032	535	11.65	474,918	97,979	-	29,740	-	-	347,199	162,489	38,265	146,444	83,559	63,749	48,939	29,353	17,992
31.12.2033	535	11.65	474,888	97,973	-	29,739	-	-	347,175	162,478	38,357	146,340	79,524	59,260	44,459	25,506	14,983
31.12.2034	535	11.65	475,086	98,014	-	29,740	-	-	347,332	162,551	38,613	146,168	75,648	55,060	40,369	22,153	12,471
31.12.2035	535	11.65	465,155	95,965	-	29,702	7,849	-	331,640	155,207	38,885	137,548	67,797	48,198	34,535	18,127	9,780

Total discounted cash flow from 2P (proved + probable) reserves as of December 31, 2020 (in dollars in thousands in relation to the Partnership's share)																	
Cash flow components																	
Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Gas sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Develop-ment costs	Abandon-ment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Taxes		Total discounted cash flow after tax					
										Levy	Income Tax	Discounted at 0%	Discounted at 5%	Discounted at 7.5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2036	535	11.65	465,331	96,002	-	29,703	35,019	-	304,609	142,557	43,229	118,823	55,778	38,732	27,122	13,617	7,040
31.12.2037	535	11.65	463,970	95,721	-	29,697	22,385	-	316,166	147,966	42,820	125,381	56,054	38,018	26,017	12,494	6,191
31.12.2038	535	11.65	464,215	95,771	-	29,698	42,867	-	295,879	138,471	44,533	112,874	48,060	31,838	21,292	9,781	4,644
31.12.2039	535	11.65	464,437	95,817	-	29,699	-	-	338,920	158,615	38,955	141,351	57,319	37,089	24,240	10,651	4,847
31.12.2040	535	11.65	464,703	95,872	-	29,700	42,867	-	296,264	138,651	43,595	114,018	44,033	27,830	17,775	7,471	3,258
31.12.2041	535	11.65	464,547	95,840	-	29,700	-	-	339,007	158,655	37,979	142,373	52,366	32,326	20,178	8,112	3,390
31.12.2042	514	11.19	446,055	92,025	-	29,629	-	-	324,402	151,820	36,192	136,390	47,776	28,807	17,573	6,757	2,706
31.12.2043	446	9.71	386,934	79,828	-	29,401	-	-	277,705	129,966	30,478	117,261	39,120	23,039	13,735	5,052	1,939
31.12.2044	385	8.38	333,827	68,871	-	29,197	-	-	235,759	110,335	25,346	100,078	31,797	18,291	10,656	3,749	1,379
31.12.2045	332	7.24	288,319	59,483	-	29,022	-	-	199,815	93,513	20,948	85,354	25,828	14,512	8,262	2,781	980
31.12.2046	287	6.25	248,811	51,332	-	28,870	-	-	168,609	78,909	17,310	72,390	20,862	11,449	6,370	2,051	693
31.12.2047	247	5.39	214,502	44,254	-	28,738	-	-	141,511	66,227	14,828	60,455	16,593	8,894	4,836	1,489	482
31.12.2048	214	4.66	185,388	38,247	-	28,626	-	-	118,515	55,465	12,530	50,520	13,206	6,914	3,674	1,082	336
31.12.2049	185	4.02	159,873	32,983	-	28,528	-	-	98,362	46,034	10,609	41,719	10,386	5,311	2,758	777	231
31.12.2050	159	3.47	137,954	28,461	-	28,443	-	-	81,049	37,931	8,491	34,627	8,210	4,101	2,081	561	160

Total discounted cash flow from 2P (proved + probable) reserves as of December 31, 2020 (in dollars in thousands in relation to the Partnership's share)																	
Cash flow components																	
Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Gas sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Develop-ment costs	Abandon-ment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Taxes		Total discounted cash flow after tax					
										Levy	Income Tax	Discounted at 0%	Discounted at 5%	Discounted at 7.5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2051	138	3.00	119,228	24,598	-	28,371	-	19,009	47,250	22,113	9,713	15,424	3,483	1,699	843	217	59
31.12.2052	119	2.59	102,899	21,229	-	28,309	-	19,009	34,352	16,077	8,135	10,140	2,181	1,039	504	124	32
31.12.2053	17	0.38	14,901	3,074	-	27,970	-	19,009	(35,152)	-	-	(35,152)	(7,199)	(3,351)	(1,587)	(374)	(94)
31.12.2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**13,626**	**297**	**11,748,509**	**2,423,813**	**-**	**967,205**	**287,766**	**57,027**	**8,012,697**	**3,646,725**	**976,046**	**3,389,925**	**1,878,265**	**1,479,571**	**1,202,784**	**858,135**	**661,308**

Total discounted cash flow from possible reserves as of December 31, 2020 (in dollars in thousands in relation to the Partnership's share)																	
Cash flow components																	
Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Gas sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Develop-ment costs	Abandon-ment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Taxes		Total discounted cash flow after tax					
										Levy	Income Tax	Discounted at 0%	Discounted at 5%	Discounted at 7.5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2021	-	-	-	-	-	-	-	-	-	-	(9)	9	9	9	9	8	8
31.12.2022	-	-	-	-	-	-	-	-	-	-	(9)	9	8	8	8	7	7
31.12.2023	-	-	-	-	-	-	-	-	-	-	(9)	9	8	7	7	6	5
31.12.2024	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2025	-	-	-	-	-	-	(68,603)	-	68,603	32,387	(7,449)	43,665	35,057	31,535	28,436	23,280	19,223
31.12.2026	-	-	-	-	-	-	26,722	-	(26,722)	(12,506)	4,459	(18,676)	(14,280)	(12,547)	(11,056)	(8,658)	(6,851)
31.12.2027	-	-	-	-	-	-	41,881	-	(41,881)	(19,600)	4,518	(26,798)	(19,515)	(16,747)	(14,423)	(10,804)	(8,193)
31.12.2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2030	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2031	-	-	-	-	-	-	-	-	-	-	9	(9)	(5)	(4)	(3)	(2)	(1)
31.12.2032	-	-	-	-	-	-	-	-	-	-	9	(9)	(5)	(4)	(3)	(2)	(1)
31.12.2033	-	-	-	-	-	-	-	-	-	-	9	(9)	(5)	(3)	(3)	(1)	(1)
31.12.2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2035	-	-	-	-	-	-	(7,849)	-	7,849	3,673	(845)	5,020	2,474	1,759	1,260	662	357

Total discounted cash flow from possible reserves as of December 31, 2020 (in dollars in thousands in relation to the Partnership's share)																	
Cash flow components																	
Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Gas sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Develop-ment costs	Abandon-ment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Taxes		Total discounted cash flow after tax					
										Levy	Income Tax	Discounted at 0%	Discounted at 5%	Discounted at 7.5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2036	-	-	-	-	-	-	(35,019)	-	35,019	16,389	(5,172)	23,802	11,173	7,759	5,433	2,728	1,410
31.12.2037	-	-	-	-	-	-	20,482	-	(20,482)	(9,586)	3,210	(14,106)	(6,307)	(4,277)	(2,927)	(1,406)	(697)
31.12.2038	-	-	-	-	-	-	(20,482)	-	20,482	9,586	(1,690)	12,586	5,359	3,550	2,374	1,091	518
31.12.2039	-	-	-	-	-	-	-	-	-	-	986	(986)	(400)	(259)	(169)	(74)	(34)
31.12.2040	-	-	-	-	-	-	-	-	-	-	986	(986)	(381)	(241)	(154)	(65)	(28)
31.12.2041	-	-	-	-	-	-	-	-	-	-	986	(986)	(363)	(224)	(140)	(56)	(23)
31.12.2042	21	0.46	18,335	3,783	-	71	42,867	-	(28,385)	(13,284)	7,372	(22,473)	(7,872)	(4,747)	(2,895)	(1,113)	(446)
31.12.2043	89	1.94	77,284	15,944	-	297	-	-	61,042	28,568	7,469	25,005	8,342	4,913	2,929	1,077	413
31.12.2044	150	3.27	130,235	26,868	-	501	-	-	102,865	48,141	12,587	42,138	13,388	7,701	4,487	1,579	581
31.12.2045	202	4.41	175,587	36,225	-	675	-	-	138,686	64,905	16,970	56,811	17,191	9,659	5,499	1,851	652
31.12.2046	248	5.40	214,939	44,344	-	827	-	-	169,769	79,452	20,592	69,725	20,094	11,027	6,136	1,975	667
31.12.2047	287	6.26	249,092	51,390	-	958	-	-	196,744	92,076	23,059	81,609	22,399	12,006	6,529	2,010	651
31.12.2048	321	6.99	278,049	57,364	-	1,069	-	-	219,616	102,780	26,357	90,478	23,650	12,383	6,580	1,938	601
31.12.2049	295	6.43	255,893	52,793	-	984	-	-	202,116	94,590	24,185	83,340	20,747	10,610	5,510	1,552	462
31.12.2050	289	6.30	250,622	51,705	-	964	-	-	197,952	92,642	23,676	81,635	19,355	9,668	4,907	1,322	377

Total discounted cash flow from possible reserves as of December 31, 2020 (in dollars in thousands in relation to the Partnership's share)																		
Cash flow components																		
Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Gas sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Develop-ment costs	Abandon-ment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Taxes		Total discounted cash flow after tax						
										Levy	Income Tax	Discounted at 0%	Discounted at 5%	Discounted at 7.5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2051	263	5.72	227,281	46,890	-	874	-	(19,009)	198,526	92,910	19,374	86,242	19,474	9,501	4,712	1,215	332
31.12.2052	220	4.80	190,657	39,334	-	733	-	(19,009)	169,599	79,372	15,394	74,833	16,093	7,669	3,717	916	240
31.12.2053	288	6.28	249,532	51,480	-	960	-	(19,009)	216,101	84,684	21,701	109,716	22,471	10,459	4,955	1,168	293
31.12.2054	247	5.38	213,608	44,069	-	28,734	-	19,009	121,795	57,000	18,835	45,960	8,965	4,076	1,887	426	102
31.12.2055	195	4.25	168,580	34,779	-	28,561	-	19,009	86,230	40,356	14,483	31,392	5,832	2,590	1,172	253	58
31.12.2056	92	2.00	79,332	16,367	-	28,218	-	19,009	15,738	7,365	5,858	2,515	445	193	85	18	4
Total	**3,209**	**70**	**2,779,025**	**573,335**	**-**	**94,428**	**-**	**-**	**2,111,261**	**971,900**	**257,899**	**881,462**	**223,401**	**118,028**	**64,858**	**22,900**	**10,686**

Total discounted cash flow from 3P (proved + probable + possible) reserves as of December 31, 2020 (in dollars in thousands in relation to the Partnership's share)

Cash flow components

Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Gas sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Develop-ment costs	Abandon-ment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Taxes		Total discounted cash flow after tax					
										Levy	Income Tax	Discounted at 0%	Discounted at 5%	Discounted at 7.5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2021	395	8.60	299,712	61,833	-	32,112	14,570	-	191,197	45,805	29,611	115,781	112,991	111,669	110,393	107,966	105,693
31.12.2022	421	9.16	337,784	69,688	-	29,068	6,172	-	232,856	71,022	31,667	130,167	120,981	116,785	112,827	105,549	99,021
31.12.2023	419	9.13	344,590	71,092	-	28,928	5,555	-	239,016	87,243	31,487	120,286	106,473	100,391	94,784	84,814	76,254
31.12.2024	436	9.49	357,417	73,738	-	28,879	-	-	254,800	107,127	29,589	118,084	99,547	91,677	84,590	72,402	62,382
31.12.2025	475	10.35	392,114	80,896	-	29,019	-	-	282,199	131,048	30,427	120,724	96,926	87,188	78,619	64,365	53,147
31.12.2026	488	10.62	412,572	85,117	-	29,068	68,603	-	229,784	107,539	40,477	81,768	62,524	54,934	48,409	37,909	29,998
31.12.2027	501	10.91	429,558	88,621	-	29,108	41,881	-	269,948	126,336	37,148	106,464	77,531	66,535	57,300	42,921	32,548
31.12.2028	505	11.00	440,918	90,965	-	29,609	-	-	320,344	149,921	34,119	136,304	94,534	79,240	66,691	47,783	34,726
31.12.2029	526	11.46	464,557	95,842	-	29,700	-	-	339,015	158,659	36,786	143,571	94,832	77,641	63,860	43,766	30,481
31.12.2030	535	11.65	476,544	98,315	-	29,746	-	-	348,483	163,090	38,080	147,313	92,671	74,107	59,568	39,049	26,063
31.12.2031	535	11.65	476,800	98,368	-	29,747	-	-	348,686	163,185	38,355	147,146	88,158	68,859	54,091	33,917	21,694
31.12.2032	535	11.65	474,918	97,979	-	29,740	-	-	347,199	162,489	38,274	146,436	83,555	63,746	48,936	29,351	17,991
31.12.2033	535	11.65	474,888	97,973	-	29,739	-	-	347,175	162,478	38,365	146,332	79,519	59,256	44,456	25,504	14,982
31.12.2034	535	11.65	475,086	98,014	-	29,740	-	-	347,332	162,551	38,613	146,168	75,648	55,060	40,369	22,153	12,471
31.12.2035	535	11.65	465,155	95,965	-	29,702	-	-	339,488	158,880	38,040	142,568	70,271	49,957	35,795	18,789	10,137

Total discounted cash flow from 3P (proved + probable + possible) reserves as of December 31, 2020 (in dollars in thousands in relation to the Partnership's share)																	
Cash flow components																	
Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Gas sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Develop-ment costs	Abandon-ment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Taxes		Total discounted cash flow after tax					
										Levy	Income Tax	Discounted at 0%	Discounted at 5%	Discounted at 7.5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2036	535	11.65	465,331	96,002	-	29,703	-	-	339,627	158,945	38,057	142,625	66,952	46,490	32,554	16,345	8,451
31.12.2037	535	11.65	463,970	95,721	-	29,697	42,867	-	295,684	138,380	46,030	111,274	49,748	33,741	23,090	11,089	5,494
31.12.2038	535	11.65	464,215	95,771	-	29,698	22,385	-	316,361	148,057	42,843	125,460	53,419	35,388	23,667	10,872	5,162
31.12.2039	535	11.65	464,437	95,817	-	29,699	-	-	338,920	158,615	39,941	140,365	56,919	36,830	24,071	10,577	4,813
31.12.2040	535	11.65	464,703	95,872	-	29,700	42,867	-	296,264	138,651	44,580	113,032	43,653	27,589	17,622	7,406	3,230
31.12.2041	535	11.65	464,547	95,840	-	29,700	-	-	339,007	158,655	38,965	141,387	52,003	32,102	20,038	8,056	3,367
31.12.2042	535	11.65	464,390	95,808	-	29,699	42,867	-	296,017	138,536	43,564	113,917	39,904	24,061	14,677	5,644	2,260
31.12.2043	535	11.65	464,218	95,772	-	29,698	-	-	338,748	158,534	37,948	142,266	47,462	27,952	16,664	6,129	2,352
31.12.2044	535	11.65	464,062	95,740	-	29,698	-	-	338,624	158,476	37,932	142,216	45,186	25,993	15,143	5,328	1,960
31.12.2045	535	11.65	463,906	95,708	-	29,697	-	-	338,501	158,418	37,917	142,165	43,019	24,171	13,762	4,631	1,632
31.12.2046	535	11.65	463,750	95,675	-	29,697	-	-	338,378	158,361	37,902	142,115	40,955	22,476	12,506	4,026	1,360
31.12.2047	535	11.65	463,594	95,643	-	29,696	-	-	338,254	158,303	37,887	142,064	38,991	20,901	11,365	3,499	1,133
31.12.2048	535	11.65	463,437	95,611	-	29,695	-	-	338,131	158,245	38,887	140,999	36,856	19,297	10,255	3,020	937
31.12.2049	480	10.45	415,766	85,776	-	29,512	-	-	300,478	140,624	34,795	125,060	31,133	15,921	8,268	2,329	693
31.12.2050	449	9.77	388,575	80,166	-	29,407	-	-	279,002	130,573	32,167	116,262	27,565	13,769	6,988	1,883	537

Total discounted cash flow from 3P (proved + probable + possible) reserves as of December 31, 2020 (in dollars in thousands in relation to the Partnership's share)																	
Cash flow components																	
Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Gas sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Develop-ment costs	Abandon-ment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Taxes		Total discounted cash flow after tax					
										Levy	Income Tax	Discounted at 0%	Discounted at 5%	Discounted at 7.5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2051	400	8.72	346,509	71,488	-	29,246	-	-	245,776	115,023	29,087	101,666	22,956	11,200	5,555	1,432	391
31.12.2052	339	7.39	293,556	60,563	-	29,042	-	-	203,951	95,449	23,529	84,973	18,273	8,708	4,221	1,041	272
31.12.2053	306	6.66	264,433	54,555	-	28,930	-	-	180,948	84,684	21,701	74,564	15,271	7,108	3,367	794	199
31.12.2054	247	5.38	213,608	44,069	-	28,734	-	19,009	121,795	57,000	18,835	45,960	8,965	4,076	1,887	426	102
31.12.2055	195	4.25	168,580	34,779	-	28,561	-	19,009	86,230	40,356	14,483	31,392	5,832	2,590	1,172	253	58
31.12.2056	92	2.00	79,332	16,367	-	28,218	-	19,009	15,738	7,365	5,858	2,515	445	193	85	18	4
Total	**16,835**	**367**	**14,527,533**	**2,997,149**	**-**	**1,061,633**	**287,766**	**57,027**	**10,123,958**	**4,618,625**	**1,233,945**	**4,271,388**	**2,101,666**	**1,597,599**	**1,267,642**	**881,036**	**671,994**

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

Caution concerning forward-looking information – The aforesaid discounted cash flow figures constitute forward-looking information, within the meaning thereof in Section 32A of the Securities Law. The above figures are based on various assumptions, *inter alia*, in relation to the quantities of gas and condensate that shall be produced, the pace and duration of sales of the natural gas from the project, operating costs, capital expenditure, abandonment expenses, royalty rates and sale prices, including with respect to the price adjustments according to the agreement with the IEC, and there is no certainty that such assumptions will materialize. It is noted that the quantities of natural gas and/or condensate that shall actually be produced, such expenses and such revenues may materially differ from the above assumptions and estimates, *inter alia* as a result of the competition conditions prevailing on the market and/or operating and technical conditions and/or regulatory changes and/or supply and demand conditions on the domestic market and/or the export

markets of the natural gas and/or condensate and/or the actual performance of the project and/or as a result of the actual sale prices and/or as a result of geopolitical changes that shall occur. It is further noted that the price adjustment rate on the price adjustment dates as set forth in the agreement with the IEC may materially differ from the Partnership's estimate, *inter alia* as a result of the actual natural gas prices on the domestic market on the price adjustment dates and all according to the adjustment mechanism as stipulated in the agreement with the IEC.

4. Set forth below is an analysis of sensitivity to the main parameters comprising the discounted cash flow (the gas price and the gas sales volume[71]) as of December 31, 2020 (dollars in thousands) which was performed by the Partnership:

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% growth in the gas price					**10% decrease in the gas price**				
1P (Proved) Reserves	2,716,123	1,184,192	881,051	693,538	1P (Proved) Reserves	2,150,721	952,590	710,341	559,685
Probable Reserves	1,053,129	145,961	66,555	35,976	Probable Reserves	860,293	122,757	58,116	33,112
Total 2P (Proved+Probable) Reserves	3,769,252	1,330,153	947,605	729,513	Total 2P (Proved+Probable) Reserves	3,011,014	1,075,346	768,457	592,797
Possible Reserves	970,900	70,929	24,753	11,329	Possible Reserves	791,690	58,592	20,895	9,923
Total 3P (Proved+Probable+Possible) Reserves	4,740,151	1,401,082	972,358	740,842	Total 3P (Proved+Probable+Possible) Reserves	3,802,704	1,133,938	789,352	602,721
15% growth in the gas price					**15% decrease in the gas price**				
P1 (Proved) Reserves	2,856,492	1,241,718	923,356	726,620	P1 (Proved) Reserves	2,009,061	894,397	667,316	525,837
Probable Reserves	1,102,546	152,112	68,936	36,920	Probable Reserves	812,457	117,021	56,054	32,435
Total P2 (Proved+Probable) Reserves	3,959,037	1,393,830	992,293	763,540	Total P2 (Proved+Probable) Reserves	2,821,517	1,011,418	723,370	558,272
Possible Reserves	1,015,510	73,893	25,622	11,602	Possible Reserves	746,956	55,603	20,027	9,665
Total P3 (Proved+Probable+Possible)	4,974,547	1,467,724	1,017,915	775,142	Total P3 (Proved+Probable+Possible)	3,568,474	1,067,021	743,396	567,937

[71] It is emphasized that the said analyses of the sensitivity to changes in the gas quantity sold do not take into account changes in the future investment plan, either with respect to an increase or a decrease in the quantity.

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%
Reserves					Reserves				
20% growth in the gas price					20% decrease in the gas price				
1P (Proved) Reserves	2,996,816	1,299,135	965,538	759,567	1P (Proved) Reserves	1,867,449	836,097	624,146	491,821
Probable Reserves	1,152,017	158,337	71,393	37,939	Probable Reserves	764,477	111,200	53,924	31,704
Total 2P (Proved+Probable) Reserves	4,148,833	1,457,472	1,036,931	797,506	Total 2P (Proved+Probable) Reserves	2,631,926	947,297	678,070	523,525
Possible Reserves	1,060,121	76,858	26,491	11,876	Possible Reserves	702,643	52,868	19,359	9,567
Total 3P (Proved+Probable+Possible) Reserves	5,208,953	1,534,330	1,063,422	809,383	Total 3P (Proved+Probable+Possible) Reserves	3,334,569	1,000,165	697,429	533,092

Sensitivity / Category	Present value discounted at 10%	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% growth in the gas sales volume					10% decrease in the gas sales volume				
1P (Proved) Reserves	2,518,837	1,160,331	872,152	690,073	1P (Proved) Reserves	2,150,739	952,599	710,348	559,691
Probable Reserves	964,605	147,792	68,771	37,303	Probable Reserves	860,302	122,758	58,117	33,112
Total 2P (Proved+Probable) Reserves	3,483,441	1,308,122	940,922	727,376	Total 2P (Proved+Probable) Reserves	3,011,041	1,075,357	768,465	592,804
Possible Reserves	838,865	72,683	26,456	12,160	Possible Reserves	791,698	58,592	20,896	9,924
Total 3P (Proved+Probable+Possible) Reserves	4,322,307	1,380,805	967,378	739,536	Total 3P (Proved+Probable+Possible) Reserves	3,802,739	1,133,949	789,360	602,727

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%
15% growth in the gas sales volume					**15% decrease in the gas sales volume**				
P1 (Proved) Reserves	2,575,728	1,204,118	908,480	720,453	P1 (Proved) Reserves	2,009,087	894,411	667,327	525,846
Probable Reserves	928,763	151,543	71,704	39,035	Probable Reserves	812,469	117,023	56,054	32,435
Total P2 (Proved+Probable) Reserves	3,504,490	1,355,661	980,184	759,487	Total P2 (Proved+Probable) Reserves	2,821,557	1,011,434	723,381	558,281
Possible Reserves	842,980	78,861	29,208	13,320	Possible Reserves	746,969	55,604	20,027	9,665
Total P3 (Proved+Probable+Possible) Reserves	4,347,471	1,434,522	1,009,392	772,807	Total P3 (Proved+Probable+Possible) Reserves	3,568,526	1,067,037	743,408	567,945
20% growth in the gas sales volume[72]					**20% decrease in the gas sales volume**				
1P (Proved) Reserves	2,585,187	1,238,984	940,600	748,730	1P (Proved) Reserves	1,867,483	836,113	624,158	491,831
Probable Reserves	928,877	161,013	77,363	42,168	Probable Reserves	764,493	111,202	53,925	31,705
Total 2P (Proved+Probable) Reserves	3,514,064	1,399,998	1,017,963	790,898	Total 2P (Proved+Probable) Reserves	2,631,976	947,316	678,083	523,535
Possible Reserves	843,308	85,926	32,579	14,828	Possible Reserves	702,660	52,869	19,359	9,567
Total 3P (Proved+Probable+Possible) Reserves	4,357,373	1,485,923	1,050,541	805,726	Total 3P (Proved+Probable+Possible) Reserves	3,334,635	1,000,185	697,443	533,102

[72] Note that due to infrastructure limitations, the gas quantities cannot be increased by such rate.

5. <u>Set forth below is an analysis of sensitivity to the main Linkage Components of the gas price according to the gas sale agreements in which the Tamar Partners have engaged (the U.S. CPI and the Electricity Production Tariff) as of December 31, 2020 (dollars in thousands) which was performed by the Partnership</u>[73]:

Sensitivity / Category	**Total**	**Present value discounted at 10%**	**Present value discounted at 15%**	**Present value discounted at 20%**	**Sensitivity / Category**	**Total**	**Present value discounted at 10%**	**Present value discounted at 15%**	**Present value discounted at 20%**
10% growth in the CPI forecast					**10% decrease in the CPI forecast**				
1P (Proved) Reserves	2,435,932	1,069,860	796,947	627,703	1P (Proved) Reserves	2,432,143	1,067,510	795,048	626,145
Probable Reserves	955,885	134,096	62,134	34,380	Probable Reserves	955,906	134,112	62,148	34,393
Total 2P (Proved+Probable) Reserves	3,391,817	1,203,956	859,081	662,083	Total 2P (Proved+Probable) Reserves	3,388,049	1,201,621	857,196	660,538
Possible Reserves	881,464	64,863	22,905	10,690	Possible Reserves	881,461	64,853	22,896	10,682
Total 3P (Proved+Probable+Possible) Reserves	4,273,280	1,268,819	881,986	672,773	Total 3P (Proved+Probable+Possible) Reserves	4,269,510	1,266,475	880,093	671,221
10% growth in the Electricity Production Tariff forecast					**10% decrease in the Electricity Production Tariff forecast**				
1P (Proved) Reserves	2,596,169	1,121,833	830,757	651,122	1P (Proved) Reserves	2,303,249	1,029,839	771,953	611,111
Probable Reserves	1,027,057	143,012	65,606	35,781	Probable Reserves	892,918	126,130	58,993	33,079
Total 2P (Proved+Probable) Reserves	3,623,226	1,264,844	896,363	686,903	Total 2P (Proved+Probable) Reserves	3,196,167	1,155,969	830,945	644,190
Possible Reserves	946,632	69,245	24,217	11,125	Possible Reserves	823,665	60,995	21,757	10,317
Total 3P (Proved+Probable+Possible) Reserves	4,569,858	1,334,089	920,580	698,029	Total 3P (Proved+Probable+Possible) Reserves	4,019,832	1,216,964	852,703	654,507

[73] Although the Electricity Production Tariff is affected, *inter alia*, by the CPI, the sensitivity analysis in the table below does not take such effect into account.

6. Set forth below is an analysis of sensitivity to the sale of quantities exceeding the minimum quantities (take or pay) according to the gas sale agreements in which the Partnership has engaged as of December 31, 2020 (dollars in thousands) which was performed by the Partnership:

Sensitivity / Category	**Total**	**Present value discounted at 10%**	**Present value discounted at 15%**	**Present value discounted at 20%**	Sensitivity / Category	**Total**	**Present value discounted at 10%**	**Present value discounted at 15%**	**Present value discounted at 20%**
10% growth in the gas sales volume in respect of quantities exceeding the take or pay					**10% decrease in the gas sales volume in respect of quantities exceeding the take or pay**				
1P (Proved) Reserves	2,567,659	1,126,997	836,544	656,330	1P (Proved) Reserves	2,227,651	1,002,589	752,718	596,500
Probable Reserves	942,425	140,997	65,779	36,102	Probable Reserves	859,457	122,059	57,481	32,534
Total 2P (Proved+Probable) Reserves	3,510,084	1,267,994	902,323	692,432	Total 2P (Proved+Probable) Reserves	3,087,109	1,124,648	810,200	629,034
Possible Reserves	853,817	70,170	25,209	11,606	Possible Reserves	792,104	58,834	21,086	10,074
Total 3P (Proved+Probable+Possible) Reserves	4,363,901	1,338,164	927,532	704,038	Total 3P (Proved+Probable+Possible) Reserves	3,879,213	1,183,482	831,285	639,109

7. Agreement between the report data and data of previous reports in respect of the quantity of reserves attributed to the petroleum asset

The main differences between the present reserves report and the Previous Reserves and Contingent Resources Report derive from the production of approx. 172 BCF of natural gas and approx. 225.5 thousand barrels of condensate in H2/2020.

8. Production Data

Production data in respect of the Tamar Project, which are attributable to the Partnership in 2018-2020[74], are presented below:

Natural Gas[75,76]				
		Y2018	**Y2019**	**Y2020**
Total output (100%) during the period (in MMCF)		363,950	368,712	291,339
Total output (attributable to the holders of the equity interests of the Partnership) during the period (in MMCF)		92,698	81,117	64,095
Average price per output unit (attributable to the holders of the equity interests of the Partnership) (Dollars per MCF) [77]		5.49	5.46	5.13
Average royalties (any payment derived from the output of the producing asset, including from the gross revenues from the petroleum asset) paid per output unit (attributable to the holders of the equity interests of the Partnership) (Dollars 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 production costs per output unit (attributable to the holders of the equity interests of the Partnership) (Dollars per MCF)[78]		0.39	0.46	0.38
Average net revenues per output unit (attributable to the holders of the equity interests of the Partnership)		4.05	3.88	3.70

[74] It is noted that from the date of commencement of the natural gas piping from the Tamar Project (i.e. March 30, 2013) until December 31, 2020, customers were supplied with natural gas in a total quantity of approx. 69 BCM and approx. 3.2 million barrels of condensate. It is further noted that the average daily production volume of natural gas in the past two years (January 1, 2019 – December 31, 2020) amounted to approx. 0.9 BCF.

[75] The share attributed to the holders of the Partnership's equity interests in the output, in the royalties paid, in the production costs and in net revenues, was rounded off up to two digits after the decimal point.

[76] The 2019 and 2020 production data are based on the Partnership's direct holding in the Tamar Project at the rate of 22%. The production data for 2018 include, in addition to the Partnership's direct holding in the Tamar Project, also the Partnership's share in the production data of Tamar Petroleum.

[77] The average price per output unit weights the Partnership's actual price, which includes the outline for the sale of natural gas between the Tamar Project and the Yam Tethys project. In this regard, see Sections 7.7 and 7.26.2 below.

[78] The data include current production costs only and do not include exploration and development costs of the reservoir and tax payments that shall be paid by the Partnership in the future.

(Dollars per MCF)			
Petroleum and gas profit levy	-	-	0.06
Average net revenues per output unit after petroleum and gas profit levy (attributable to the holders of the equity interests of the Partnership) (Dollars per MCF)	4.05	3.88	3.64
Depletion amount during the reported period relative to the total amounts of gas in the project (in %)[79]	3.29	3.31	2.70

Condensate[80,81]				
		Y2018	**Y2019**	**Y2020**
Total output during the period (in MMCF)		2,614	2,643	2,098
Total output (attributable to the holders of the equity interests of the Partnership) during the period (in barrels in thousands)		121.51	106.11	84.2
Average price per output unit (attributable to the holders of the equity interests of the Partnership) (Dollars per barrel)		63.01	56.42	34.88
Average royalties (any payment derived from the output of the producing asset, including from the gross revenues from the petroleum asset) paid per output unit (attributable to the holders of the equity interests of the Partnership) (Dollars per barrel)	The State	7.03	6.38	4.0
	Third parties	1.05	1.31	1.3
	Interested Parties	4.12	3.73	1.7
Average production costs per output unit (attributable to the holders of the equity interests of the Partnership) (Dollars per barrel)[82]		2.11	2.5	2.06
Average net revenues per output unit (attributable to the holders of the equity interests of the Partnership) (Dollars per barrel)		48.7	42.50	25.8
Petroleum and gas profit levy		-	-	0.3
Average net revenues per output unit after petroleum and gas profit levy (attributable to the holders of the equity interests of the Partnership) (Dollars per barrel)		48.7	42.50	25.5
Depletion rate during the reported period relative to the total quantities of condensate in the project (in %)[83]		3.31	3.35	2.76

[79] The depletion rate is the amount of natural gas produced in the relevant report period, out of the balance of proved and probable reserves as of the beginning of such report period or the production commencement date, whichever is later. The said depletion rate is calculated at the end of the year and not during the year.
[80] See Footnote 75 above.
[81] See Footnote 77 above.
[82] See Footnote 78 above.
[83] The quantity of condensate produced from the Tamar Project derives directly from the quantity of natural gas produced from the project.

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

Opinion of the Evaluator

A reserves report for the Tamar Project (which includes the Tamar and Tamar SW reservoirs), which was prepared by NSAI, as of December 31, 2020 is attached hereto as **Annex B**, and the Evaluator's consent to the inclusion thereof in this report is attached to this chapter as **Annex A**.

Management Statement

(1) Date of statement: March 14, 2021;

(2) The corporation's name: Delek Drilling, Limited Partnership;

(3) The person authorized to evaluate the resources at the Partnership, his name and position: Gabi Last, Chairman of the Board of the General Partner;

(4) We hereby confirm that the evaluator was provided with all of the data required for the purpose of performing his work;

(5) We hereby confirm that no information indicating a dependence between the evaluator and the Partnership has come to our knowledge;

(6) We hereby confirm that, to the best of our knowledge, the resources reported are the best and most updated estimates held by us;

(7) We hereby confirm that the data included herein were drafted according to the professional terms listed in Chapter G of the Third Schedule to the Securities Regulations (Details of the Prospectus and Draft Prospectus – Structure and Form), 5729-1969 and within the meaning ascribed thereto by 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 effective on the report release date;

(8) We hereby confirm that no change has been made in the identity of the evaluator who made the last disclosure released by the Partnership with respect to the reserves or the contingent resources;

(9) We agree to the inclusion of the aforesaid statement herein.

____

Gabi Last,
Chairman of the Board

(b) Contingent and prospective resources in the Dalit Lease

For details regarding contingent and prospective resources in the Dalit Lease, as of December 31, 2017, see Section 7.3.9(b) of the Partnership's periodic report for 2017, as released on March 21, 2018 (Ref.: 2018-01-022209) (the "**Periodic Report for 2017**"), the information in which is hereby presented by way of reference. As of December 31, 2020, no change has occurred in such details. NSAI's consent to the inclusion of the said report herein, including by way of reference, and a letter from NSAI regarding the absence of material changes in the Dalit Lease are attached hereto as **Annex A**.

7.4. Interests in Cyprus

7.4.1. Background

On February 11, 2013 the authorities in Cyprus approved transfer to the Partnership of 30% of the rights of Noble Cyprus in a production sharing contract dated October 24, 2008 (the "**Production Sharing Contract**" or the "**PSC**") conferring gas and/or oil exploration, evaluation, development and production rights in the EEZ of the Republic of Cyprus in an area known as Block 12 ("**Block 12**") and in an exploration license according to the PSC (in this Section, the "**Exploration License**").

On November 7, 2019, the right holders in the Production Sharing Contract and the Government of Cyprus signed an amendment to the Production Sharing Contract (the "**Amendment to the Production Sharing Contract**") and, at the same time, the right holders were given a production and exploitation license (in Section 7.4: the "**License**" or the "**Production License**" or the "**Block 12 License**"), and a production and development plan for the reservoir was approved (in Section 7.4: the "**Development Plan**"), as described in Section 7.4.11 below. The Production Sharing Contract and the Amendment to the Production Sharing Contract shall hereinafter be referred to as the: "**Production Sharing Contract**".

7.4.2. General details regarding Block 12

General details about the petroleum asset	
Name of Petroleum Asset:	Block 12
Location:	An offshore area at the EEZ of Cyprus, located approx. 35 km north-west of the Leviathan reservoir[84].

[84] It is noted that the vast majority of the Aphrodite reservoir is in the area of the EEZ of Cyprus, and several percent in the area of the 370/Yishai license (the "**Yishai License**"), which is in the area of the EEZ of Israel. It is noted that the partners in the Aphrodite reservoir were contacted by both the partners in the Yishai License

General details about the petroleum asset	
Area	Approx. 386 square km
Type of petroleum asset and description of actions permitted according to this type:	Exploitation license granted subject to the Production Sharing Contract.
Original grant date of the petroleum asset:	November 7, 2019
Original expiration date of the petroleum asset:	November 7, 2044
Dates on which an extension of the petroleum asset period was decided:	-
Current date for expiration of the petroleum asset:	November 7, 2044 (25 years from the date on which the license was granted).
Statement whether there is another option for the extension of the petroleum asset period; if such an option exists – please state the possible extension period:	Extendable by 10 more years.
Statement of Operator's Name:	Noble Cyprus
Statement of the names of the direct partners in the petroleum asset, and their direct share in the petroleum asset, and, to the best of the Partnership's knowledge, the names of the controlling shareholders in the said partners:	▪ Noble Cyprus (35%) ▪ BG Cyprus (35%). To the best of the Partnership's knowledge, BG Cyprus is a subsidiary (indirect holdings) of Royal Dutch Shell Plc. ("**Shell**"), an energy company engaged in all fields of activity of the gas and oil industry, which is active in more than 70 countries worldwide[85]. ▪ The Partnership (30%).

General details regarding the Partnership's share in the petroleum asset	
For a holding in a purchased petroleum asset – the purchase date:	January 22, 2009. On February 11, 2013, the approval of the authorities in Cyprus was granted for the transfer of the rights in the Production Sharing Agreement and in the exploration license to the Partnership.
Description of the nature and manner of holding of the petroleum asset by the Partnership:	The Partnership holds directly 30% of the license.
Statement of the actual share attributed to the holders of the equity interests of the Partnership in the revenues from the petroleum asset:	For details see Section 7.4.8 below.
The total share of the holders of the equity interests of the Partnership in the aggregate investment in the petroleum asset during the five years preceding the last day of the report	Approx. $13,370 thousand.

and the Ministry of Energy with respect to the need to regulate the parties' rights as aforesaid prior to the adoption of 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 that they will act in accordance with such mechanism for regulation of the parties' rights as shall be determined by the governments and in accordance with international law. It is further noted that further to contacts which took place between the governments of Israel and Cyprus to regulate the parties' rights in the Aphrodite reservoir, on March 9, 2021, the aforesaid governments signed a Memorandum of Understanding which gives the instruction to 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 overflow of the Aphrodite reservoir, which includes principles and timetables for conducting the negotiations.

[85] Further details about Shell are available on the website: https://www.shell.com/about-us/who-we-are.html.

year (whether recognized as an expense or as an asset in the financial statements):	

7.4.3. Following are further details regarding the license in Block 12 and the Production Sharing Contract

(a) As part of the Production Sharing Contract, the partners undertook, *inter alia*, to comply with the key milestones for promotion of the reservoir's development, as follows:

1. Drilling a development/appraisal well in the area of the License in accordance with the Development Plan and completion thereof within 24 months of the date of receipt of the Production License.

2. Completion of the Front-End Engineering Design ("**FEED**"), transfer of the deliverables according to the Development Plan and adoption of a final investment decision (FID) for development of the reservoir within 48 months of the day of receipt of the Production License (i.e. in November 2021).

   The Production Sharing Contract determines certain conditions upon whose fulfillment the partners in the License shall be entitled to receive an extension for the purpose of compliance with the aforesaid milestones, with the last date for the adoption of a final investment decision (FID) being the expiration of 6 years from the day of receipt of the Production License. It is noted that failure to comply with the milestones defined in the Production Sharing Contract is a cause for revocation of the PSC, unless resulting from a "*force majeure*" (as defined in the Production Sharing Contract).

(b) It is further noted that additional changes and revisions were made as part of the Amendment to the Production Sharing Contract, *inter alia*, as pertains to the transfer of rights by the parties, the approval of a work plan and an annual budget, the manner of approval of changes of plans and budgets, the method of calculation of the various expenses, changes in relation to the causes for revocation of the PSC. Arrangements with respect to ensuring the plugging, decommissioning and disposal of wells and facilities at the end of the term of the PSC, and more.

(c) Payments to the Republic of Cyprus

1. The Republic of Cyprus is entitled to receive one-time bonuses from the holders of rights in Block 12 upon the fulfillment of milestones regarding the average daily production rate for a consecutive period of 30 days which can amount to a sum total of $9 million (for 100%).

2. The Production Sharing Contract specifies mechanisms for the distribution of natural gas and oil output, as specified below. It is noted that the Republic of Cyprus is entitled to receive its share of the produced natural gas or oil, in whole or in part, in kind.

a. Sharing of oil

The holders of the rights in Block 12 will share the oil produced (after setting off expenses as specified below) with the Republic of Cyprus according to the daily average production rate of oil, to the extent it shall be produced, as follows[86]:

Average daily production (in barrels)[87]	**Price per barrel (in Dollar)**		
	Up to 50	From 50.1 to 100	Above 100
	The share of the Republic of Cyprus (including corporate tax in Cyprus)		
For the share in the average daily production lower than 50,000 (inclusive)	60%	63%	65%
For the share in the average daily production between 50,001 and 100,000 (inclusive)	63%	67%	72%
For the share in the average daily production between 100,001 and 150,000 (inclusive)	70%	75%	80%
For the share in the average daily production between 150,001 and 200,000 (inclusive)	77%	80%	83%
For the share in the average daily production higher than 200,000	83%	85%	85%

b. Sharing of natural gas

1. The Production Sharing Contract, prior to the amendment of November 7, 2019 thereto, provided a mechanism for the distribution of the natural gas to be produced in the area of the PSC, based on the average daily production rate, as described in detail in Section 7.8.3(f) of the Partnership's periodic report for 2018 released on March 24, 2019 (Ref. No.: 2019-01-023982).

[86] It is noted that the oil sharing mechanism was not amended in the amendment to the Production Sharing Contract.
[87] The calculation is made progressively according to the brackets presented in the table.

2. Following the Production Sharing Contract amendment, a new mechanism for the distribution of the natural gas output was determined, as noted, which is based on a factor of the R-Factor type. According to such mechanism, the partners will be entitled to 55% of the annual revenues to be derived from the natural gas output, up to the coverage of all of their recognized capital and current expenditures (the "**Expenditure Coverage Output**"), whereas the balance (the "**Distributable Output**") will be distributed among the partners and the Government of Cyprus according to the R-Factor, the numerator of which consists of the total of Net Accrued Revenues and the denominator of which consists of the total of Accrued Capital Investments. Under the new mechanism, the share of the Government of Cyprus in the Distributable Output linearly increases as a function of the factor and will reach the maximum rate when the R-Factor equals 2.5. For this purpose:

    - "**Net Accrued Revenues**" shall mean: The partners' share in revenues actually received from the gas output (including the Expenditure Coverage Output), net of the operating expenses borne by the partners in the area of the PSC, from the date of signing of the Production Sharing Contract (October 28, 2008) to the end of the quarter preceding the day of the calculation (the "**Calculation Period**").

    - "**Accrued Capital Investments**" shall mean: The development expenses, production expenses of a capital nature (excluding operating expenses) and all exploration expenses, in respect of the area to which the Production Sharing Contract pertains, which were actually expended during the Calculation Period.

For details with respect to the participation rate of the holders of equity interests in the Partnership according to 4 theoretical scenarios only, according to which the R-Factor has been determined, see Section 7.4.8 below.

(d) The calculation of the share of the Republic of Cyprus in the natural gas and/or oil produced will be performed every year from the revenues from the sale of natural gas and/or oil which will remain after setting off the expenses of the holders of rights in the Block 12 project in respect of exploration, evaluation, development, production and operation ("**Block 12 Expenses**")[88] at a rate of up to 55% of the total revenues from the gas produced and up to 49% of the total revenues from the oil produced ("**Output Designated for Expense Reimbursement Coverage**"). In case that the expenses will be higher than the **Output** Designated for Expense Reimbursement Coverage, any surplus will be carried forward to the following year until full coverage of the expenses or until termination of the PSC. An expense not covered on the PSC termination date will not be recovered.

(e) The expenses recognized within the Output Designated for Expense Reimbursement Coverage according to the PSC as aforesaid, are subject to the approval of the Republic of Cyprus and include, *inter alia*, direct expenses in respect of exploration and evaluation, expenses in respect of the employment of workers and subcontractors, leasing offices, costs related to statutory requirements pertaining to environmental quality, material costs, insurance expenses, legal expenses, costs related to employee training, general and administrative costs of the Operator related to the project and any other reasonable expense which is required for reasonable and effective exploration activity. It shall be stated that expenses related to the construction and operation of an export facility are not recognized within the Output Designated for Expense Reimbursement Coverage.

(f) The bonuses as specified in Section 7.4.31 above are not included in the expenses which may be offset as aforesaid.

(g) The payment of the share of the Republic of Cyprus in the gas and/or oil produced engrosses also the payments of corporate tax which the holders of the rights should have paid the Republic of Cyprus.

(h) In addition, the Republic of Cyprus may, upon provision of a prior written notice, obligate the holders of rights in Block 12 to sell gas thereto from the production which is not designated for coverage of expense reimbursement subject to the compliance of the holders of rights in Block 12 with their commitments according to agreements for the supply of natural gas, if such will be executed.

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

[88] Recognition of the Block 12 Expenses is done every year according to reports filed by the operator of the project and is limited to a budget submitted to the Republic of Cyprus for approval thereby as part of the process for approval of the annual work plan under the Production Sharing Contract.

(j) Termination of the Production Sharing Contract

1. The Republic of Cyprus may terminate the PSC by giving an advance notice of 3 months or 6 months, as specified in the PSC, upon the fulfillment of one of the following conditions: (a) Violation of the provisions of the Cypriot law and regulations promulgated thereunder; (b) Arrearage in payment to the Republic of Cyprus for 3 consecutive months; (c) Breach of the development plan for 6 consecutive months except due to an event of "Force Majeure" as defined in the PSC; (d) Regarding the production period, a continuous cessation of production for two consecutive months or a disruption of production for 6 consecutive months due to a reason which was not approved by the Republic of Cyprus, except due to a "Justified Reason" or a "Force Majeure" event as defined in the PSC; (e) Financial or technical inability of the partners to comply with the undertakings pursuant to the PSC as a result of the occurrence of an event of bankruptcy, composition with creditors, receivership of any of the partners or its parent company or any other event the result of which is a material reduction of the financial or technical abilities of any of the partners relative to its condition at the time of execution of the PSC.

2. The holders of rights in the project may waive their rights regarding any oil and/or gas field in the license area after provision of a 6 months advance notice to the Republic of Cyprus.

(k) Grant of a performance guarantee to the Republic of Cyprus

For details regarding a performance guarantee in an unlimited amount provided by Delek Group in favor of the Republic of Cyprus to secure fulfillment of all of the undertakings of the Partnership under the PSC, see Section (e) of Regulation 22 of Chapter D of this report.

7.4.4. Activities within Block 12 which were performed before the Partnership held the petroleum asset

Performing Entity	**Period in which the action was performed**	**Summary description of the action**	**Summary description of the action results**
Noble Cyprus	2011-2012	Preparation for drilling of the test well "Aphrodite A-1", drilling of the said well and an analysis of the well results	-

Performing Entity	Period in which the action was performed	Summary description of the action	Summary description of the action results
		and preparation for drilling of an appraisal well[89].	

7.4.5. Compliance with the binding Block 12 Work Plan

The binding Block 12 Work Plan has been fully complied with until the report approval date.

7.4.6. Actual and planned work plan for Block 12

Below is a concise description of the main activities actually carried out in the petroleum asset between January 1, 2018 and the report approval date, as well as a concise description of planned activities:

Block 12 Project			
Period	**Summary description of actions actually carried out for the period or of the planned work plan**	**Estimated overall budget per action on the petroleum asset level (in Dollars in thousands)[90]**	**Scope of actual participation of the holders of the equity interests of the Partnership in the budget (in Dollars in thousands)**
2018	• Continued examination of various alternatives for the development of the Aphrodite reservoir. • Continued geological, geophysical and engineering analysis of the database existing at the license, *inter alia*, while integrating data from adjacent fields, and updating the geological model and the flow model. • Examination of a possible location for an appraisal well, and the scope of the appraisal actions therein.	Approx. 1,898	Approx. 569
	• Continued analysis of the prospectivity in the area of the license, *inter alia*, in view of findings from adjacent fields, and in particular, a technical and financial analysis of a deep prospect. • Preparation for drilling additional wells in the area of the license.	Approx. 386	Approx. 116

[89] On October 2, 2013, the Aphrodite A-2 appraisal well, which was started on June 7, 2013, was completed.
[90] The amounts for 2017-2018 are amounts actually expended and audited in the framework of the financial statements.

Block 12 Project			
Period	**Summary description of actions actually carried out for the period or of the planned work plan**	**Estimated overall budget per action on the petroleum asset level (in Dollars in thousands)[90]**	**Scope of actual participation of the holders of the equity interests of the Partnership in the budget (in Dollars in thousands)**
2019	• Continued examination of various alternatives for the development of the Aphrodite reservoir.	Approx. 3,190	Approx. 957
	• Submission of an updated plan for development of the Aphrodite reservoir to the Cypriot government. • Continued geological, geophysical and engineering analysis of database existing at the license, *inter alia*, while integrating data from adjacent fields, and updating the geological model and the flow model.	Approx. 1,175	Approx. 353
	• Continued examination of a possible location for an appraisal well and the scope and cost thereof. • Continued analysis of the prospectivity in the area of the license, *inter alia*, in view of findings from adjacent fields, and in particular, a technical and financial analysis of a deep prospect. • Preparation for the drilling of additional wells in the area of the license.	Approx. 296	Approx. 89
2020	• Continued geological, geophysical and engineering analysis of database existing at the license, *inter alia*, while integrating data from adjacent fields, and updating the geological model and the flow model.	Approx. 2,056	Approx. 617
	• Planning of an appraisal well that will be converted, insofar as required, into a production well. • Continued analysis of the prospectivity in the area of the production license, *inter alia*, in view of findings from adjacent fields, and in particular, a technical and financial analysis of a deep prospect.	Approx. 3,372	Approx. 1,012
	• Performance of detailed technical design ahead of adoption of a final investment decision.	Approx. 2,131	Approx. 639
	• Continued examination of options for commercialization of the natural gas from the Aphrodite reservoir.	Approx. 885	Approx. 266

Block 12 Project			
Period	**Summary description of actions actually carried out for the period or of the planned work plan**	**Estimated overall budget per action on the petroleum asset level (in Dollars in thousands)[90]**	**Scope of actual participation of the holders of the equity interests of the Partnership in the budget (in Dollars in thousands)**
2021[91]	• Continued geological, geophysical and engineering analysis of database existing at the license, *inter alia*, while integrating data from adjacent fields, and updating the geological model and the flow model.	Approx. 3,474	Approx. 1,086
	• Planning and examination of the drilling of an appraisal well that will be converted, insofar as required, into a production well. • Continued analysis of the prospectivity in the area of the production license, *inter alia*, in view of findings from adjacent fields, and in particular, a technical and financial analysis of a deep prospect.	Approx. 27,071[92]	Approx. 8,507[93]
	• Continued examination of options for commercialization of the natural gas from the Aphrodite reservoir, *inter alia* through the performance of pre-FEED and offshore surveys.	Approx. 18,637	Approx. 5,647
2022 forth	• Continued geological, geophysical and engineering analysis of database existing at the license, *inter alia*, while integrating data from adjacent fields, and updating the geological model and the flow model. • Examination of drilling of an appraisal well that will be converted, insofar as required, into a production well. • Continued analysis of the prospectivity in the area of the production license, *inter alia*, in view of findings from adjacent fields, and in particular, a technical and financial analysis of a deep prospect.	Approx. 100,000	Approx. 30,300[94]
	• Promotion of an alternative for commercialization of the natural gas from the Aphrodite reservoir. Performance of FEED, detailed technical design and preparations for	Approx. 35,000	Approx. 10,605

[91] As of the report approval date, out of the said budgets, the partners in Block 12 have approved a budget for 2021 in the sum of approx. $28 million.
[92] This budget is a contingent budget by the partners in Block 12 and depends on the timing of the drilling.
[93]This amount includes management fees to the Partnership's General Partner in respect of exploration activity. For details, see Section (b)7 of Regulation 21 in Chapter D of this report.
[94]This amount includes management fees to the Partnership's General Partner in respect of exploration activity. For details, see Section (b)7 of Regulation 21 in Chapter D of this report.

Block 12 Project			
Period	**Summary description of actions actually carried out for the period or of the planned work plan**	**Estimated overall budget per action on the petroleum asset level (in Dollars in thousands)[90]**	**Scope of actual participation of the holders of the equity interests of the Partnership in the budget (in Dollars in thousands)**
	performance. • Examination of the possibility of adoption of an investment decision for the development of the Aphrodite reservoir in the format specified in Section 7.4.11 below.	Approx. 2,500,000 up to 3,000,000	Approx. 757,500 up to 909,000

Caution concerning forward-looking information – The Partnership's evaluation regarding the activities planned at Block 12 (including development of the Aphrodite reservoir) including in respect of costs, timetables and the actual performance thereof, is forward-looking information within the meaning thereof in Section 32A of the Securities Law, based on estimates of the General Partner regarding the components of the work plan, which are all based on evaluations received by the General Partner from the Operator. The actual performance of the work plan, including timetables and costs, is subject to the partners' approval and might be materially different from the aforesaid evaluations and it is contingent upon, *inter alia*, the applicable regulation, technical ability and economic merit.

7.4.7. Actual participation rate in the expenses and revenues at Block 12

Participation Rate	**Percentage Pre Investment-Recovery**	**Percentage Post Investment-Recovery**	**Rate grossed-up to 100% Pre Investment-Recovery**	**Rate grossed-up to 100% Post Investment-Recovery**	**Explanations**
The rate actually attributed to the holders of the equity interests of the Partnership in the petroleum asset	30%	30%	100%	100%	See description of the chain of holdings in Section 7.4.2 above.
The rate actually attributed to the holders of the equity interests of the Partnership in the **revenues** from the petroleum asset	For details see Section 7.4.8 below.				
The actual participation rate of the holders of the equity interests of the Partnership in the	30.3%-31.2%	30.3%-31.2%	101%-104%	101%-104%	For details see Section 7.4.9 below.

expenses involved in the exploration, development and production activity at the petroleum asset					

7.4.8. <u>Participation rate of holders of the equity interests of the Partnership in the revenues from Block 12</u>

The table below presents details with respect to the participation rate of the holders of equity interests in the Partnership out of revenues that will derive in respect of natural gas to be produced from the petroleum asset, if any, in accordance with the new distribution mechanism, according to 4 theoretical scenarios only, according to which the R-Factor has been 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, *inter alia*, with respect to the rate of production of the natural gas from the reservoir and sale thereof, the costs of development of the reservoir and the facilities, the current production costs, and more, which may in practice materially differ from the assumptions and assessments thereon that have been taken into account.

	R-factor 1	**R-factor 1.5**	**R-factor 2**	**R-factor 2.5**	**Notes**
Total revenues from natural gas production	100%	100%	100%	100%	
Cypriot Republic's share of the revenues from natural gas production	15.75%	21.75%	50.75%	67.5%	The figures specified in the table are based on calculations that were made based on various working hypotheses, *inter alia*, with regard to the development and operating costs of the project, rate of the production and sale, gas prices, etc.
The partners' share of the revenues from natural gas production	84.25%	78.25%	49.25%	32.5%	
The Partnership's rate of holding of the oil asset	30.00%	30.00%	30.00%	30.00%	
The Partnership's share of the revenues from natural gas production, before payment of overriding royalties	25.28%	23.48%	.1478%	9.75%	

	R-factor 1	R-factor 1.5	R-factor 2	R-factor 2.5	Notes
Payment of overriding royalties to various entities	1.14%	2.23%	.140%	0.93%	The parties entitled to royalties are Delek Energy, Delek Group and others that are not related parties. For further details see Section 7.25.9 below. It is noted that the figures specified in this table were calculated according to the Partnership's position, whereby the overriding royalties in respect of Block 12 apply to the Partnership's share in the natural gas output, i.e., after deduction of the State's share in the output (as opposed to the overriding royalties in respect of petroleum assets in Israel, which apply to the Partnership's share in the output before payment of the State's royalties under the Petroleum Law).
Rate of the effective participation of the holders of the equity interests in the Partnership, in the revenues from natural gas production	24.14%	21.25%	13.38%	8.82%	

Caution concerning forward-looking information – The aforesaid figures with respect to the rate of participation of the holders of the equity interests in the Partnership in the revenues that will derive from the petroleum asset, if any, constitute "forward-looking information" within the meaning thereof in Section 32A of the Securities Law. The aforesaid figures are largely based on various estimations and working hypotheses, *inter alia*, with regard to the rate of production of the natural gas from the reservoir, quantities and prices of sale of the natural gas, costs of development of the reservoir and the facilities, current production costs, etc. It is emphasized that such figures may materially differ from the aforesaid estimations and hypotheses, and are *inter alia*, affected by and contingent on completion of the detailed design of the development plan, actual performance of the project, and a gamut of additional factors over which the Partnership does not have full control or which it is unable to estimate in an adequate level of certainty.

7.4.9. Participation rate of the holders of the equity interests of the Partnership in the exploration, development and production expenses in Block 12

Item	**Percentage**	**Summary explanation of how the royalties or payments are calculated**
Theoretical expenses within the framework of a petroleum asset (without the said royalties)	100%	
Specification of the payments (derived from the expenses) on the petroleum asset level:		
The Operator	1%-4%	A rate of 1.5% in respect of the indirect expenses of the Operator out of all of the direct expenses in connection with development and production actions, subject to certain exclusions, such as marketing activity. The 1%-4% rate pertains to exploration expenses. Such sums are for payment of the Operator's indirect expenses and are in addition to the reimbursement of direct expenses paid thereto. The rate of payment to the Operator decreases as exploration expenses increase.
Total actual expense rate on the petroleum asset level	101%-104%	
The share of the holders of equity interests of the Partnership in the petroleum asset expenses (indirect holdings)	30%	
Total actual share of the holders of the equity interests of the Partnership, in the expenses, on the petroleum asset level (and prior to other payments on the Partnership level)	30.3%-31.2%	
Specification of payments (derived from the expenses) in respect of the petroleum asset and on the Partnership level (the following percentage will be calculated according to the share of the holders of the equity interests of the Partnership in the petroleum asset):		
The rate actually attributed to the holders of the equity interests of the Partnership in expenses involved in the exploration, development or	30.3%-31.2%	The Partnership pays management fees to the General Partner, that are comprised of a fixed amount and a variable

Item	Percentage	Summary explanation of how the royalties or payments are calculated
production activity at the petroleum asset.		amount that is calculated from the exploration expenses (for details see Section (b)7 of Regulation 21 in Chapter D of this report). Such amounts were not taken into account in this table.

7.4.10. Fees and payments paid during exploration and development activity at Block 12 (in Dollars in thousands)[95]

Item	Total share of the holders of the equity interests of the Partnership in the investment in the petroleum asset in this period[96]	Out of which, the share of the holders of the equity interests of the Partnership in payments to the General Partner	Out of which, the share of the holders of the equity interests of the Partnership in payments to the Operator (beyond the reimbursement of its direct expenses)
Budget actually invested in 2018	Approx. 2,176	-	Approx. 70
Budget actually invested in 2019	Approx. 2,439	-	Approx. 77
Budget actually invested in 2020	Approx. 4,264	-	Approx. 57

7.4.11. Plan for the development of the Aphrodite reservoir

The development plan, which 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 production and processing facility in the area of the License, with an estimated maximum production capacity of approx. 800 MMCF per day, through 5 production wells at the first stage, and a subsea system for transmission to the Egyptian market. According to the Operator's current estimate, which was delivered to the Partnership and the Cypriot Government, and prior to completion of the technical-economic feasibility tests, including the performance of the FEED, the estimated cost of the development plan, excluding the cost of construction of the pipelines to the target markets, is estimated at approx. $2.5 billion to approx. $3 billion (in 100% terms). The estimated budget for the work plan until the date of adoption of a final

[95] The costs in the table reflect the Partnership's post-Merger holding in Block 12, i.e. 30%.
[96] Including costs in respect of which no payments are made to the Operator.

investment decision is approx. $150-200 million (in respect of 100%). Formulating the development plan and reaching the stage of adoption of a final investment decision for development of the Aphrodite reservoir are subject, *inter alia*, to the drilling of an additional appraisal/development well and the FEED, commercial arrangements for the development of the export pipelines, execution of agreements for the supply of natural gas and fulfillment of the conditions precedent in those agreements, regulatory approvals and the execution of finance arrangements. Insofar as the aforesaid conditions precedent are fulfilled, the date of commencement of natural gas supply from the Aphrodite reservoir may occur during 2026. It is noted that the aforesaid estimated costs do not include costs in respect of the development and construction of a pipeline for the export of natural gas from the Aphrodite reservoir.

In Q4/2020 the partners in the Aphrodite reservoir made an initial application to the government of Cyprus to make changes to the work plan approved under the development plan of November 7, 2019. The change pertains mainly to the postponement of the partners' commitment to drill appraisal well A-3 (Aphrodite 3) until November 2021, such that said well shall be drilled after the adoption of a decision for investment in the Aphrodite project and conversion thereof to a production well. The position of the partners in the Aphrodite reservoir is that there is no need to drill the well before a decision is made to invest in the project.

In several meetings held with the government of Cyprus in recent months, the application was presented to the government of Cyprus in detail, including the geological and other arguments in support thereof. As of the report approval date, discussions are held between the partners and the government of Cyprus in connection with the aforesaid. Probably, if the government of Cyprus accepts the request, such change in the work plan and in the development plan will require an amendment to the PSC and the development plan as well as approval by the Minister of Energy and the government of Cyprus.

The partners in the Aphrodite reservoir have submitted to the government of Cyprus a work plan and budget for 2021 in the sum of approx. $55.5 million. Of this sum, the partners have approved a work plan and budget for 2021 in the sum of approx. $28 million (for 100% of the rights). The balance of the total budget will be presented for the partners' approval with the progress made in the project, including the adoption of a decision on the drilling of appraisal well A-3. It is noted that as of the report approval date, no approval had yet been received from the government of Cyprus for the 2021 work plan.

Caution concerning forward-looking information – The details presented above, with respect to the possible date for adoption of a final investment decision, the estimated cost of the development plan, and the possible date for commencement of the natural gas supply, are "forward-looking information" within the meaning thereof in Section

32A of the Securities Law, which are largely based on various working assumptions and assessments, *inter alia*, the completion of the detailed planning of the development plan, the actual performance of the project, and a gamut of additional factors over which the Partnership does not have full control or which it is unable to estimate with an adequate level of certainty.

7.4.12. Contingent and prospective resources in Block 12

According to a report the Partnership received from NSAI, which was prepared in accordance with the rules of the Petroleum Resources Management System (SPE-PRMS) (hereinafter in this section the "**Resource Report**"), as of December 31, 2020 part of the natural gas and condensate resources in the Aphrodite reservoir[97] in the Block 12 area, were proven by the "Aphrodite A-1" drilling and the "Aphrodite A-2" drilling (as well as the "Aphrodite 2" drilling in the area of the Yishai License), and therefore were classified as contingent resources, while part of the natural gas and condensate resources, in fault blocks adjacent to the fault block where the said drilling was performed, were not proven and therefore remain classified as prospective resources.

(a) Contingent Resources

1. Quantity data[98]

According to the Resource Report, as of December 31, 2020, the contingent natural gas and condensate resources in the Aphrodite reservoir, that are classified at the Development Pending stage, are as specified below:

Target	Probability	Total (100%) Gas in the Petroleum Asset (Gross)		Total Rate Attributed to the Holders of the Equity Interests of the Partnership (Gross)[99]	
		Natural Gas BCF	Condensate Million Barrels	Natural Gas BCF	Condensate Million Barrels
Sands A	Low Estimate	18.7	0.0	5.6	0.0
	Best Estimate	87.3	0.2	26.2	0.1

[97] It is noted that the vast majority of the Aphrodite reservoir is in the area of the EEZ of Cyprus, and the minority thereof is in the area of the Yishai/370 license (the "**Yishai License**"), which is in the area of the EEZ of Israel.

[98] The table does not include resources which are located in the area of the Yishai License.

[99] In light of the fact that the Republic of Cyprus' share in the gas which shall be produced from Block 12 depends on the rate of production, which is not known and cannot be estimated as of the report release date, it is not possible to determine, as of the report release date, the net share of the holders of the equity interests of the Partnership in the resources. Therefore, the gross share of the holders of the equity interests of the Partnership are included in the above table before the deduction of the Republic of Cyprus' share pursuant to the provisions of the PSC and before payment of royalties.

Target	Probability	Total (100%) Gas in the Petroleum Asset (Gross)		Total Rate Attributed to the Holders of the Equity Interests of the Partnership (Gross)[99]	
		Natural Gas BCF	**Condensate Million Barrels**	**Natural Gas BCF**	**Condensate Million Barrels**
	High Estimate	117.2	0.3	35.2	0.1
Sands C	Low Estimate	1,539.4	3.1	461.8	0.9
	Best Estimate	2,269.1	5.0	680.7	1.5
	High Estimate	2,946.7	7.1	884.0	2.1
Sands D1U	Low Estimate	55.9	0.1	16.8	0.0
	Best Estimate	267.6	0.6	80.3	0.2
	High Estimate	365.0	0.9	109.5	0.3
Sands D1M	Low Estimate	12.1	0.0	3.6	0.0
	Best Estimate	190.7	0.4	57.2	0.1
	High Estimate	306.1	0.7	91.8	0.2
Sands D1L	Low Estimate	64.9	0.1	19.5	0.0
	Best Estimate	196.5	0.4	59.0	0.1
	High Estimate	250.7	0.6	75.2	0.2
Sands D2U	Low Estimate	236.6	0.5	71.0	0.2
	Best Estimate	330.0	0.7	99.0	0.2
	High Estimate	367.2	0.9	110.2	0.3
Sands D2M	Low Estimate	61.3	0.1	18.4	0.0
	Best Estimate	104.9	0.2	31.5	0.1
	High Estimate	132.1	0.3	39.6	0.1
Sands D2L	Low Estimate	17.9	0.0	5.4	0.0
	Best Estimate	30.6	0.1	9.2	-
	High Estimate	61.4	0.1	18.4	-

2. The Resource Report states that the contingent resources are contingent, *inter alia*, on the finalization of the development plan, adoption of a final investment decision and signing of agreements. For details regarding the plan for the development of the Aphrodite reservoir, see Section 7.4.6 above. Additionally, it is stated that the report does not include an economic analysis of the petroleum asset and that based on development of similar reservoirs, the contingent resources in the best estimate category have a reasonable chance of commercial production.

Caution – there is no certainty that it will be commercially possible to produce any of the contingent resources.

(b) Prospective Resources

1. Quantity data[100]

According to the Resource Report, as of December 31, 2020 the prospective natural gas and condensate resources in the Aphrodite reservoir are as specified below:

Target	Probability	Total (100%) Gas in the Petroleum Asset (Gross)		Total Rate Attributed to the Holders of the Equity Interests of the Partnership (Gross) [101]	
		Natural Gas BCF	Condensate Million Barrels	Natural Gas BCF	Condensate Million Barrels
Sands A	Low Estimate	3.8	0.0	1.1	0.0
	Best Estimate	9.8	0.0	2.9	0.0
	High Estimate	18.5	0.0	5.6	0.0
Sands C	Low Estimate	33.0	0.1	9.9	0.0
	Best Estimate	52.3	0.1	15.7	0.0
	High Estimate	81.0	0.2	24.3	0.1
Sands D1U	Low Estimate	98.4	0.2	29.5	0.1
	Best Estimate	166.1	0.4	49.8	0.1
	High Estimate	296.0	0.7	88.8	0.2
Sands D1M	Low Estimate	46.0	0.1	13.8	0.0
	Best Estimate	105.4	0.2	31.6	0.1
	High Estimate	263.9	0.6	79.2	0.2
Sands D1L	Low Estimate	127.1	0.3	38.1	0.1
	Best Estimate	194.7	0.4	58.4	0.1
	High Estimate	291.5	0.7	87.5	0.2
Sands D2U	Low Estimate	165.2	0.3	49.6	0.1
	Best Estimate	356.2	0.8	106.9	0.2
	High Estimate	883.0	2.1	264.9	0.6
Sands D2M	Low Estimate	2.5	0.0	0.8	0.0
	Best Estimate	23.6	0.0	7.1	0.0
	High Estimate	271.1	0.7	81.3	0.2
Sands D2L	Low Estimate	0.2	0.0	0.1	0.0
	Best Estimate	4.5	0.0	1.4	0.0
	High Estimate	206.5	0.5	62.0	0.2

2. The Resource Report was prepared based on 3D seismic surveys carried out in 2009 and 2013 by Petroleum Geo-

[100] The table does not include resources which are located in the area of the Yishai License.
[101] Before deduction of the Republic of Cyprus' share pursuant to the provisions of the PSC and before payment of royalties.

Services, which were consolidated and reprocessed recently in 2014, based on data collected from the "Aphrodite A-1" and "Aphrodite A-2" wells in the areas of the Aphrodite reservoir, and from the "Aphrodite 2" well in the area of the Yishai License, and by comparison to nearby and similar reservoirs around the world.

3. Set forth below are the basic parameters used for calculation of the various scenarios:

Since the prospective resources in the reservoir are located in two separate fault blocks, the basic parameters that were used for calculation of the various scenarios in each of the fault blocks are presented below separately:

The Central Fault Block

Target	**Average Gross Thickness (feet)**		**Area (Acree)**		**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

The South-Western Fault Block

Target	Average Gross Thickness (feet)		Area (Acree)		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 D2	0.7	0.6	379	379

4. The significant risks entailed by the continuation of the process are related to proving a commercial discovery and include, *inter alia*, costs of appraisal and development of the reservoir. Additionally, there are risks in proving the prospective resources that are in the fault breaks which have

not yet been drilled. For a specification of the risk factors entailed by exploration activity, see Section 7.29 below.

5. An estimate of the probability of success of each one of the risk factors in the drilling as well as a statistical estimate of the geological probability of the presence of natural gas in the fault breaks in which the prospective resources are located, are as follows (in %):

The Central Fault Break

Target	Trap Integrity	Reservoir Quality	Source Quality	Timing & 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

The South Western Fault Break

Target	Trap Integrity	Reservoir Quality	Source Quality	Timing & 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

6. Estimate of probability of development for commercial production: For details see Subsections (2)-(4) above.

7. The Partnership's reasons regarding the basis for the basic parameters used in the calculation of the scenarios: The parameters used in the calculation of the various estimates are based primarily on data collected from the "Aphrodite A-1" and "Aphrodite A-2" wells in the areas of the Aphrodite reservoir, and from the "Aphrodite 2" well in the area of the Yishai License, on the results of the three-dimensional seismic survey and on general information with respect to similar reservoirs and targets.

(c) In the Resource Report, NSAI noted, among other things, several assumptions and reservations, including that:

1. The estimations regarding the contingent resources were not adjusted to reflect development risks;
2. NSAI did not visit the oil field and did not examine the mechanical operation of the facilities and wells or their condition;

3. NSAI did not examine possible exposure stemming from environmental protection issues. However, NSAI noted that, as of the date of the Resource Report, it is not aware of a possible liability pertaining to environmental protection issues, which might materially affect the estimated quantity of resources in the Resource Report or the commerciality thereof;

4. The resources described in the Resource Report are located in a site that has not been developed and therefore the evaluation is based on estimates of reservoir volume and recovery efficiencies, while drawing an analogy to reservoirs with similar geological and reservoir characteristics.

(d) <u>Conformity between the Resource Report data and data of previous reports pertaining to the petroleum asset</u>

The differences between the current Resource Report and the previous resource report which was published in the Partnership's Periodic Report for 2017, stem from an update of the mapping of the reservoir and an update of the geological model such that it will include the entire updated database as well as from a comparison to adjacent reservoirs.

The Partnership declares that all of the above data has been compiled in accordance with the SPE-PRMS rules.

Caution – There is no certainty that any part of the possible resources stated will indeed be discovered. If discovered, there is no certainty that any part of the resources will be commercially recoverable. The prospective information does not constitute an evaluation of contingent resources and reserves, which may only be evaluated after the exploration drilling, if at all.

Caution regarding forward-looking information – NSAI's estimates regarding the contingent and prospective resources in the Aphrodite reservoir are forward-looking information, within the meaning thereof in the Securities Law. The above estimates are based, *inter alia*, on geological, geophysical, engineering and other information received from the operator from the wells at the Aphrodite reservoir and from wells in adjacent reservoirs and constitute professional estimates and assumptions of NSAI only, in respect of which there is no certainty. The quantities of natural gas and/or condensate that will actually be extracted (if any) may be different to the said estimates and assumptions, *inter alia* as a result of

operating and technical conditions and/or regulatory changes and/or supply and demand conditions in the market and/or commercial terms and/or the actual performance of the reservoir. The said estimates and assumptions may be updated insofar as additional information will accumulate and/or as a result of a gamut of factors relating to projects of oil and natural gas exploration and production.

Opinion of the evaluator

A report on the contingent and prospective resources in Block 12 which was prepared by NSAI, as of December 31, 2020, is attached hereto as **Annex C**, as well as the NSAI's consent to the inclusion thereof in this report, including by way of reference, which is attached hereto as **Annex A**.

Management declaration

(1) Date of the declaration: March 14, 2021;
(2) Name of the corporation: Delek Drilling, Limited Partnership;
(3) Name and position of the resource evaluation officer at the Partnership: Gabi Last, Chairman of the Board of the General Partner;
(4) We confirm that all of the data required for performance of his work were provided to the evaluator;
(5) We confirm that no information has come to our attention which indicates the existence of dependency between the evaluator and the Partnership;
(6) We confirm that, to the best of our knowledge, the resources reported are the best and most current estimates in our possession;
(7) We confirm that the data included herein were prepared according to the professional terms listed in Chapter G of the Third Schedule to the Securities Regulations (Details of the Prospectus and Draft Prospectus – Structure and Form), 5729-1969, and within the meaning afforded thereto in Petroleum Resources Management System (2018), as published by the SPE, the AAPG, the WPC and the SPEE, as being at the time of release of the report;
(8) We confirm that no change has been made to the identity of the evaluator who performed the last contingent resource or reserve disclosure released by the Partnership;
(9) We agree to the inclusion of the foregoing declaration herein.

____

Gabi Last
Chairman of the Board

Repercussions of the Covid-19 Crisis

As specified in Section 6.9 above, due to the Covid-19 Crisis there is, on the report approval date, significant and unusual uncertainty as to the possible repercussions of the crisis in and after 2021 on global economy in general, and energy prices in particular. Therefore, insofar as the Covid-19 Crisis continues or worsens, the possibility of making decisions on investment in general, and in new projects in particular, may be barred thereby.

7.5. New Ofek License

On March 19, 2019, the Partnership entered into an agreement with S.O.A Energy Israel Ltd. ("**SOA**") for the purchase of interests at the rate of 25% (out of 100%) in the onshore 405/New Ofek license (the "**New Ofek License**"), which is situated in the *Shfela* region (the Judean Foothills) in central Israel (in this section: the "**Purchase Agreement**"). Upon fulfillment of the conditions precedent in the agreement, on October 10, 2019 the aforesaid transaction for the purchase of the interests was closed and on November 5, 2019 the Petroleum Commissioner announced that the transfer of the interests as aforesaid was recorded in the Petroleum Register. For additional details with respect to the Purchase Agreement, see Section 7.25.12 below.

The New Ofek License is a negligible petroleum asset compared with all of the Partnership's operations and assets, and therefore a limited description thereof is presented below.

7.5.1. General details

General Details about the Petroleum Asset	
Name of the petroleum asset:	405/New Ofek
Location:	Onshore license in the Shfela region in central Israel
Area:	Approx. 344 km^2
Type of petroleum asset:	Oil exploration license
Original grant date of the petroleum asset:	June 21, 2017
Original expiration date of the petroleum asset:	June 20, 2020
Dates on which an extension of the petroleum asset period was decided:	April 5, 2020
Current expiration date of the petroleum asset:	June 20, 2021
State whether there is another option to extend the petroleum asset period; if such an option exists – state the possible extension period:	Subject to the Petroleum Law it may be extended for another 3 years, with an option, in the case of a discovery, to extend by an additional two years.
The operator's name:	SOA
The names of the direct partners in the petroleum asset, and their direct share in the petroleum asset and, to the best of the Partnership's knowledge, the names of the control holders of the said partners:	▪ SOA - 45%, to the best of the Partnership's knowledge, the control holder of SOA is Mr. Saed Sarsur (a businessman, Israeli citizen and resident of England); ▪ The Partnership - 25%; ▪ Globe Exploration (Y.C.D.), Limited Partnership ("**Globe**") – 20%, to the best of the Partnership's knowledge, the control

General Details about the Petroleum Asset	
	holder of Globe is Globe Exploration, which serves as Globe's general partner;[102] ▪ Capital Point Ltd. ("**Capital**") - 10%, to the best of the Partnership's knowledge, Capital has no controlling shareholder.

7.5.2. The Partnership's share in the petroleum asset

General details regarding the Partnership's share in the Petroleum Asset	
For a holding in a purchased petroleum asset – the purchase date:	March 19, 2019.
Description of the nature and manner of the Partnership's holding in the petroleum asset:	The Partnership directly holds 25% of the interests in the license.
State the actual share attributed to the holders of the equity interests of the Partnership in the revenues from the petroleum asset:	Pre Investment-Recovery – 20.50%. Post Investment-Recovery – 19.25%.
The total share of the holders of the Partnership's equity interests in the aggregate investment in the petroleum 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):	Approx. $6,345 thousand[103]

7.5.3. Actual and planned work plan

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

In September 2020, the partners in the license made a decision regarding participation in the performance of the production tests that will be performed during 2021 with a budget of between approx. $10 million and approx. $13 million (100%). The Partnership's share in the budget is between approx. $7.5 million and approx. $8.5 million[104].

[102] As of the report approval date, the voting shares in Globe Exploration are held by Griffin Exploration Ltd., a private company controlled (indirectly) by: (a) Messrs. Menachem and Gil Sternberg – 17.21%; (b) C.P.H Investments Ltd., a private company controlled (indirectly) by Yaakov OBM and Margaret Chai – 34.68%; (c) Derin Holdings Ltd., a private company controlled by Dr. Baruch Derin and Zvi Derin – 23.12%; (d) The estate of Mr. Zvika Boroditzky OBM – 17.5%; and (e) L.I.A. Pure Capital Ltd., a private company controlled by Mr. Kfir Zilberman – 7.49%.

[103] The Partnership paid $500 thousand out of this amount, in accordance with the Purchase Agreement (for details, see Section 7.25.12 below).

[104] It is noted that in the Purchase Agreement, the Partnership undertook that it would bear the costs of production tests in the New Ofek License up to a sum total of no more than U.S. $6.5 million, and that insofar as the cost of the production tests would exceed the said amount, each one of the partners in the New Ofek

Below is a concise description of the main activities actually carried out in the New Ofek License between January 1, 2018 and the report approval date, as well as a concise description of the planned activities in the license, in accordance with the updated work plan approved by the Petroleum Commissioner on December 24, 2020.

New Ofek			
Period	**Concise description of actions actually performed for the period or of the planned work plan**	**Total estimated budget for activity at the petroleum asset level (dollars in thousands)**	**Amount of actual participation in the budget by the holders of the Partnership's equity interests (dollars in thousands)**
2018	• Signing of an agreement with a drilling contractor and submission of a production tests plan for approval by the Petroleum Commissioner.		
2019	• Delivery of the digitization of seismic sections, log interpretation and petrophysical analysis to the Petroleum Commissioner. • Submission of a plan for re-entry into the well and for the performance of production tests to the Petroleum Commissioner on May 15, 2019. • Receipt of all of the necessary permits and approvals for breaking ground and performing the production tests, including approval by the landowner and approval by the Local Committee.	Approx. 30 Approx. 60 Approx. 351	Approx. 7.5 Approx. 15 Approx. 8
2020	• Planning and preparation for performance of production tests in the Ofek-2 well. • Submission of a signed agreement with a contractor for the performance of the production tests in the area of the license and an engineering plan to the Petroleum Commissioner.	Approx. 5,845	Approx. 5,845
2021 forth	• Receipt of all of the approvals required for performance of production tests in the Ofek-2 well. • Performance of production tests in the Ofek-2 well. • Submission of a summary report on the production tests to the Petroleum Commissioner three months after the date of completion of performance of the production tests.	Approx. 5,914	Approx. 1,970

Caution concerning forward-looking information – The Partnership's aforesaid estimations with respect to the planned activities, costs, timetables and actual performance of the planned activities in the New Ofek License, constitute forward-looking information within the meaning thereof in Section 32A of the Securities Law, which is based on the estimations of the General Partner of the Partnership with respect to the planned activities, costs, timetables and actual performance of the planned activities, which are all based on estimations that the General Partner of the Partnership received from the operator (SOA). In

License, including the Partnership, would pay its proportionate share in such additional cost, according to the provisions of the Joint Operating Agreement (JOA).

actuality, the planned activities, costs, timetables and production rates may materially differ from the aforesaid estimations and are contingent, *inter alia*, on the adoption of fitting decisions by the New Ofek partners, receipt of the approvals required pursuant to any law, completion of the detailed planning of the components of the activities, receipt of proposals from contractors, changes in the raw material and the suppliers market around the world, the applicable regulation, technical abilities and economic merit.

Repercussions of the Covid-19 Crisis

As specified in Section 6.9 above, due to the Covid-19 Crisis there is, on the report approval date, significant and unusual uncertainty as to the possible repercussions of the crisis in and after 2021 for the global economy in general, and energy prices in particular. Therefore, insofar as the Covid-19 Crisis continues or worsens, the promotion of existing projects or the possibility of making decisions on investment in general, and in new projects in particular, may be barred thereby.

7.6. New Yahel License

On March 19, 2019, the Partnership entered into an agreement with SOA for the purchase of a 25% interest (out of 100%) in the onshore 406/"New Yahel" license (the "**New Yahel License**"), which is situated in northern Israel (in this section, the "**Purchase Agreement**" and the "**Transaction**"). Upon fulfillment of the conditions precedent in the agreement, on October 10, 2019 the aforesaid Transaction for the purchase of the interests was closed and on November 5, 2019 the Petroleum Commissioner announced that the transfer of the interests as aforesaid was recorded in the Petroleum Register. For additional details on the Purchase Agreement, see Section 7.25.12 below.

The New Yahel License is a negligible petroleum asset compared with all of the Partnership's operations and assets, and therefore a limited description thereof is presented below.

7.6.1. General details

General Details about the Petroleum Asset	
Name of the petroleum asset:	406/New Yahel
Location:	Onshore license in the Haifa Bay area, south of the Akko-Safed highway and north of Yokneam
Area:	397.5 km^2
Type of petroleum asset:	Oil exploration license
Original grant date of the petroleum asset:	June 21, 2017
Original expiration date of the petroleum asset:	June 20, 2020
Dates on which an extension of the petroleum asset period was decided:	April 5, 2020

General Details about the Petroleum Asset	
Current expiration date of the petroleum asset:	June 20, 2021
State whether there is another option to extend the petroleum asset period; if such an option exists – state the possible extension period:	Subject to the Petroleum Law, it may be extended for another 3 years, with an option, in the case of a discovery, to extend by an additional two years.
The operator's name:	SOA
The names of the direct partners in the petroleum asset, and their direct share in the petroleum asset and, to the best of the Partnership's knowledge, the names of the control holders of the said partners:[105]	▪ SOA - 45%; ▪ The Partnership - 25%; ▪ Globe – 20%; ▪ Capital - 10%.

7.6.2. The Partnership's share in the petroleum asset

General details regarding the Partnership's share in the Petroleum Asset	
For a holding in a purchased petroleum asset – the purchase date:	March 19, 2019.
Description of the nature and manner of the Partnership's holding in the petroleum asset:	The Partnership directly holds 25% of the interests in the license.
State the actual share attributed to the holders of the equity interests of the Partnership in the revenues from the petroleum asset:	Pre Investment-Recovery – 20.50%. Post Investment-Recovery – 19.25%.
The total share of the holders of the Partnership's equity interests in the aggregate investment in the petroleum 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):	Approx. $513 thousand[106].

7.6.3. Actual and planned work plan

Below is a concise description of the main activities actually carried out in the New Yahel License between January 1, 2018 and the report approval date, as well as a concise description of the planned activities in the license, in accordance with the updated work plan approved by the Petroleum Commissioner on January 11, 2021.

[105] For details with respect to the control holders of the partners, see Section 7.5.1 above.
[106] The Partnership paid $500 thousand out of this amount, in accordance with the Purchase Agreement (for details, see Section 7.25.11 below).

New Yahel			
Period	**Concise description of actions actually performed for the period or of the planned work plan**	**Total estimated budget for activity at the petroleum asset level (dollars in thousands)**	**Amount of actual participation in the budget by the holders of the Partnership's equity interests (dollars in thousands)**
2019	• Completion of an environmental document according to the Petroleum Regulations (Authorization for Deviation from the Provisions of the Planning and Building Law), 5772-2012. • Submission of an application according to the Uniform Plan Structure Procedure together with the environmental document on June 11, 2019. • A discussion at the North District Planning and Building Committee on August 15, 2019, and in this context, addressing the Committee's conditions.	Approx. 27 Approx. 12	Approx. 7 Approx. 3
2020	• Planning and preparation ahead of exploration drilling in the area of the license, including obtainment of all required approvals.		
2021 [107]	• Discussion and receipt of the District Committee's decision to approve drilling application by September 1, 2021. • Submission of an application for approval of drilling and a signed agreement with a drilling contractor for the commissioner's approval by October 3, 2021.	Approx. 60	Approx. 15
2022 forth	• Commencement of drilling of well by February 1, 2022. • Submission of a summary report within three months from the date of completion of the drilling.	Approx. 20,000	Approx. 5,000

Caution concerning forward-looking information – The Partnership's aforesaid estimations with respect to the planned activities, costs, timetables and actual performance of the planned activities in the New Yahel License, constitute forward-looking information within the meaning thereof in Section 32A of the Securities Law, which is based on the estimations of the General Partner of the Partnership with respect to the planned activities, costs, timetables and actual performance of the planned activities, which are all based on estimations that the General Partner of the Partnership received from the operator (SOA). The planned activities, costs and timetables may materially differ from the aforesaid estimations and are contingent, *inter alia*, on the adoption of fitting decisions by the New Yahel partners, receipt of the approvals required pursuant to any law, completion of the detailed planning of the components of the activities, receipt of proposals from contractors, changes in the raw material and the suppliers market around the world, the applicable regulation, technical abilities and economic merit.

[107] As of the report approval date, the budget for 2021 forth has not yet been approved by the partners.

Repercussions of the Covid-19 Crisis

As specified in Section 6.9 above, due to the Covid-19 Crisis there is, on the report approval date, significant and unusual uncertainty as to the possible repercussions of the crisis in and after 2021 for the global economy in general, and energy prices in particular. Therefore, insofar as the Covid-19 Crisis continues or worsens, the promotion of existing projects or the possibility of making decisions on investment in general, and in new projects in particular, may be barred thereby.

7.7. **The Yam Tethys project**

The Yam Tethys project includes the Noa lease, in the area of which the Noa natural gas reservoir was discovered in 1999, and the Ashkelon lease, in the area of which the Mari B and Pinnacles reservoirs were discovered in 2000 and 2012 respectively. The production of natural gas in the Yam Tethys project began in March 2004 and was discontinued in May 2019 due to a depletion of the reservoirs. As of the report approval date, the principal use of the project's assets is the provision of infrastructure services to the Tamar Reservoir[108]. In view of the aforesaid, the Partnership deems the Yam Tethys project as a negligible petroleum asset.

According to the approvals and directives received from the Petroleum Commissioner, the operator is preparing to perform a decommissioning and abandonment of the project's facilities, other than the platform, including the production wells and the subsea equipment, in accordance with an approved decommissioning plan. At the same time, the aforesaid parties are in discussions with respect to the operator's request to approve "cold stacking" of the Yam Tethys platform, which will allow, *inter alia*, to turn it into an unmanned platform. A discussion is also being held with respect to possible future uses and/or decommissioning and abandonment of the Yam Tethys platform, considering the existing link between the facilities of the Yam Tethys project and production from the Tamar Project. For further details, see Section 7.25.11 below. It is noted that, based, *inter alia*, on consultants with expertise in the field, the Partnership recorded in its financial statements an estimate in respect of full abandonment of the assets of the Ashkelon and Noa Leases (both wells and subsea equipment and the Yam Tethys platform) in the sum of approx. $99.6 million.

It is noted that on May 3, 2020, an agreement was signed between the Partnership, Noble, Delek Group and Ratio, in which the manner of supply of natural gas to the customers of the holders of the rights in the Yam Tethys reservoir (Noble, the Partnership and Delek Group) from the Leviathan Reservoir was regulated.

[108] The Gas Framework provides that the holders of the interests in the Tamar Lease will be entitled to use the Mari B platform for the entire term of the Tamar Lease, for the purpose of export or supply of natural gas to the domestic market from the Tamar reservoir, subject to the conditions stipulated in the Gas Framework.

In view of the said project being classified as negligible, a limited description thereof is presented below:

7.7.1. General

General Details with respect to the Petroleum Asset	
Name of the petroleum assets:	Noa Lease Ashkelon Lease
Location:	Ashkelon Lease – approx. 25 km west of the shores of Ashkelon. Noa Lease – approx. 40 km west of the shores of Ashkelon.
Area:	The overall area of the leases is approx. 500 km^2.
Type of petroleum asset and description of the activities permitted for such type:	Lease; Permitted activities under the Petroleum Law – exploration and production.
Original granting date of the petroleum asset:	Ashkelon Lease – June 11, 2002. Noa Lease – February 10, 2000.
Original expiration date of the petroleum asset:	Ashkelon Lease – June 10, 2032. Noa Lease – January 31, 2030.
Dates on which an extension of the term of the petroleum asset was decided:	-
Current expiration date of the petroleum asset:	Ashkelon Lease – June 10, 2032. Noa Lease – January 31, 2030.
Note on whether there is an additional option to extend the term of the petroleum asset; if such option exists – the optional extension term should be noted:	Subject to the Petroleum Law, by 20 additional years.
The name of the operator:	Noble
The names of the direct partners in the petroleum asset and their direct share in the petroleum asset, and, to the best of the Partnership's knowledge, the names of the controlling shareholders of such partners:	▪ The Partnership (48.5%). ▪ Noble (47.059%). ▪ Delek Group (4.441%).

7.7.2. Work plan for the Yam Tethys project – actual and planned

Below is a concise description of the main activities actually carried in the Noa Lease and the Ashkelon Lease between January 1, 2018 and the report approval date, as well as a concise description of planned activities:

Yam Tethys project			
Period	**Concise Description of Activities Actually Performed for the Period or of the Planned Work Plan**	**Total Estimated Budget for Activity at the Petroleum Asset Level (Dollars in thousands)**	**Amount of Actual Participation in the Budget by the Holders of the Equity Interests of the Partnership (Dollars in thousands)**
2018	• Production from the Mari B reservoir, ongoing operation and maintenance. • Examination of uses of existing infrastructures and preservation or increase of the production capacity. • Preparation ahead of future abandonment of wells and facilities in the reservoirs of the Yam Tethys project. • Continued update of the geological model and the flow model, *inter alia* according to the well and production data. • Mapping out and definition of additional prospects in the area of the petroleum asset, including a deep target prospect in the area of the petroleum asset.	Approx. 472.8	Approx. 229.3
2019	• Production from the Mari B reservoir, ongoing operation and maintenance. • Examination of uses of existing infrastructures and preservation or increase of the production capacity. • Preparation ahead of future abandonment of wells and facilities in the reservoirs of the Yam Tethys project. • Preparation of the cold stacking platform including air gapping of the gas pipelines from the production wells to the processing and production facilities on the platform. • Continued update of the geological model and the flow model, *inter alia* according to the well and production data. • Mapping out and definition of additional prospects in the area of the petroleum asset, including a deep target prospect in the area of the petroleum asset.	Approx. 1,497 Approx. 299.7	Approx. 726.3 Approx. 145.3
2020	• Ongoing operation and maintenance. • Preparation of the cold stacking platform including air gapping of the gas pipelines from the production wells to the processing and production facilities on the platform. • Examination of uses of existing infrastructures and preservation or increase of the production capacity. • Preparation ahead of future abandonment of wells and facilities in the reservoirs of the Yam Tethys project.	Approx. 2,342 Approx. 7,962	Approx. 1,135 Approx. 3,862
2021 forth	• Examination of uses of existing infrastructures of the project. • “Cold stacking” of the Mari-B platform, *inter alia*, by disconnecting the gas pipeline to the platform (including from the reservoir, from the Tamar platform and from the 30-inch pipe) and clearing out equipment and materials which are not required. • Plug and abandonment of the project’s production wells, in accordance with standards and the directives of the Petroleum Commissioner.	Approx. 158,464	Approx. 76,855

Yam Tethys project			
Period	**Concise Description of Activities Actually Performed for the Period or of the Planned Work Plan**	**Total Estimated Budget for Activity at the Petroleum Asset Level (Dollars in thousands)**	**Amount of Actual Participation in the Budget by the Holders of the Equity Interests of the Partnership (Dollars in thousands)**
	Decommissioning and abandonment of subsea facilities, in accordance with standards and the directives of the Petroleum Commissioner		

Caution concerning forward-looking information – The Partnership's assessment with respect to the activities planned in the Yam Tethys project, including as pertains to costs, timetables and the actual performance thereof, constitutes forward-looking information within the meaning thereof in Section 32A of the Securities Law, which is based on the estimations of the General Partner with respect to the components of the work plan, which are all based on estimations received by the General Partner from the Operator. The actual performance of the work plan, including timetables and costs, may materially differ from the aforesaid estimations and is conditioned, *inter alia*, on applicable regulation, technical ability and economic merit.

7.8. The Tanin and Karish Leases

As specified below, the Partnership has rights to receive royalties from the Tanin and Karish Leases which are owned by Energean Israel Ltd. ("**Energean Israel**"). It is clarified that the description presented below in relation to the Tanin and Karish Leases is based mainly on public reports of Energean Oil & Gas Plc. ("**Energean**"), a foreign public company whose shares are traded on the London Stock Exchange and the Tel Aviv Stock Exchange, which is, to the best of the Partnership's knowledge, the controlling shareholder of Energean Israel. It is clarified that the Partnership is unable to independently corroborate the veracity of the details presented in these reports.

7.8.1. General

Following the Government's decision to ratify the Gas Framework, on August 16, 2016, an agreement was signed between the Partnership, Noble and Avner and Energean Israel, for the sale of all of the interests of the Partnership, Avner and Noble in the I/16 Tanin and I/17 Karish leases (collectively: the "**Tanin and Karish Leases**"), in consideration for a payment, which constitutes reimbursement of past expenses invested in the leases by the Partnership, Avner and Noble plus royalties in connection with natural gas and condensate that shall be produced from the leases. After fulfillment of all of the conditions precedent on December 26, 2016, the transaction was closed and all of the interests in the leases were transferred to Energean Israel. For further details regarding the agreement, see Section 7.25.13 below.

As of the report approval date, the Partnership deems the benefit from the Tanin and Karish Leases as a petroleum asset that is negligible to the results of the Partnership's operations and its business, after quantitative examination of the current value of the total projected revenues, in the Partnership's estimation, from its right to receive royalties from the Tanin and Karish Leases out of the total current value of the projected cash flows, including from the Tamar Project and from the Leviathan project and together with the cost of the Partnership's investment in the Block 12 project in Cyprus and quantitative examination of the Partnership's share in reserves and contingent resources in the Karish and Tanin Leases relative to the total reserves and contingent resources attributed to the Partnership in its petroleum assets. In addition, also in qualitative terms the asset should be deemed as negligible, in view of the fact that the Partnership's rights in the Tanin and Karish Leases are passive, and that it has no ability to influence the activity therein.

In view of the classification of the benefit in the leases as a negligible petroleum asset, a limited description of the Tanin and Karish Leases is presented below.

General details about the Petroleum Asset	
Name of Petroleum Asset:	Tanin lease Karish lease
Location:	Offshore assets located approx. 80-130 km west of the shores of Nahariya
Area:	The total area of both leases collectively is approx. 500 square km
Type of petroleum asset and description of actions permitted according to this type:	Lease; Actions permitted under the Petroleum Law – exploration and production
Original grant date of the petroleum asset:	December 24, 2015, valid since August 11, 2014 (amended on April 25, 2017)
Original expiration date of the petroleum asset:	August 10, 2044
Dates on which an extension of the petroleum asset period was decided:	-
Current date for expiration of the petroleum asset:	August 10, 2044
Statement of whether there is another option for the extension of the petroleum asset period; if such an option exists – please state the possible extension period:	By 20 additional years, subject to the Petroleum Law
Statement of Operator's Name:	Energean Israel
Statement of the names of the direct partners in the petroleum asset, and their direct share in the petroleum asset, and, to the best of the Partnership's knowledge, the names of the controlling shareholders in the said partners:	100% Energean Israel

General details regarding the Partnership's share in the petroleum asset	
For a holding in a purchased petroleum asset – the purchase date:	-
Description of the nature and manner of	The Partnership is entitled to royalties in

holding of the petroleum asset by the Partnership:	connection with natural gas and condensate that shall be produced from the leases
Statement of the actual share attributed to the holders of the equity interests of the Partnership in the revenues from the petroleum asset:	Approx. 5.12% before payment of a petroleum profit levy under the Taxation of Profits from Natural Resources Law, 5771-2011 (the "**Levy**") and before the Investment Recovery Date; Approx. 2.47% before payment of the Levy and after the Investment Recovery Date; and Approx. 3.22% upon commencement of payment of the Levy and after the Investment Recovery Date
The total share of the holders of the equity interests of the Partnership in the aggregate investment in the petroleum asset during the five years preceding the last day of the report year (whether recognized as an expense or as an asset in the financial statements):	Approx. $(5,516) thousand[109]

7.8.2. Actual and planned work plan in the Tanin and Karish Leases

To the best of the Partnership's knowledge, the development plan for the Karish and Tanin natural gas reservoirs, that was submitted to the Petroleum Commissioner by Energean Israel, was approved by the Ministry of Energy in August 2017 (in this section: the "**Development Plan**") with the Karish reservoir being developed at the first stage and the Tanin reservoir being developed further down the line.[110]

In 2018, Energean adopted a Final Investment Decision for development of the Karish reservoir. On November 17, 2020 Energean released a notice from which it transpires that it believes gas will begin to flow from the Karish reservoir in Q4/2021.

On February 11, 2021, Energean released a presentation and a reserves report was prepared by a third party, from which it arises that the gas flow from the Karish reservoir is expected to commence, in its estimation, on the beginning of 2022.

On April 15, 2019 Energean announced[111] a natural gas discovery at the Karish North well. According to Energean's reports, the plan for development of the Karish North reservoir filed thereby, had been approved by the Ministry of Energy in August 2020, and a FID for development of the Karish North reservoir had been adopted on January 14, 2021.[112] According to Energean's estimation, production from this reservoir is expected to commence in H2/2023.

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[109] The said investment is from the pre-sale period, in which the petroleum asset was held directly by the Partnership; the specified cost presents the Partnership's post-Merger cost, i.e. 52.941%. The investment in the said period includes a budget update (reduction) in the sum of approx. $5,516 thousand.

[110] https://www.gov.il/he/Departments/news/spokesperson_development.

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

[112] ps://www.energean.com/media/4647/20210113-karish-north-fid.pdf

To the best of the Partnership's knowledge, the current data on the resources attributed to the Karish, Tanin and Karish North reservoirs (in this section: the "**Reservoirs**"), were last reported by Energean on February 11, 2021[113]. According to this report, the Reservoirs contain natural gas reserves (2P) of approx. 98.2 BCM and hydrocarbon liquids of approx. 99.6 million barrels (compared with natural gas resources (2P + 2C) of approx. 98.6 BCM and hydrocarbon liquids of approx. 82 million barrels, according to a previous report by Energean of April 2020). Energean further noted that the FPSO would reach production capacity of some 8 BCM per year in 2023. Energean further reported the quantities of prospective resources in the areas of the Karish and Tanin reservoirs and in the areas of the licenses held thereby in Israel's EEZ, including in the Karish and Tanin reservoirs.

For details with respect to a highly material valuation of the Partnership's royalty interest in the Karish and Tanin Leases, see Note 8B to the financial statements (Chapter C of this report), which are attached below, and Annex C to the Board of Directors' Report (Chapter B of this report).

It is emphasized that the Partnership, as the holder of a right to royalties, does not bear the development plan expenses of the Karish, Tanin and Karish North reservoirs.

It is noted that in April 2020, Energean and the Partnership exchanged letters in connection with the Partnership's right to receive royalties from the leases. Energean claimed, *inter alia*, that its undertaking to pay royalties does not apply to hydrocarbons from the Karish North reservoir and, additionally, that not all hydrocarbon liquids to be produced from the Karish lease, meet the definition of Condensate under the agreement for the sale of the Partnership's rights in the leases. It is the Partnership's position, based on its counsel, that according to the agreement for the sale of the Partnership's rights in the leases, the royalty documents and the records in the Petroleum Register, Energean's duty to pay royalties applies to all natural gas and condensate to be produced from the leases, including from the Karish North reservoir, and that any and all hydrocarbon liquids to be produced from the leases constitute Condensate, as defined in the agreement.

Repercussions of the Covid-19 Crisis

As specified in Section 6.9 above, due to the Covid-19 Crisis, on the report approval date there is significant and unusual uncertainty with respect to the possible repercussions of the crisis later in and after 2021 for the global economy in general, and energy prices in particular.

[113] Link to Energean's notice: https://www.energean.com/investors/reports-presentations/

Insofar as the Covid-19 Crisis continues or worsens, a delay may be caused thereby in the progress of the development and production work of the Karish and Tanin reservoirs, leading to a decline in the current value of the Partnership's royalties from the Karish and Tanin reservoirs.

Caution concerning forward-looking information – The above description regarding the activities planned in the Karish lease, including the timetables for performance thereof and the date of commencement of gas piping from the Karish reservoir, constitutes forward-looking information, within the meaning thereof in Section 32A of the Securities Law, and is based only on public releases by Energean. Actual performance of the work plan, including the timetables, may materially differ from the foregoing and is contingent, *inter alia*, on applicable regulation, technical abilities and economic merit.

Below is a concise description of the main activities actually carried out in the Tanin and Karish Leases between January 1, 2018 and the report approval date, and a concise description of planned activities. Since the Partnership does not bear the development and production costs in the Karish and Tanin Leases, the table below does not present data regarding the budget for the activities and the actual scope of the participation of the holders of the equity interests of the Partnership in the budget:

Karish and Tanin Leases			
Period	**Concise description of actions actually taken for the period or of the planned work plan**	**Estimated overall budget per action on the petroleum asset level (in Dollars in thousands)**	**Scope of actual participation of the holders of the equity interests of the Partnership in the budget (in Dollars in thousands)**
2018	• Adoption of a final investment decision for the development of the Karish and Tanin reservoirs. • Planning and commencement of manufacture of a FPSO with a maximum production capacity of approx. 8 BCM per annum and approx. 0.8 million barrels of hydrocarbon liquids, to be connected by a 24-inch pipe to Dor Beach. • Planning of the subsea transmission system that will connect the production wells of the Karish reservoir to the FPSO.		
2019	• Continued planning and manufacture of the FPSO. • Drilling of an exploration well in the Karish North prospect. On April 15,		

Karish and Tanin Leases			
Period	**Concise description of actions actually taken for the period or of the planned work plan**	**Estimated overall budget per action on the petroleum asset level (in Dollars in thousands)**	**Scope of actual participation of the holders of the equity interests of the Partnership in the budget (in Dollars in thousands)**
	2019, Energean announced[114] a natural gas discovery in the Karish North well. • Drilling of three production wells in the Karish reservoir, beginning in Q2/2019, and commencement of completion thereof. • Continued planning, manufacture and commencement of installation of the subsea transmission system that will connect the production wells of the Karish reservoir to the FPSO.		
2020	• Finalization of completion of three production wells in the Karish reservoir. • Continuation of manufacture and placement of the subsea transmission system that will connect the production wells to the FPSO and to the shore. • On April 4, 2020, the FPSO hull has departed, which was manufactured by a shipyard in China to Singapore, for the purpose of installation of the gas and condensate production and processing systems (the topsides). • Submission and receipt of approval of the development plan for the Karish North reservoir.		
2021	• On January 14, 2021, Energean announced the adoption of a FID for the development of the Karish North reservoir. • Completion of installation of the gas and condensate production and processing systems on the FPSO hull in Singapore. • Departure of the FPSO, with all of the relevant systems thereon, to Israel. • Completion of connection of the systems and the running-in thereof.		
2022	• Commencement of commercial production from the Karish reservoir, partners' operation and maintenance. • Installation of a second export razor,		

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

Karish and Tanin Leases			
Period	**Concise description of actions actually taken for the period or of the planned work plan**	**Estimated overall budget per action on the petroleum asset level (in Dollars in thousands)**	**Scope of actual participation of the holders of the equity interests of the Partnership in the budget (in Dollars in thousands)**
	installation and running-in of a second oil train system in liquids and completion of Karish North 1 drilling.		
2023 forth	• Continuation of commercial production from the Karish reservoir, partners' operation and maintenance. • Completion of 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 and Karish North reservoirs, insofar as required. • Development of the Tanin reservoir, including the drilling of production wells, manufacture and installation of a subsea system and connection thereof to the FPSO. Commencement of production from the Tanin reservoir is expected, according to the publications of Energean, in 2027.		

7.9. **Discontinued operations**

Below are details regarding petroleum assets, the activity in which was discontinued in recent years:

7.9.1. **399/Royee License** (the "**Royee License**")

According to an agreement of November 26, 2012, the Partnership was granted an option to purchase working interests at the rate of 20% (out of 100%) in the Royee License[115]. The Partnership notified the partners of the exercise of the option on March 19, 2019, and in this context, the parties agreed on certain changes in the terms and conditions of the option, whereby the Partnership will purchase from Ratio interests at the rate of 24.99% in the license. One of the conditions precedent that were determined for the closing of the transaction was the granting of an exemption from approval of a restrictive arrangement. On July 28, 2019, the Competition Commissioner's decision was received whereby the parties were not granted the requested exemption from approval of

[115] To the best of the Partnership's knowledge, the partners in the Royee License are Edison, Ratio and Israeli Opportunity.

a restrictive arrangement. On March 22, 2020, Ratio reported that the partners in the license had notified the Petroleum Commissioner at the Ministry of Energy that they were forced to withdraw from the license and to return their working interests therein to the State, and later, on July 13, 2020, Ratio reported that in accordance with the notice of the Petroleum Commissioner, the Royee License had expired on June 14, 2020.

7.9.2. **Eran License**

The Eran License expired on June 14, 2013. Following the decision of the Petroleum Commissioner not to extend the Eran License, on October 3, 2013, the holders of the interests in the Eran License (including the Partnership) submitted an appeal to the Minister of Energy from the decision of the Petroleum Commissioner as aforesaid. On August 10, 2014, the Minister of Energy denied such appeal. On November 17, 2014, the holders of the interests in the Eran License, including the Partnership, filed a petition on this decision with the High Court of Justice. On June 2, 2016, the High Court of Justice entered a decision on the parties' agreement to defer to a mediation proceeding as proposed thereby. With the parties' consent, (Ret.) Chief Justice of the Supreme Court, A. Grunis, was appointed as mediator. At the end of the mediation proceeding, the parties reached agreements that were established in a mediation arrangement. On March 20, 2019, this mediation arrangement was filed with the court, which was moved to enter a judgment on the arrangement. In the mediation arrangement, the parties to the mediation agreed (with the consent of the Tamar Partners) on the division of the Tamar SW reservoir between the area of the Tamar Lease (78%) and the area of the Eran License (22%). It was further agreed that the interest in the area of the Eran License would be divided at a ratio of 76% to the State and 24% to the holders of the interests in the Eran License prior to its expiration. On April 11, 2019, a judgment was entered on the mediation arrangement agreed to by the parties, as aforesaid. As of the report approval date, the parties are continuing to act to formulate the agreements required for implementation of the mediation arrangement, as specified above, but there is no certainty that they will be able to reach such understandings, which will allow commencement of development work for the reservoir in the near future.

7.9.3. **Alon D license**

The Alon D license expired on June 21, 2020.

In this context it is noted that the partners in the Alon D license submitted a bid in the competitive process declared by the Ministry of Energy on June 23, 2020 for the granting of a natural gas and oil exploration license in Block 72, over whose area the license extended ("**Block 72**"), and that on October 21, 2020, a demand was received at the Partnership's offices from the Competition Authority for the provision of information and documents in connection with Block 72.

It is noted that the winner of the competitive process as aforesaid has not yet been declared by the Ministry of Energy. On September 30, 2020, the Petroleum Commissioner approached the Concentration Committee to hold a consultation on the decision on the winners of the said competitive process. On January 10, 2021 the Concentration Committee announced its recommendation not to allow the Partnership to win the competitive process, irrespective of its meeting the terms and conditions of the process. On January 14, 2021 the Partnership delivered a letter to the Petroleum Commissioner, whereby he should disregard the recommendation of the Concentration Committee as it is lacking and inaccurate and disregards material facts. It is noted that, to the best of the Partnership's understanding, on the same day the Petroleum Commissioner delivered a request to the Concentration Committee to hold another consultation on the matter. The Partnership believes that insofar as its offer (together with Noble) is superior to other offers submitted in the process, considering the conditions that were determined therein in advance, then it has the full right to win the License and intends to take any and all legal measures available thereto to defend its rights.

See Section 7.26.10 below for details regarding a legal proceeding in connection with the non-extension of the license.

7.10 **Products**

7.10.1 Natural Gas

The vast majority of the natural gas discovered in the reservoirs held by the Partnership is comprised of methane gas and is therefore defined as "dry", even though upon production and processing, small quantities of non-corrosive liquid separate therefrom. Therefore, the required treatment of the gas for the purpose of supply to customers is relatively minimal.

As a rule, natural gas is transportable in three main ways: (a) through pipelines; (b) through the liquefaction thereof (i.e., the turning thereof into liquid, LNG) by the cooling thereof to a temperature of 161 degrees Celsius below zero, which decreases its volume by a factor of 600 and allows the transportation and storage thereof in large quantities; and (c) through the compression thereof (CNG), which decreases its volume by a factor of 100-300, depending on the compression pressure.

Liquefied gas and compressed gas may be transported in large quantities and great distances through designated tankers.

For details regarding the domestic gas market, including developments and changes therein, see Section 6 above, and for details regarding the natural gas export and sale on the international market, see Section 7.12.2 below.

7.10.2 Condensate

In the course of the process of production and treatment of natural gas, condensate is also produced. Condensate is a hydrocarbon product of condensation of various components of natural gas, which is caused as a result of temperature and pressure differences between the reservoir and the surface. Condensate requires minimal treatment, and mainly stabilization, to enable transportation thereof to the Partnership's customers, and it mainly serves as feedstock in the production of refined oil products. It is noted that the amount of condensate produced relative to the quantity of gas produced from the Partnership's assets is small, and is a few barrels per million square feet of natural gas (MMCF). For details regarding the engagement of the Partnership, together with its partners, in agreements for the supply of condensate from the Tamar Project and the Leviathan project and regarding the examination of alternatives for the transmission and sale of the condensate, see Section 7.11.6 below.

7.11 **Customers**

7.11.1 Domestic Market: As of the report approval date, the Partnership, together with its partners in the Tamar and Leviathan projects, supplies natural gas to the IEC, independent power producers, natural gas marketing companies and industrial customers, as well as condensate from Tamar and Leviathan projects, as specified in Sections 7.11.4(a)3, 7.11.4(a)4 and 7.11.6 below. In addition, the Tamar and Leviathan Partners are continuing to conduct negotiations, at various stages, in order to sign agreements for the supply of natural gas and condensate to the domestic market from the Tamar and Leviathan projects.

7.11.2 Export: As of the report approval date, the Partnership, together with its partners in the Leviathan and Tamar Projects, exports natural gas to Jordan and Egypt, in accordance with the agreements specified in Sections 7.11.4 and 7.11.5 below. In addition, negotiations are being conducted for the export of natural gas to other consumers, as specified in Section 7.11.5 below.

7.11.3 Key customers: The IEC, NEPCO and Dolphinus are the largest customers of the Partnership and therefore, termination of the agreements executed between them and the Tamar Partners and the Leviathan Partners, or the non-fulfillment thereof, will materially affect the Partnership's business and future revenues. The Partnership's revenues from sales of gas to the IEC from the Tamar Project in 2018 and 2019 constituted approx. 50%, and approx. 46% of its total revenues, respectively, and the Partnership's revenues from gas sales to the IEC from the Tamar Project and the Leviathan project in 2020 constituted approx. 32% of its total revenues; the Partnership's revenues from gas sales to Dolphinus from the Leviathan and Tamar projects in 2020 constituted approx. 17% of its total revenues; and its revenues from gas sales to NEPCO from the Leviathan project in 2020 constituted approx. 19% of its total revenues. The Partnership's other revenues in 2020 were from independent power producers, industrial customers in Israel and Jordan and natural gas marketing companies. For details regarding the agreements of the Tamar Partners and the Leviathan Partners with the IEC, NEPCO and Dolphinus, see Sections 7.11.4(a), 7.11.4(a)4 and 7.11.5(a)2 below.

Caution regarding forward-looking information – the Partnership's estimates in relation to the scope of its income from the IEC, NEPCO and Dolphinus in the coming years constitutes forward-looking information within the meaning thereof in Section 32A of the Securities Law, which there is no certainty will materialize, in whole or in part, in the manner specified above or in any other manner, and which may materialize in a materially different manner than that described above, due to various factors including, *inter alia*, changes in the scope, pace and timing of consumption of the natural gas and

condensate by all of the customers of the Tamar and Leviathan projects, including the IEC, NEPCO and Dolphinus, the sale prices of the natural gas and condensate from the Tamar and Leviathan reservoirs, and the date of the decline in the rate of the Partnership's holdings in the Tamar reservoir.

7.11.4 Engagements for the supply of natural gas

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

1. Below are concise details regarding the agreements for the supply of natural gas from the Tamar Project signed by the Partnership, together with the other Tamar Partners, that are valid as of the report approval date. It is noted that other than the IEC and Dalia Power Energies Ltd. ("**Dalia Energies**"), the Tamar Partners do not have any other customer, the revenues from which in 2018-2020 constituted more than 10% of the Partnership's revenues. The remaining customers with whom the Tamar Partners have engaged in gas supply agreements are grouped in the table below according to the price linkage basis determined in such agreements. For further details regarding such agreements, see subsections (2) and (3) below. For details with respect to the Partnership's engagement, together with its partners, in an agreement for the supply of condensate from the Tamar Project, with PAR, see Section 7.11.6(a) below.

	Supply commence-ment year	Basic agreement period[116]	Is there an extension option[117]	Balance of total maximum contract quantity for supply (100%) (BCM)[118]	Quantity supplied until December 31, 2020 (100%) (BCM)	Main linkage basis of the gas price
IEC[119]	2013	15 years	The IEC has the option to extend the agreement period by two more years, insofar as the full total contract gas quantity was not supplied in the base period.	Approx. 54.4	Approx. 32.6	The linkage basis determined in the supply agreement is the U.S. Consumer Price Index (U.S. CPI).
Dalia Energies[120]	2015	17 years	Each of the parties has	Approx. 17	Approx. 6.3	The Electricity Production Tariff which includes a

[116] In most of the agreements, the gas supply period, which commences from the date of the piping with respect to the relevant agreement, will be according to the table presented above, or until the purchaser shall consume the maximum contract quantity set forth in the agreement, whichever is earlier..

[117] In part of the supply agreements in which the purchasers have options to extend the agreement, the agreement defines specific terms and conditions for the exercise of the options by the purchasers..

[118] This quantity is the balance of the maximum gas supply quantity set forth in the agreements for the entire term of the agreements. The minimum quantity which the customers undertook to purchase is lower than such quantity. For details on the order backlog see Section 7.13 below. Said quantity includes quantities that were reduced in practice according to the reduction option, as set forth in Section 7.11.4(a)(3)(c) below.

[119] In the Partnership's estimation, as of December 31, 2020, the balance of the financial scope of the agreement with the IEC is approx.$3,400 million (100%), based on the terms and conditions of the supply agreement with the IEC (including the settlement agreement of January 30, 2021, as described in Section 7.11.4(a)6C below) and the Partnership's estimates with respect to the minimal gas quantities and the price of the gas to be purchased by the IEC.

	Supply commence-ment year	Basic agreement period[116]	Is there an extension option[117]	Balance of total maximum contract quantity for supply (100%) (BCM) [118]	Quantity supplied until December 31, 2020 (100%) (BCM)	Main linkage basis of the gas price
			the option to extend the agreement period by two more years, insofar as the total contract gas quantity was not supplied in the base period.			floor price.[121]
Other independent power producers	2013-2020	15-18 years other than one agreement for a period of eight years and two agreements for shorter periods.	In most of the agreements, both parties are afforded the possibility to extend them, for a period of between one to three more years, insofar as the total contract gas quantity was not consumed in the base period.	Approx. 20.2	Approx. 19.2	Most of the agreements include a linkage formula to the Electricity Production Tariff which includes a floor price.
Industrial customers and natural gas marketing companies	2013-2020	2-7 years	In part of the agreements both parties are afforded the option to extend by an additional period, insofar as the total contract gas quantity was not consumed in the base period.	Approx. 1.6	Approx. 6.9	Most of the agreements determine a fixed price without linkage.
APC and JBC export agreements (described in Section 7.11.5(a)1 below)	2017-2018	13-15 years	Both parties are afforded the option to extend by two more years, insofar as the contract gas quantity was not consumed in the base period.	Approx. 2.3	Approx. 0.65	A linkage formula that is based on the Brent prices and includes a “floor price”.

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[120] In the Partnership’s estimation, as of December 31, 2020, the balance of the financial scope of the agreement with Dalia Energies will be approx. $850 million (100%), based on the terms and conditions of the supply agreement and the Partnership’s estimations regarding the minimal gas quantities and the price of the gas that shall be purchased by the purchaser.

[121] The linkage to the Electricity Production Tariff in the contracts for supply to power producers is in accordance with the terms of the alternative set forth in the Gas Framework that includes a floor price. For details see Section 7.23.2(b)3 below.

	Supply commence-ment year	Basic agreement period[116]	Is there an extension option[117]	Balance of total maximum contract quantity for supply (100%) (BCM)[118]	Quantity supplied until December 31, 2020 (100%) (BCM)	Main linkage basis of the gas price
Dolphinus export agreement (described in Section 7.11.5(a)2 below)	2020	Approx. 15 years	In the event that the purchaser does not buy the total contract quantity in the base period, the supply period will be extended by two more years.	Approx. 25	Approx. 0.25	A linkage formula that is based on the Brent prices and includes a “floor price”.
Total				**Approx. 120.6**	**Approx. 65.9**	

2. <u>The table below presents a breakdown of the Partnership's revenues from the Tamar Reservoir in 2018, 2019 and 2020 in accordance with the price linkage basis determined therein[122]</u>:

	2018		**2019**		**2020**	
Name of customer	**Total revenues ($ in millions)**	**In % of the total revenues**	**Total revenues ($ in millions)**	**In % of the total revenues**	**Total revenues ($ in millions)**	**In % of the total revenues**
IEC (U.S. CPI)	Approx. 256.8	Approx. 50	Approx. 209.3	Approx. 46	Approx. 113.7	Approx. 34
Independent Power Producers						
Dalia Energies	Approx. 52.4	Approx. 10	Approx. 44.9	Approx. 10	Approx. 40.3	Approx. 12
Others	Approx. 157.8	Approx. 30	Approx. 143.9	Approx. 32	Approx. 121.2	Approx. 37
Industrial customers and marketing companies						
	Approx. 49.5	Approx. 10	Approx. 55.2	Approx. 12	Approx. 56.8	Approx. 17

3. <u>Further details regarding all of the agreements for the sale of natural gas to the domestic market that have been signed by the Tamar Partners</u>

   a. Most of the gas supply agreements determine, *inter alia*, the purchasers' undertaking, insofar as the gas supply under the agreement is on a firm basis, to take or pay for a minimum annual quantity of natural gas at the scope and according to the mechanism determined in the supply agreement (the "**Minimum Quantity**"). In the event that such purchasers do not buy the Minimum Quantity in any year, they will be obligated to pay the sellers for the difference between the Minimum Quantity that was defined and the quantity actually purchased by the purchasers. Note that in most of the agreements that include a Minimum Quantity undertaking as aforesaid, provisions and mechanisms were determined allowing the purchasers, after paying for non-consumed gas due to the activation of the mechanism of the minimum billable quantity, to receive gas for no additional payment, up to the balance of the gas quantity that was not consumed in previous years and for which they paid the sellers in the framework of their commitment to a minimum billable quantity, as aforesaid (make up).

[122] The revenues in the table reflect the Partnership's holding in the Tamar Project at the rate of approx. 25.7% until December 31, 2018; and at the rate of 22% from January 1, 2019.

b. Most of the supply agreements further determine a mechanism for accrual of a balance in respect of surplus quantities consumed by the purchasers in any given year and application thereof to reduce the purchasers' obligation to purchase the Minimum Quantity as aforesaid, in several subsequent years ("**Carry Forward**").

c. Following the decisions of the Competition Commissioner stated in Section 7.23.2(b) below regarding the granting of an exemption from a restrictive arrangement in connection with agreements in which the basic supply period is longer than 7 years, except for the agreement with the IEC (the "**Long-Term Agreements**"), in some of the agreements that were signed with customers, the purchasers were given an option to reduce the Minimum Quantity, so that it will be approx. 50% of the average annual quantity consumed thereby in the three years preceding the notice regarding exercise of the option, subject to adjustments as specified in the supply agreement (in this section: the "**Reduction Option**"). Upon the reduction of the Minimum Quantity, the other quantities specified in the supply agreement will be reduced accordingly. For details regarding the said decisions of the Competition Commissioner, see Section 7.23.2(b)3 below.

   In this context it is noted that in 2019-2020, the Tamar Partners signed amendments to agreements with several independent power producers, including Dalia Energies, in which such producers undertook to purchase from the Tamar Project, the natural gas that shall be consumed in their facilities in the period commencing from the date of flow of gas from the Leviathan reservoir until such time as such producers exercise the Reduction Option (in this section: the "**Period**"), if exercised. In addition, in the context of such amendments, the parties agreed that for the purpose of calculation of the average quantity consumed by such producers under the said agreements in the three years preceding the notice of exercise of the Option relative to the Period, the calculation shall be made based on the Minimum Quantity (in accordance with the mechanism set forth in the amendments to the agreements as aforesaid), and not based on the quantity they will actually consume. All of the amendments to the agreements have taken effect, including the amendment to the agreement with Dalia Energies.

d. Note that in 2020, several customers gave notices of exercise of the aforesaid Reduction Option, including various independent power producers. These notices are expected to take effect on various dates during 2021-2022.

e. In accordance with the terms and conditions of the Gas Framework, in the agreements for the supply of natural gas signed commencing from August 16, 2015 for a period exceeding 8 years, the consumer received a one-sided right to shorten the term of the agreement. Such right was also granted in agreements signed up to December 13, 2020 for a period exceeding 8 years. For details, see Section 7.23.1(b)3.b below. Note that in 2020, two customers gave a notice of exercise of the early termination option and they have ended on March 1, 2021.

f. The supply of all of the quantities specified in the supply agreements executed prior to October 2012, utilizes, at points of peak consumption, the full capacity of the production, processing and transmission system of the Tamar Project (collectively in this section: the "**Production System**") and therefore, in the agreements for sale of natural gas executed from the beginning of October 2012, an interim period was determined which began during May 2015 and will end when the capacity of the Production System will allow to supply to them the quantities specified in the supply agreements (in this section: the "**Interim Period**"). According to said agreements, the gas supply in the Interim Period was subject, *inter alia*, to the gas quantities that are available at such time, after the supply of gas to customers who have executed supply agreements before October 2012 according to mechanisms determined in each respective supply agreement. In all of said agreements the undertaking to purchase a minimum gas quantity will not apply in the Interim Period.

   In November 2016, the Tamar Partners notified most of the customers with which agreements for the sale of natural gas were signed from October 2012 as aforesaid (according to the order of precedence of signing of the agreements), including independent power producers, including Dorad Energy Ltd. and OPC Rotem Ltd. ("**OPC**"), natural gas marketing companies and industrial customers, that on September 30, 2020, the Interim Period shall end, and accordingly, from such date, the Tamar Partners will supply to such customers natural gas under agreements on a firm basis. Further thereto, on January 22, 2020, the Tamar Partners notified the said customers that the date of conclusion of the Interim Period (i.e. September 30, 2020) had been brought forward to March 1, 2020, and accordingly, from this date, the Tamar Partners began to supply such customers with natural gas on a firm basis. Note further that in 2020, similar notices were delivered to additional customers and with respect thereto the Interim Period expired on different dates, starting from August 2020 until January 2021.

g. The supply agreements specified further provisions, *inter alia*, on the following issues: right for termination of the agreement in case of breach of a material undertaking, right of the Tamar Partners to supply gas to the said purchasers from other natural gas sources, compensation mechanisms in case of a delay in the gas supply from the Tamar Project or in case of non-supply of the quantities specified 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 upon the occurrence of a *force majeure* event (as defined in the agreements), mechanisms for resolving disputes and disagreements between the parties, and in respect of the relations between the sellers themselves, in all matters related to the gas supply to the said purchasers.

h. In 2020, pursuant to the outbreak of the Covid-19 Crisis, several customers gave notices of occurrence of *force majeure* events but later, when it transpired that the crisis did not have a material effect on their ability to fulfill the minimal purchase commitments, no further arguments were raised in such context.

i. The agreements are subject to the laws of the State of Israel and are interpreted in view thereof.

4. <u>Further details regarding a gas supply agreement between the Tamar Partners and the IEC</u>

a. A gas supply agreement between the Tamar Partners and the IEC was signed on March 14, 2012 and was amended on July 22, 2012, May 7, 2015 and September 1, 2016, *inter alia*, in connection with the exercise of options that were conferred on the IEC for increasing the gas quantities that it will consume (the “**IEC-Tamar Agreement**” or, in this section: the “**Agreement**”).

b. The term of the IEC-Tamar Agreement will continue until the supply of the total contract quantity set forth in the Agreement or until July 1, 2028, whichever is earlier, unless the Agreement is terminated prior thereto by one of the parties in accordance with the terms and conditions of the Agreement, or the Agreement is extended in accordance with the terms and conditions thereof.

c. The total contract quantity determined in the IEC-Tamar Agreement (as amended) is approx. 87 BCM and the minimum billable quantity, from January 1, 2019 until the end of the term of the Agreement, shall be approx. 3 BCM per annum. The Agreement contains provisions regarding the calculation and adjustment of the minimum billable quantity including under circumstances of *force majeure* or non-supply by the sellers. A mechanism was also determined for accrual of a balance in respect of surplus quantities consumed by the purchasers in any given year and application thereof to reduce the purchasers' obligation to purchase the Minimum Quantity as aforesaid, in several subsequent years ("**Carry Forward**"). Accordingly, the IEC may reduce the purchased quantity while using the mechanism as aforesaid, up to a level of 1.75 BCM per year (such that the maximum usable quantity in a calendar year is 1.25 BCM).

   The quantity accrued to the credit of the IEC in the context of the Carry Forward mechanism as of December 31, 2020 is approx. 1.85 BCM (for 100% of the reservoir).

d. The gas price is determined according to a formula which includes a base price and a linkage mechanism which is based on the U.S. CPI, with respect to some of the quantities, and subject to specific adjustments.

e. The Agreement stipulated two dates on which each party may request the adjustment of the price (according to a mechanism stipulated in the Agreement), if such party believes that the price stipulated in the Agreement is not suitable anymore for a long-term contract with an anchor buyer for consumption of natural gas for use in the Israeli market: upon the lapse of 8 years and 11 years from the commercial operation date (as defined in the Agreement commencing on July 1, 2013) of the Tamar Project (i.e.: July 1, 2021 and July 1, 2024), whichever is earlier. On the first adjustment date (July 1, 2021) (the "**First Adjustment Date**"), the adjustment which will be carried out to the price will be at a range of up to 25% (addition or reduction), and on the second adjustment date (July 1, 2024), the adjustment which will be carried out to the price will be at a range of up to 10% (addition or reduction) of the price on such date.[123] If the Tamar Partners and the IEC fail to reach an agreement on the rate of the price adjustment, either party may refer the matter to arbitration. In the context of the discounted cash flow which is included in the Tamar resource report the Partnership assumed that on the First Adjustment Date the price of the gas will be reduced by 25%, and that on the second adjustment date the price of the gas will be reduced by 10%.

f. In the event that one of the parties to the Agreement fails to timely make a payment that is required thereof according to the Agreement, the delinquent amount shall accrue interest at an annual rate equal to LIBOR interest plus 5%, from the payment due date according to the Agreement until the date of actual payment. If the delinquency lasts 7 days or more, the party entitled to the payment may, by giving prior written notice of 14 days, suspend provision or receipt of the gas, as the case may be. If the delinquency lasts 120 days from the relevant payment due date, the party entitled to the payment may, by giving prior written notice of 14 days, terminate the Agreement. Exercising the right to terminate the Agreement shall not constitute a waiver of other remedies that are available to such party.

g. The IEC-Tamar Agreement stipulates, *inter alia*, provisions whereby the IEC or the Tamar Partners will be entitled to terminate the Agreement, in the event that the other party will perform an insolvency act (as defined in the Agreement) which is likely to have a material adverse effect on the performance of the undertakings thereof according to the Agreement, by providing an advance written notice of at least 120 days. If, due to an event of *force majeure*, the Tamar Partners or the IEC are unable to perform any material undertaking that is required according to the Agreement, and their inability to perform such undertaking lasts for a period of three consecutive years, the other party may terminate the Agreement by giving prior written notice of at least 90 days. The IEC and the Tamar Partners agreed not to exercise any right which they might have to terminate the Agreement according to any law, other than with respect to significant or continuous violations of material provisions of the Agreement and only after provision of a 120-day period to the party in breach (unless a shorter period had been stipulated in the Agreement) for remedying the breach.

[123] In this regard, see the Partnership's assumptions in the discounted cash flow figures for the Tamar Lease in Section 7.3.11(a)3 above.

h. According to the Agreement, if the Tamar Partners fail to supply the gas quantities ordered by the IEC according to the provisions of the Agreement, and the quantity not supplied exceeds the deviation rates permitted by the Agreement, the Tamar Partners shall compensate the IEC by way of supplying gas in the subsequent month in the quantity not supplied, for a reduced price. Also, the Agreement sets forth special violations in respect of which compensation at higher rates will be paid. Limitation of the liability of each of the parties was stipulated in the Agreement in respect of breach of some of the provisions of the Agreement at the rates specified in the Agreement, both on an annual basis and throughout the term of the Agreement. The IEC is not liable vis-à-vis the Tamar Partners and the Tamar Partners are not liable vis-à-vis the IEC for indirect, consequential or punitive losses or damage. The Tamar Partners will be liable, severally and not jointly, for such breaches of the Agreement.

i. The Agreement determines that no provision in the Agreement will be construed as creating mutual liability among the Tamar Partners and each of the Tamar Partners will be responsible towards the IEC only in respect to their share in the petroleum interests in respect to liability which will arise from the Agreement. Even though the IEC may nominate gas quantities through one notice which will be issued to the coordinator on behalf of the Tamar Partners, the quantity which will be deemed as ordered from each of the Tamar Partners will be the share of each of the Tamar Partners out of the overall ordered quantity.

j. The gas supply and the Tamar Partners' commitment to provide available gas according to the Agreement is on an hourly basis with a maximum quantity per hour, according to the mechanisms and procedures specified in the Agreement. The delivery of the gas is done at the connection point to the INGL national transmission system, adjacent to the Terminal or at any other connection point which will be agreed upon between the parties. The natural gas which is supplied at the delivery point according to the Agreement is required to comply with certain requirement specifications stipulated in the Agreement. The IEC has the right to refuse to accept non-standard gas until the flaw is corrected. Any dispute between the parties pertaining to the gas quality will be referred (upon the request of any party) to an expert for decision.

k. The assignment of the IEC's obligations and rights under the Agreement, is contingent upon the transferee having a technical and financial ability to meet its undertakings under the Agreement and the transferee also being transferred such proportionate share of IEC's power plants (namely, if a proportionate share of the rights and obligations are transferred to a certain transferee, it will also receive a proportionate share of IEC's power plants).

l. The IEC or the Tamar Partners, as the case may be, shall be released from liability under the Agreement, in the event that their non-compliance with an undertaking according to the Agreement (including an undertaking of making reasonable efforts) derived from an event of *force majeure*, and only in the event that performance of such undertaking was prevented, thwarted or delayed due to the event of *force majeure*. The term '*force majeure*' is defined in the Agreement and mainly includes any event or circumstances that are not within the control of the IEC or the Tamar Partners (who acted and are acting reasonably and cautiously), which caused the non-performance or inability of the IEC or the Tamar Partners to perform one or more of their undertakings (including an undertaking of making reasonable efforts) according to the Agreement.

m. The Agreement with the IEC shall be governed by, and construed under, the laws of the State of Israel. Any dispute or claim that pertains to the Agreement will be resolved by a decision of an expert on specific issues that were determined in the Agreement (mainly of a professional technical nature) or in an arbitration proceeding in accordance with the procedures set forth in the Agreement.

n. Disputes pertaining to matters in which the amount in dispute is lower than the agreed threshold set forth in the Agreement, will be discussed before a sole arbitrator, in accordance with the arbitration rules of the Israeli Institute of Commercial Arbitration, and the arbitration venue will be in Tel Aviv. Any dispute in amounts above the said threshold but within an agreed range that is determined in the Agreement will be discussed before a panel of three arbitrators, and the arbitration will be carried out in accordance with the rules of the London Court of International Arbitration, and the venue of the arbitration will be in Tel Aviv. Disputes pertaining to matters whose amount exceeds the said range that is determined in the Agreement will be discussed before a panel of three arbitrators, and the arbitration will be carried out in accordance with the rules of the London Court of International Arbitration, and the venue of the arbitration will be in London.

5. A Competitive Process by the IEC for short-term supply of natural gas

   On December 2, 2018, the IEC delivered an RFP to the Tamar Partners and the Leviathan Partners for the supply of natural gas at an estimated annual quantity of up to 2 BCM, to be supplied from the later of October 1, 2019 or the date of commencement of production of gas from the Leviathan reservoir, until the earlier of June 30, 2021 or the date of commencement of production of gas from the Karish reservoir (in this section and in Section 6 below: the "**Supply Period**" and the "**Competitive Process**", as the case may be). On March 7, 2019, the Tamar and Leviathan Partners submitted proposals in the Competitive Process, and on April 4, 2019, the IEC notified the Leviathan Partners that their proposal had been selected as the winner of the Competitive Process. On June 12, 2019, the IEC and the Leviathan Partners signed the agreement for the supply of natural gas which is described in Section 7.11.4(b)2 below (the "**IEC- Leviathan Agreement**").

   Following the Leviathan Partners' winning of the Competitive Process, the Tamar Partners who are not holders of the Leviathan reservoir (i.e., Isramco, Tamar Petroleum, Dor and Everest, hereinafter jointly: the "**Other Tamar Partners**"), filed an administrative petition with the Tel Aviv District Court against the IEC and the Leviathan Partners, which was denied on July 7, 2019. Further thereto, the Other Tamar Partners filed an appeal with the Supreme Court, which was also denied on August 24, 2020. For further details see Section 7.26.7 below.

6. Annulment of the right of veto on marketing decisions; Balancing agreement for separate marketing of the gas produced from the Tamar reservoir, and a settlement agreement between the Tamar partners and the IEC

   a. Against the backdrop of the Competitive Process held by the IEC as detailed above, a dispute arose in 2019 between the Other Tamar Partners and between the Partnership and Noble, *inter alia* regarding the Other Tamar Partners' right to enter into an amendment to the IEC-Tamar Agreement with the IEC, without the consent of the Partnership and Noble.

      Following the aforesaid, the Other Tamar Partners applied on November 20, 2019 to the Competition Commissioner, asking, *inter alia*, that she clarify that the Partnership and Noble may not exercise a veto right (jointly or severally) to prevent joint marketing of their share in the gas from the Tamar Lease to a new customer, or amendment to an agreement for gas from the

Tamar Lease to an existing customer, to which the Partnership and Noble are a party, including the amendment proposed by them to the IEC-Tamar Agreement, on the terms and conditions agreed by the Other Tamar Partners, without the involvement of the Partnership and Noble.

On April 13, 2020, an announcement was released by 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 whereby, inter alia, the Tamar Partners had been given a short period of time to modify the arrangements between them so as to ensure that the Partnership, Noble and Isramco do not hold a veto right over decisions on the marketing of natural gas from the Tamar reservoir.

Further thereto, on September 6, 2020, a notice was received from the Competition Authority whereby, *inter alia*, the Partnership's holding of the right and power to prevent the other holders of the Tamar reservoir from making decisions or taking actions for the marketing of gas from the Tamar reservoir contrary to the terms and conditions of the exemption decision, is a violation of the provisions of Section 4 of the Economic Competition Law, 5748-1988, and therefore the Partnership is required to act within one month to nullify the veto right held thereby. Until the date of nullification of the veto right, the Partnership may hold its rights as being until to date and make new contracts, although in the conduct of negotiations for contracts in the said period, the Partnership shall not exercise its veto right alone. To the best of the Partnership's knowledge, a similar notice was also received by Isramco. The opinion of the Deputy Attorney General (economic law)[124] was also released regarding Noble's veto right in the Tamar reservoir, according to which each one of the holders of the Tamar reservoir holds a veto right, including Noble, which is entitled to hold such veto right until the date of the sale of holdings in the Tamar reservoir to a third party that is not affiliated 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 object alone to decisions or acts

[124] 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

regarding the marketing of natural gas to be produced from Tamar. The Partnership, in its own independent decision, will be able to join, ad hoc, a consent or refusal of one of the partners with respect to a decision or act in the Tamar Project, provided that such joining is not made under a framework agreement, agreed collaboration or for consideration. It is further clarified that the Partnership will not be able to join a demand of a Tamar partner to receive a price which is higher 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 post factum) for its consent to a decision or act for gas marketing, whether the demand is made thereby or made by another. Even if there is a decision, in the context of which a partner receives compensation, the Partnership will neither be able to demand such compensation, nor condition its consent to an act or decision by demanding such compensation.

Furthermore, according to reports by the Other Tamar Partners, on October 1, 2020 the Other Tamar Partners signed a cooperation agreement with respect to the marketing and sale of gas from the Tamar Project which, *inter alia*, nullifies Isramco's veto right in decisions on marketing and sale of gas in the Tamar reservoir.

On October 4, 2020, the Other Tamar Partners notified the Partnership and Noble that they had signed an agreement (the "**Agreement in Dispute**") which, according to their position, is a supplement to the IEC-Tamar Agreement, amending the price of natural gas quantities to be supplied to the IEC, if any, above the minimum billable quantity under the IEC-Tamar Agreement. The Other Tamar Partners informed the Partnership and Noble that they could join the Agreement in Dispute within 60 days from the date of signing thereof, and that insofar as the Partnership and/or Noble choose not to join the Agreement in Dispute, the Other Tamar Partners will supply the IEC with the quantities they undertook to supply thereunder, out of their share in the reserves of the Tamar Reservoir. The Partnership joined Noble’s position, and together they informed the Other Tamar Partners that they would not join the Agreement in Dispute which, according to the Partnership's position based on its legal advisors, is not a supplement to or part of the IEC-Tamar Agreement, as the Other Tamar Partners claim, but rather a new agreement which breaches the IEC-Leviathan Agreement signed following the Competitive Process held by the IEC. For further details see the Partnership's immediate reports of October 5, 2020 and

October 14, 2020 (Ref. nos. 2020-01-108018 and 2020-01-111918, respectively).

Following the aforesaid, the Other Tamar Partners and the IEC approached the Competition Commissioner with claims regarding Noble's refusal to supply natural gas from the Tamar reservoir to the IEC according to the Agreement in Dispute, and sought her intervention.

b. Concurrently with the aforesaid, the Tamar Partners held negotiations, and on January 30, 2021 reached an agreement and signed an MOU aimed at allowing each partner in the Tamar Reservoir to market gas separately, not jointly with the other partners in the Tamar reservoir, and to allow each partner to market gas over and above its relative share in the output, subject to the existence of available production capacity on a daily basis, and insofar as another partner has not marketed its share of the gas on that day. In such a case, balancing arrangements shall apply, in order to balance the partners' rights relative to the gas sold as needed, according to the partners' relative share in the reservoir. In addition, principles were determined regarding the right of a partner to join agreements for the sale of gas entered into by another partner in the reservoir, to enable the Tamar Partners to market their share in the gas in the Tamar reservoir if marketing is done other than by all of the partners in the reservoir, without derogating from the possibility for joint marketing of gas from the reservoir, subject to regulatory decisions (in this section: the "**MOU on Separate Marketing**").

The MOU on Separate Marketing determines, *inter alia*, that the Tamar Partners shall negotiate in order to reach a detailed and binding agreement based on the MOU on Separate Marketing by February 17, 2021 (in this section: the "Detailed Agreement" and the "Effective Date", as applicable).

The Tamar Partners have submitted the MOU for approval by the Competition Authority.

In addition, further to the information provided above and in the Partnership's immediate reports of January 31, 2021 and February 18, 2021 (Ref. nos. 2021-01-012016 and 2021-01-020533, respectively), on February 23, 2021, the Tamar Partners signed the Detailed Agreement, on the basis of the MOU on Separate Marketing, as aforesaid, the purpose of which is to determine the detailed mechanisms and rules in connection with the taking of the share of any one of the Tamar

Partners in the gas output in accordance with the Joint Operating Agreement,[125] and balancing arrangements that shall apply between the partners in the event that the marketing of the gas is not performed according to the proportionate share of the partners in the output as aforesaid (the "**Balancing Agreement**" or the "**Agreement**"). Below are the main principles of the Agreement:

Each one of the partners will be entitled to join a contract for the supply of gas from the Tamar reservoir ("**Supply Contract**") that shall be signed by another partner, as a full party, according to its proportionate share in the reservoir and the mechanisms and terms and conditions determined in the Agreement (the "**Tag Along Right**"). With respect to a supply contract for export, the Tag Along Right is subject to arrangements that shall be agreed between the partners on a specific basis in relation to each supply contract for export.

The Balancing 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 ("**Oversupply Partner**"), after each one of the other partners has first been afforded the possibility of nominating its full proportionate share in the output, and a certain partner shall not have marketed its full share in the daily output ("**Undersupply Partner**"). In such a case, balancing arrangements shall 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 (i.e.: through a payment to be made by an Oversupply Partner to an Undersupply Partner) or in gas (i.e.: 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 determined mandatory monetary balancing arrangements in each one of the following cases: (1) when excess gas quantities have accrued in favor of an Undersupply Partner in a volume exceeding a cap determined in the Agreement; (2) on the date on which the operator shall have determined that 60 BCM of proven gas reserves remain in the reservoir; (3) on the date on which

[125] The Joint Operating Agreement (JOA) of November 16, 1999 (as amended from time to time). For further details see Section 7.25.7 below.

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 forth in the Agreement.

The operator will be responsible, *inter alia*, for implementing the provisions of the Agreement and managing the nominations thereunder, as well as for supplying the gas at the delivery point in accordance with its instructions. 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 JOA.

In the case of a discrepancy between the Agreement and the JOA, the provisions of the Agreement shall prevail.

Each party to the Balancing Agreement will bear the payment of the taxes, the statutory royalties, the levies and the statutory payments that apply in respect of 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.

The taking effect of the Balancing Agreement is subject to the approval of the Competition Authority.[126] In the event that such approval is not received by May 31, 2021, the Balancing Agreement will be terminated by the giving of prior notice of 30 days by any of the parties thereto (unless the said approval is received prior to conclusion of the Agreement). The Agreement will be in effect until the conclusion of the JOA.

Insofar as any of the partners shall seek to transfer its interests in the Tamar Lease to another/others, the said interests shall be transferred together with the rights and undertakings of the partner under the Balancing Agreement.

The law that governs the Balancing Agreement is the law of England and Wales. Any dispute between the parties that is not resolved in accordance with the mechanism set forth in the

[126] Insofar as required.

Agreement shall 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 which pertain, *inter alia*, to the available output, the allocation of nominations and the date stated above, or a determination of any party to the Agreement regarding the relevant prices for the performance of monetary balancing, may refer the issue to be decided by an expert who shall 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. Insofar as the expert does not decide the dispute, the dispute will be referred to arbitration as aforesaid.

Implementation of the provisions of the Agreement requires the establishment of various systems and the adoption of procedures as well as receipt of approvals and clarifications from the tax authorities and various 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).

c. Concurrently, on January 30, 2021 the Tamar Partners and the IEC signed a settlement agreement with regard to the disagreements which erupted with respect to the Agreement in Dispute (in this section: the "**Tamar Settlement Agreement**"). The Tamar Settlement Agreement provides, *inter alia*, that: (1) The Agreement in Dispute shall be terminated, and shall be null and void; (2) Until June 30, 2021 the IEC shall be able to buy from the Tamar reservoir a quantity of 1.25 BCM, for a price lower than the IEC-Tamar Agreement, varying according to the purchased quantity, including a quantity of approx. 0.81 BCM supplied in 2020 and, in certain conditions, additional quantities insofar as such quantities are not supplied by the Leviathan Partners under the IEC-Leviathan Agreement; (3) Gas quantities supplied and to be supplied at such reduced price, shall not be taken into account for calculation of the Take-or-Pay and the Carry Forward in 2020 and 2021.

The Tamar Settlement Agreement further determines that the maximum daily contract quantity which the Tamar Partners will be required to supply to the IEC under the IEC-Tamar Agreement in H1/2021 shall be limited to 500,000 MMBTU (compared with 655,000 MMBTU).

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

The Tamar Settlement Agreement is subject to the fulfillment of conditions precedent and regulatory approvals, including, *inter alia*, the approval of the Competition Authority, and the approval of the Competition Court for an agreed order under Section 50B of the Economic Competition Law, 5748-1988, whereby the Competition Commissioner shall not continue her processing and shall take no enforcement measures against Noble for the complaints filed against it in connection with the Supplement. Insofar as such conditions precedent are not fulfilled within 30 days of the date of signing of the Settlement Agreement, and with respect to the approval of the Competition Court – 60 days, each party shall have the right to terminate the agreement. For further details on the said agreed order, see Section 7.23.2(b)4 below. As of the report approval date, not all of the aforesaid conditions precedent have yet been fulfilled.

d. Concurrently with the signing of the Tamar Settlement Agreement, the Leviathan Partners also signed a settlement agreement with the IEC, as described in Section 7.11.4(b)2 below.

Caution regarding forward-looking information – the aforesaid evaluations regarding the overall financial scopes of the supply agreements specified above, the natural gas quantities which will be purchased by the purchasers specified above, the commencement of the supply dates according to the supply agreements and the accumulative revenues from the sale of natural gas to the IEC according to the settlement agreements as aforesaid, constitute forward-looking information within the meaning thereof in Section 32A of the Securities Law, in respect of which there is no certainty it will materialize, in whole or in part, and which might materialize in a materially different manner, due to different factors including due to the non-fulfillment of the conditions precedent in each of the supply agreements (to the extent such have not been fulfilled yet), non-obtainment of regulatory approvals, changes in scope, rate and timing of the natural gas consumption by each of the said purchasers, the gas prices which will be determined according to the formulas stipulated in the supply agreements, the Electricity Production Tariff, the Dollar-Shekel exchange rate (to the extent relevant to the supply agreement), the Brent prices (to the extent relevant to the supply agreement), the U.S. CPI (to the extent relevant to the supply agreement), performance and completion of the expansion

of capacity of the Tamar Project (to the extent relevant to the supply agreement), construction and operation of the power stations and/or other facilities of the purchasers (to the extent relevant to the supply agreement), exercise of the options granted in each of the supply agreements and the date of exercise thereof, changes in the scope and timing of the consumption of natural gas by the IEC, *inter alia*, as a result of the capacity and production limitations of the Tamar and Leviathan reservoirs, and/or as a result of changes in demands in the natural gas market and/or non-fulfillment **of the closing conditions or other factors which are unforeseeable at that time and/or other factors that the Partnership has no control of, etc.**

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

Below are concise details regarding the agreements for the supply of natural gas from the Leviathan project signed by the Partnership, together with the other Leviathan Partners, that are valid as of the report approval date. For details regarding the Partnership's engagement, together with its partners, in agreements for the supply of condensate, see Section 7.11.6(a) below.

	Supply commencement year	**Agreement period**[127]	**Total maximum contract quantity for supply (100%) (BCM)** [128]	**Quantity supplied until December 31, 2020 (100%) (BCM)**[129]	**Main linkage basis of the gas price**
IEC[130]	2020	Until June 30, 2021.	Approx. 3.6[131]	Approx. 2.4	Fixed non-linked gas price.
Independent power producers	2020, or the date of commencement of the commercial operation of the purchasers' power plant (whichever is later).	Some of the agreements are for a short period of up to approximately two and a half years, and the rest are for a longer term of 14 to 20 years. About half of the agreements do not grant the parties an option for extension. In most of the remaining agreements each party is granted with an option for the extension of the agreement in the event that the total quantity is	Approx. 38.3	Approx. 0.7	In most of the agreements the linkage formula of the gas price is based on the Electricity Production Tariff and includes a "floor price". Several short-term agreements determine a fixed price without linkage.

[127] In most of the agreements, the gas supply period may end on the date when the maximum contract quantity set forth in the agreement was supplied to the customers.

[128] This quantity is the maximum quantity which the Leviathan Partners have undertaken to supply to the customers throughout the term of the agreements. The quantity which the customers undertook to purchase is lower than this quantity (for details regarding the order backlog, see Section 7.13 below). It is noted that there are agreements in which a mechanism is determined whereby the purchaser will be entitled to increase/reduce the purchased quantities (including the total maximum quantity) until the date set forth in the agreement, according to its needs and the provisions determined in the agreement. It is noted that several agreements do not state a maximum supply quantity.

[129] Due to the fact that this is the first year of operation of the Leviathan project, the quantities in 2020 include an accounting for the date of commencement of commercial supply.

[130] For details regarding the agreement with the IEC, see Section 7.11.4(b)2 below.

[131] The original supply agreement that was signed with the IEC did not stipulate the total maximum contract quantity for supply. The figure stated above is equal to the quantity of gas supplied according to the contract until December 31, 2020 (approx. 2.4 BCM) plus an additional quantity of 1.2 BCM which the IEC undertook to nominate from the Leviathan Partners during H1/2021 (subject to certain adjustments) according to the settlement agreement in Leviathan described in Section 7.11.4(b)2.

		not purchased.			
Industrial customers	2020	Some of the agreements are for a period of 5 to 15 years, and the rest are for a shorter period of up to approximately two years. In most of the agreements the parties are not granted with an option to extend the agreement period.	Approx. 3.8	Approx. 0.4	The linkage formula in most of the agreements is based in part on linkage to the Brent prices and in part to the Electricity Production Tariff, and includes a "floor price". There is partial linkage also to the refining margin index and to the general TAOZ index published by the Electricity Authority.
NEPCO export agreement (described in Section 7.11.5(b)1 below)	2020	15 years. The agreement stipulates that in the event that the purchaser does not buy the total contract quantity during the base period, the basic supply period will be extended by another two years.	Approx. 45	Approx. 1.9	The linkage formula is based on linkage to the Brent prices and includes a "floor price".
Dolphinus export agreement (described in Section 7.11.5(b)2 below)	2020	15 years. The agreement stipulates that in the event that the purchaser does not buy the total contract quantity, the period of the supply will be extended by another two years.	Approx. 60	Approx. 1.9	The linkage formula is based on linkage to the Brent prices, and includes a "floor price". The agreement includes a mechanism for updating the price by up to 10% (up or down) after the fifth year and after the tenth year of the agreement, upon fulfillment of certain conditions determined in the agreement.
Total			**Approx. 151**	**Approx. 7.25**	

The table below presents a breakdown of the Partnership's revenues from the Leviathan reservoir in 2020 in accordance with the price linkage basis determined therein:

Name of customer	Total revenues ($ in millions)	In % of total revenues
IEC	Approx. 183.3	Approx. 31
Independent power producers		
Others	Approx. 48.5	Approx. 8
Industrial customers and marketing companies		
Others	Approx. 32	Approx. 5
Export of natural gas		
NEPCO	Approx. 178.8	Approx. 30
Dolphinus	Approx. 144.5	Approx. 25

1. Further details regarding the agreements for the sale of natural gas to independent power producers and industrial customers in the domestic market which were signed by the Leviathan Partners

   a. In most of the agreements for the sale of natural gas to independent power producers and industrial customers (in this section: the "**Agreements**"), the customers undertook to take or pay for a minimal annual amount of natural gas at the scope and according to the mechanism determined in the supply agreement (the "**Minimum Quantity**"). It is noted that in the said Agreements, provisions and mechanisms were determined allowing each of the said purchasers, after paying for gas it did not consume under the Agreement, due to the operation of the Take-or-Pay mechanism as aforesaid, to receive gas for no additional payment up to the quantity that it paid for in respect of gas which it did not consume. The supply agreements further determine a mechanism for accrual of a balance in respect of surplus quantities consumed by the purchasers in any given year and application thereof to reduce the purchasers' obligation to purchase the Minimum Quantity as aforesaid, in several subsequent years – Carry Forward.

   b. In accordance with the Gas Framework, each of the purchasers in the Agreements signed by June 13, 2017 and for a period exceeding 8 years, was given an option to reduce the Minimum Quantity to a quantity equal to 50% of the average annual quantity that it actually consumed in the three years preceding the date of the notice of exercise of the option, subject to adjustments as determined in the supply agreement (in this section: the "**Option**"). Upon reduction of the Minimum Quantity, the other quantities determined in the supply agreement will be reduced accordingly. Each of the said purchasers will be entitled to exercise the said Option by notice to be given to the sellers during a 3-year period commencing 5 years after the date of commencement of the piping of the gas from the Leviathan project to the purchaser or 4 years after the date on which the Petroleum Commissioner approves the transfer of the rights in the Karish and Tanin leases in accordance with the Gas Framework (i.e. December 13, 2020) (whichever is later). If the purchaser gives notice of exercise of the Option as aforesaid, the quantity shall be reduced 12 months after the date of the giving of the notice.

c. Conditions precedent were determined in most of the supply agreements, including, *inter alia*, receipt of the approvals required on the part of the purchasers in connection with the Agreement. As of the report approval date, said conditions precedent have been fulfilled in most of the Agreements.

d. The supply agreements determined additional provisions, *inter alia* on the following issues: A right to terminate the Agreement in the case of a breach of a material undertaking, a right of the Leviathan Partners to supply gas to the said purchasers from other natural gas sources, compensation mechanisms in the case of non-supply of the quantities set forth in the Agreement, limits on the liability of the parties in the Agreement, and in relation to the relationship between the sellers themselves with respect to the supply of the gas to the said purchasers.

2. <u>Details regarding a gas supply agreement between the Leviathan Partners and the IEC</u>

Following the Competitive Process conducted by the IEC as specified above, on June 12, 2019, as aforesaid, the IEC-Leviathan Agreement was signed which regulates the supply of natural gas from the Leviathan reservoir to the IEC on an available capacity basis (in this section: the “**Agreement**”).

On October 29, 2019, all of the supply agreement’s closing conditions were fulfilled.

The supply of the gas to the IEC pursuant to the Agreement began on December 31, 2019 and will end, according to the provisions of the Agreement, on June 30, 2021, or on the date of commencement of the production of gas from the Karish reservoir, whichever is earlier, unless ended earlier according to the terms of the Agreement. A non-linked fixed gas price was determined in the supply agreement.

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 parties' undertakings under the IEC-Leviathan Agreement, the IEC undertook to nominate from the Leviathan Partners, during the first half of 2021, approx. 1.2 BCM of natural gas, from which certain gas quantities will be deducted, as agreed, and primarily gas quantities that shall be nominated from Leviathan by the IEC and shall not be supplied thereby and gas quantities that are not 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 nominate the Base Quantity in the said period, it will be charged with payment to the Leviathan Partners for the difference between the Base Quantity and the quantity actually nominated thereby. The IEC will be entitled to consume the balance of the Base Quantity that it did not consume but for which it paid, in accordance with the mechanism determined in the Leviathan Settlement Agreement.

In addition, the Leviathan Partners shall give the IEC a discount on the price for nomination of gas quantities exceeding approx. 0.5 BCM that shall be nominated from January 1, 2021.

Similarly to the Tamar Settlement Agreement, the Leviathan Settlement Agreement is also subject to the fulfillment of conditions precedent and regulatory approvals, including the approval of the Competition Authority, and the approval of the Competition Court for the agreed order. As of the report approval date, not all of the aforesaid conditions precedent have yet been fulfilled.

The aggregate supply from the sale of natural gas to the IEC from the Leviathan reservoir (in relation to 100% of the interests in the Leviathan project), until December 31, 2020, amounts to approx. 2.4 BCM totaling approx. U.S. $404.8 million.

Caution regarding forward-looking information – the above estimates regarding the total financial scopes of the supply agreements specified above, the natural gas quantities which shall be purchased by the buyers stated above, and commencement of the supply dates according to the supply

agreements, constitute forward-looking information, within the meaning thereof in Section 32A of the Securities Law, which there is no certainty will materialize, in whole or in part, and which may materialize in a materially different manner, due to various factors including due to non-fulfillment of the conditions precedent in each of the supply agreements (insofar as not yet fulfilled), non-receipt of regulatory approvals, changes in the scope, rate and timing of the natural gas consumption by each of the said buyers, the gas prices that shall be determined according to the formulas set forth in the supply agreements, the Electricity Production Tariff, the Dollar-Shekel exchange rate (insofar as relevant to the supply agreement), the Brent prices (insofar as relevant to the supply agreement), the U.S. CPI (insofar as relevant to the supply agreement), exercise of the options granted in each of the supply agreements and the date of exercise thereof, and so forth.

7.11.5 Engagements for natural gas export

(a) Tamar Project

1. On February 19, 2014, an agreement was executed for the supply of natural gas between the Tamar Partners and NBL Eastern Mediterranean Marketing Limited ("**NBL**") for the export of natural gas to consumers in Jordan (the "**First NBL-Tamar Agreement**") which was amended on February 16, 2016 and on September 30, 2017. NBL is a fully owned subsidiary (indirect holdings) of Noble Inc. which is the controlling shareholder in Noble, the operator of the Tamar Project.

   Simultaneously with the execution of the First NBL-Tamar Agreement, NBL executed an agreement with two companies from Jordan, Arab Potash Company and Jordan Bromine Company (jointly in this section: the "**Purchasers**"), according to which the Purchasers will purchase from NBL natural gas which will be used thereby at their plants which are located on the eastern bank of the Dead Sea in Jordan (in this section: the "**First Supply Agreement**").

   Within the First NBL-Tamar Agreement, the Tamar Partners undertook to supply NBL natural gas for the sale thereof by NBL to the Purchasers within the First Supply Agreement under Back-to-Back conditions (i.e.: the Tamar Partners will be responsible for the fulfillment of NBL's undertakings according to the Supply Agreement and will be entitled to all of the net revenues due to NBL by virtue thereof).

According to the First Supply Agreement (as amended), NBL undertook to supply the Purchasers with natural gas at an overall scope of up to approx. 2 BCM. The supply according to the First Supply Agreement began during January 2017 and is expected to continue approx. 15 years.

On October 14, 2018, another agreement was signed for the supply of natural gas between the Tamar Partners and NBL for the export of natural gas to consumers in Jordan and the supply thereof to the Purchasers (the "**Second NBL-Tamar Agreement**"). Concurrently with the signing of the Second NBL-Tamar agreement, NBL signed another agreement with the Purchasers, according to which the Purchasers will buy from NBL an additional quantity of natural gas which will be used thereby as aforesaid at their plants which are located on the eastern bank of the Dead Sea in Jordan (the "**Second Supply Agreement**"), on an interruptible basis, at a scope of approx. 0.1 BCM per annum, while NBL is entitled, in accordance with the dates determined in the agreement, to notify the Purchasers that the supply under the Second NBL-Tamar Agreement shall be carried out on a firm basis. The supply according to the Second NBL-Tamar Agreement began during Q1/2019 and is expected to continue until the date of completion of the supply under the First Supply Agreement.

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

On January 29, 2020, the Tamar Partners notified NBL that from August 1, 2020, the supply will be performed according to the Second NBL-Tamar Agreement, on a firm basis.

It is noted that in a tax decision regarding the First Supply Agreement and the Second Supply Agreement, given to Tamar Partners by the Tax Authority, the Tamar Partners undertook to offer new potential consumers to engage in agreements for the sale of natural gas, at a price which be calculated according to the optimal formula, based on the Brent Price, as specified in the Gas Framework, with an undertaking for such offer to apply for a period of 3 years from the date of the government decision (i.e., until August 16, 2018) and from the date of execution of the Second Supply Agreement (i.e., until October 14, 2021), respectively. The offer will be carried out according to the provisions of the Gas Framework, including with respect to the date of supply which may apply at any time commencing from the commencement of supply under the supply agreements (the first and the second, as the case may be) up to six years from their execution date, as specified above. For details see Sections 7.23.1(c)1 and 7.23.1(c)4 below. With respect to the NBL agreements, see also Section 7.23.4(d) below.

2. On February 19, 2018, an agreement was signed between the Partnership and Noble and Dolphinus for the export of natural gas from the Tamar Project to Egypt (in this section: the "**Original Tamar-Dolphinus Agreement**" and the "**Buyer**", respectively), which superseded a previous agreement that was signed between the said parties on March 17, 2015.

   On September 26, 2019, the signing of an 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 in connection with the allocation of the available capacity in the transmission system from Israel to Egypt between the Leviathan Partners and the Tamar Partners (for details, see Section 7.25.6(c) below).

   It is noted that concurrently with the signing of the Amendment to the Tamar-Dolphinus Agreement, an amendment was signed to the agreement between the Leviathan Partners and Dolphinus ("**Amendment to the Leviathan-Dolphinus Agreement**"). For details, see Section 7.11.5(b)2 below. Upon fulfillment of all of the conditions precedent for the Amendment to the Tamar-Dolphinus Agreement, on December 24, 2019 the Partnership updated that the Amendment to the Tamar-Dolphinus Agreement had taken effect.

   In July 2020, after a marine discharge permit was received from the Natural Gas Authority and the running-in of the compressor installed at the EMG terminal in Ashkelon was completed, the gas flow from the Tamar reservoir to Egypt began.

   In July 2020, Dolphinus endorsed the export to Egypt agreements to Blue Ocean Energy, an affiliate of Dolphinus.[132]

   It is noted that in a tax decision in connection with the Amendment to the Tamar-Dolphinus Agreement that was issued to the Tamar Partners by the Tax Authority on December 9, 2019, and according to the terms and conditions of the Gas Framework, the Tamar

[132] The reference to Dolphinus in this chapter below means Dolphinus or Blue Ocean Energy, according to the context.

Partners undertook to offer new customers (as defined in the Gas Framework) with which they engaged or shall engage from February 19, 2018 until 3 full years after the date of the signing of the tax decision, i.e. December 9, 2022, to enter into agreements for the sale of natural gas at a price that shall be 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 specified 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 and conditions of the Amendment to the Tamar-Dolphinus Agreement</u>:

a. The supply of gas to the Buyer according to the Amendment to the Tamar-Dolphinus Agreement is on a firm basis (compared with supply according to the Original Tamar-Dolphinus Agreement which was on an interruptible basis with an option for the Tamar partners to transition to a firm basis).

b. The total contract gas quantity which the Tamar Partners undertook to supply to the Buyer according to the Amendment to the Tamar-Dolphinus Agreement is approx. 25.3 BCM (the "**Total Contract Quantity (on a Firm Basis) in the Tamar Agreement**") (compared with approx. 32 BCM according to the Original Tamar-Dolphinus Agreement which was, as aforesaid, on an interruptible basis).

c. The supply according to the Amendment to the Tamar-Dolphinus Agreement will begin on June 30, 2020, and will be until December 31, 2034 or until the supply of the full total contract quantity, whichever is earlier (the "**Date of Conclusion of the Tamar-Dolphinus Agreement**"). In a case where the Buyer shall not purchase the total contract quantity by December 31, 2034, each party will be entitled to extend the supply period by up to two additional years.

d. According to the Amendment to the Tamar-Dolphinus Agreement, the Tamar Partners undertook to supply the Buyer with annual gas quantities as follows: (i) in the period commencing June 30, 2020 and ending June 30, 2022, approx. 1 BCM per year; and (ii) in the period commencing July 1, 2022 and ending on the date of conclusion of the Amendment to the Tamar-Dolphinus Agreement, approx. 2 BCM per year, by upgrading the systems at the EMG terminal in Ashkelon, including installing another compressor, and increasing the transmission capacity in the INGL system, as specified in Section 7.12.2(b)3.b.1 below.

e. The Buyer undertook to take or pay for quarterly and annual quantities, in accordance with the mechanisms set forth in the Amendment to the Tamar-Dolphinus Agreement, which, *inter alia*, allow the Buyer to reduce the TOP quantity in a year in which the average daily Brent price (as defined in the agreement) shall have fallen below $50 per barrel, such that it will be 50% of the annual contract quantity. It is noted that insofar as the contract quantity is reduced in a case of non-consent to update the gas price, as stated in Paragraph f. below, Dolphinus's right to reduce the Take-or-Pay quantity as aforesaid will be null and void. It is noted that further to the sharp decline in energy prices in H1/2020, the average daily Brent price (as defined in the agreement) fell below $50 per barrel.[133]

f. The price of the gas that shall be supplied to the Buyer will be determined according to a formula that is based on the Brent oil barrel price, and includes a "floor price". The Amendment to the Tamar-Dolphinus Agreement includes a mechanism for updating the price by up to 10% (up or down) after the fifth year and after the tenth year of the Amendment to the Tamar-Dolphinus Agreement (in this section: the "**First Adjustment Date**" and the "**Second Adjustment Date**", respectively), upon fulfillment of certain conditions set forth in the agreement. In a case where the parties fail to reach an agreement regarding the price update as described above, the Buyer will be entitled to reduce the contract quantity by up to 50% on the First Adjustment Date and by up to 30% on the Second Adjustment Date. It is noted that the agreement includes an incentive mechanism that is quantity-contingent and subject to the oil barrel price.

g. The Amendment to the Tamar-Dolphinus Agreement includes accepted provisions relating to conclusion of the agreement, as well as a provision for conclusion of the agreement in the case of conclusion of the Amendment to the Leviathan-Dolphinus Agreement as a result of a breach thereof, and the Tamar Partners' not agreeing to supply also the quantities stated in the Amendment to the Leviathan-Dolphinus Agreement, as specified in the agreement, and also includes compensation

[133] For details regarding a claim and motion for certification thereof as a class action that was filed against the Partnership regarding said stipulation see Section 7.26.9 below.

mechanisms in such a case. The Amendment to the Leviathan-Dolphinus Agreement also includes similar provisions. For details see Section 7.11.5(b)2 below.

h. In 2020 the Tamar Partners supplied 0.25 BCM to the Buyer according to the terms of the Amendment to the Tamar-Dolphinus Agreement. As estimated by the Partnership, on the signing date of the Amendment to the Tamar-Dolphinus Agreement**,** the aggregate scope of the revenues with respect to all of the Tamar Partners from the sale of natural gas to the Buyer under the Amendment to the Tamar-Dolphinus Agreement may amount to approx. U.S. $5 billion. The Partnership's estimate as aforesaid was based on the assumption that the Buyer would consume the total contract quantity set forth in the Amendment to the Tamar-Dolphinus Agreement, as well as on the Partnership's estimate regarding the price of natural gas during the term of the Amendment to the Tamar-Dolphinus Agreement. It is noted that the actual revenues from the Amendment to the Tamar-Dolphinus Agreement will be derived from a gamut of factors, including the gas quantities that shall actually be purchased by the Buyer and the Brent prices at the time of the sale.

Caution regarding forward-looking information – the above estimates regarding the scope of the projected revenues under the Amendment to the Tamar-Dolphinus Agreement and the natural gas quantities that may be sold to the Buyer according to the Amendment to the Tamar-Dolphinus Agreement, constitute forward-looking information, within the meaning thereof in Section 32A of the Securities Law, which there is no certainty will materialize, in whole or in part, and may materialize in a materially different manner, due to various factors, including due to changes in the scope, rate and timing of the natural gas consumption by the Buyer, changes in the gas price in accordance with the Amendment to the Tamar-Dolphinus Agreement, or other factors that are not foreseeable at this time and over which the Partnership has no control.

(b) <u>Leviathan project</u>

1. On September 26, 2016, a detailed agreement was signed for the supply of natural gas between NBL Jordan Marketing Limited (the "**Marketing Company**") and the national electric 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, which hold it

proportionately to the rate of their holdings in the Leviathan project.

According to the Export Agreement, the Marketing Company undertook to supply to NEPCO natural gas for a period of approx. 15 years from the date of commencement of the commercial supply or until the total supply volume would be approx. 45 BCM. The supply according to the Export Agreement began on January 1, 2020.

The gas delivery point according to the Export Agreement is at the connection between the Israeli transmission system at the border between Israel and Jordan and the Jordanian transmission system. In December 2019, INGL completed the construction of the Israeli transmission system up to the border between Israel and Jordan at a cost of approx. $120 million (100%).

NEPCO has undertaken to take-or-pay for a minimum annual quantity of gas, at the scope and according to the mechanism as determined in the Export Agreement.

The gas price determined in the agreement is based on a price that is linked to the Brent oil barrel prices, and includes a "floor price" plus a marketing fee, a transmission fee and NEPCO's bearing the cost of the transmission payments to INGL. On the signing date, the Leviathan Partners estimated that the aggregate scope of the revenues from the sale of natural gas to NEPCO may amount to approx. U.S. $10 billion, assuming that NEPCO consumes the total contract quantity, and based on the Partnership's estimate with respect to 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 that shall 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, an Offtake Intercredifor and Security Trust Deed was signed between the Marketing Company, the Leviathan Partners and HSBC Corprate Trustee Company (UK) Limited ("**HSBC**"), which deed is intended to secure the Marketing Company's undertakings vis-à-vis the Leviathan Partners under the Back-to-Back GSPA, according to which HSBC was appointed as trustee for the collateral and undertakings by virtue of the Export Agreement. In March 2020, against the backdrop of the Covid-19

Crisis, the partners in the Tamar and Leviathan petroleum assets received several notices from their customers, including NEPCO, claiming that the Covid-19 Crisis and the repercussions thereof constitute a '*force majeure*' event, which may affect the ability of such customers to fully and timely fulfill their future undertakings under the agreements. It is noted that as of the report approval date, the said customers are continuing to fulfill their undertakings in accordance with the agreements. It is the Partnership's position that the circumstances alleged in the notices received from the customers do not constitute a *force majeure* event, as required according to the provisions of the gas sale agreements.

Caution regarding forward-looking information – the Partnership's estimates regarding the total financial scope of the agreement, and the quantity of natural gas that is expected to be purchased, constitute forward-looking information within the meaning thereof in Section 32A of the Securities Law, which there is no certainty will materialize, in whole or in part, in the manner specified above or in any other manner, and may materialize in a materially different manner than described above, due to various factors including changes in the scope, pace or timing of the natural gas consumption by NEPCO, a change in the gas price as a result of a change in the Brent oil barrel price, etc.

2. On February 19, 2018, an agreement was signed between the Partnership and Noble and Dolphinus, which in July 2020 endorsed its rights as aforesaid to Blue Ocean Energy (in this section: the "**Purchaser**"), 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 in connection with the allocation of the available capacity in the transmission system from Israel to Egypt between the Leviathan Partners and the Tamar Partners (for further details, see Section 7.25.6(c) below).

   On January 15, 2020, the flow of natural gas to Egypt from the Leviathan reservoir began in accordance with the Amendment to the Leviathan-Dolphinus Agreement. In July 2020, after receipt of a marine discharge permit from the Natural Gas Authority, the running-in of the compressor that was installed at the EMG terminal in Ashkelon was completed. The installation of the compressor enabled to increase the quantity of the gas piped to Egypt.

It is noted that in a tax decision in connection with the Amendment to the Leviathan-Dolphinus Agreement that was issued to the Leviathan Partners by the Tax Authority on December 9, 2019, and according to the terms and conditions of the Gas Framework, the Leviathan Partners undertook to offer new customers (as defined in the Gas Framework) with which they engaged or shall engage from February 19, 2018 until 3 full years after the date of the signing of the tax decision, i.e. December 9, 2022, to enter into agreements for the sale of natural gas at a price that shall be 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 specified 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 and conditions of the Amendment to the Leviathan-Dolphinus Agreement</u>:

a. The total contract gas quantity which the Leviathan Partners undertook to supply to the Buyer according to the Amendment to the Leviathan Agreement is on a firm basis and increased considerably to approx. 60 BCM (compared with 32 BCM according to the Original Leviathan-Dolphinus Agreement) (the "**Total Contract Quantity in the Leviathan Agreement**").

b. The supply according to the Amendment to the Leviathan-Dolphinus Agreement began on January 15, 2020, and will be until December 31, 2034 or until the supply of the full total contract quantity, whichever is earlier (the "**Date of Conclusion of the Amendment to the Leviathan Agreement**"). The agreement prescribes that in the event that the Buyer does not purchase the total contract quantity, each party will be entitled to extend the supply period by two additional years.

c. According to the Amendment to the Leviathan-Dolphinus Agreement, the Leviathan Partners undertook to supply the Buyer with annual gas quantities as follows: (i) in the period that began January 15, 2020 and ends June 30, 2020, approx. 2.1 BCM per year; (ii) in the period commencing July 1, 2020 and ending June 30, 2022, approx. 3.6 BCM per year; and (iii) in the period commencing July 1, 2022 and ending on the date of conclusion of the Leviathan agreement, approx. 4.7 BCM per year, by upgrading the systems at the EMG terminal in Ashkelon, including installing another compressor, and increasing the transmission capacity in the INGL system, as specified in Section 7.12.2(b)3.b.1 below.

d. The Buyer undertook to take or pay for quarterly and annual quantities, in accordance with the mechanisms set forth in the Amendment to the Leviathan-Dolphinus Agreement, which, *inter alia*, allow the Buyer to reduce the TOP quantity in a year in which the average daily Brent price (as defined in the agreement) shall have fallen below $50 per barrel, such that it will be 50% of the annual contract quantity. It is noted that insofar as the contract quantity is reduced in a case of non-consent to update the gas price, as stated in Paragraph e. below, Dolphinus's right to reduce the Take-or-Pay quantity as aforesaid will be null and void. It is noted that further to the steep decline in energy prices in H1/2020, the average daily Brent price (as defined in the agreement) fell below $50 per barrel.[134]

e. The price of the gas that shall be supplied to the Buyer will be determined according to a formula that is based on the Brent oil barrel price, and includes a "floor price". The Amendment to the Leviathan-Dolphinus Agreement includes a mechanism for updating the price by up to 10% (up or down) after the fifth year and after the tenth year of the Amendment to the Leviathan-Dolphinus Agreement, (in this section: the "**First Adjustment Date**" and the "**Second Adjustment Date**", respectively), upon fulfillment of certain conditions set forth in the agreement. In a case where the parties fail to reach an agreement regarding the price update as described above, the Buyer will be entitled to reduce the contract quantity by up to 50% on the First Adjustment Date and by up to 30% on the Second Adjustment Date. It is noted that the agreement includes an incentive mechanism that is quantity-contingent and subject to the oil barrel price.

f. The Amendment to the Leviathan-Dolphinus Agreement includes standard provisions pertaining to conclusion of the agreement as well as provisions in the case of conclusion of the Amendment to the Tamar-Dolphinus Agreement between the Buyer and all of the partners in the Tamar reservoir as a result of a breach thereof, and the lack of consent of the Leviathan

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[134] For details regarding a claim and motion for certification thereof as a class action that was filed against the Partnership regarding said stipulation see Section 7.26.9 below.

Partners to supply also the quantities according to the Amendment to the Tamar-Dolphinus Agreement, and includes compensation mechanisms in such a case. The Amendment to the Tamar-Dolphinus Agreement also includes similar provisions. For details see Section 7.11.5(a)2 above.

g. In 2020 the Leviathan Partners supplied to the Buyer approx. 1.9 BCM according to the terms of the Amendment to the Leviathan-Dolphinus Agreement. As estimated by the Partnership on the signing date of the Amendment to the Leviathan-Dolphinus Agreement, the aggregate scope of the revenues with respect to all of the Leviathan Partners from the sale of natural gas to the Buyer under the Amendment to the Leviathan-Dolphinus Agreement may amount to approx. U.S. $12.5 billion. The Partnership's estimate as aforesaid is based on the assumption that the Buyer would consume the total contract quantity set forth in the Amendment to the Leviathan-Dolphinus Agreement, as well as on the Partnership's estimate regarding the price of natural gas during the term of the Amendment to the Leviathan-Dolphinus Agreement. It is noted that the actual revenues will be derived from a gamut of factors, including the gas quantities that shall actually be purchased by the Buyer and the Brent prices at the time of the sale.

Caution regarding forward-looking information – the above estimates regarding the scope of the projected revenues under the Amendment to the Leviathan-Dolphinus Agreement and the natural gas quantities that may be sold to the Buyer according to the Amendment to the Leviathan-Dolphinus Agreement, constitute forward-looking information, within the meaning thereof in Section 32A of the Securities Law, which there is no certainty will materialize, in whole or in part, and may materialize in a materially different manner, due to various factors, including due to changes in the scope, rate and timing of the natural gas consumption by the Buyer, changes in the gas price in accordance with the Amendment to the Leviathan-Dolphinus Agreement, or other factors that are not foreseeable at this time and over which the Partnership has no control.

(c) The Partnership, together with its partners in the Aphrodite reservoir, is examining, *inter alia*, the possibility of supplying natural gas in a joint pipeline with the Leviathan project to the liquefaction facility in Egypt, that will be performed, insofar as performed, from the Aphrodite reservoir, at a scope of approx. 6 BCM per year for a period of approx. 10-15 years, in accordance with the terms and conditions of the Aphrodite reservoir's development plan as specified in Section 7.4.11 above, and from the Leviathan reservoir, in the context of additional development stages of the Leviathan reservoir (beyond Phase 1A of the Leviathan reservoir's development plan), as specified in Section 7.2.5 above. It is noted that, to the best of the Partnership's knowledge, the maximum annual feed gas capacity of the liquefaction facility is approx. 12 BCM per year.

The Partnership, together with its partners in the Leviathan and Aphrodite reservoirs, are conducting negotiations in connection with a joint construction agreement for the pipeline as aforesaid and an agreed budget for the financing thereof, which shall include the commercial, operating, economic and regulatory principles. According to the agreement that is being formulated, the parties shall agree to share the costs in connection with the viability studies and development of the project as aforesaid, but not in connection with the execution and construction of the project, and, in the event that the partners do indeed wish to move ahead to such stage, they will enter into another agreement such as a shareholders' agreement or a JOA. It is noted that the costs pertaining to development of the pipeline, both at the preliminary stage and at the construction stage, are not part of the costs of the upstream development, and are not included in the cost recovery in the Production Sharing Contract.

(d) The Partnership is promoting negotiations at various stages with the owners of liquefaction facilities for the export of LNG in Egypt, both in relation to the ELNG liquefaction facility that is operated by Shell and is situated in proximity to the city of Idku, and in relation to the SEGAS liquefaction facility that is operated by SEGAS (Joint Venture) and is situated in proximity to the city of Damietta. The arrangements being examined include, *inter alia*, options for the purchase of liquefaction capacity, arrangements in relation to receipt of liquefaction services that will enable the Partnership to market natural gas in LNG form while paying for liquefaction services, and additional possibilities in connection with the purchase of rights in these facilities.

7.11.6 <u>Agreements for the supply of condensate</u>

(a) <u>Agreement for the supply of condensate from the Tamar reservoir to PAR</u>

The Tamar Partners have been supplying PAR with condensate since 2013 in a designated pipeline at a scope which is not material, according to an agreement (as amended) which is expected to end in December 2030. The condensate price is determined according to the Brent prices less a margin, as set forth in the supply agreement. All of the sales of condensate by the Tamar Partners is in the context of the aforesaid engagement.

(b) <u>Agreement for the supply of condensate from the Leviathan reservoir to ORL</u>

On December 15, 2019, an agreement was signed whereby condensate that will be produced from the Leviathan reservoir shall be piped via the existing fuels pipeline of EAPC to a container site of PEI in Kiryat Haim, and from there it will be piped to ORL's facilities, according to, *inter alia*, regulatory directives (the "**ORL Agreement**").

The ORL Agreement is on an interruptible basis, for a period of 15 years from the date of commencement of condensate piping in commercial quantities, with each party having the right to terminate the ORL Agreement by giving notice, no less than 360 days in advance, to the other party. In addition, each party may cancel the ORL Agreement on a shorter notice upon the occurrence of various events, including upon the occurrence of a breach event by the other party, and upon the occurrence of regulatory and other changes which will not allow the piping of condensate according to the provisions of the ORL Agreement.

The piping of condensate to ORL pursuant to the ORL Agreement shall be made on an interruptible basis up to a maximum quantity that was agreed by the parties (the "**Maximum Quantity**"). The parties may update the Maximum Quantity from time to time, subject to compliance with the terms that were determined by the authorities in this respect, including the Ministry of Energy and the Ministry of Environmental Protection.

The ORL Agreement stipulates that the delivery of the condensate to ORL shall be for no consideration, and the Leviathan Partners shall bear any and all expenses, including the tax exposure, with respect to the condensate piping.

The ORL Agreement includes several conditions precedent, pertaining primarily to the receipt of the regulatory approvals for the piping of condensate to ORL, including approvals in all aspects pertaining to the sale of condensate for no consideration. The ORL Agreement took effect on January 29, 2020.

The loss of revenues caused to the Leviathan project due to the terms of the agreement, is immaterial for the Partnership. For further details regarding an examination of alternatives for the transmission and sale of the condensate that will be produced from the Leviathan reservoir, see subsection (d) below.

Caution regarding forward-looking information - the information specified above regarding the scope of the loss of revenues from the ORL Agreement is forward-looking information, within the meaning thereof in Section 32A of the Securities Law, and there is no certainty that it will materialize, in whole or in part, and it may materialize in a materially different manner, due to various factors which cannot be anticipated at this time and which are beyond the Partnership's control.

(c) Agreement for the supply of condensate from the Leviathan reservoir to an international trading company in the field of fuels (in this section: the "**Buyer**")

On December 15, 2019, the Leviathan partners signed an agreement whereby condensate that will be produced from the Leviathan reservoir shall be transported by road tankers and delivered to the Buyer at the PEI container site (the "**Supply Agreement**").

The Supply Agreement took effect upon the commencement of piping of natural gas from the Leviathan reservoir and it prescribes that it will be renewed annually for a period of one additional year, unless one of the parties shall have chosen not to renew it, by advance notice of no less than 60 days. Each party may terminate the Supply Agreement in the case of a breach thereof by the other party and upon the occurrence of regulatory and other changes which shall not allow the supply of the condensate according to the provisions of the Supply Agreement.

The condensate shall be supplied by the Leviathan Partners to the Buyer according to the Supply Agreement on an interruptible basis up to a daily maximum quantity that was agreed between the parties.

According to the Supply Agreement, the Leviathan partners shall bear all costs with respect to the condensate until its delivery to the Buyer ex-PEI container site and the Buyer shall bear all costs with respect to the condensate from this point forth.

The condensate price that was determined in the Supply Agreement shall be linked to the Brent barrel price and the Buyer shall be entitled to a discount on condensate piped thereto which deviates from the specification that was determined in the Supply Agreement.

The scope of revenues from the sale of condensate to the Buyer according to the terms of the agreement is not expected to be material for the Partnership.

It is clarified that the condensate will be sold according to the Supply Agreement only in cases where the transport of the condensate is not possible, according to the ORL Agreement described above.

Caution regarding forward-looking information - the information specified above regarding the Supply Agreement and its financial scope is forward-looking information, within the meaning thereof in Section 32A of the Securities Law, and there is no certainty that it will materialize, in whole or in part, and it may materialize in a materially different manner, due to various factors including as a result of changes to the scope of supply of condensate to the Buyer, the Brent barrel price and so forth.

(d) It is noted that concurrently with the piping of the condensate according to the agreements described above, the Leviathan Partners are continuing to explore other alternatives for the piping and sale of the condensate that shall be produced from the Leviathan reservoir, and *inter alia*, alternatives are being examined for the laying of a pipeline that will transport condensate to storage containers in Hadera and/or in Ashkelon, and from there the condensate shall be delivered via designated vessels to consumers in and/or outside of Israel, and the possibility is also being examined of a cooperation with Energean for the storage of the condensate produced from the Leviathan reservoir on the FPSO, from which it will be delivered to potential consumers.

7.12 **Marketing and Distribution**

7.12.1 Supply to the domestic market

The Partnership, together with its partners in the Tamar Project and in the Leviathan project, is acting for the marketing of natural gas and condensate to potential consumers (see Section 7.10.2 above) and is conducting negotiations at various stages with potential customers in the domestic market including independent power producers and industrial consumers, aiming to engage in agreements for the sale of natural gas and/or condensate from the said projects, all in accordance with the gas prices and the term of the agreements set forth in the Gas Framework, as specified in Sections 7.23.1(b)3 and 7.23.1(c)1 below, and subject to supply capacity of said projects.

Piping the natural gas to some of the additional customers may also be contingent upon the continued development of the natural gas national transmission system by INGL, and the completion of the regional distribution systems.

As of the report approval date, the marketing of natural gas produced from the Leviathan reservoir to the customers is performed by way of joint marketing, according to supply agreements that were signed between the customers and all of the Leviathan Partners. Until recently, the marketing from the Tamar reservoir was also performed by way of joint marketing as aforesaid. For details regarding the Balancing Agreement that was signed between the Tamar Partners for the separate marketing of the naturel gas produced from the Tamar reservoir, see Section 7.11.4(a)6.b above.

7.12.2 Export

(a) General

The Partnership, together with its partners in the various projects, is acting to find markets outside of Israel and outside of Cyprus for the marketing of the natural gas. The Partnership estimates that the potential markets include the countries that are close to Israel (including the Palestinian market which currently purchases electricity from Israel, and in which there are plans to build power plants for the production of its own electricity), chiefly Egypt and Jordan, to which gas is exported via pipelines from the Tamar reservoir and from the Leviathan reservoir, and the more distant global markets to which it is possible to export natural gas via LNG (liquefied natural gas) and/or CNG (compressed natural gas). As aforesaid, in the context of the Partnership's marketing efforts for export, several agreements were signed with customers in Jordan and in Egypt, and negotiations are also being conducted for the supply of natural gas to additional customers in these and other countries. The Partnership is further examining the economic merit of several projects for the export of natural gas via LNG (including liquefaction of natural gas in a floating facility - FLNG) and CNG, as specified below.

(b) Export via pipeline

1. The Partnership is acting, in addition to the export agreements in which it has engaged and which are specified in Section 7.11.5 above, for promotion of possibilities of using an (existing and/or new) pipeline, and in this context is promoting talks and/or negotiations, at various stages, pertaining to the export of natural gas through pipes in significant scopes to regional markets.

2. In the context of the said talks and/or negotiations, the main parameters in the possible agreements for the sale of natural gas via a pipeline are being discussed, including, *inter alia*¸ engagement term, amounts, capacity, price per unit, linkage formula, minimal purchase undertaking (take-or-pay), undertaking to build the pipeline etc. In this context, it is noted that on July 19, 2020, government resolution no. 235 was adopted, in which the government ratified an agreement of January 2020 between Israel, Cyprus, Greece and Italy with respect to the construction of a pipeline for the transport of natural gas originating in natural gas reservoirs in Israel and Cyprus to the European markets, in which

the parties undertook to cooperate with one another in connection with the construction of the project.[135]

Caution regarding forward-looking information – the information specified above regarding contacts and/or negotiations as aforesaid constitutes forward-looking information within the meaning thereof in Section 32A of the Securities Law, which there is no certainty that it will materialize, in whole or in part, in the manner stated or in any other manner, and it may materialize in a materially different manner than described above, and in particular there is no certainty that the aforesaid contacts and/or negotiations will mature into binding gas sale agreements and that the conditions required according to any law for such agreements to take effect, if signed, shall be fulfilled.

3. Following is a description of the main potential target markets for the export of natural gas through pipelines from the Tamar Project and from the Leviathan project:[136]

   a. Jordan – To the Partnership's understanding, and based on independent consulting firms, the gas consumption in Jordan for domestic use was approx. 4 BCM in 2020, which consumption is similar in scope to the consumption in 2019. Natural gas is the main source of energy for the production of electricity in Jordan. It is estimated that in 2020, approx. 77% of the electricity in Jordan was produced through natural gas, while the remaining production of electricity was based on renewable energies (approx. 16%) and refined oil products (approx. 7%). In the Partnership's estimation, based on independent outside consulting firms and on adjustments that the Partnership made to these data, in 2021, natural gas consumption in Jordan is expected to be approx. 4 BCM, and it is estimated that in the upcoming decade is expected to range between 3.8 and 4.2 BCM. The stability in the forecast for the consumption of natural gas in Jordan, despite the projected increase in demand for energy in general and specifically for

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[135] For information regarding the agreement for the "East-Med" gas pipeline that will run from Israel through Cyprus and Greece to Europe, see the notice of the Energy Ministry of January 1, 2020:
https://www.gov.il/he/departments/news/ng_021220
and of March 9, 2021: https://www.gov.il/he/departments/news/east_med_080321.
For information regarding an MOU for the laying of the EuroAsia subsea power cable, see the notice of the Energy Ministry of March 9, 2021:
https://www.gov.il/he/departments/topics/exploration_and_production_of_oil_and_natural_gas.

[136] The said information was prepared by the Partnership, *inter alia* based on the data of reports released by independent consulting firms.

electricity, originates from accelerated penetration of renewable energies into the electricity production sector in Jordan, following proactive activity of the government in this sector and due to production of electricity from a Jordanian power plant (Attart power plant), the fuel source for the production of electricity therein is oil shale. The target that was set by the Jordanian government is that renewable energies shall constitute approx. 20% of the scope of the electricity production in the country in 2020, and in practice, electricity production from renewable energies constituted as aforesaid approx. 16% of the total electricity production in this year. The current forecast is that this rate is expected to rise to approx. 30% in 2025, and to approx. 45% in 2030. Jordan currently imports natural gas from the Leviathan project, which constitutes the majority of the gas consumed in Jordan, and also imports natural gas from the Tamar Project to industrial plants in the area of the Jordanian Dead Sea. Jordan also imports small quantities of natural gas from Egypt via the Arab Gas Pipeline, while to the Partnership’s best knowledge such import amounted in 2020 to less than 0.5 BCM, and further produces negligible quantities of natural gas. Prior to the singing of the NEPCO agreement (specified in Section 7.11.5(b)1 below), LNG constituted Jordan’s main natural gas source, and it was imported via a floating regasification facility situated in Aqaba. However, in the context of past agreements, in 2020, Jordan imported LNG in an estimated amount of approx. 1.1 BCM via the facility in Aqaba. It is noted that such facility is still active and Jordan is able to continue importing LNG, by seizing opportunities on LNG spot markets. With respect to the export of gas from the Tamar Project to the Jordanian Dead Sea plants, since early 2017, the Tamar Partners have exported natural gas to two industrial plants that are situated on the Eastern bank of the Dead Sea in Jordan, as specified in Section 7.11.5(a)1 above, through connection of the Israeli transmission system via a designated pipeline to the plants located on the eastern bank of the Dead Sea in Jordan (the “**Southern Pipeline**”). With respect to the export of gas from the Leviathan project to Jordan, it is noted that in January 2020, the laying of a parallel pipeline to the existing pipeline from the area of Tel Kashish to Dovrat was completed, in addition to the construction of a new natural gas pipeline that connects INGL's transmission system (from the Dovrat area) to the border with Jordan, as well as the construction of a follow-on pipeline on the Jordanian side, that connects the Israeli transmission system to the existing transmission pipeline in Jordan (the Arab Gas Pipeline that is operated by FAJR) (the

"**Northern Pipeline**"). With respect to the budget for construction of the Northern Pipeline, as approved by the Leviathan Partners, see Section 7.2.4 above. Based on the figures that are known to the Partnership, the Northern Pipeline's capacity shall enable the flow of natural gas in an annual amount of up to approx. 10 BCM to Jordan and via Jordan to Egypt.

With respect to the agreements signed in respect of the supply of natural gas to Jordan, see Sections 7.11.5(a)1 and c7.11.5(b)1 above.

b. Egypt – To the Partnership's best knowledge, and based on independent consulting firms, natural gas plays a key role in the Egyptian energy market, while natural gas consumption in Egypt is mainly used for electricity production but also for industry and households. Natural gas is the main energy source for the production of electricity in Egypt. In 2020, approx. 84% of the electricity in Egypt was produced through natural gas. To the Partnership's understanding, the local production in Egypt in 2020 was approx. 60 BCM, down approx. 10% relative to 2019, with the reduction in production deriving mainly from initiated output cutbacks. The demand for natural gas in Egypt in 2020 was approx. 61 BCM (stable compared with 2019). The gradual increase in local production in the last four years, transformed Egypt from a net importer of natural gas to a net exporter. As a result of the increase in the scope of production, the Egyptian government reduced the number of LNG regasification facilities (which are used for the import of liquefied natural gas) from two to one, and import of the LNG to the domestic market decreased almost entirely and totaled approx. 0.1 BCM only in 2019. It is noted that seasonality in the use of natural gas in Egypt contributes to the possibility that Egypt may export certain quantities of natural gas in the winter months and import natural gas in the summer months. In addition, in Egypt there are two facilities for the liquefaction of natural gas for the production of LNG for export from Egypt, with a total liquefaction capacity of approx. 12.2 million tons of liquefied gas per year, in respect of which natural gas is required for feed gas at a scope of approx. 17-18 BCM per year, in addition to the domestic demand. As of the report approval date, the scope of the natural gas production capacity in Egypt is sufficient to fill the needs of the domestic market and for export via LNG, but is not sufficient for the operation of the two liquefaction facilities at full capacity. In this situation, one of the facilities is operating at partial output. The second facility, which has been shut down since the end of

2012, resumed liquefaction activity in Q1/2021. As of the report approval date, these two facilities operate at partial output. Based on independent consulting firms, the demand forecasts for the local Egyptian market for 2021, 2022 and 2023 are approx. 63 BCM, approx. 64 BCM and approx. 66 BCM, respectively, while forecasts for domestic production from producing fields, either at development stages or with a high probability of commencement of production in 2021, 2022 and 2023, are approx. 65 BCM, approx. 65 BCM and approx. 67 BCM, respectively, disregarding the demand for natural gas as feed gas for the LNG export facilities. The oversupply expected in coming years is expected to lead to increased export of natural gas from Egypt in this period, mainly as LNG, depending on the global market conditions and the global energy prices. However, the oversupply in these years is not sufficient to make up the liquefaction capacity in the two existing LNG export facilities in Egypt. In addition, it is forecasted that from the middle of the decade, a gas shortage is expected to arise for domestic consumption in the local Egyptian market, based on forecasts for domestic production from producing fields, fields at development stages or with a high probability of production. The demand forecasts for 2025 to 2030 relate to a scope of consumption in the domestic market of approx. 70-75 BCM per year, without including the natural gas required as feed gas for feeding the said liquefaction facilities. It is noted that these forecasts are due to be updated periodically insofar as new information is received and/or an update is made to forecasts by the independent consulting firms. To the best of the Partnership's knowledge, the Egyptian government is acting to promote projects for the supply of natural gas from discoveries in Israel and Cyprus, with the aim of turning Egypt into a natural gas hub, in order to supply the needs of the domestic market alongside use of the existing export facilities and promotion of investments in new export facilities, all at the same time as encouraging activities for the development and exploration of natural gas projects in Egypt. Natural gas exploration activity, which is promoted by the Egyptian government, may reinforce and spur the natural gas exploration activity in Egypt, and therefore there may be additional natural gas discoveries in Egypt. For details regarding engagements for the export of natural gas to Egypt, see Sections 7.11.5(a)2 and 7.11.5(b)2 above.

For details regarding the EMG Transaction, which allows the flow of natural gas to Egypt, see Section 7.25.6 below.

Engagement with INGL in transmission agreements

In July 2020, with the operation of the compressor at the entrance of the ENG system in Ashkelon, the flow capacity in the EMG pipeline, via INGL's existing transmission system infrastructure, increased to approx. 450,000 MMCF per day (approx. 4.5 BCM per year).

On May 28, 2019, an agreement was signed between Noble and INGL with respect to the provision of interruptible transmission services in connection with the piping of natural gas from the Leviathan reservoir and the Tamar reservoir to the EMG terminal in Ashkelon, for purposes of export to Egypt (in this section: the "**2019 Agreement**"). On January 18, 2021, Noble engaged with INGL in an agreement for the provision of transmission services on a firm basis for the piping of natural gas from the Tamar reservoir and from the Leviathan reservoir to the EMG terminal in Ashkelon and for the transmission thereof to Egypt, which took effect on February 15, 2021, after fulfillment of all of the conditions precedent determined therein (the "**Transmission Agreement**" or, in this section: the "**Agreement**"), the main principles of which are described below:

1. In the Transmission Agreement, INGL undertook to provide transmission services for the natural gas that shall be supplied from the Tamar Reservoir and from the Leviathan Reservoir, including maintaining an annual base capacity in the transmission system of approx. 5.5 BCM (the "**Base Capacity**"). For the transmission services in relation to the Base Capacity, Noble will pay capacity fees and a payment for the gas quantity that shall actually be piped (throughput), in accordance with the accepted transmission rates in Israel, as shall be updated from time to time.[137] In addition, INGL undertook to provide non-continuous transmission services, on an interruptible basis, of additional gas quantities over and above the Base Capacity, subject to the capacity that shall be available in the transmission system. For transmission of the additional quantities as aforesaid, Noble will pay a transmission rate for non-continuous transmission services in relation to the quantities that shall actually be piped. To the best of the

[137] As of the report date, the capacity and throughput fees collected by INGL from its customers amount to approx. ILS 0.90 per MMBTU. It is noted that on February 23, 2021 the Natural Gas Authority published a decision regarding reduction of the capacity and throughput fees by approx. 5% from March 1, 2021.

Partnership's knowledge, the transmission system was planned to allow the transmission of the full contract quantity set forth in the export agreements.

2. In the Transmission Agreement, Noble committed to payment for the piping of a gas quantity that shall be no less than 44 BCM throughout the term of the Agreement. If the parties agree on an increase in the Base Capacity, the minimum quantity for piping as aforesaid will be increased accordingly.

3. The gas flow according to the Transmission Agreement will begin on the date on which INGL shall complete the construction of the Ashdod-Ashkelon offshore transmission system section, in accordance with the provisions of the decision of the Natural Gas Council in connection with the financing of projects for export via the Israeli transmission system, and division of the costs of the construction of the Ashdod-Ashkelon combined section (the "**Council's Decision**"), in a manner which will allow the piping of the full quantities under the Transmission Agreement (the "**Date of Commencement of the Piping**"). According to the Transmission Agreement, the Date of Commencement of the Piping is expected to be in the period between July 2022 and April 2023. For details regarding the annual gas quantities which the Tamar Partners and the Leviathan Partners undertook to supply to Dolphinus, see Sections 7.11.5(a)(2)(d) and 7.11.5(b)(2)(c) above. For further details regarding the Council's Decision, see Section 7.12.2(b)3.b.3 below.

4. It was further determined that the transmission period under the 2019 Agreement will be extended until January 1, 2024 or until the Date of Commencement of the Piping under the Transmission Agreement, whichever is earlier.

5. The Transmission Agreement will end on the earlier of: (1) the date on which the total quantity that is piped is 44 BCM; (2) 8 years after the Date of Commencement of the Piping; or (3) upon expiration of INGL's transmission license. In the Partnership's estimation, upon expiration of the term of the Agreement, no difficulty is expected with extending it at the capacity and transmission rates of the transmission license holder at such time.

6. In accordance with the principles determined in the Council's Decision, Noble undertook to pay for the partners' share (56.5%) in the total cost of construction of the Ashdod-Ashkelon combined section, which is estimated at ILS 738 million. Noble also undertook to pay ILS 27 million for the partners' share in the costs of accelerating the doubling of the Sorek-Nesher and Dor-Hagit sections, which is estimated, at present, at approx. ILS 48 million.

7. In accordance with the Council's Decision, the Leviathan Partners and the Tamar Partners will provide a bank guarantee to secure INGL's share in the cost of construction of the foregoing infrastructure, and to cover Noble's commitment to pay the capacity and transmission fees. It is noted that in February 2021, the Partnership provided guarantees as aforesaid in the sum of approx. ILS 172.9 million, against which the Partnership pledged a deposit in the sum of approx. ILS 13.3 million.

8. The Leviathan partners and the Tamar partners will bear the costs stated in Paragraph 5 above and will provide the guarantees stated in Paragraph 6 above at the rates of 69% and 31%, respectively.

9. The Transmission Agreement determined that if the export of natural gas from the Tamar Project and from the Leviathan project to Egypt stops, Noble will be entitled to terminate the Transmission Agreement subject to payment of compensation to INGL due to the early termination, in an amount equal to 120% of the costs of construction of the Ashdod-Ashkelon combined section, plus the costs of accelerating the doubling of the Sorek-Nesher and Dor-Hagit sections, net of the amounts Noble paid until the date of the termination in respect of such construction and acceleration costs and in respect of the piping of the gas under the Transmission Agreement. If, after the termination of the Transmission Agreement, export to Egypt resumes, the Transmission Agreement will be renewed subject to and in accordance with the capacity that shall be available in the transmission system at such time.

10. On February 14, 2021, Noble informed the Partnership that all of the conditions precedent for the taking effect of the Transmission Agreement have been fulfilled.

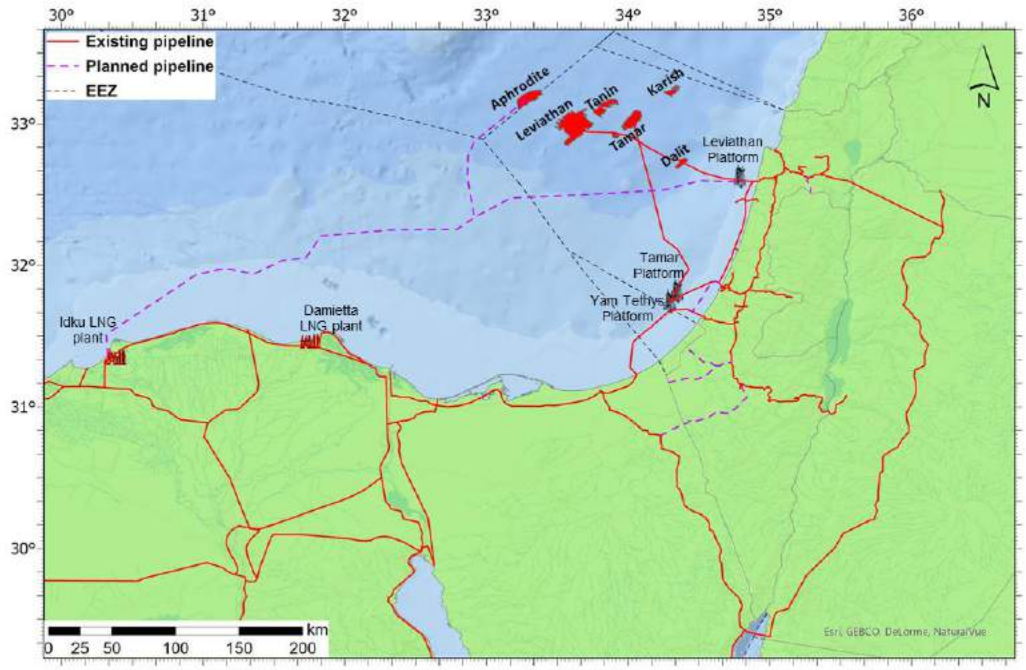
11. Concurrently with the signing of the Transmission Agreement, Noble, the Partnership and the other Leviathan partners and Tamar partners signed a back-to-back services agreement (in this section: the “Services Agreement”), which determined that the Leviathan partners and the Tamar partners will be entitled to transmit gas (through Noble) under the Transmission Agreement, and will be responsible for fulfillment of Noble’s undertakings under the Transmission Agreement (back-to-back), as if the Leviathan partners and the Tamar partners were a party to the Transmission Agreement in Noble’s stead, each according to its share, as determined in the Capacity Allocation Agreement between the Leviathan partners and the Tamar partners, as specified in Section 7.25.6(c) below. The Services Agreement further determined that the Base Capacity that is kept in the transmission system for Noble will be allocated between the Leviathan partners and the Tamar partners according to the rates specified in Paragraph 8 above, and according to the order set forth in the Capacity Allocation Agreement. The aforesaid notwithstanding, the Leviathan partners and the Tamar partners will bear capacity fees at a fixed ratio of 69% (the Leviathan partners) and 31% (the Tamar partners), except in a case where a party (the Leviathan Partners or the Tamar Partners, as the case may be) used the available share in the capacity of the other party.

Caution regarding forward-looking information:

The above estimates in relation to the costs of construction of the Ashdod-Ashkelon combined section, the costs of accelerating the doubling of the Sorek-Nesher and Dor-Hagit sections, the gas transmission costs, the Date of Commencement of the Piping, the quantities that it will be possible to pipe under the Transmission Agreement, and the estimate regarding the possibility of extending the Transmission Agreement constitute forward-looking information, within the meaning thereof in the Securities Law, 5728-1968, which there is no certainty will materialize, in whole or in part, and may materialize in a materially different manner, due to various factors, including delays and malfunctions in the construction of the transmission system sections, actual construction costs that are different to the estimated costs, non-receipt of the required regulatory approvals, changes in the transmission rates that apply in Israel, and other factors beyond the Partnership’s control.

Transmission through construction of new infrastructures

As of the report approval date, the Partnership is examining, together with Noble, additional possibilities for the transport of natural gas from Israel to Egypt, including the possibility of transporting the natural gas from Israel via Jordan through the Northern Pipeline and the Arab Gas Pipeline (for additional details, see Section 7.25.6(e) below) and/or the possibility of construction of a new offshore pipeline to Egypt and/or construction, by INGL, of a new onshore connection between the Israeli transmission system and Egypt (in the area of Nitzana or Kerem Shalom).



Caution regarding forward-looking information

The information specified above regarding negotiations with third parties and examination of various alternatives regarding the construction and/or use of infrastructures, as specified above, constitutes forward-looking information within the meaning thereof in Section 32A of the Securities Law, regarding which there is no certainty that it will materialize, in whole or in part, in the said manner or in any other manner, and it may materialize in a materially different manner than as described above, due to various factors over which the Partnership has no control.

In addition, the forecasts and estimates regarding the Jordanian and Egyptian market are forward-looking

information within the meaning thereof in Section 32A of the Securities Law. This information is based, *inter alia*, on information received from independent advisory companies and constitutes estimated assumptions and projections which are naturally subject to uncertainty. Such projections and estimations may not materialize, in whole or in part, or may materialize in a materially different manner, due to various factors beyond the Partnership's control, including changes in the demand for natural gas, changes in the supply of natural gas – including local production, discovery of new reservoirs and commencement of production therefrom, changes in the energy mix – including accelerated penetration of additional energy sources including renewable energy, changes due to macro-economic effects which impact on the economic activity in these markets, including acceleration or deceleration in the economic activity, etc.

c. <u>The Palestinian Authority</u> – Israel is the main source that provides electricity to the territories of the Palestinian Authority (West Bank and Gaza Strip). In recent years, the Palestinian Authority began a process of creating independent electricity production capabilities, *inter alia*, by promoting the construction of a new power plant for production of electricity in Jenin. As of the report approval date, the Partnership, together with its partners in the various projects, is conducting negotiations, that are at various stages, with various entities, pertaining, *inter alia*, to the possibility of supplying natural gas to an existing power plant in Gaza and/or a future plant that shall be built in the Jenin area and/or in other areas controlled by the Palestinian Authority.

   The Partnership estimates that the demand for natural gas for the benefit of operating the power plants to be established in the Jenin area will be approx. 0.2 BCM per year, while the demand for natural gas for the operation of the existing power plant in Gaza will be up to approx. 0.25 BCM per year.

d. <u>Cyprus</u> – As of the report approval date, Cyprus is almost completely dependent on import of the various petroleum products, for purposes of production of electricity in Cyprus which is based mainly (around 90%) on the use of petroleum-based products such as diesel. In addition, Cyprus encounters difficulties in connecting to the energy infrastructures in Europe due to its geographical location and its being an island. In 2007, the Cypriot government established the public gas company ("**DEFA**"), which is solely responsible for the import, storage, marketing, transportation, supply and trade of natural gas in Cyprus, including management of the natural gas transmission and distribution system in Cyprus. According to regulations promulgated in Cyprus in 2007 with regards to the natural gas market in Cyprus, the said gas company has exclusivity for the import and marketing of natural gas in Cyprus. As of the report approval date, Cyprus does not consume any natural gas. For further details pertaining to the Cypriot market, see Section 7.14.4(b) below. The Partnership is continuing to promote, together with its partners in the Aphrodite reservoir, discussions and/or negotiations, at various stages, in relation to the export of natural gas from the Aphrodite reservoir to regional markets, including the Egyptian market, including negotiations for the supply of natural gas for feeding the existing liquefaction facility in Idku, Egypt, at a scope of approx. 6 BCM per year for a period of approx. 10-15 years.

Caution regarding forward-looking information – the information specified above with respect to the said discussions and/or negotiations, constitutes forward-looking information, within the meaning thereof in Section 32A of the Securities Law, which there is no certainty will materialize, in whole or in part, in the manner stated or in any other manner, and it may materialize in a manner materially different to the description above, and in particular there is no certainty that the said discussions and/or negotiations will result in binding gas sale agreements or that the conditions required pursuant to any law for the taking effect of such agreements, if signed, will be fulfilled.

(c) Liquefied Natural Gas (LNG)

The Partnership is examining the possibility of liquefying the gas and transporting it in a liquefied state (LNG) in designated tankers to various countries where there is demand for LNG. The construction of a natural gas liquefaction facility is a highly complex project, *inter alia* due to the tremendous scope of the investment of liquefaction facilities whose liquefaction capacity is millions of tons of LNG per year, and due to design, engineering, environmental and commercial challenges that are entailed by such a project.

In this context the Partnership is examining the construction of a floating liquefaction facility (FLNG) to be located offshore on a designated ship. In recent years, several FLNG facilities have begun operating around the world, and there are additional floating liquefaction facilities in planning and construction phases, while the trend in the market is a transition to standardization of the facilities, which will allow the reduction of their cost, the shortening of the timetables for production, and reduction of the construction risks. It is noted that the Leviathan reservoir, which is an operating reservoir which supplies processed gas and is in a relatively comfortable climate with access to several main LNG markets, has many advantages over competitor FLNG facilities. On July 29, 2019, the Leviathan Partners entered into two separate interim agreements with FLNG service and technology providers, as specified below:

1. An agreement with Golar LNG Limited ("**Golar**") for examination of the suitability of generic FEED (Front End Engineering and Design), that is carried out thereby for a FLNG facility for the Leviathan project which shall be located in the EEZ of Israel (in Section 7.13.2(c): the "**Facility**") and for engineering planning of the Facility.

   Golar is a public company that is traded on NASDAQ, which specializes in the entire value chain of the LNG, 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 vessels for transportation of the LNG and regasification thereof.

2. An agreement with Exmar NV ("**Exmar**") for the performance of designated FEED for the Leviathan project and engineering planning for the construction of the Facility.

   Exmar is a public company that is traded on Euronext in Belgium, which specializes in the entire value chain of the LNG, including gas liquefaction, transportation and regasification, and in the field of transportation of liquefied petroleum gas (LPG). 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 shores of Hadera.

In the said two interim agreements, the Leviathan Partners are conducting negotiations with the two said providers with respect to the commercial terms and conditions for the construction of the Facility at an estimated capacity of between 2.5 and 5 million tons of LNG per year (approx. 3.5-7 BCM) and operation thereof, including for promotion of receipt of the required regulatory approvals. Insofar as it is found that the construction of the Facility is the preferred alternative for promotion of the future development stages for the Leviathan project, the Leviathan Partners shall engage with one of the providers in a long-term agreement for the lease of the Facility that shall be built, financed, operated and maintained thereby.

During April 2020, pre-FEED proposals for the provision of FLNG services were received from these two providers. As of the report approval date, the Leviathan Partners are examining the said proposals and holding discussions with these providers for the purpose of obtaining clarifications for and improving the proposals.

In this context, it is noted that in March 2020, the Ministry of Energy released a request for public comment regarding the alternatives proposed by the Ministry of Energy for an offshore FLNG facility for export of liquefied natural gas in Israel's EEZ[138]. The Association of Oil and Gas Exploration Industries in Israel, of which the Partnership is a member, submitted its comments on the said document on May 17, 2020.

Impact of the Covid-19 Crisis

As specified in Section 6.9 above, due to the Covid-19 Crisis, there is, on the report approval date, significant and unusual uncertainty as to the possible repercussions of the crisis, in and after 2021, on the global economy in general and on energy prices in particular. Therefore, insofar as the Covid-19 Crisis continues or deteriorates, the possibility of making decisions on investment in general, and in new projects in particular, may be barred thereby.

Caution regarding forward-looking information – the information specified above with respect to the possibility of and forecast for the signing of the agreement as aforesaid, constitutes forward-looking information, within the meaning thereof in Section 32A of the Securities Law, which there is no certainty will materialize, in whole or in part, in the manner stated or in any other manner, and may materialize in a materially different manner than described above, and in particular there is no certainty that the parties will reach an agreement regarding the terms and conditions of the agreement.

(d) Compressed Natural Gas (CNG) – the Partnership is examining the possibility of exporting gas to countries in the Mediterranean Basin, through natural gas compression (CNG) and transportation thereof in designated ships or using portable designated containers. Export of natural gas in this manner may allow access to new and additional export markets, including Greece, the Mediterranean Islands, Italy and other countries. The Partnership held preliminary discussions with customers interested in purchasing Israeli natural gas in such a manner. It is noted that to the Partnership's best knowledge, there are

[138] For further details, see the Ministry of Energy's announcement at: https://www.gov.il/he/departments/publications/Call_for_bids/flng_public.

currently no existing projects in the world for the supply of CNG through maritime transportation at large scopes.

7.13 **Order backlog**

7.13.1 Following are data regarding the Partnership's order backlog calculated on the basis of the minimum gas quantities (according to the take or pay (TOP) quantity) determined in binding agreements (agreements on a firm basis in which all of the conditions precedent were fulfilled) for the supply of natural gas and condensate from the Tamar and Leviathan projects, which the customers have undertaken to consume or pay for, subject to the following main assumptions: (1) all of the options granted to the customers of the Leviathan and Tamar Partners to reduce the contract quantity, as specified in Section 7.11.4(a)3 above shall be exercised; (2) in 2021-2022, the IEC's consumption under the Tamar agreement will be lower than the TOP, due to exercise of Carry Forward. In H1/2021, the Partnership's revenues from the IEC were reduced according to the provisions of the settlement agreements in Tamar and Leviathan described below; (3) the consumption of the IEC in 2021 over and above the minimum annual quantity under the Tamar agreement shall be carried out in accordance with the provisions of the Tamar and Leviathan settlement agreements which are described above; (4) the price forecasts are based on the assumptions used in relation to the calculation of the discounted cash flows in the Tamar Project, as specified in Section 7.3.11(a)3 and in relation to the Leviathan project as specified in the Partnership's immediate report of March 10, 2021 (Ref. no. 2021-01-030942), which is incorporated herein by reference; (5) no change shall occur in the minimal annual quantities in the Export to Egypt Agreements, as specified in Sections 7.12.5(a)(2) and 7.12.5(b)(2) above; (6) the revenues from the Tamar Project were calculated according to the Partnership's direct holdings in the Tamar Project (22%):

Year	**Total Revenues (dollars in millions) As of Dec. 31, 2020**	
	Leviathan Project	Tamar Project
Q1/2021*	Approx. 178	Approx. 54
Q2/2021*	Approx. 180	Approx. 52
Q3/2021*	Approx. 158	Approx. 82
Q4/2021*	Approx. 157	Approx. 82
2022	Approx. 530	Approx. 222
2023	Approx. 603	Approx. 247
2024	Approx. 629	Approx. 241
2025	Approx. 653	Approx. 245
2026	Approx. 657	Approx. 250
2027	Approx. 661	Approx. 255

Year	Total Revenues (dollars in millions) As of Dec. 31, 2020	
2028	Approx. 685	Approx. 185
2029	Approx. 697	Approx. 123
2030	Approx. 702	Approx. 118

* The division between the quarters was made on a linear basis and in accordance with the terms and conditions of the gas sale agreements (insofar as determined) in relation to the gas quantities that shall be supplied and the Partnership's assumptions.

Caution regarding forward-looking information – the Partnership's estimations with regard to the time and scope of anticipated revenue from the order backlog constitute forward-looking information within the meaning thereof in Section 32A of the Securities Law, based on the minimum gas quantities set forth in the binding agreements for natural gas supply from the Yam Tethys, Tamar and Leviathan projects, and on the assumptions detailed in this section: and there is no certainty of their consummation, and this *inter alia*, due to the effect of the risk factors associated with the Partnership's activity, as detailed in Section 7.29 below.

7.13.2 As of December 31, 2019, the Partnership's order backlog for 2020 was approx. $790 million. The Partnership's actual revenues in 2020 from such order backlog amounted to approx. $935 million. The difference between the anticipated amount of revenues from the order backlog and the actual revenues in 2020 derives from the fact that in most of the agreements, the actual sales volume was higher than the minimum gas quantities set forth in the agreements for the supply of natural gas from the aforesaid projects. For the purpose of the forecast of the order backlog, only agreements on a firm basis were taken into account, while agreements on an interruptible basis were calculated only on the basis of actual consumption in January-February 2021.

7.14 <u>**Competition**</u>

7.14.1 <u>Natural gas discoveries in Israel</u>

The supply of natural gas from the Partnership's petroleum assets is currently performed via pipeline and is mainly designated for the domestic market, and markets in adjacent countries. The Partnership's main competition is with the owners of natural gas and oil assets which operate in Israel and in neighboring countries and with LNG importers. It is noted that insofar as LNG facilities shall be built or the access to existing facilities shall be expanded, and insofar as the possibilities of export via pipeline are expanded, the target market potential will expand, the motivation for exploration, development and production activity in the market will increase.

With the commencement of the piping of natural gas from the Leviathan reservoir in December 2019, the vast majority of the natural gas currently supplied to the Israeli market originates from the Leviathan and Tamar reservoirs, which are the only producing reservoirs, as of the date of this report, in the area of the State of Israel. In addition, small quantities of liquefied natural gas (LNG) are supplied to the IEC via an LNG regasification vessel through the offshore buoy set up by INGL (the "**Offshore Buoy for LNG Import**"). For further details see Section 7.14.2 below.

In order to fulfill the provisions of the Gas Framework (which was designed to increase the competition between the holders of interests in the natural gas reservoirs discovered in Israel, as specified in Section 7.23.1 below), (a) the Partnership and Noble sold all of their interests in the Karish and Tanin reservoirs to Energean Israel; (b) the Partnership sold 9.25% of its interests in the Tamar and Dalit leases to Tamar Petroleum, as specified in Section 1.7.6 above; and (c) Noble sold 3.5% of its interests in the Tamar and Dalit leases to Everest and 7.5% of its interests to Tamar Petroleum. In addition, in accordance with the provisions of the Gas Framework, the Partnership is required to transfer, by December 17, 2021, all of its interests in the Tamar and Dalit leases, and in such case the Tamar reservoir will become a competitor of the Partnership. For details regarding the alternatives being explored by the Partnership in this regard, see Section 7.27.2 below.

On February 23, 2021 the Tamar Partners signed a balancing agreement for the separate marketing of the natural gas, which is subject to the fulfillment of certain conditions, the implementation of which by the Tamar Partners may increase competition. For further details see Section 7.11.4(a)6 above.

In August 2020, Energean filed with the Ministry of Energy a development plan for the Karish Norther reservoir 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 domestic market only. After completion of the development of the Karish, Karish North and Tanin reservoirs, these reservoirs are expected to be another significant supplier of natural gas to the domestic market, alongside the Leviathan and Tamar reservoirs. As stated in Section 7.8.2 above, to the Partnership's best knowledge and based on Energean's reports, the Karish reservoir is expected to begin production in Q1/2022.

On November 15, 2016, the Minister of Energy declared the opening of Israel's EEZ for oil and natural gas exploration, in a competitive proceeding (the "**Competitive Process**"), in view of the findings of independent research which was carried out for the Ministry of Energy, in which it was determined that in Israel's EEZ there is potential for identifying new discoveries at a total scope of approx. 6.6 billion barrels of oil and approx. 2,137 BCM of natural gas. In the framework of the Competitive Process, 24 exploration areas were offered of a maximum size of 400 km^2 each, at least 7 km from the shoreline, all in accordance with the directives of the Ministry of Energy on the matter. According to the terms and conditions of the tender, in order to encourage competition in the gas market in Israel, a body which holds more than 25% of the interests (directly or indirectly) in an offshore lease in which there is more than 200 BCM in the 2C category (contingent resources) on the date of publication of the tender (including the Partnership) was barred from submitting a bid in the tender.

As part of the Competitive Process, on January 15, 2018, the Ministry of Energy granted five licenses for exploration in Israel's EEZ to the Greek company Energean, and on April 9, 2018, it granted an oil exploration license in one block to a consortium of Indian companies. To the Partnership's best knowledge, as of the report approval date, the consortium of Indian companies waived rights to continue exploration in the area of the license. In addition, on November 10, 2020, Energean announced the waiver of rights to continue exploration in the area of the "Block 22" license, thus retaining four exploration licenses that were granted thereto in the context of the Competitive Process.

On November 4, 2018, the Minister of Energy announced a second competitive process for natural gas and oil exploration in the EEZ of Israel (in this section: the "**Second Competitive Process**"), in the framework of which 19 exploration licenses (blocks) were offered in five clusters of an area of approx. 1,600 km^2 each. The Ministry of Energy limited the number of licenses that shall be granted to each entity to 8 licenses only. In addition, it was determined that an entity that holds more than 25% in a petroleum interest in which there are reserves of more than 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 that is included in existing leases. As part of the Second Competitive Process, on October 28, 2019, the Energy Minister granted to a consortium that includes two British companies, Cairn Energy Plc. (the operator), Pharos Energy Plc., and

Ratio, 8 petroleum licenses in two clusters, and to Energean (the operator) and Israeli Opportunity 4 petroleum licenses in one cluster.[139]

On June 23, 2020, the Minister of Energy announced the launch of a third competitive process for natural gas and oil exploration in the EEZ of Israel (in this section: the "**Third Competitive Process**"), in the framework of which a single license known as "block 72" was offered which covers extensive parts of the Alon D license, with regard to which the Partnership, together with Noble as the operator, submitted an offer to receive the license in block 72. Note that on October 21, 2020, the Partnership received a request from the Competition Authority to produce information and documents in relation to block 72 (for additional details, see Section 7.9.3 above). As of the date of this report, no answer was received from the Ministry of Energy in relation to winning the Third Competitive Process. Note that block 72 borders with the offshore, unregulated border between Israel and Lebanon. To the best of the Partnership's knowledge, in the past year talks were held between the countries, brokered by the United States, in relation to the regulation of the border as aforesaid, however, no final agreements were reached in the matter.

On January 7, 2021, the Minister of Energy announced the launch of a fourth competitive process for natural gas and oil exploration in the EEZ of Israel (in this section: the "**Fourth Competitive Process**"), in the framework of which approx. 25 exploration licenses (blocks) were offered in six clusters of a maximum area of approx. 1,600 km^2 each.

Insofar as wells that shall be drilled in the areas of existing and/or new licenses as aforesaid lead to significant natural gas discoveries, and insofar as these discoveries (if any) will be developed, these reservoirs shall also constitute competition in the Partnership's field of business.

It is further noted that, to the Partnership's best knowledge, the British Gas Group (currently owned by Shell) discovered, over 15 years ago, off the Gaza coast, a natural gas reservoir called Gaza Marine, the scope of the resources in which is estimated at approx. 1 TCF, and this reservoir may in the future be developed and natural gas be marketed to the domestic market and to the Palestinian Authority.

7.14.2 <u>LNG import</u>

In January 2013, LNG import began to the domestic market using the LNG import buoy and the regasification vessel off the shores of Hadera. The LNG import buoy is intended to connect to a LNG tanker, which

[139] For the location of the licenses (blocks), see a publication from the website of the Ministry of Energy: http://www.energy-sea.gov.il/English-Site/Pages/Offshore%20Bid%20Rounds/2nd-Bid-Round.aspx.

converts LNG into gas via the regasification vessel, in an amount of up to approx. 0.5 BCF per day. During 2020, following a decline in LNG prices, the IEC purchased several LNG shipments at the expense of purchasing natural gas from the Leviathan and Tamar reservoirs. The position of the Leviathan Partners is that the purchase of LNG shipments by the IEC was performed in contradiction of the IEC-Leviathan Agreement. The dispute between the parties regarding such matter was resolved in the context of the Leviathan Settlement Agreement.

Note in such context that, on December 29, 2020, the Ministry of Energy reported that the regasification vessel, which operates since 2013 and was used over the years as backup for the energy sector in Israel for cases of shortage of natural gas in the peak hours or malfunctions, will discontinue its activity in approx. two years.[140] As aforesaid, the decision will be implemented in 2022, when the three natural gas reservoirs, Leviathan, Karish and Tamar will be connected to the shore and operate regularly. In addition, the existing infrastructure for the regasification vessel will remain ready for operation and will serve the sector if needed.

7.14.3 Coal and other alternative energy products

Coal and other alternative energy products also constitute competition for the natural gas suppliers. In relation to the consumption of natural gas by the IEC, the natural gas suppliers are in competition with the use of coal for electricity production, and therefore the level of the consumption and the price of the natural gas may be affected by the price of coal worldwide and by the tax policy thereon in Israel. For details regarding the decision of the Energy Minister to reduce the use of coal, see Section 7.23.5(d) below.

In addition, the natural gas supplied by the Partnership to industrial customers, replaces the use of liquid fuels, such as diesel oil and mazut. The price of the liquid fuels is usually higher than the price of the natural gas supplied by the Partnership. However, despite their being polluting, a drop in the oil prices worldwide may render these fuels competitive relative to the natural gas which is supplied to these consumers. However, it is noted that the Ministry of Environmental Protection institutes policy measures designed to ensure that plants with infrastructure for connection that enables usage of natural gas refrain from using polluting liquid fuels. Additionally, the wish to increase production of electricity from renewable and clean energies, such as wind energy or solar energy, may also lead to competition in the natural gas. For additional details on substitutes for natural gas, see Section 7.1.8 above.

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[140] Additional information is available on the Ministry of Energy's website at: https://www.gov.il/he/departments/news/press_291220

7.14.4 Renewable energy sources

Against the backdrop of public discourse regarding climate changes and the impact of humans thereon, significant incentives are presently being offered for the development of renewable energy sources, such as solar energy and wind energy, which compete with the natural gas sold by the Partnership for electricity generation purposes.

In 2020, the generation of electricity from renewable energy sources amounted to approx. 6% of all electricity generated in the State of Israel, and according to the Government's targets, as specified in Section 7.23.57.23.5(f) below, the rate of electricity generation from renewable energy sources is expected to amount to approx. 30% of all electricity generated in 2030, inter alia, by means of regulatory support and tax incentives to power plants generating electricity from renewable energy sources. It is noted that the generation of electricity from renewable energy sources holds many advantages, particularly in the environmental aspect; however, in Israel, the generation of electricity from renewable energy sources chiefly refers to solar energy, which employs a technology that is still relatively expensive and requires extensive areas. As such technology develops, along with the development of electricity storage technology which will allow for inexpensive and stable generation of power from solar energy, the share of renewable energy in the electricity generation mix in Israel is expected to grow.

7.14.5 Discoveries of natural gas in neighboring countries

(a) Egypt

To the best of the Partnership's knowledge, the scope of the reserves and the contingent resources of natural gas discovered in Egypt is estimated at approx. 50.6 TCF, of which approx. 30.1 TCF are defined as reserves and the remainder as contingent resources. In addition, there is potential for additional significant discoveries following the considerable offshore and onshore exploration activity that is being carried out in Egypt. In 2015, the natural gas reservoir 'Zohr' was discovered in Egypt, the scope of the resources in which, as of the report approval date, based on various reports, is estimated at approx. 19 TCF (2P). Production of gas from the Zohr reservoir began in December 2017, and is intended, to the best of the Partnership's knowledge, for supply mainly to the Egyptian domestic market. To the Partnership's best knowledge, the production from the Zohr reservoir currently constitutes approx. 40% of the total domestic gas production in Egypt, and such rate is expected to increase to 80% in 2030, insofar as no other large reservoirs shall be discovered and/or no other producing fields shall commence operations. Recently, Egypt authorized the partners in the Zohr reservoir to export specific quantities of natural gas from the reservoir as LNG, in international markets, after it is liquefied in the SEGAS facility. The export authorization was granted as part of a separate agreement between the facility's owners, which included the sale of holdings of Naturgy Energy Group S.A. in the facility and the restructuring of the ownership and operating agreements of the facility. Note that in recent years, considerable exploration and production activity has been conducted in Egypt's onshore and offshore areas, *inter alia*, upon the entry and expansion of the presence of significant players (such as Exxon Mobil, Shell, Chevron and Eni). In 2020 several dry or non-commercial wells were drilled in Egypt's EEZ. In addition in the H2/2020, Eni reported two shallow water discoveries in the Nile Delta which jointly amount, according to informal report, to approx. 1 TCF. For details regarding the scope of the domestic demand of the Egyptian market in 2019 and 2020 and forecasts of the domestic demand in Egypt for 2020 and 2021, see Section 7.12.2(b)2.b above. For additional details on the main possible target markets for the export of natural gas by the Partnership, see Section 7.12.2(b)3 above. Over the course of 2020, Egypt granted 8 licenses for exploration in its EEZ in the Mediterranean Sea. In February 2021, Egypt announced the launch of another tender, which consists, *inter alia*, of 9 licenses for exploration in its EEZ in the Mediterranean Sea.

(b) Cyprus

For further details regarding the Cypriot market, see Section 7.12.2(b)3.d above. It is noted that, as of the report approval date, there is no consumption of natural gas in Cyprus, even though significant gas discoveries have been made in its EEZ. The main reasons therefor are the scope of the investment required for development of the discoveries on the one hand, and the limited scope of the potential domestic market in Cyprus, on the other hand. However, it appears that the Cypriot government is acting for the import natural gas to Cyprus by other means, including through the construction of a floating regasification facility and the purchase of LNG, as specified below.

As of the report approval date, in the absence of relevant regulation in Cyprus with regard to natural gas export facilities, it cannot be estimated what effect, if at all, additional discoveries, if any, may have on the manner in which natural gas is exported from Cyprus and on competition, to the extent it develops, with regard to the domestic market and the access to export infrastructures.

To the best of the Partnership's knowledge, the Cypriot government and the Cypriot electricity company are acting to promote the replacement of use of petroleum-based products for electricity production with the use of natural gas. In October 2018, the Cypriot government published a tender for the construction of a facility for regasification of imported LNG for the needs of the domestic Cypriot market, while in December 2019, it reported that the winner of the tender is a consortium led by China Petroleum Pipeline Engineering Co. Ltd. Simultaneously with the aforesaid report, the Cypriot government stated that the facility construction project is due to be completed in Q1/2022. Accordingly, in June 2019, the Cypriot government published an LNG import tender. In December 2020, the Cypriot government updated that 25 different bids were received and that in 2021 it intend to sign agreements for future import of LNG with the different companies.

In February 2018, it was publicized that a consortium of the companies Eni and Total had discovered a new natural gas discovery in block 6 in the EEZ of Cyprus, called ‘Calypso’. Estimates of the resources in the said discovery have not yet been published, but it is estimated that they are approx. 6.4 TCF in a reservoir whose characteristics are similar to those of the Zohr reservoir. Note that a confirmation well was planned to be drilled in 2020, which was postponed to 2021 due to the Covid-19 Crisis. Calypso may have an impact on the Partnership's activities in Cyprus and/or Egypt. In addition, the companies that own the reservoir may wish to export the gas to the Egyptian domestic market and/or transport it to the Egyptian liquefaction facilities in order to sell the same in the international markets. It is noted that liquefaction of gas will utilize part of the liquefaction capacity in the Egyptian liquefaction facilities.

In September 2018, it was publicized that a consortium led by ExxonMobil had begun drilling two exploration wells in block 10 in the EEZ of Cyprus.[141] In February 2019, the consortium publicized in the media that it had made a new natural gas discovery called ‘Glaucus’, with preliminary estimates of approx. 5-8 TCF of gas in place, and that the consortium intends to continue the interpretation work and drilling appraisal wells in order to better estimate the scope of the resources. Note that a confirmation well was planned to be drilled in 2020, which was postponed to 2021 due to the Covid-19 Crisis. Such discovery may have an impact on the Partnership’s activity in Cyprus and/or in Egypt.

In September 2019, it was reported that the Cypriot government had granted an exploration license in block 7 to Total and Eni in the context of a tender proceeding that was offered to companies holding licenses that are attached to block 7 only. In addition, the Cypriot

[141] Based on public releases of ExxonMobil.

government announced Total's entry into blocks 2, 3, 8, 9 that are owned by Eni (together with additional partners).

In addition, to the best of the Partnership's knowledge, in the coming years, additional exploration wells are expected to be drilled in the EEZ of Cyprus, by a consortium headed by Eni in blocks 3 and 8.[142] Confirmation and appraisal drillings are planned this year in Glaukos (Block 10) and Calypso (Block 6). It is noted that according to reports in the media, the existing tension between Cyprus and Turkey may affect the timetables for exploration activity in the EEZ of Cyprus. *Inter alia*, it was reported in the media that drilling rigs of the Turkish national oil company had attempted to perform exploration activity, including drillings in the EEZ of Cyprus. To the best of the Partnership's knowledge, no activity of drilling rigs belonging to Turkey has been taking place in Block 12 (in which the Aphrodite reservoir is situated), since it is not located in the area of the EEZ which Turkey, on behalf of the Turkish Republic of Northern Cyprus, is claiming as its territory.

(c) Lebanon

At the end of February 2020, Total, which heads a consortium in block 4 in the EEZ of Lebanon, announced the arrival of the Tungsten Explorer drilling vessel in the area of the license and a forecast for commencement of an exploration drilling, probably to a Miocene layer target. On April 26, 2020 the drilling ended, according to Total's reports, without a significant finding. To the Partnership's knowledge, this consortium is planning a well in Block 9, which partially overlaps the maritime area in dispute between Lebanon and Israel. It is noted that since September 2020, indirect discussions are held between the countries, with American mediation, in order to regulate the EEZ rights in this region. In addition, note that Block 9 is situated on the border of Block 72 which is offered in the bid for exploration of gas and oil in Israel's EEZ, as well as on the border of the Alon D license.

7.15 **Seasonality**

7.15.1 In Israel and in Jordan, the consumption of natural gas for electricity production is affected, *inter alia*, by seasonal fluctuations in the demands for electricity and by the maintenance plans of the electricity producers. Generally, in the first and third quarter of the year (the winter and summer months) electricity consumption will be highest. In Egypt, gas consumption is significantly affected by the demand for electricity and for

[142] Based on public releases of Eni.

energy for cooling purposes, and therefore the summer months are the peak months in demand for natural gas.

7.15.2 Following is data regarding the segmentation of natural gas sales (in terms of 100% of the Tamar and Leviathan projects) in the past two years:[143]

Period	Q1 (in BCM)	Q2 (in BCM)	Q3 (in BCM)	Q4 (in BCM)
2020	3.6	2.9	4.6	4.4
2019	2.7	2.4	2.8	2.6

7.16 Facilities and production capacity

7.16.1 The Leviathan project

(a) Phase 1A of the Leviathan project's development plan

The production system of Phase 1A comprises five main segments, as follows:

1. Production wells: Four subsea production wells with a production capacity of up to approx. 400 MMCF per day, each. Natural gas from the Leviathan reservoir, which is at a depth of approx. 3 km below the seabed, is piped from the production wells to the subsea production system.

2. A subsea production system: The subsea production system connects between the production wells and the production platform, and is on the seabed. The subsea system comprises 14-inch pipes through which the natural gas and the condensate are transported from the wells to the subsea manifold; two pipes with a diameter of 18 inches and approx. 120 km long come out of the manifold, transmitting gas and condensate to the production platform. In addition, the subsea system includes two pipes with a diameter of 6 inches and approx. 120 km long, for the transmission of MEG from the production platform to the wells; a command and control cable (umbilical), approx. 120 km long, that connects the production platform to the wells and enables the control and command of the production of the natural gas from the wells.

3. Processing and production platform: The Leviathan platform is situated approx. 10 km from the shore. The platform is attached to the seabed at a water depth of approx. 86 meters via a jacket. On the upper part of the jacket, which protrudes above sea level, the topsides of the platform are assembled, which are

[143] The data relates to the total sales of natural gas of all of the Leviathan Partners and the Tamar Partners, rounded off to one tenth of a BCM. It is noted that the data do not include quantities supplied from the maritime buoy for the import of LNG, which usually operates mainly during the months of peak demand for natural gas.

divided at this stage into two main modules: (1) the domestic supply module which contains, *inter alia*, the natural gas and condensate production and processing facilities, including facilities to separate out water from the gas, facilities for treatment of MEG, a facility for reduction of emissions (FGRU), generators, tanks, pumps, air compressors, a helipad, workers' living quarters, firefighting facilities, lifeboats, security facilities, gas dehydration facilities and auxiliary facilities and services, etc.; (2) the liquids supply module which stores condensate and MEG. The platform is planned to process approx. 1,200 MMCF of gas per day and approx. 5,400 barrels of condensate per day. Note that under certain operational conditions, *inter alia* via the turbo expanders, the production capacity of the platform is expected to exceed such quantity. It is noted that unlike the Tamar Project, in which the final processing of the gas and condensate is performed at the onshore terminal, in the Leviathan project the entire processing is performed at sea, on the platform.

4. Transmission system to the shore: The pipeline that comes out of the Leviathan platform to the shore comprises a 32-inch pipe for the transmission of natural gas[144] and a 6-inch pipe for the transmission of condensate. These pipes run under the shoreline, via a designated 52-inch pipe which serves as a sleeve, and reach the coastal valve station and from there, the Dor valve station, which is situated near the INGL valve station, to which the natural gas is transferred. The condensate pipe connects to EAPC's buried onshore oil pipeline at the Nachsulim Valve Station.

5. Hagit site: The Hagit site includes a condensate storage tank and the pipes, apparatus, equipment, pumps, command, control and operating systems, a tanker-filling facility, auxiliary facilities and services, insofar as required for safe and environmentally-friendly operation. The condensate reaches the Hagit site via a buried 6-inch pipe. With no ability to transport to ORL, the condensate will be transported and stored at the Hagit site, and transported to ORL when made possible, or insofar as necessary, will be removed therefrom using tankers, to the customers. Note that the works for the construction of the condensate storage system at the Hagit site has been completed in 2020 and in February 2021, all of the permits required for the operation thereof have been obtained.

[144] For details regarding a license for the construction and operation of a transmission system, see Section 7.23.5(l) below.

As of the date hereof, and according to the development plan, the maximum daily production capacity from the Leviathan project amounts to approx. 1,200 MMCF per day. As of the report approval date, the approval of the Ministry of Energy to begin the operation of the turbo expander system has been received. The system's operation is expected to increase the production capacity above 1,200 MMCF.

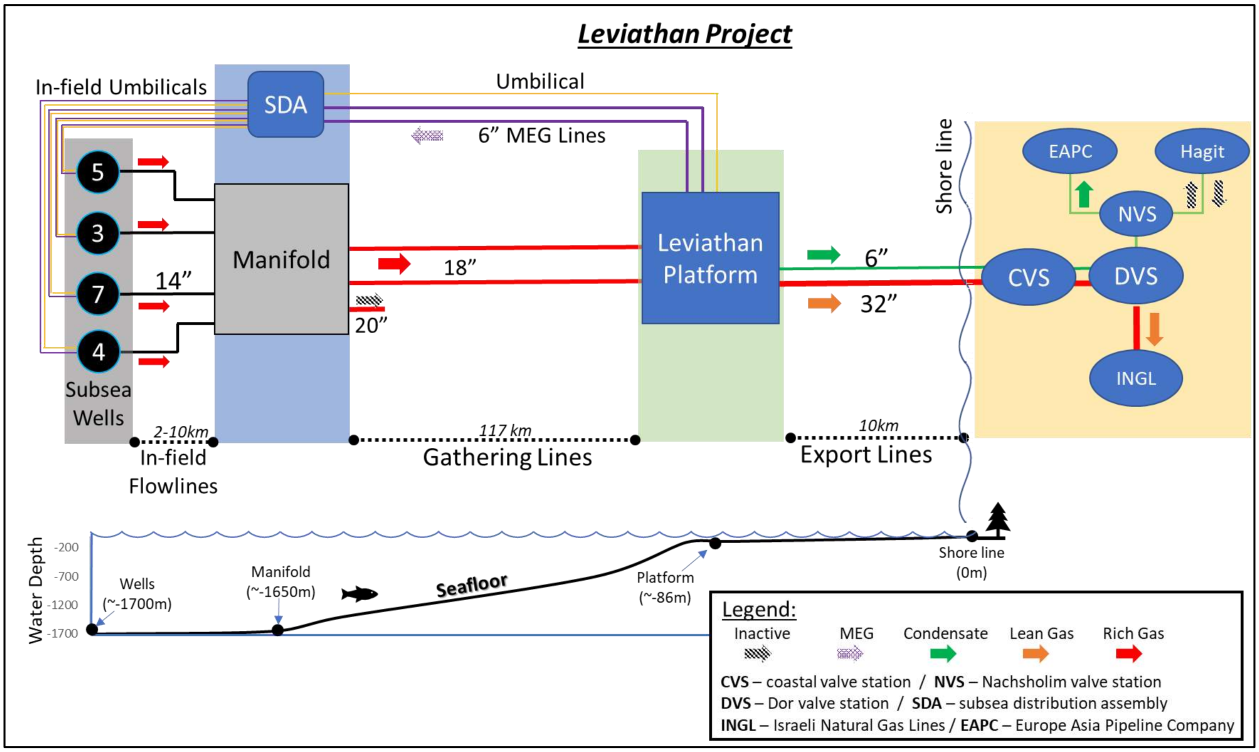
It is further noted that during the preliminary stages of activity of the Leviathan project, operational events were recorded at the Leviathan platform which are being examined by the operator with a view to improve the regularity and continuity of the production. As informed by the operator, such operational events had a negligible impact on the ability to meet the demand and the environmental data, *inter alia*, from the onshore monitoring systems, indicated that no damage was caused to the environment. Accordingly, as informed by the operator, in 2020 the Leviathan project's up time was approx. 98.5%, equivalent to or exceeding the performance of comparable facilities in the world which are at a similar stage to that of the Leviathan project.

(b) Phase 1B of the Leviathan project's development plan

The facilities planned in the Leviathan project in accordance with Phase 1B of the development plan, if and when a decision to approve it shall be adopted, may include, *inter alia*: four more production wells with a production capacity of approx. 400 MMCF per day each, that shall be connected via a sub-sea pipeline to the existing production system; another sub-sea pipeline, with a diameter of 20 inches and approx. 120 km long for the transmission of gas from the manifold to the platform; a regional export module will be added to the platform with processing facilities similar to those existing in Phase 1A plus compressors, and with a processing capacity of approx. 900 MMCF per day, which are mainly intended for regional export, such that together with the Phase 1A processing facilities, the total daily production capacity of the platform shall be approx. 2,100 MMCF. The transmission of the gas from the platform to the export markets shall be performed, *inter alia*, via a designated pipeline, as specified in Section 7.12.2(b) above.

Regarding various alternatives for the additional stages in the Leviathan project's development plan, see Section 7.2.5(b) above.

(c) Below is a diagram of the Leviathan project's facilities for Phase 1A:



7.16.2 Tamar Project

(a) The Tamar Project's production system comprises five main segments, as follows:

1. Production wells: Six subsea production wells with a production capacity of up to approx. 250 MMCF per day each. Natural gas from the Tamar reservoir, which is at a depth of approx. 3 km below the seabed, is piped from the production wells to the production system on the seabed.

2. A subsea production system: The subsea system connects between the production wells and the production platform, and is on the seabed. The subsea system comprises of pipes with a diameter of 10 inches through which the natural gas and the condensate are transported from the wells to the subsea manifold; two pipes with a diameter of 16 inches and approx. 150 km long each (the "**Double Pipeline**") come out of the manifold, transporting natural gas and condensate to the production platform. In addition, the subsea system includes two pipes with a diameter of 6 inches and approx. 150 km long, for the transmission of MEG (an antifreeze substance) from the production platform to the wells; two command and control cables (umbilicals), approx. 150 km long,

that connect the production platform to the wells and enable control and command of the production of the natural gas from the wells. Means have been installed in the Double Pipeline that will in future enable the connection of the Dalit reservoir to the Tamar Project's production system. The maximum gas supply that may be transported via the Double Pipeline under the current conditions is approx. 1.1 BCF per day, and it therefore constitutes the bottleneck of the production system in the project.

3. Processing and production platform: The Tamar platform is situated approx. 25 km from the shore and approx. 2 km north of the Mari-B platform. The platform is fixed to the seabed at a depth of around 236 meters by means of a jacket. On the upper part of the jacket, which is exposed above sea level, the topsides of the platform are assembled, which contain, *inter alia*, the natural gas production and processing facilities, including facilities to separate out water from the gas, facilities for storage, treatment and recycling of MEG, TEG gas dehydration units, an emission reduction facility, generators, tanks, pumps, air compressors, a helipad, workers' living quarters, firefighting facilities, lifeboats, security facilities, etc. The platform is planned to process approx. 1,200 MMCF of natural gas per day and approx. 5,400 barrels of condensate per day. The processing capacity on the platform may be increased by operating the four existing trains, to a level of approx. 1,600 MMCF of natural gas per day and approx. 7,200 barrels of condensate per day, subject to the performance of necessary adjustments on the platform.

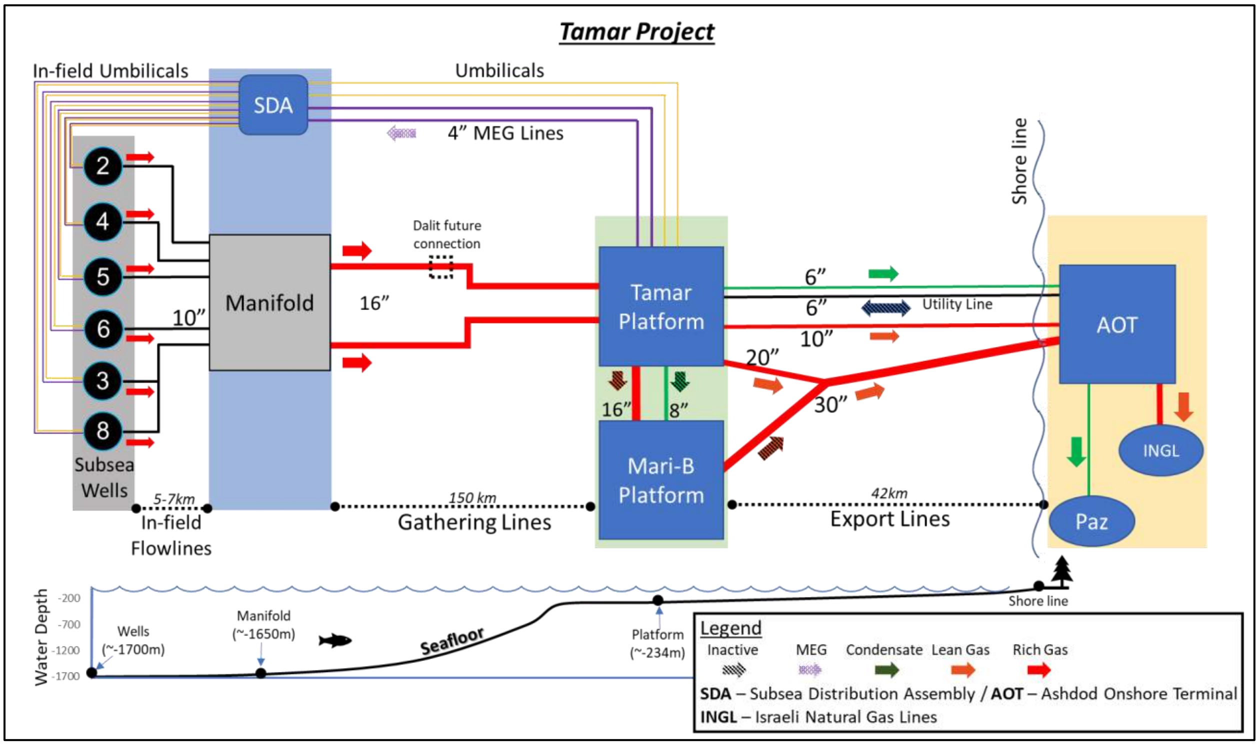
4. A transmission system to the shore and to the Mari-B platform: The transmission system from the Tamar platform comprises two parts – (1) a pipeline from the platform to the Terminal, which includes a short section of pipe with a diameter of 20 inches that connects to a 30-inch pipe for the transport of natural gas, a pipe with a diameter of 10 inches for the supply of natural gas, and two pipes with a diameter of 6 inches for the supply of condensate and/or MEG from the Tamar platform to the Terminal; (2) a pipeline that connects the Tamar platform to the Mari-B platform, which includes a pipe with a diameter of 16 inches for the supply of natural gas, a pipe with a diameter of 8 inches for the supply of condensate, and the equipment required in order to insert natural gas and condensate into the Mari-B reservoir, insofar as shall be required.

5. The Terminal: which includes a system for supplementary processing of the gas transported from the processing and production platform such that it will comply with the quality requirements for the purpose of the transport thereof in INGL's

national gas transmission system, and a condensate stabilization, storage and transmission system.

For further details regarding the development plan for the Tamar Project, including expansion of the supply capacity, see Section 7.3.4(b)-(c) above.

(b) Below is a diagram of the Tamar Project's facilities:



7.17 **Raw materials and suppliers**

In general, the Partnership does not directly engage with suppliers or professional contractors, since the engagement is between the suppliers or the contractors and the project's operator. In Israel, at this point in time, generally, there are no drilling contractors nor contractors for seismic surveys and some of the offshore infrastructure and development work of the type performed by the Partnership, together with its partners, in the various projects, and therefore the operator engages with contractors from overseas for the purpose of performance of such work, which are instructed to integrate into their activity, insofar as possible, local services and consultants. The offshore drilling facilities and other designated equipment are leased and brought in from all over the world in accordance with their availability, the work type and the project requirements. An additional important parameter that affects this matter is the crude oil price, an increase in which generally affects the scope of the activity in the industry and consequently the availability of contractors and the required equipment.

7.18 **Human capital**

7.18.1 The Partnership is managed by the General Partner in accordance with the provisions of the Partnership Agreement. The General Partner provides the Partnership with management services including, *inter alia*, managers (the directors of the General Partner who are not outside directors, and the CEO of the General Partner), controller services, finance management and bookkeeping. In general the Partnership's workers are employed under personal employment agreements. The officers and senior management of the Partnership are employed under the terms and conditions agreed with each one of them, and include, *inter alia*, monthly salary, the right to a company car, a cellular phone, and contributions to manager's insurance and a continuing education fund. For further details regarding the employment conditions of said officers and senior management, see regulations 21, 26 and 26A of Chapter 4 hereof.

7.18.2 In accordance with the provisions of the Partnerships' Ordinance, on July 10, 2019, the general meeting of the holders of the Participation Units in the Partnership approved an updated compensation policy for officers of the Partnership and the General Partner. For further details, see Subsection (b)(1) of Reg. 21 of Chapter D hereof.

7.18.3 As of December 31, 2019 and December 31, 2020, the Partnership employed employees as follows:

Department	**Number of Employees as of December 31, 2019**	**Number of Employees as of December 31, 2020**
Management, Headquarters and Finance	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**

7.18.4 In addition to the managers of the General Partner and the Partnerships' workers above, the Partnership uses various consultants, including geological and professional consultants, lawyers and financial consultants) to the extent that such counsel is required. In addition, it should be noted that in the framework of operational agreements in various projects, the projects operator employs manpower to manage and operate the projects.

7.19 Working capital

7.19.1 The Partnership's working capital comprises, on the assets side, primarily the cash balances, short-term investments, trade and other receivables balances deriving from the joint ventures, while on the liabilities side, primarily bonds, loans from financial corporations and payables deriving from the joint ventures.

7.19.2 Working Capital Deficit

According to the figures in the Partnership's financial statements as of December 31, 2020, the Partnership has a working capital deficit of approx. $148, which primarily derives from the current maturities of Series A Bonds, payment of which is due in December 2021. On March 14, 2021, the board of directors of the General Partner determines that such deficit does not indicate a liquidity problem for the Partnership, and, accordingly, there is no warning sign, within the definition of such term in Section 10(b)(14)(a) of the Securities Regulations (Periodic and Immediate Reports), 5730-1970. For further details on this matter, see Section 3E of the Part One of the Board of Directors' Report (Chapter B of this report).

	Sum included in the Financial Statements as of December 31, 2020 ($ in thousands)
Current assets	417,903
Current liabilities	566,047
Excess of current liabilities over current assets	148,144

7.20 Financing

7.20.1 General

As of the report approval date, the Partnership finances its activity mainly from income from the sale of natural gas to customers of the Tamar and Leviathan projects and from the issue of bonds to the institutional market in Israel and overseas and to the Israeli public.

7.20.2 Bonds of Leviathan Bond Ltd.

On August 18, 2020, Leviathan Bond Ltd., an SPC which is wholly (100%) owned by the Partnership, completed an issuance of bonds to foreign and Israeli institutional investors, in accordance with Rule 144A and Regulation S, in the overall amount of $2.25 billion, in 4 different bond series, as follows (in this section: the "**Bonds**" and the "**Leviathan Bond Issuance**", respectively):

(a) Bonds in the overall amount of $500 million par value, payable on June 30, 2023 (in one installment), bearing fixed annual interest of 5.75%.

(b) Bonds in the overall amount of $600 million par value, payable on June 30, 2025 (in one installment), bearing fixed annual interest of 6.125%.

(c) Bonds in the overall amount of $600 million par value, payable on June 30, 2027 (in one installment), bearing fixed annual interest of 6.5%.

(d) Bonds in the overall amount of $550 million par value, payable on June 30, 2030 (in one installment) bearing fixed annual interest of 6.75%.

The Bond principal and interest are in dollars. The interest on the Bonds of each series shall be paid twice per year, on June 30 and on December 30. The Bonds were listed on TASE's "TACT-Institutional" system. For additional information on the Leviathan Bond Issuance see the Company's Immediate Report of August 5, 2020, which is incorporated herein by reference (Ref. no. 2020-01-084006).

The issue proceeds were made available by the subsidiary as aforesaid as a loan to the Partnership, and under terms and conditions that are identical to the Bond terms and conditions (back-to-back). The balance of the loan as of December 31, 2020 (net of capital raising costs) was approx. $2,219.3 million. Note that, upon completion of the Leviathan Bond Issuance on August 18, 2020, the loan which was provided to the Partnership for the purpose of financing its share of the balance of the investment in the development of the Leviathan project in the overall amount of $1.75 billion, was fully repaid, and the loans provided to the Partnership in the overall amount of $300 million were also fully repaid. For additional details, see Sections 7.21.1(a) and 7.21.1(b) of the Partnership's 2019 periodic report, as released on March 30, 2020 (Ref. no. 2020-01-032010) and see Note 10C to the financial statements (Chapter C of this report) and Part Five of the Board of Directors' Report (Chapter B of this report).

7.20.3 <u>The bonds of Delek & Avner (Tamar Bond) Ltd.</u>

On May 19, 2014 Delek & Avner (Tamar Bond) Ltd., a wholly owned special purpose company (SPC) (100%) of the Partnership completed a bond offering to accredited investors in the U.S., Israel and other countries, in the total amount of $2 billion in 5 different bond series in the sum of $400 million each, which are payable in December of each of the years 2016, 2018, 2020, 2023 and 2025 (in this section: the "**Bonds**"). The Bonds were registered for trade on the TACT-institutional system of TASE.

The issue proceeds were provided by such subsidiary as a loan to the Partnership, and under the same terms and conditions as the terms and conditions of the Bonds (back-to-back). On October 6, 2016, the Partnership prepaid the first series in the total (original) amount thereof of $400 million, instead of on the original repayment date thereof on December 30, 2016. On July 27, 2017, the Partnership performed a partial repayment of the four series (2018, 2020, 2023 and 2025) at the rate of 20% of the sum of the unpaid balance of each one of the bond series (i.e. U.S. $80 million in each one of the series), plus accrued interest in the sum total of approx. $1.1 million, all in accordance with the provisions of the indenture of the Bonds. On August 31, 2018, the second series (2018) was prepaid at the total scope thereof of $320 million, instead of on the original payment due date thereof on December 30, 2018. The amount of the prepayment of the second series as aforesaid included the principal amount, plus accrued interest in the sum total of approx. $2.1 million and plus a prepayment fee in the sum of approx. $1.3 million. For further details, see the Partnership's immediate report of July 19, 2018 (Ref.: 2018-01-068986), the details appearing in which are incorporated herein by reference. On July 15, 2020 the Partnership partially repaid the third series (2020) in the amount of $240 million, of the overall amount of $320 million, instead of on its original repayment date, December 30, 2020. The amount of partial repayment of the third series as aforesaid includes the principal amount together with accrued interest of approx. $0.4 million and together with a prepayment fee of approx. $4.2 million. For additional details, see the Partnership's immediate report dated June 14, 2020 (Ref. no. 2020-01-061266), the details appearing in which are incorporated herein by reference. On December 30, 2020, the balance of the third series (2020) was repaid at a scope of $80 million. The balance of the loan as of December 31, 2020 (net of raising costs) was approx. $635 million. For further details, see Note 10B to the financial statements (Chapter C hereof) and Part Five of the Board of Directors' Report (Chapter B hereof).

7.20.4 Series A bonds

On December 26, 2016, the Partnership completed a bond offering to the public in the amount of approx. ILS 767.8 million and in a parallel offering of bonds of the Avner Partnership, a similar sum of approx. ILS 760.7 million was raised. Upon completion of the Merger, the Series A bonds of the Partnership were consolidated with the Series A bonds of the Avner Partnership, such that the two series shall constitute a single series of Series A bonds in the sum of approx. ILS 1.5 billion. The Series A bonds are registered for trade on TASE. The issue proceeds are designated for use by the Partnership for investment in and the financing of the activity in the Partnership's petroleum assets and for the financing of the Partnership's other current needs and, *inter alia*, for profit distributions. The balance of the loan as of December 31, 2020 (net of capital raising costs) was approx. $394 million. For further details, see Note 10E to the financial statements (Chapter C hereof) and Part Five of the Board of Directors' Report (Chapter B hereof).

7.20.5 As provided in Section 1.7.6 above, on July 20, 2017, the Partnership closed a sale transaction for Tamar Petroleum of rights in the rate of 9.25% (of 100%) of the Tamar and Dalit leases against, *inter alia*, consideration in cash of approx. ILS 3 billion. Of the total consideration in cash, the Partnership designated approx. U.S. $321 million for partial prepayment of the four bond series of Tamar Bond (series 2018, 2020, 2023 and 2025) as provided in Section 7.20.3 above.

7.20.6 As part of the implementation of the Gas Framework, the Partnership sold its holdings in Karish and Tanin and is acting to sell its holdings in the Tamar Project. The net proceeds (after tax, repayment of bonds/loans and other relevant liabilities, if any, *inter alia*, under the Partnership Agreement) to be received from the sale of such Leases shall serve, *inter alia*, to finance the Partnership's operations.

7.20.7 According to the approval of the Income Tax Commission that was granted to the Partnership around the time it was formed, the Partnership undertook not to take out loans in an amount exceeding 3% of the amount that would be raised from the investors in the Partnership, other than in coordination, and with the prior approval of the Income Tax Commission.

7.20.8 On May 17, 2018, the meeting of the holders of the Participation Units in the Partnership approved the performance of an offering of Participation Units and/or securities convertible into Participation Units by way of a rights offering to the existing holders of the Participation Units, during a period from the date of the meeting's approval as aforesaid until May 6, 2021, at a scope and under conditions to be determined according to the resolution of the General Partner for the purpose of raising sums that will be required, in the opinion of the General Partner, for the financing of the Partnership's operating activity, including the making of investments in the Partnership's petroleum assets and repayment of its existing liabilities, and authorized the General Partner to determine the structure, scope and timing of the offering, at its sole and absolute discretion, subject to the sum total of the proceeds of the offering (or offerings) in the said period not exceeding the sum in ILS equal to $300 million. As of the report approval date, such securities have not yet been issued. Performance of such offerings may be carried out at any time in the framework of one or more prospectuses and/or one or more shelf offering reports, as shall be determined by the General Partner.

7.20.9 With respect to non-distribution of some of the profits of the Partnership for the financing of drilling, exploration and development actions and the EMG Transaction, see Sections 4.4.4 to 4.4.7 above.

7.20.10 On July 26, 2020, the board of directors of the General Partner approved a plan for purchase of the Series A bonds and for purchase of the bonds of Delek and Avner (Tamar Bond) Ltd., in the estimated overall cost of up to US $50 million (for purchase of the Series A bonds and the bonds of Delek and Avner (Tamar Bond) Ltd. together). For additional details, see the Partnership's immediate report dated July 27, 2020 (Ref. no. 2020-01-072868), the details appearing in which are incorporated herein by reference. The Partnership performed buy-backs in accordance with the purchase plan as aforesaid in the amount of ILS 11,413,393 par value Series A bonds in consideration for approx. $3 million.

7.20.11 On November 17, 2020, the board of directors of the General Partner approved an additional plan for purchase of the Series A bonds, in the estimated overall cost of up to $30 million. The purchases were made from time to time in the period between November 19, 2020 and December 31, 2020, in transactions on or off TASE. Note that this plan replaced the buy-back plan stated in Section 7.20.10 above. For additional details, see the Partnership's immediate report dated November 18, 2020 (Ref. no. 2020-01-115468), the details appearing in which are incorporated herein by reference. In accordance with the aforesaid purchase plan, the Partnership performed buy-backs in the amount of ILS 7,450,000 par value Series A bonds in consideration for approx. $2 million. For additional details, see Section 3E of Part Five of the Board of Directors' Report (Chapter B of this report).

7.20.12 Financial covenants

(a) Series A bonds - The Partnership has met the financial covenants to which it committed in the framework of the issuance of the Series A bonds to the public as stated in Section 7.20.4 above, as specified below:

Financial covenant[145]	**Method of calculation**	**The ratio checked as of December 31, 2020 and the report approval date**[146]
The Partnership's economic capital[147]	If the economic capital falls below \$400 million (the "**Minimum Economic Capital**") for two consecutive quarters. [148]	Approx. 3,438
The economic capital to debt ratio	If the ratio between the Partnership's economic capital and the Partnership's debt on a standalone basis falls below 300% (x3) for two consecutive quarters.	Approx. 9
Distribution	If the Partnership performed a distribution or gave notice of an intention to perform a distribution which is one of the following: (a) a distribution contrary to the provisions of the Partnerships Ordinance and the Companies Law, 5759-1999 (the "**Companies Law**"); (b) a distribution of revaluation profits; and (c) a distribution after which the economic capital to debt ratio will fall below 450% (x4.5).	-

7.21 **Taxation**

[145] As specified in the indenture, non-compliance with the financial covenants described shall constitute grounds for acceleration for the trustee and for the bondholders.

[146] The ratio was calculated, *inter alia*, based on the discounted cash flow of the Tamar Project as of December 31, 2020 and which is included in this report, and the discounted cash flow of the Leviathan project as of December 31, 2020 and which is included in this report.

[147] The Partnership's equity, according to the last annual or quarterly financial statements published by the Partnership, as the case may be, net of the cost of the investment recorded in the said statements in all of the projects in respect of which discounted cash flow was included in the last annual periodic report published by the Partnership, or in respect of which discounted cash flow was published on a date later than the last annual periodic report in the framework of the Partnership's reports pursuant to the provisions of the Securities Law (the "**Projects**" and the "**Last Discounted Cash Flow**", respectively), plus the sum of the Last Discounted Cash Flow of the Projects and plus the abandonment expenses recorded in the said statements in respect of the Projects. For this purpose: (a) "Discounted cash flow" – as defined in Section 36 of the Third Schedule to the Securities Regulations (Details of the Prospectus and Draft Prospectus – Structure and Form), 5729-1969; and (b) "Sum of the discounted cash flow" – the sum of the discounted cash flow of the 2P probable reserves and/or of the 2C probable contingent resources of the Projects, as the case may be, after income tax at the rate applicable to companies, discounted at a rate of 10%.

[148] If, on any date, the sum of the unpaid par value of the bonds in circulation falls below ILS 400 million, then the Minimum Economic Capital will be \$250 million. The aforesaid notwithstanding, if, on any date after an update of the Minimum Economic Capital as aforesaid, the bond series is expanded such that the sum of the unpaid par value of the bonds in circulation is ILS 800 million and above, then the Minimum Economic Capital will return to \$400 million.

7.21.1 For details regarding taxation, see Note 20 to the financial statements (Chapter C hereof).

7.21.2 On October 12, 2020, the draft Income Tax Regulations (Rules for Tax Calculation due to Holding and Sale of Participation Units in an Oil Exploration Partnership) (Amendment), 5781-2020 (in this section: the “Draft Regulations”), was published for public comment. In accordance with the Draft Regulations, it was proposed to determine, *inter alia*, that commencing from the tax year 2021, a petroleum partnership whose participation units are listed for trade on a stock exchange shall be taxed as a “company”, i.e., according to the two-phase taxation method, beginning from the tax year in which the petroleum partnership generated taxable income or distributed profits. For additional details, see the Partnership’s immediate report dated October 22, 2020 (Ref. no. 2020-01-115485). On November 4, 2020, the Partnership submitted its comments on the Draft Regulations. For additional details, see Note 20A4 to the financial statements (Chapter C of this report).

7.21.3 <u>Section 19 of the Taxation of Profits from Natural Resources Law</u>

(a) The Partnership is a “transparent” entity for tax purposes, according to the provisions of the Income Tax Ordinance (New Version) 5721-1961 (the "**Income Tax Ordinance**") and the Taxation of Profits from Natural Resources Law, and the taxable income as well as the losses of the Partnership are allocated to the unit holders, who are "Entitled Holders" as this term is defined in the Income Tax Regulations (Participation Units) according to the ratio of their holdings in the Partnership. An "Entitled Holder" is the holder of participation units at the end of December 31 of the tax year.

(b) Pursuant to the provisions of Section 19 of the Taxation of Profits from Natural Resources Law ("**Section 19**"), the General Partner must submit to the assessing officer a report on the Partnership's taxable income and pay the tax deriving therefrom, on account of the tax payable by the partners in the Partnership in the tax year in respect of which the report was filed (i.e. on account of the tax owed by the holders of participation units, as they shall be on December 31 of each tax year) (the "**Entitled Holders**"). Pursuant to the provisions of Section 19, the tax owed by the General Partner upon the filing of the report shall be calculated according to the holding rate in the Partnership of the Entitled Holders who are a body corporate ("**Corporate-Holders**") and the holding rate in the Partnership of individual Entitled Holders ("**Individual-Holders**") and in this respect the taxable income of Individual Holders shall be deemed as subject to the maximum tax rate, unless it was proven to the assessing officer that the tax rate applicable to an individual is lower that the said rate (the "**Tax Calculation Under Section 19**").

(c) In the context of a motion for instructions that the Supervisor filed with the court on October 30, 2016, the interpretation and manner of implementation of Section 19 was discussed for the first time. On November 1, 2017, the District Court issued its judgment, in which it was ruled *inter alia* that: (a) the tax payment deriving from the provisions of Section 19 should not be deemed as an equal distribution, in a uniform amount per unit, but rather as differential payment according to the various tax rates which apply to individuals and corporations; (b) payment of the tax under Section 19 creates a difference in the expense incurred by the Partnership between individuals and corporations, but Section 19 pertains to the collection of tax, not the regulations of relationships between the holders of participation units; and (c) as long as the collection arrangement prescribed by Section 19 is in effect, the Partnership and/or the General Partner must find the appropriate way to balance between the additional expense entailed by the tax rate applicable to Individual-Holders and the expense entailed by the tax rate applicable to Corporate-Holders.

(d) On December 31, 2017, the General Partner in the Partnership filed an appeal from the judgment of the District Court (in this section: the "**Partnership's Appeal**"), in which the Supreme Court was moved to rule on the proper interpretation of Section 19, in such manner as to determine a fixed, known and industry-wide method for taxing the taxable income of petroleum partnerships, whereby all petroleum partnerships will be able to act, *inter alia*, with certainty, while allocating the tax payment among the holders equally, thus avoiding the oppression of holders liable for a lower rate than the maximum tax rate that applies to an individual. The Supreme Court was further moved to rule as follows: (a) the tax paid by a petroleum partnership under Section 19 should be equally allocated among all of the units in the partnership; (b) accordingly, the Partnership should issue to the unit holders equal tax certificates, such that the tax paid by the Partnership, on account of the tax for which the unit holders are liable, shall 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 needed, whether for purposes of supplementation of the tax payment required therefrom, or receipt of a tax refund; (c) alternatively, to determine that the decision of the District Court, whereby the tax should be allocated to holders in a differential manner shall apply from prospectively, whereas in respect of the past, petroleum partnerships may allocate the tax paid to the relevant holders equally, and accordingly be entitled to issue equal tax certificates; (d) alternatively, insofar as it is determined that the tax payment pursuant to Section 19 is not a distribution within the meaning thereof in the Companies Law, it shall then be determined that also a balancing payment that is made to Corporate-Holders (in order 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 oppression of holders who are liable for a rate lower than the maximum tax rate that applies to individuals (such as corporations or institutional bodies).

(e) On July 28, 2019, the judgment of the Supreme Court was received, denying the Partnership’s appeal (the "**Appeal Judgment**"). The Supreme Court adopted the judgment of the District Court and ruled, *inter alia*, that an arrangement whereby the Partnership shall bear the full tax rate of the holders, individuals and corporations alike, as mandated by Section 19 and shall concurrently, or thereafter, make balancing payments to Corporate-Holders, is not a "distribution" as defined in the law, but rather an outcome mandated by the fact that payments were made out of the profits on account of the tax. However, the Supreme Court clarified that it does not purport to make recommendations or to set hard and fast rules regarding the balancing payment technique.

(f) As specified at length below, in proximity to the end of the tax years 2017 to 2020, alongside payments on account of the tax owed by Individual-Holders, the Partnership made balancing payments to Corporate-Holders. It is noted that the balancing payments that were so made in respect of such tax years do not necessarily constitute full balancing of the payment derived from the tax rate applicable to Individual-Holders against the payment derived from the tax rate applicable to Corporate-Holders, since if there shall be a gap between the estimated taxable income according to which the payments were made and the final assessment issued to the Partnership in the future ("**Differences**"), the Partnership shall be required to pay the Tax Authority (or receive as a refund therefrom) the tax difference mandated by the Differences. It is noted that as of the date of the report, there is ambiguity regarding the correct balancing arrangement in respect of tax payments deriving from the Differences, if any.

(g) Since balancing payments, as made in respect of the tax years 2017-2020, were not made in respect of the tax years 2015 and 2016 (the "**Past Period**"), there is ambiguity, on the report approval date, regarding the proper balancing arrangement which the Partnership should apply with respect to the Past Period.

For further details see Note 20 to the financial statements (Chapter C hereof).

In view of the existing ambiguity regarding the proper balancing arrangements which the Partnership should apply, in respect of both the Past Periods and the Differences that shall transpire only in the future, the Partnership and the General Partner filed an originating application with the Tel Aviv District Court, in the context of which the court was moved, *inter alia*, to determine the appropriate arrangements for striking a balance between individuals and corporations holding Participation Units of the Partnership, in view of tax payments the Partnership is required to make pursuant to Section 19, including: (a) Tax payments insofar as any derive as a result of a difference between the estimation of the taxable income made by the Partnership toward the end of the tax year and the self-assessment submitted by the Partnership; and/or tax payments insofar as any derive from a difference between the self-assessment submitted by the Partnership and the final tax assessment issued therefor (the "**Assessment Differences**"); and (b) Tax payments made due to the Past Periods; considering the fact that it may be that whoever held a Participation Unit on the record date for a tax year in Past Periods, will no longer hold the same when it transpires (if at all) that the Partnership is required to pay an additional tax for that tax year (or vice versa) and considering the difference in the rates of the tax which applies to individuals and corporations. In the originating application, the court was presented with various possible alternatives for arrangements in connection with the tax payments due to Assessment Differences and due to Past Periods, for it to rule what such appropriate arrangements are. A copy of the originating application specifying the aforesaid alternatives was attached as an annex to the Partnership's immediate reports dated July 13, 2020 and October 19, 2020 (Ref. numbers 2020-01-067480 and 2020-01-113487, respectively), the details appearing in which are incorporated herein by reference. The respondents in the originating application are holders of Participation Units in the Partnership on the dates that are relevant to the originating application and the Partnership's Supervisor that asked to join the originating application as a respondent in order to be able to present an independent position on his behalf in the context thereof.[149] Note that on October 18, 2020, the court approved the motion of the Partnership and the General Partner to effect alternative service of process on holders of Participation Units by way of advertising a public notice, which enabled each holder of a Participation Unit of the Partnership on the dates that are relevant to the originating application (including all the current holders of Participation Units of the Partnership) to join as a party to the proceeding. The court also ordered that the originating application be heard together with an

[149] On August 18, 2020, the meeting of the participation unit holders approved a budget for the Partnership's Supervisor in order to engage with Adv. Dr. Zeev Hollander, for the purpose of his representation as a respondent in the legal proceeding as aforesaid. For additional details, see the Partnership's immediate reports dated August 10, 2020 and August 18, 2020 (reference numbers: 2020-01-076858 and 2020-01-080758, respectively), the details appearing in which are included herein by reference.

originating application filed by Isramco on the same matter (O.A. 32178-03-20). On December 29, 2020, another pre-trial hearing was held, in which the court asked for 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 ordered that the parties may apply to the Tax Authority to find out its detailed position with respect to such proposals and thereafter file a summary document with the court which presents the Tax Authority's position. On March 11, 2021, following an application to the Tax Authority by one of the holders' groups, the Tax Authority's position was filed with the Court. The Court allowed the parties to respond to such position by March 18, 2021.

The Partnership estimates, based on the opinion of its legal counsel, that there is a higher than 50% chance that the Partnership will be required to pay no less than $13.1 million or so however, it is unable to estimate the probability that the Partnership will be required to incur an amount which is higher than the aforesaid amount pursuant to past tax payments.

It is further noted that based on the Partnership's tax report for 2019, and based on the Partnership's results for 2020, the Partnership has updated the estimate of its taxable income for each of the tax years 2019 and 2020. Since, as of the report approval date, there is ambiguity as to the correct balancing arrangement that the Partnership is required to adopt with respect to 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 in the financial statements in respect of the aforesaid.

7.21.4 On December 2, 2020, the Taxation of Profits from Natural Resources Regulations (Advances due to the Oil Profit Levy), 5781-2020 were published (in this section: the "**Regulations**")[150] regulating the payment of the advances that shall be paid by holders of petroleum interests in a petroleum project, including the method of calculation of the advances, the dates of payment thereof, and the reporting thereon.

The Regulations are promulgated by virtue of Sections 10(b) and 51 of the Taxation of Profits from Natural Resources Law, 5771-2011 (in this section: the "**Law**") and their aim is to regulate the payment of the advances that shall be paid by holders of petroleum interests in a petroleum project. The Regulations pertain to the determination of the

[150] https://www.gov.il/BlobFolder/legalinfo/law8957/he/LegalInformation_kesher_8957.pdf

calculation of the advances, the payment dates, and the reporting thereon, as defined in the Law. Below is the essence of the main provisions included in the Regulations:

(a) The Regulations determine that a holder of a petroleum interest in a petroleum project (in this section: the "**Holder of a Petroleum Interest**") shall pay advances on account of the levy for that tax year, the payment starting from the tax year following the tax year in which the levy coefficient is 1 or more, plus interest and linkage differentials from the date set for the payment until the payment of the advance amount.

(b) In addition, formulae were determined for the calculation of the advance amount, rate, payment date and manner of reporting of the amount paid. According to the Regulations, anyone who is a Holder of a Petroleum Interest shall be liable for payment of the advances according to its proportionate share of the petroleum interest. It was further determined that for purposes of sale of petroleum separately in co-owned projects under Section 18 of the Taxation of Profits from Natural Resources Law, the current revenues in the effective month of the Holder of a Petroleum Interest in the petroleum project. Additionally, it was determined that in the first three tax years starting from the tax year following the tax year in which the levy coefficient is 1 or more, or starting from the 2021 tax year, whichever is later, the rate of the advance shall be: in the first tax year-21%; in the second tax year-30%; and in the third tax year, 37%.

(c) Pursuant to Section 9(b)(1) of the Law, a derivative payment is a payment calculated as a rate of the petroleum produced in the petroleum project area, from the project revenues or from the oil profits of the project. The recipient of a derivative payment is liable for payment of a levy known as the "participation amount". The section determines that the participation amount shall be subtracted from the levy for which the Holder of a Petroleum Interest is liable. Hence, the Regulations determine that the participation amount withheld by a Holder of a Petroleum Interest, as payment on account of advances for which it is liable. Such withholding is contingent on the fulfillment of all the following: (1) The Holder of a Petroleum Interest transferred the amount of the levy withheld thereby to the assessing officer, no later than the date of payment of the advance for the effective month; (2) The transferred withheld amount was not previously offset; (3) The effective month due to which the setoff was required falls in the same tax year as that in which the derivative payment was received.

(d) The assessing officer may decrease or increase the rate of the advance for a specific tax year if it shall have been proven to his satisfaction that the levy for the tax year in which the advance is paid is higher or lower than the total advances calculated for that tax year.

According to the Regulations, in 2020, the Partnership paid advances on account of the oil profit levy in the sum of approx. $2 million for its interests in the Tamar Project.

7.21.5 Taxation of Profits from Natural Resources Legislative Memorandum (Amendment), 5781-2021

On January 7, 2021, a Taxation of Profits from Natural Resources Legislative Memorandum (Amendment), 5781-2021 (in this section: the "**Proposed Memorandum**") was released for public comment, proposing several amendments to the Law, including: (1) amendment of Section 11 of the Law in a manner enabling the Tax Authority to collect a levy under dispute already after the decision of the Tax Authority in an administrative objection to a levy assessment and before the dispute was litigated at the Court; (2) amendment of Section 13 of the Law in a manner requiring that levy reports be certified by an accountant as defined in the Accountants Law, 5715-1955; (3) amendment of Sections 14-15 of the Law in a manner enabling an extension of the assessment period of the levy reports from one year of the submission date of the levy report to a period of 4 years of the end of the year in which the levy report was filed; (4) addition of Section 16(a) to the Law contemplating the application of the provisions of Section 86 of the Ordinance regarding the authority of the assessing officer to disregard certain transactions; and (5) addition of Section 41(a) to the Law granting the assessing officer with authority to impose a fine on the deficit deriving from the difference between the actual levy charge and the payment of the levy according to a self-assessment. There is no certainty as to whether and when the Proposed Memorandum shall be adopted and in which format (if adopted). .

7.21.6 Tax Years 2015-2016

(a) On December 13, 2017, temporary tax certificates were received for Entitled Holders in respect of holding a participation unit of the Partnership and the Avner Partnership (jointly: the "**Partnerships**") for the tax year 2015 and the tax year 2016 (in this section: "**Entitled Holders**").[151] It is hereby emphasized and clarified as follows:

1. Holders of participation units of the Partnership will be entitled (but not obligated) to include in their tax reports for 2015 and 2016 their share in the taxable income of the Partnership and their share in the tax amount that was paid by the Partnership, in respect of the participation units that were held thereby for such years, according to the temporary tax certificates.

2. The temporary certificate will allow the participation unit holders who are an "entitled holder" and who have losses for tax purposes or an exemption from tax in any of the said tax years,

[151] Everything described above in respect of the participation units of the Partnership applies, *mutatis mutandis*, also to the participation units of the Avner Partnership.

to receive tax refunds for the tax that was paid by the Partnership and was attributed to them.

3. In accordance with agreements with the Tax Authority, this is a temporary tax certificate only, and the final tax certificate for any such tax year will be produced only upon completion of the Tax Authority's audit. The final tax accounting of any "entitled holder" shall be carried out according to the final assessment of the Partnership and the final certificate for the purpose of calculation of the tax of an "entitled holder".

4. The unit holders that shall act according to Paragraph 1 above shall be required to amend their reports in accordance with the final tax certificate that shall be released by the Partnership, in which case the amount of the refund or the payment to which the entitled holder is entitled or for which it is liable may decrease or increase as a result of the aforesaid, and accordingly, unit holders may also be required to repay the Tax Authority amounts that were received thereby based on the temporary certificate.

5. The table below specifies the data stated in the temporary tax certificates for the purpose of calculation of the gain (deduction) for an entitled holder of one participation unit of par value ILS 1 (in ILS) in 2015-2016:

Tax Year	Profit from business for tax purposes		Capital gain from marketable securities		Interest from marketable securities		Tax paid on account of the tax for which individual entitled holders[152]		Tax paid on account of the tax for which body corporate entitled holders are liable[153]	
	The Partnership	Avner	The Partnership	Avner	The Partnership	Avner	The Partnership	Avner	The Partnership	Avner
2015	0.36424	0.05335	0.05220	0.00925	0.03006	0.00493	0.19409	0.02894	0.11698	0.01768
2016	0.71042	0.10373	-	-	0.01568	0.00213	0.34492	0.05033	0.18152	0.02647

6. For further details, see temporary tax certificates for Entitled Holders due to the holding of a participation unit of the Partnership and the Avner Partnership[154] for the tax years 2015 and 2016, which were attached to the Partnership's immediate report of December 13, 2017 (Ref.: 2017-01-116190), the

[152] In the tables included in this section: individual – including a liable mutual fund and partnership.
[153] In the tables included in this section: body corporate – including a company, provident fund, public institution and exempt mutual fund.
[154] It is noted that due to the merger of the Avner Partnership with and into the Partnership, the tax certificate for an entitled holder due to the holding of a participation unit of the Avner Partnership was released in the Partnership's immediate reports.

information appearing in which is incorporated herein by reference.

(b) It is noted that although as of the date of the report, the Tax Authority audit of the tax reports of the Partnership and Avner for the tax year 2015 is completed, and assessment agreements were signed with the Tax Authority (the "**2015 Assessment Agreements**"), final tax certificates for the tax year 2015 have not yet been issued, since the Income Tax Regulations (Participation Units) were in effect until June 30, 2015, and they have not yet been extended to a later date. Final tax certificates according to the 2015 Assessment Agreements shall be issued and released only after the extension of the effect of the regulations. According to the 2015 Assessment Agreements the taxable income of the Partnership and the Avner Partnership in 2015 is approx. ILS 317.4 million and approx. ILS 293.3 million, respectively, in respect of which the Partnership and the Avner Partnership paid tax on account of the holders of units in the Partnership and the Avner Partnership in the amount of approx. ILS 92 million and ILS 88 million, respectively.

(c) It is further noted that in view of the disputes between the Partnership and the Tax Authority and disagreements regarding the amount of the Partnerships’ taxable income in 2016, assessments to the best of judgment were received from the Tax Authority on November 22, 2018, pursuant to Section 145(a)(2)(b) of the Income Tax Ordinance (in this section: the "**Tax Assessment**"), whereby the taxable income from a business of the Partnership and the Avner Partnership for 2016 is approx. $149.8 million and approx. $135.7 million, respectively (instead of approx. $124.1 million and approx. $110.1 million, respectively, as included in the Partnerships' tax reports which were filed with the Tax Authority), and the capital gain of the Partnership and the Avner Partnership for 2016 is approx. $54 million and approx. $71.8 million, respectively (instead of approx. $7.4 million and approx. $17 million, respectively, as included in the Partnerships' tax reports which were filed with the Tax Authority). Note that the foregoing amounts were translated from ILS to $ according to the dollar exchange rate known as of December 31, 2020.

The dispute pertains primarily to the interpretation of the manner of recognition of various expenses actually borne by the Partnerships, and the method of calculating the capital gain from the sale of the Karish and Tanin Leases.

Further to the administrative objection filed by the Partnership to the Tax Assessments, the Tax Authority issued to the Partnership an order for tax assessments pursuant to Section 152(b) of the

Ordinance (the “**Orders**”) primarily pertaining, as aforesaid, to the manner of recognition of financing expenses and other expenses actually incurred by the partnerships and the manner of calculation of the capital gain from the sale of the Karish and Tanin leases.

According to the tax assessments, and if all of the Tax Authority's arguments are accepted, the Partnership shall be liable to pay additional tax (including interest and linkage differentials) on account of the tax owed by holders of participation units in the Partnerships of approx. U.S. $46.3 million. On September 15, 2020, the Partnership filed an appeal from the Orders to the Tel Aviv District Court. The grounds for the assessment in this appeal were submitted by the assessing officer on December 9, 2020, and according to the Court’s decision, the deadline for submitting the notice of the grounds for the appeal by the Partnership is May 3, 2021.

It is noted that in view of the aforesaid, the issue of final tax certificates for Entitled Holders, in respect of the holding of a participation unit of the Partnership and the Avner Partnership for the tax year 2016, may be delayed until the completion of the proceeding required for the determination of a final assessment. In the Partnership's estimation, based on the opinion of its legal counsel and past experience, the chances that the main arguments of the Partnership are accepted are higher than 50%.

(d) For details regarding the current ambiguity regarding the proper balancing arrangement which the Partnership should apply in respect of the tax years 2015 and 2016, see Section 7.21.3(g) above.

7.21.7 Tax Year 2017

(a) For details regarding an agreement on tax collection for the tax year 2017, which was signed between the Partnership and the Assessing Officer for Large Enterprises (the "**2017 Arrangement**"), an estimate of the Partnership's taxable income for 2017, and payments made by the Partnership on January 18, 2017 pursuant to the 2017 Arrangement, see immediate reports of December 21, 2017 and December 24, 2017, December 28, 2017 and December 31, 2017 (Ref.: 2017-01-118860, 2017-01-119130, 2017-01-122175 and 2017-01-123051), the information appearing in which is incorporated herein by reference.

(b) On November 8, 2018, a temporary tax certificate was received for an entitled holder due to the holding of a participation unit of the Partnership for the tax year 2017 (in this section: “**Entitled Holder**”). It is hereby emphasized and clarified that:

1. Holders of participation units of the Partnership will be entitled (but not obligated) to include in their tax reports for 2017 their share in the taxable income of the Partnership and their share in the tax amount that was paid by the Partnership, including tax that was deducted in the framework of the payments the Partnership made on January 18, 2018 for the tax year 2017, in respect of the participation units that were held thereby at the close of December 31, 2017, according to the temporary tax certificate.

2. The temporary certificate will allow the participation unit holders who are an "entitled holder" and who have losses for tax purposes or an exemption from tax in the tax year 2017, to receive tax refunds for the tax that was paid by the Partnership and was attributed to them.

3. In accordance with agreements with the Tax Authority, this is a temporary tax certificate only, and the final tax certificate for 2017 will be produced only upon completion of the Tax Authority's audit. The final tax accounting of any "entitled holder" shall be carried out according to the final assessment of the Partnership and the final certificate for the purpose of calculation of the tax of an "entitled holder", which may be materially different to the temporary tax certificate.

4. The unit holders that shall act according to Paragraph 1 above shall be required to amend their reports in accordance with the final tax certificate that shall be released by the Partnership, in which case the amount of the refund or the payment to which the entitled holder is entitled or for which it is liable may decrease or increase as a result of the aforesaid, and accordingly, unit holders may also be required to repay the Tax Authority amounts that were received thereby based on the temporary certificate.

5. The table below specifies the data stated in the temporary tax certificate for the purpose of calculation of the gain (deduction) for an entitled holder of one participation unit of par value ILS 1 (in ILS) in 2017:

Taxable income from a business for tax purposes	Capital gain in a business	Capital loss from marketable securities overseas	Interest from marketable securities		Income from dividend overseas	Tax paid on account of the tax for which individual entitled holders are liable	Tax paid on account of the tax for which body corporate entitled holders are liable	Credit from foreign tax paid overseas[155]	
			Overseas	In Israel				On income from interest from overseas	On income from a dividend from overseas
0.62266	1.61050	(0.02665)	0.01167	0.00008	0.00035	0.54832	0.53236	0.00002	0.00056

6. For further details, see the temporary tax certificate for an entitled holder due to the holding of a participation unit of the Partnership for 2017 that was attached to the Partnership's immediate report of November 8, 2018 (Ref. No.: 2018-01-101494), the information appearing in which is incorporated herein by reference.

(c) Against the backdrop of the disputes which erupted between the Partnership and the Tax Authority and disagreements regarding the amount of the taxable income of the Partnership for tax purposes for 2017, on July 23, 2020, a tax assessment to the best of judgment was received from the Tax Authority, pursuant to Section 145(a)(2)(b) of the Income Tax Ordinance (in this section: the "Tax Assessment"), whereby the Partnership's taxable income from a business for 2017 is approx. $392.6 million (in lieu of approx. $231.8 million, as included in the Partnership's tax report that was filed with the Tax Authority) and the Partnership's capital gain for 2017 is approx. $705 million (in lieu of approx. $578.3 million, as included in the Partnership's tax report that was filed with the Tax Authority). Note that the foregoing amounts were translated from ILS to $ according to the dollar exchange rate known as of December 31, 2020. The main disputes pertain to the interpretation of the manner of recognition of financial expenses and additional expenses actually borne by the Partnership, including attribution of financial income

[155] In a case where offsetable losses may be offset against income of Israeli residents, such losses must be offset and may not be deferred to subsequent years, other than in irregular cases explicitly permitted by the Ordinance, even if such setoff prevents another benefit, such as a credit from foreign taxes. In other words, where there is an offsetable loss in Israel and taxable income from overseas, the loss setoff rules in the Ordinance require setoff before the rules of credits.

deriving from exchange rate differences to a property under construction, the manner of implementation of Section 20(b) of the Taxation of Profits from Natural Resources Law with regard to deduction of depreciation expenses and the manner of calculation of the capital gain from the sale of 9.25% (of 100%) of the rights in the Tamar and Dalit leases. As of the report approval date, and pursuant to the Tax Assessment, and insofar as all the Tax Authority's claims are accepted, the Partnership will be required to make an extra tax payment (including interest and linkage differentials) at the expense of holders of Participation Units in the Partnership in the amount of approx. $87 million. Note that in view of the aforesaid, the issuance of a final tax certificate for an eligible holder due to the holding of a Participation Unit of the Partnership for the 2017 tax year may be delayed pending the completion of the proceedings which will be required for the determination of the final assessment. On December 10, 2020, the Partnership filed an administrative objection to the Tax Assessment. On March 7, 2021, a preliminary hearing of the administrative objection took place at the offices of the assessing officer, and several additional hearings are expected to be held further thereto. The Partnership estimates, based on the opinion of its legal counsel, that the chances of the main part of the Partnership's arguments being accepted are higher than 50% and therefore, the Partnership intends to exhaust the administrative and legal proceedings which are available thereto.

7.21.8 <u>Tax Year 2018</u>

(a) For details regarding the Partnership's decision to act in respect of the tax year 2018 similarly to the way it acted in the tax year 2017 (according to the 2017 Arrangement), and regarding the estimate of the Partnership's taxable income for 2018, as well as payments made by the Partnership in respect thereof on January 14, 2019 see immediate reports of December 24, 2018 and December 31, 2018 (Ref.: 2018-01-117988 and 2018-01-120982, respectively), the information appearing in which is incorporated herein by reference.

(b) On February 18, 2020, a temporary tax certificate was received for an entitled holder due to the holding of a participation unit of the Partnership for the tax year 2018 (in this section: "**Entitled Holder**"). It is hereby emphasized and clarified that:

1. Holders of participation units of the Partnership will be entitled (but not obligated) to include in their tax reports for 2018 their share in the taxable income of the Partnership and their share in the tax amount that was paid by the Partnership, including tax that was deducted in the framework of the payments the Partnership made on January 14, 2019 for the tax year 2018, in

respect of the participation units that were held thereby at the close of December 31, 2018, according to the temporary tax certificate.

2. The temporary certificate will allow the participation unit holders who are an "entitled holder" and who have losses for tax purposes or an exemption from tax in the tax year 2018, to receive tax refunds for the tax that was paid by the Partnership and was attributed to them. In addition, the temporary certificate will allow an entitled holder to offset a loss incurred thereby up to and including the tax year 2017 against a deferred capital gain in a business.

3. In accordance with agreements with the Tax Authority, this is a temporary tax certificate only, and the final tax certificate for the tax year 2018 will be produced only upon completion of the Tax Authority's audit. The final tax accounting of any "entitled holder", including determination of the rate of holdings by individuals and bodies corporate in the Partnership, shall be carried out according to the final assessment of the Partnership and the final certificate for the purpose of calculation of the tax of an "entitled holder", which may be materially different to the temporary tax certificate.

4. The unit holders that shall act according to Paragraph 1 above shall be required to amend their reports in accordance with the final tax certificate that shall be released by the Partnership, in which case the amount of the refund or the payment to which the entitled holder is entitled or for which it is liable may decrease or increase as a result of the aforesaid, and accordingly, unit holders may also be required to repay the Tax Authority amounts that were received thereby based on the temporary certificate.

5. The table below specifies the data stated in the temporary tax certificate for the purpose of calculation of the gain (deduction) for an entitled holder of one participation unit of par value ILS 1 (in ILS) in 2018.

Taxable income from a business	Deferred capital gain in a business[156]	Capital loss from marketable securities overseas	Interest from marketable securities		Dividend income received from an Israeli-resident body corporate	Tax paid on account of the tax owed by Individual Entitled Holders	Tax paid on account of the tax owed by Body-Corporate Entitled Holders	Foreign tax credit paid overseas on income from interest from overseas
			Overseas	**In Israel**				
0.3759719	0.0491379	(0.0126482)	0.0127708	0.0006408	0.0491379	0.1112019	0.0984108	0.0000314

6. For further details, see temporary tax certificates for Entitled Holders due to the holding of a participation unit of the Partnership for the tax years 2018, which were attached to the Partnership's immediate report of February 19, 2020 (Ref.: 2020-01-017376), the information appearing in which is incorporated herein by reference.

7.21.9 Tax Year 2019

For details regarding the Partnership's decision to act in respect of the tax year 2019 similarly to the way it acted in the tax years 2017 and 2018, and regarding the estimate of the Partnership's taxable income for 2019, as well as payments made by the Partnership in respect thereof on January 9, 2019 see immediate reports of December 23, 2019 and December 24, 2019 (Ref.: 2019-01-112650 and 2019-01-113175, respectively), the information appearing in which is incorporated herein by reference.

According to the tax report filed by the Partnership, which is subject to review by the Tax Authority, the taxable income for tax purposes is approx. ILS 573.6 million. It is noted that the Partnership is acting to issue a temporary tax certificate.

7.21.10 Tax Year 2020

For details on the Partnership’s decision to operate with regard to the 2020 tax year similarly to the manner in which the Partnership operated in the 2017 to 2019 tax years, and with regard to the estimation of the Partnership’s taxable income for tax purposes for 2020 and payments made by the Partnership in relation thereto on January 20, 2021, see the

[156] According to the tax decision received on July 20, 2017 in respect of the sale of 9.25% (out of 100%) of the interests in the Tamar and Dalit leases, it was agreed that Entitled Holders may offset the deferred capital gain in a business only against a loss incurred thereby up to and including the tax year 2017. For further details, see Note 20A10 to the financial statements (Chapter C of this report).

Partnership's immediate report dated December 27, 2020 (Ref. no. 2020-01-140187), the information included in which is incorporated herein by reference.

In the preparation of the Partnership's financial statements upon the conclusion of the audit, the Partnership's estimate of taxable income for the 2020 tax year was updated, based on, *inter alia*, estimations of the General Partner, assumptions and various taxation opinions, to a total amount of approx. ILS 594 million.

As of the report approval date, the Partnership's estimate of taxable income for the 2020 tax year was updated based on various taxation opinions, notes and assumptions, to a total amount of approx. ILS 594 million.

7.21.11 **To clarify and emphasize**: in respect of each one of the tax years 2016 forth, in respect of which the Tax Authority audit of the tax report of the Partnership is yet uncompleted, it may transpire after the completion of the Tax Authority audit that there are assessment differences, such that the final tax assessment is higher than the tax payments made by the Partnership (net of refunds which were paid thereto), and in such case the Partnership will be required to pay to the Tax Authority, on account of the holders, the tax balance deriving from the Assessment Differences, according to the tax calculated under Section 19. Similarly, should it transpire in the future that advances were paid by the Partnership in amounts exceeding the amount required by law, the balance will be repaid to the Partnership.

For details regarding the Partnership's application to the Court in connection with the implementation of Section 19, see Section 7.21.3(c) above.

In view of the aforesaid, it is emphasized that as long as there is no decision regarding the manner in which the Partnership should act in respect of the said cases, the ambiguity remains with respect to both the Past Period (the tax years 2015 and 2016) and Assessment Differences, whose existence and scope (if any) shall transpire in the future.

7.21.12 It is further noted that the Income Tax Regulations (Rules for the Calculation of Tax due to the Holding and Sale of Participation Units in Oil Exploration Partnerships), 5749-1988 are in effect only until June 30, 2015, and as of the date of this report, their effect has not yet been extended. It is noted that on October 12, 2020 the Ministry of Energy published for public comment draft Income Tax Regulations (Rules for the Calculation of Tax due to the Holding and Sale of Participation Units in

Oil Exploration Partnerships) (Amendment), 5781-2020 for public comment, as specified in Section 7.21.2 above.

Every holder should examine its tax status through professional consultants, as well as the need for preparation according to the recommendations of its professional consultants as aforesaid. The Partnership is not responsible and shall not bear any responsibility in connection with the reports of the unit holders and/or amendment thereof and/or repercussions of amendment thereof.

7.21.13 It is clarified that the unique tax issues, including the levy pursuant to the Taxation of Profits from Natural Resources Law, related to the Partnership's activity have yet to be addressed in Israeli case law, and it is difficult to anticipate or to determine how the Court will rule if and when said legal issues are brought before them. In addition, with regard to certain of the legal issues, it is difficult to anticipate what the Tax Authority's position will be. For further details see Note 20B to the financial statements (Chapter C of this report).

7.22 **Environmental risks and management thereof**

7.22.1 Activity of exploration, development and production of oil or natural gas naturally entails the risk of causing damage to the environment, that may occur, *inter alia*, from faults in equipment and/or work procedures, and/or unforeseen events. The severity of the risks varies from event to event, and therefore the manner of management and treatment of them varies too.

7.22.2 The Partnership is subject to the provisions of the law and/or instructions of competent authorities on environmental issues.

(a) The Petroleum Law and its regulations provide, *inter alia*, that upon performing drilling cautionary measures will be taken, such that there will be no unchecked liquids or gases flowing into the earth or rising from it and that there be no penetration from one geological layer into another. In addition, it is forbidden to abandon a well without plugging it according to the instructions of the Petroleum Commissioner.

(b) In addition, the Partnership's activity via the operator may be subject to the provisions of various environmental laws including the Prevention of Sea Pollution (Dumping of Waste) Law, 5743-1983 and the regulations promulgated thereunder; Prevention of Sea Pollution from Land-Based Sources Law, 5748-1988 (the "**Prevention of Sea Pollution Law**") and the regulations promulgated thereunder; Prevention of Sea Water Pollution by Oil Ordinance (New Version), 5740-1980; Hazardous Substances Law, 5753-1993 and the regulations promulgated thereunder; Maintenance of Cleanliness Law, 5744-1984 and the regulations promulgated thereunder; Liability for

Compensation for Oil Pollution Damage Law, 5764-2004 and the regulations promulgated thereunder; Environmental Protection (Supervision and Enforcement Powers) Law, 5771-2011 and the regulations promulgated thereunder; Prevention of Environmental Nuisances (Civil Actions) Law, 5752-1992; Clean Air Law, 5768-2008 (the "**Clean Air Law**") and the regulations promulgated thereunder; Environmental Protection (Emissions and Transfers to the Environment – Reporting Duty and Register) Law, 5772-2012 and the regulations promulgated thereunder; Abatement of Nuisances Law, 5721-1961 and the regulations promulgated thereunder; Protection of the Coastal Environment Law, 5764-2004; Licensing of Businesses Law, 5728-1968, the regulations and the orders promulgated thereunder.

(c) In addition, apart from the regulation prescribed by Israeli law, there are additional provisions on environmental issues determined also in the terms of the lease deeds that were given to the Partnership, and in the approvals for the construction and operation of the production systems of the projects in which the Partnership is a partner. Upon exploration, drilling and/or in the framework of the production of oil and natural gas, the Partnership purchases, independently and/or through the operator, in accordance with directives for provision of collateral in connection with petroleum interests (see Section 7.23.4(a) below), insurance to cover damage for expenses of environmental cleanup, removal of debris and bodily injury and/or property damage to third parties which derive from a sudden, unexpected and uncontrolled accidental eruption of oil and/or natural gas. The Partnership does not take out insurance for non-accidental pollution damage resulting from a gradual and ongoing process. In such context, the Petroleum Regulations (Principles for Offshore Petroleum Exploration and Production), 5777-2016 (which revoked the regulations of 2006) include various provisions regarding offshore petroleum exploration and production activity, and *inter alia* conditions in relation to the identity of an operator, including with respect to its experience in maintaining safety and environmental protection in the framework of petroleum exploration and production.

(d) In September 2016, the Ministry of Energy, jointly with the Ministry of Environmental Protection and additional government offices, published directives intended to regulate the environmental aspects of the offshore exploration, development and production of oil and natural gas. These directives aim to instruct the offshore petroleum interest holder of the activities and documents they need to prepare in the framework of their activity in the area of their rights, in order to prevent or minimize, to the extent possible, environmental damage which may occur upon offshore exploration, development and production of oil and natural gas. For details regarding the environmental directives as aforesaid, see Section 7.23.5(i) above.

(e) In addition to the instructions of the Ministry of Energy and the Ministry of Environmental Protection, in its activity the Partnership may, directly or indirectly, be subject to environmental directives of additional authorities that may be given from time to time, on behalf of other governmental bodies, including the Israel Land Authority.

(f) In addition, the operating approvals of the Leviathan and Tamar platforms determine the leaseholder’s duty to act, on issues of environmental protection, pursuant to the law and instructions and permits that are given pursuant to any law, and also determine provisions with respect to the discharge of emissions into the sea, emissions into the air, etc. The said operating approvals further determined that on matters in respect of which there are no provisions in Israeli legislation, U.S. standards will apply, subject to law, in relation to issues of safety and environmental protection, as well as the provisions specified in some of the annexes to the MARPOL Convention (The International Convention for the Prevention of Pollution from Ships) which apply or shall apply with respect to (mobile) rigs or permanent rigs.

7.22.3 Events in connection with the environment

According to information provided to the Partnership by the operator, in 2020 there was no event or matter relating to the Partnership’s operations in connection with the environment which had a material effect on the Partnership. For details regarding material legal or administrative proceedings related to the environment, see Section 7.22.6 below.

7.22.4 Environmental risk management policy

The operator in the various projects, adopts a strategic environmental policy for the protection of the environment and for compliance with the provisions of the law in general, and the environmental laws in particular. This policy includes the operator taking care to act in accordance with internal procedures for environmental risk management of its activity, including training suitable manpower, and including a work plan for the reduction of environmental damage, for the prevention of incidents and accidents and for the constant improvement of the organizational culture on issues of safety, environment and hygiene. In this framework the operator has a designated team both for the development stage and the operating stage, which is responsible for implementation of and supervision over such policy, and for fulfillment of the procedures for ensuring fulfillment of and compliance with all of the requirements and standards, including various systems for the management of environmental risks, such as SEMS (Safety & Environmental Management System). In addition, the operator performs due diligence by a third party, in addition to current audits performed by the Ministry of Energy and the Ministry of Environmental Protection in the production facilities. The operator carries out current activities on issues of the environment, safety and hygiene to increase awareness, knowledge and preparedness, including training of and drills for the operator's teams. The Partnership is acting to receive periodic and specific updates, as needed, regarding the operator's activity as aforesaid. It is further noted that although the operator has a different position with respect to the legal interpretation regarding the applicability of Israeli laws, and environmental laws in particular, to its offshore activity outside of the territorial waters (including its activity in the area of the EEZ) to that adopted in the framework of the opinion mentioned in Section 7.23.5(c) below, in addition to the aforesaid, the operator is acting to obtain all of the permits by virtue of the environmental regulation that are required for each one of the sites operated thereby, as the case may be, including a business license by virtue of the Business Licensing Law, 5728-1968, a toxic materials permit by virtue of the Hazardous Substances Law, 5753-1993, a permit for discharge of emissions into the sea by virtue of the Prevention of Sea Pollution from Land-Based Sources Law, 5748-1988 and an emission permit by virtue of the Clean Air Law.

In this context it is noted that on November 6, 2019, the operator received an air emission permit for the Leviathan rig, the validity of which is determined in the law for a period of 7 years until 2026 ("**Leviathan's Emission Permit**"). The emission permit includes, *inter alia*, maximum emission values for emission sources on the Leviathan rig, and provisions with respect to implementation of the best available technology, monitoring, sampling, control and reporting to the Ministry of Environmental Protection.

In addition, during 2019, the operator in the Leviathan project received a preliminary business license, permit for discharge of emissions into the sea and toxic materials permit for the Leviathan rig, which are extended from time to time in accordance with the requirements of the law. A business license and a toxic materials permit were also received for the Hagit site, which are extended in a similar manner.

On August 31, 2020 the Ministry of Environmental Protection released an emission permit for the Tamar platform, that is valid for a 7-year period. However, the language of the final permit that was given includes material changes versus the draft released to the public, according to the Tamar project operator, without affording an opportunity to submit comments regarding the aforesaid changes. Pursuant to the release of the permit, the Tamar project operator applied to the Ministry of Environmental Protection with regard to the flaws, according thereto, in the process of drafting the permit and the technical problems which arise from the final language thereof. The Tamar Project operator updated the Partnership that on December 30, 2020, it submitted an application to modify the permit, in accordance with the provisions of the Clean Air Law, and an additional filing which included the position of the operator whereby it reserves its rights on the matter.

The Ashdod terminal operates pursuant to an emission permit given for a 7-year period starting from December 10, 2014 (the "**AOT Emission Permit**"). According to the information relayed to the Partnership by the operator, pursuant to the demand of the Ministry of Environmental Protection, in May 2019, the operator submitted a request to update the AOT Emission Permit. On October 30, 2020, the Ministry of Environmental Protection released a draft update to the AOT Emission Permit for public comment, aiming to regulate any and all activity which is carried out in the Terminal and further thereto, on December 16, 2020, an updated emission permit for AOT was issued. Note that based on information relayed to the Partnership by the operator, the demand to update the AOT Emission Permit was given incidentally to a hearing conducted by the Ministry of Environmental Protection due to alleged non-compliance with the provisions of the AOT Emission Permit, which constitutes, according to the Ministry of Environmental Protection, a violation of the Clean Air Law. To the best of the Partnership's knowledge, as of the report approval date, after the operator presented claims regarding such matter to the Ministry of Environmental Protection, no additional enforcement measures were instituted. Simultaneously, the operator submitted a request to renew the facility's emission permit, which is expected to expire in December 2021.

7.22.5 Environmental costs and investments

The projected costs of actions relating to environmental protection are included in the budgets of the various projects and are updated from time to time according to the approved work plans. As of the report approval date, no additional material costs are expected.

On March 31, 2019, the installation of a designated system for the reduction of emissions into the air from the Tamar platform had been completed, at a budget of approx. $40 million (100%), which reduces the emission of various pollutants by more than 98% at values exceeding the operator's commitment to the Ministry of Environmental Protection.

7.22.6 Material legal or administrative proceedings in connection with the environment

As of the report approval date and to the best of the Partnership's knowledge, no material legal and/or administrative proceeding is being conducted against the Partnership and/or any of the officers of the General Partner and/or of the Partnership in connection with environmental protection, which is expected to have a material effect on the Partnership.

a. On August 28, 2019, the Homeland Guards Association (in this section: the "**Petitioner**") petitioned to the Jerusalem District Court against the Ministry of Environmental Protection and position holders therein and against Noble and the Ministry of Energy, in which it sought to instruct the Ministry of Environmental Protection and position holders therein to require Noble or the Ministry of Energy to furnish various items of information which are necessary, so the Petitioner claimed, to make a decision on the application for Leviathan's Emission Permit; to publicly release all of the information and to allocate a 45-day period for the submission of comments; and to refrain from granting an Emission Permit for the rig until the petition has been heard. Concurrently with the petition, a motion was filed for a temporary order and an interim order, intended to prevent the granting of Leviathan's Emission Permit until the petition has been heard. On September 5, 2019, the motion for a temporary order and an interim order was denied. On December 19, 2019, the court's judgement was received, dismissing the petition with prejudice and charging the Petitioner with the respondents' costs in the sum total of ILS 60 thousand. On February 3 ,2020, the Petitioner appealed the District Court's judgment as aforesaid to 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 of the report approval date, in the Partnership's estimation, based on the opinion of legal counsel representing the operator in the proceeding, the chances of the appeal being denied exceed the chances of it being granted.

b. 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 that Leviathan's Emission Permit is null and void and to rule that there would be no activity on the Leviathan rig which entails the emission of gases. Alternatively, the court was moved to rule that approval of the rig's running-in plan would be revoked. An interim order was also sought to prevent activity on the rig which requires an emission permit. On December 17, 2019, the court decided to grant a temporary order whereby, pending another decision, the Respondents would refrain from activity on the Leviathan rig which entails the emission of gases, and that the emission permit would be frozen (in this section: the "**Temporary Order**"). On December 19, 2019, the court's decision was received regarding cancellation of the Temporary Order and denial of the motion for an interim order. On January 5, 2020, a preliminary hearing was held on the Petition. On March 15, 2020, the court's judgment was issued dismissing the Petition with prejudice. On June 22, 2020, an appeal from the judgment was filed with the Supreme Court (in this section: the "**Appeal**"). In the Appeal it is sought to amend the emission permit and order that the pollutants emitted from the platform will not be monitored by Noble or an entity with which it engaged, but by the Head of the Air Quality Division with the Ministry of Environmental Protection or an entity selected by him; and to amend the emission permit such that all the provisions pertaining to maintenance, environmental management, environmental protection and identification and treatment of leaks will be determined in the emission permit itself, and not in an external program. A hearing in the Appeal was 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 of the report approval date, the Partnership estimates, based on the opinion of legal counsel representing the operator in the proceeding, that at this stage, the chances of the Appeal being rejected are greater than the chances it is granted.

c. On January 19, 2020, the Homeland Guards Association (in this section: the "**Petitioner**") petitioned the Jerusalem District Court against the Ministry of Environmental Protection and Noble Inc., to order the Ministry of Environmental Protection to publish a reasoned decision regarding Noble Inc.'s request to deem the information on the Leviathan reservoir well flow as such that contains information which amounts to a trade secret. According to the Petitioner, the non-publication of a reasoned decision constitutes a violation of the provisions of the Clean Air Law by the Ministry of Environmental Protection. It was further argued that the Ministry of Environmental Protection violated its internal procedures which contemplate the examination of requests to recognize trade secrets. On June 3, 2020, Noble responded to the petition and argued that, since the petition does not move for a remedy of publication of any information or another remedy from Noble, Noble leaves the decision in the petition to the court's discretion. At the same time, it was argued that the Ministry of Environmental Protection did not violate the Clean Air Law or the internal procedures thereof. On June 17, 2020, the Ministry of Environmental Protection filed its answer in the petition claiming that the court ought to dismiss the petition with prejudice because it did not violate the Clean Air Law or the internal procedures thereof. A preliminarily hearing of the appeal was scheduled for May 23, 2021. As of the report approval date, the Partnership estimates, based on the opinion of legal counsel representing the operator in the proceeding, that at this stage, the chances of the Appeal being rejected are greater than the chances it is granted.

d. On April 27, 2020, Noble received a notice from the Ministry of Environmental Protection of the intention to impose a financial penalty due to alleged violations of the Prevention of Sea Pollution Law, and the sea discharge permit given to the Leviathan platform, while some of the alleged violations are with respect to the running-in period. On July 26, 2020, Noble filed written arguments in response to the aforesaid notice, and on November 12, 2020 the Ministry of Environmental Protection's decision was received whereby it was decided to cancel two of the four penalties which the Ministry intended to impose, and to partially reduce the amount of the two remaining penalties. Payment for such penalty was transferred to the Ministry of Environmental Protection on December 11, 2020.

e. On May 20, 2020, Noble received a notice from the Ministry of Environmental Protection of the intention to impose a financial penalty, in an immaterial amount, due to alleged violations of the emission permit given to the Leviathan platform and the Clean Air Law, and the Supervisor's instruction given by virtue thereof in connection with the continuous monitoring systems in the Leviathan platform. Noble has informed the Partnership that it has submitted an information request to the Ministry of Environmental Protection under the Freedom of Information Law, 5758-1998 (the "**Freedom of Information Law**"), which directly addresses the claims raised in such notice and that the Ministry of Environmental Protection has agreed to postpone the date for submission of the arguments with respect to such financial penalty and schedule such date for 30 days after the information is received. As of the report approval date, it is not possible to estimate the chances of attaining additional reductions of the amount of the penalty or Noble's ability to attain the cancellation of some of the penalty's components on their merits.

On July 1, 2020, Noble received an additional notice from the Ministry of Environmental Protection of the intention to impose a financial penalty, in an immaterial amount, due to alleged violations of the terms and conditions of the emission permit of the Leviathan platform and the Clean Air Law, with respect to the operation of flares on the production platform. On August 16, 2020, Noble filed its arguments with respect to this penalty with the Ministry of Environmental Protection. On December 13, 2020, the decision of the Ministry of Environmental Protection was received whereby it was decided to consolidate some of the penalties which the Ministry of Environmental

Protection intended to impose and to cancel some, such that 4 penalties will be imposed on Noble, and to partially reduce the amount of one of the penalties. Payment for such penalties 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 whereby it is cancelling one financial penalty that was imposed in the context of its aforesaid decision, and concurrently it notified that it intends to impose such penalty, while affording Noble the chance to complete its arguments with respect thereto by February 28, 2021. However, Noble has informed the Partnership that it has submitted an information request to the Ministry of Environmental Protection under the Freedom of Information Law, which directly addresses the claims raised in such notice, and, at the same time, a request for an extension for the submission of its arguments within 30 days of the date of receipt of the requested information. As of this time, a response to the freedom of information request and the extension request has not yet been received, and thus Noble filed its arguments on March 7, 2021.

f. On January 19, 2021, Noble received a warning and an invitation to a hearing from the Ministry of Environmental Protection with regard to an alleged violation of the sea discharge permit that was given to the Leviathan platform, with respect to the open system waste standards set forth in the permit. On February 28, 2021, Noble sent to the Ministry of Environmental Protection a letter of claims responding to the warning and invitation to a hearing. The hearing at the Ministry of Environmental Protection was scheduled for March 22, 2021.

g. On December 15, 2020, a motion for class certification 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 environment pollution, due to prohibited emissions from the gas platform operated by the Respondents in the sea, which is located opposite Dor Beach, and treats the natural gas reservoir, Leviathan, in the period from the commencement of the platform's activity in December 2019 until a judgment is issued in the claim" (below in this section: the "**Petitioner**" and the "**Class Members**"). The certification motion was filed against Noble and Chevron (in this section: the "**Respondents**"). In essence, the certification motion 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 certification motion) and damage of injury to autonomy due to the concern of health damage as aforesaid. The main remedy sought in the certification motion is compensation for the class for the damage it allegedly incurred which is estimated at approx. ILS 50 million. In addition, the

Petitioner moved for a remedy of an order instructing the Respondents to immediately fulfill the obligations imposed thereon in the Clean Air Law and the Regulations promulgated thereunder. A pre-trial hearing is scheduled for January 19, 2022. As of the report approval date, the Partnership estimates, based on the opinion of legal counsel representing the operator in the proceeding, that at this stage, the chances of the proceeding being rejected are greater than the chances it is granted.

7.22.7 Cyprus

To the best of the Partnership's knowledge, under the Cypriot Environmental Effects Of Plans And Activities Law of 2005, (which is adapted to the European Directive), a strategic environmental evaluation is required in connection with a governmental decision to perform plans that may have environmental impact. The Cyprus Ministry of Energy imposed on the companies active in the sector (after a tender) the preparation of a strategic environmental assessment in connection with petroleum exploration and production activities in Cyprus and in the Cyprus exclusive economic zone (EEZ) (the "**Environmental Report**"). The license holder for the exploration or production activity must act in accordance with the Environmental Report and perform an environmental survey prior to conducting said activities in the area of the license.

7.22.8 It is further noted that the EMG pipeline and the operation thereof, which connects between the Israeli transmission system in the area of Ashkelon and the Egyptian transmission system in the area of el-'Arīsh, are subject both to Israeli and Egyptian regulation.

7.22.9 As of the report approval date, and in accordance with information provided to the Partnership by the operator, the Partnership has no knowledge of non-compliance or deviation from environmental quality requirements in projects in which the Partnership holds rights, that is expected to have a material effect on the Partnership.

7.23 Restrictions and supervision of the Partnership's activity

7.23.1 The Gas Framework

On August 16, 2015, Government Resolution No. 476 (readopted with certain changes in a Government Resolution of May 22, 2016) was adopted with respect to a framework for the increase of the natural gas quantity produced from the "Tamar" natural gas field[157] and the expeditious development of the "Leviathan", "Karish" and "Tanin" natural gas fields and other natural gas fields (in this section: the "**Government Resolution**"), which took effect on December 17, 2015, upon the grant of an exemption from certain provisions of the Economic Competition Law, 5748-1988 (the "**Economic Competition Law**")[158] to the Partnership, Avner, Ratio and Noble (in this section: the "**Parties**") by the Prime

[157] "Tamar" was defined in the exemption annexed to the Framework as "a natural gas reservoir situated in the area of the Tamar I/12 and Dalit I/13 leases, and the rights held by the entities that hold Tamar in the gas transmission infrastructure, including all of its components and parts, including the rights of the holders of Tamar to use the onshore gas reception and processing facility, from the Tamar reservoir to the national transmission system".

[158] On January 1, 2019, the Amendment to the Competition Law was approved, in the context of which the name of the law was changed from the "Antitrust Law" to the "Economic Competition Law".

Minister, in his capacity as Minister of Economic Affairs, pursuant to the provisions of Section 52 of the Economic Competition Law (in this section: the "**Exemption**" or the "**Exemption Pursuant to the Economic Competition Law**"). Said Exemption applies to certain restrictive arrangements which ostensibly may have been attributed to the Parties, as specified in the Government Resolution (the "**Restrictive Arrangements**"). The Government Resolution and the Exemption as aforesaid shall hereinafter be referred to above and below as the "**Gas Framework**").

(a) The restrictive trade practices in relation to which the Exemption was granted are as follows:

1. The Restrictive Arrangement that was ostensibly created, according to the Competition Commissioner's position, as a result of the acquisition of the rights in the Ratio-Yam permit by the Partnership, Avner and Noble; and the Restrictive Arrangement that was ostensibly created as a result of the Parties' coming together as joint holders of the Ratio-Yam permit and the Leviathan reservoir.

2. The Restrictive Arrangement that shall ostensibly be created in a case in which the Parties or some of them jointly market the gas that shall be extracted from the Leviathan reservoir to the domestic market until January 1, 2025.[159]

3. The Restrictive Arrangement that shall ostensibly be created in a case in which the Parties or some of them jointly market the gas that shall be extracted from the Leviathan reservoir for export only.

4. The Restrictive Arrangement which may be created as a result of a certain agreement for the purchase of natural gas from the Leviathan reservoir, provided that such agreement is signed by January 1, 2025.

5. With respect to their activity in the Tamar and Leviathan reservoirs only, the Partnership, Avner and Noble being the holders of a monopoly according to the Competition Commissioner's declarations.[160]

[159] The Minister of Energy is authorized, upon the fulfillment of certain conditions as prescribed in the Exemption, to extend the Exemption until January 1, 2030.
[160] The Minister of Energy is authorized, upon the fulfillment of certain conditions as prescribed in the Exemption, to extend the Exemption until January 1, 2030.

(b) The Exemption from the Restrictive Arrangements specified in Sections 7.23.1(a)2 to 7.23.1(a)5 above, is contingent upon the fulfillment of the following conditions:

1. <u>The Karish and Tanin reservoirs</u>

   a. Pursuant to the Framework, the Partnership, Avner and Noble were obligated to transfer all of their rights in the Karish and Tanin leases to a third party not affiliated with the Parties or any of them, which shall be approved by the Petroleum Commissioner.[161]

   b. The permitted export quota from the Karish and Tanin reservoirs in the amount of 47 BCM was exchanged, as of the date of the Petroleum Commissioner's approval of the transfer of the rights in Karish and Tanin, against the duty to supply to the domestic market imposed on the holders of the Leviathan Leases.

   In accordance with the provisions of the Framework, the rights in the Karish and Tanin leases were fully transferred to a third party in December 2016. For further details, see Section 7.8.1 above.

2. <u>The Tamar Project</u>[162]

   a. The Partnership and Avner[163] shall transfer, within 72 months from the date of the grant of the Exemption Pursuant to the Economic Competition Law (the "**Effective Date for Tamar**"), all of their rights in the Tamar and Dalit leases to a third party not affiliated with the Parties or any of them or with any entity that holds means of control in the Leviathan

[161] As aforesaid, on December 26, 2016, a transaction was closed for the sale of all of the rights of the Partnership, Avner and Noble in the Tanin and Karish Leases to Energean Israel.

[162] The Framework determined that periods in which an event of "*force majeure* in Tamar" occurred shall not be taken into account. If such an event occurs, the relevant time count in Tamar shall stop running, provided that the Partnership, Avner and Noble act quickly and diligently to remedy the damage caused by the *force majeure*. "*Force majeure* in Tamar" was defined in the Framework as "war, a military action, an act of terror, a significant accident or a natural disaster, any of which result in a significant failure or significant fault in any of the facilities or systems required for the gas production, and as a result of which the gas supply was halted or significantly reduced for a significant period, and the Delek and Noble partnerships were denied the possibility of selling the relevant petroleum asset in the ordinary course of business, and a reasonable and prudent person in the shoes of the Delek and Noble partnerships could not have prevented or overcome the same".

[163] As aforesaid, on May 17, 2017, Avner was merged with and into the Partnership such that all of Avner's assets and liabilities passed, as is, to the Partnership, and at such date Avner was liquidated without dissolution and was stricken off the records of the Partnerships Registrar.

reservoir or in the Karish and Tanin reservoirs, subject to the Petroleum Commissioner's approval.[164]

b. By the Effective Date for Tamar, Noble shall deliver to the Petroleum Commissioner a binding sale contract, such that after consummation thereof, Noble's rights in the Tamar Lease will be no higher than 25% and the surplus rights will be transferred to a third party which is not affiliated with the Parties or any of them and does not hold means of control in the Leviathan reservoir or in the Karish and Tanin reservoirs, subject to the Petroleum Commissioner's approval.[165]

c. If not all of the transferred rights are transferred as stated in Subsections a. and b. above by the Effective Date for Tamar (the "**Transferred Rights in Tamar**"), the right to transfer the Transferred Rights in Tamar that were not sold will be transferred to a trustee (as defined in the Gas Framework), which will act to find buyers and to obtain the maximum bids for the sale of the Transferred Rights in Tamar, all in accordance with the provisions of the Framework and directives that it shall receive from the Competition Commissioner. The trustee shall sell the Transferred Rights in Tamar in reference to the market value and the highest bid that is made thereto, 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 Rights in Tamar).

d. Commencing on the Effective Date for Tamar or on the date of the sale of Noble's rights in the Tamar Lease as aforesaid, whichever is earlier, Noble shall not hold any veto right pertaining to the Tamar reservoir.

e. The consideration for all of the rights of the Partnership, Avner and Noble in Tamar will not be paid in royalties. The consideration may be paid in installments, provided that the

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[164] For the purpose of fulfillment of the provisions of the Framework, on July 20, 2017, a transaction was closed for the sale of 9.25% of the interests of the Partnership in the Tamar and Dalit leases to Tamar Petroleum. As of the report approval date, the Partnership holds 13.42% of the voting rights in Tamar Petroleum and 22.6% of the equity interests in Tamar Petroleum. For the purpose of fulfillment of the provisions of the Framework, the Partnership will be required to sell also its said holding in Tamar Petroleum by the Effective Date for Tamar.

[165] In December 2016, a transaction was closed for the sale of 3.5% of the rights of Noble in the Tamar and Dalit leases to Everest, in which Harel Insurance Co. Ltd. and other institutional bodies owned thereby are partners, as well as partners from the Israel Infrastructure Fund Group; on March 14, 2018, the transaction between Tamar Petroleum and Noble was closed, according to which Noble sold to Tamar Petroleum 7.5% (out of 100%) of its rights in the Tamar and Dalit leases. In this context, it is noted that Noble sold its shares in Tamar Petroleum and thus fulfilled its duty according to the Gas Framework in this regard.

milestones for payments will not be tied to the prices or to the quantities of gas sold from the Tamar reservoir. The aforesaid notwithstanding, the Partnership, Avner and Noble may retain a right to royalties from the sale of petroleum (with the exception of condensate) from the Tamar reservoir, if discovered.

3. <u>New agreements for the supply of natural gas from the Leviathan and Tamar reservoirs</u>

   a. Agreements for the supply of natural gas from the Leviathan and Tamar reservoirs that shall be signed from the date of the Government Resolution will meet all of the following provisions:

      1. The consumer shall be subject to no restriction with respect to the purchase of natural gas from any other natural gas supplier.

      2. The consumer will have the possibility of selling natural gas that it purchased in a secondary sale, in accordance with the conditions and provisions set forth in the Exemption.

      3. The parties shall not apply any restriction to the sale price at which the consumer shall sell the natural gas in a secondary sale.

   b. With respect to agreements for the sale of natural gas from the Tamar reservoir that shall be signed from the date of the Government Resolution until 4 years after the date on which the Petroleum Commissioner approved the transfer of the Rights in Karish and Tanin (the "**Date of Opening of the Options**"), the holders of the rights in the Tamar reservoir will be required to offer to any consumer the possibility of purchasing gas in an agreement for any period that he shall choose up to 8 years or a longer period to be agreed between the parties and the consumer. With respect to an agreement whose term exceeds 8 years, the consumer shall have a unilateral right to shorten the term of the agreement during a 3-year window commencing on the Date of Opening of the Options.

   c. In relation to agreements for the sale of natural gas from the Leviathan reservoir that shall be signed from the date of the Government Resolution until the Date of Opening of the Options, the holders of the rights in the Leviathan reservoir will be required to offer to any consumer the possibility of purchasing gas in an agreement for any period that he chooses up to 8 years or a longer period to be agreed between the parties and the consumer.

   d. On April 2, 2017, the Tamar Partners clarified in a notice that they sent to the Minister of Energy, to the Budget Director at the Ministry of Finance and to the Competition Commissioner, that in the event of a delay in the supply of gas for the first time by a new gas supplier, the Tamar Partners will allow their customers, in accordance with gas supply agreements that were signed from the date of the government resolution until 4 years after the date on which the Commissioner approved the transfer of the rights in the Karish and Tanin gas reservoirs (the Date of Opening of the Options), which were supposed to transition to buying gas from the new supplier, fully or partially, to extend the contract with them until the date on which the new supplier is able to supply gas in commercial quantities (but no more than 8 years from the date of the signing of the agreement with them), without modifying the terms and conditions of the agreement.

The Tamar Partners further clarified that they would grant a consumer that is an electricity producer or another consumer seeking to establish new facilities and which is forced, due to requirements of the facilities' finance providers, to sign a long-term gas supply agreement, the possibility to sign an agreement with them whose term exceeds 8 years, and in accordance with the supply capacity of the Tamar Project.

(c) Additional provisions from the Government Resolution

1. Additional provisions regarding prices

a. So long as the holders of the rights in the Tamar and Leviathan Leases meet the conditions of the Government Resolution and the Exemption Pursuant to the Economic Competition Law, it will be recommended that the provisions of the Control of Prices of Commodities and Services Order (Application of the Law to Natural Gas and Determination of the Control Level), 5773-2013, which imposes control on the gas sector in terms of reporting on profitability and the gas prices, shall remain unchanged for the period from the date of the Government Resolution, i.e., as of August 16, 2015, until the date of closing of the transfer of the rights of the Partnership, Avner and Noble in the Karish and Tanin leases in accordance with the provisions of the Framework, whichever is later (the "**Transition Period**").

b. During the Transition Period, the holders of the rights in the Tamar and Leviathan Leases, including the Partnership (in this Section 7.23.1(c): the "**Holders of the Rights in the Leases**") shall offer to potential consumers the following natural gas price and linkage options:

1. A base price to be calculated in accordance with a weighted average of the existing prices in the agreements between the Holders of the Rights in the Leases and their consumers, and to be updated every calendar quarter (in accordance with the calculation specified in the Government Resolution).[166]

2. The Brent barrel price, as shall be calculated in accordance with the optimal formula for the existing consumer on the date of the Government Resolution in agreements of the Tamar Partners.

3. For a private electricity producer (conventional or cogeneration) that meets the conditions specified in the Government Resolution in addition to the alternatives specified in subsections (1) and (2) above, also an alternative which includes linkage to the Electricity Production Tariff, on the basis of a simple average of the prices set forth in the supply agreements, as specified in the resolution.[167]

c. The provisions of Subsection (b) do not derogate from the obligation of the holders of the rights in the Tamar and Dalit leases to offer consumers in Israel, the gas price set forth in an export agreement in order to comply with the terms of the taxation mechanism as specified in Section 7.23.1(c)4 below.

With respect to tax decisions that were issued in connection with the Amendment to the Tamar-Dolphinus Agreement and the Amendment to the Leviathan-Dolphinus Agreement, see Sections 7.11.5(a)2 and 7.11.5(b)2 above.

2. Provisions regarding natural gas export

a. The Gas Framework included several clarifications and amendments to government resolution no. 442 of June 23, 2013, with regard to the adoption of the main recommendations of the committee for the examination of the government's policy regarding the natural gas sector in Israel (the Tzemach

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[166]The updated base price as calculated by the Natural Gas Authority in a release dated January 14, 2021 is $5.16 per MMBTU unit. For further details see: https://www.gov.il/BlobFolder/generalpage/decision476/he/ng_price_1_2021.pdf.

[167] According to the said release of the Natural Gas Authority of January 14, 2021, a simple average of the prices of conventional independent power producers is US$4.7 per MMBTU and a simple average of the prices of cogeneration independent power producers is US$4.7 per MMBTU.

Committee report). For further details, see Section 7.23.5(a) below.

b. In addition, it was determined that the holders of the rights in the Tamar Lease will be entitled to use the Mari B rig for the entire term of the Tamar Lease for the purpose of export or supply, to the domestic market, of natural gas from the Tamar reservoir, subject to the conditions determined in the Government Resolution.

3. <u>The Tamar SW reservoir:</u>

The Government Resolution included the Petroleum Commissioner's announcement that he will approve the development plan for the Tamar SW reservoir, subject to the production of natural gas from the Tamar SW reservoir not yielding revenues in excess of $575 million. The said production restriction will be cancelled by the Petroleum Commissioner after an agreement shall be submitted between the State and the holders of the rights in the Tamar Lease on all of the issues relating to the development of the Tamar SW reservoir. For further details regarding the Tamar SW reservoir, including the development plan that was approved, and details 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 7.3.4(d) and 7.9.2 above.

4. <u>Taxation</u>

The Government Resolution included the Tax Authority's notice which regulates various taxation issues pertaining to activity in the Tamar and Leviathan reservoirs. In addition, the government decided to act to promote amendments to the Taxation of Profits from Natural Resources Law, whose aim, *inter alia*, is the closing of tax loopholes, various clarifications and the application of assessment and collection proceedings.

It was further determined that the price of a petroleum unit in an export agreement will be taxed according to the actual income from the export agreement and not according to the "average domestic price" for such type of petroleum, as defined in the Taxation of Profits from Natural Resources Law, and that there will be no need for an annual examination of the revenues from the export agreement for this purpose, subject to the prior approval of the Tax Authority that the price of a petroleum unit under the export agreement is not lower than the "average domestic price" or alternatively, that the holder of the export agreement shall undertake to offer the price determined in the export agreement as aforesaid to new customers in Israel, in the manner and under the conditions set forth in the Gas Framework. 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).

5. Domestic content

The government took note of the announcement of the Minister of Economic Affairs that the holders of the rights in the Tamar and Leviathan reservoirs made a commitment to invest in domestic content in the aggregate sum of $500 million over 8 years from the date of the granting of the Exemption, namely as of December 17, 2015. The following, *inter alia*, shall be deemed as domestic content: expenses in respect of the purchase of commodities or services from bodies registered in Israel (including foreign entities registered in Israel), the purchase of goods, procurement from Israeli contractors, suppliers or producers, investments in the field of R&D in Israel (directly or indirectly), expenses for manpower (up to a cap of 20% of the total commitment as aforesaid), expenses for professional training, donations and activity in the field of social responsibility. It is noted that as of the report approval date, this commitment with respect to investment in domestic content has been performed in full.

6. Maintaining a regulatory environment that encourages investments

The Israeli government undertook to maintain regulatory stability in the natural gas exploration and production segment on three issues: the public's maximum share in the profits (Government Take), export and the restructuring included in the Government Resolution – for 10 years from the date of adoption of the Government Resolution.

Following the original Government Resolution and the grant of the Exemption, several petitions were filed with the High Court of Justice. On March 27, 2016, the judgment of the High Court of Justice was issued on the said petitions, ruling, *inter alia*, that the stability clause as worded in the Framework (the government's undertaking to limit future changes in the regulation of the natural gas sector) cannot stand, and the State was given a one-year period to act for the regulation of the stability issue in the Framework.

On May 22, 2016, the Government readopted its resolution of August 16, 2015 with respect to the Framework, while setting an alternative arrangement for Chapter J of the Framework concerning a "stable regulatory environment", to secure a regulatory environment that encourages investments in the natural gas exploration and production segment.

As of the report approval date, the Partnership is acting to implement the provisions of the Gas Framework relevant thereto, In this context, it has sold its holdings in the Karish and Tanin leases, as specified in Section 7.25.13 above, sold 9.25% of its holdings in the Tamar and Dalit leases to Tamar Petroleum, and the flow of natural gas from the Leviathan reservoir commenced on December 31, 2019. In addition, it continues to act to sell its remaining holdings in the Tamar and Dalit reservoirs.

7.23.2 Antitrust and economic competition law

(a) On October 12, 2000, the Competition Commissioner gave his approval to the merger transaction, in the framework of which Delek Investments and Properties Ltd.[168] ("**Delek Investments**") purchased all the rights of RB Mediterranean Ltd in the Yam Tethys project. This approval, as revised, was subject to a number of conditions, including, *inter alia*, that any purchase of a holding by Delek Group and/or Delek Investments and/or Delek Real Estate Ltd. and/or "Delek" Israel Fuel Company Ltd. ("**Delek Israel**") of 5% or more in an entity that does exploration, production, transmission, marketing or sells natural gas in Israel, requires advance approval of the Competition Commissioner, if the corporation has natural gas discoveries; the aforesaid in this section is not applicable to a joint venture in the Yam Tethys project.

(b) The Tamar Project

1. On August 28, 2006, the Competition Commissioner granted a conditional exemption from a restrictive arrangement approval – under Section 14 of the Economic Competition Law – to an agreement contemplating the parties thereto sharing in the rights in the Matan and Michal licenses, in the area of which the natural gas findings Tamar and Dalit were discovered in 2009, and some of the rights in which were later transferred to Noble). The Competition Commissioner's decision was subject to a number of conditions, summarized below:

a. The "Local Corporations" (as defined in Paragraph c below) will not hold collectively, whether directly or indirectly, any gas right other than a right directly and exclusively deriving

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[168] On April 16, 2012, and in effect since December 31, 2011, Delek Investments was merged into Delek Group pursuant to the provisions of Part One of Part Eight of the Companies Law, as a result of which it was liquidated.

from the Matan and/or Michal licenses, without a specific approval, in advance and in writing from the Competition Commissioner. By December 31, 2006 the “Local Corporations” will complete any joint holdings in gas rights, except for the rights deriving directly and exclusively from the Matan and Michal licenses, which at the time of the giving of the decision were held jointly, directly or with other holders, unless joint holding has been specifically permitted by the Competition Commissioner in writing.

b. In any arrangement, agreement or consent, in writing or verbally, with regard to determination of a mechanism or matter of decision making between the license holders of Matan and Michal with regard to the marketing of natural gas produced under the Matan and Michal licenses, any one of the “Local Corporations” will not hold, alone, directly or indirectly, any right or power to prevent the other holders decision making or action with regard to the marketing of natural gas produced under the Matan and Michal licenses.

c. For such purposes, the “Local Corporations” shall mean – “Delek Group” and “Isramco”; “Delek Group” - Avner and/or the Partnership and/or any other related person; “Isramco” and any related person.

2. On November 13, 2012 the Partnership received a notice from the Competition Commissioner of its announcement as a monopoly– together with the other partners in the Tamar Project and separately – in the supply of natural gas in Israel commencing upon the date of the beginning of commercial supply from the Tamar Project. Due to its being a monopoly, as aforesaid, the Partnership is subject to Chapter D of the Economic Competition Law, including a prohibition on the Partnership to unreasonably refuse to supply natural gas and a prohibition on abuse of its position in the market in a manner that might reduce competition in business or harm the public.

3. In 2012, the Tamar Partners were granted a conditional exemption (the conditions of which have been fulfilled) from a restrictive arrangement approval in connection with the agreement with the IEC. In addition, the Tamar Partners are obligated to submit to the Competition Commissioner all of the agreements for the sale of natural gas to domestic customers. During 2012 and 2015, several decisions were received from the Competition Commissioner regarding the granting of a conditional exemption from approval of restrictive arrangements in connection with fourteen agreements for the supply of natural gas between the Tamar Partners and

private gas consumers in which the basic supply term exceeds 7 years (the "**Commissioner's Decisions**"). Below are the main principles of the Commissioner's Decisions: The gas consumer shall have the option to choose, in respect of the agreement, one of the following two alternatives:

a. Shortening the term of the agreement to 7 years, from the date of commencement of the natural gas supply; or alternatively

b. Reducing the quantity of the gas stated in the "Take-or-pay" clause to a quantity equivalent to one half of the average annual consumption quantity of the gas consumer in the three years preceding the date of the notice. The reduction of the purchase quantity will take effect one year after the date of provision of such notice, until the end of the term of the agreement, as the case may be ("**Reduction of the Purchase Quantity**").

   Notice of Reduction of the Purchase Quantity will be possible at any time during the period ending on the later of the following two periods: (1) the period from January 1, 2018 until December 31, 2020 (with respect to five agreements for the sale of natural gas) or the period from January 1, 2020 until December 31, 2022 (with respect to nine agreements for the sale of natural gas); or (2) the period commencing at the beginning of the fifth year from the date of supply of natural gas and concluding at the end of the seventh year as aforesaid.

c. Upon determination of the minimum quantity for which the gas consumer shall be charged in accordance with the foregoing, the annual gas quantity and the aggregate gas quantity in the agreement shall be updated.

d. The gas consumer will be permitted to sell natural gas designated for the use of consumers of the gas distribution network, in an amount of up to 15% of the annual gas quantity per year.

e. No restriction shall apply to a gas consumer in respect of the purchase of natural gas thereby from any other supplier of natural gas who is not a Tamar partner.

f. The Tamar Partners shall not engage, directly or indirectly, in any agreement for the supply of gas from the Tamar reservoir, without receiving the prior approval of the head of Competition Control.

With regard to this condition, note that, on May 24, 2020, the Competition Commissioner released, pursuant to Section 14 of the Economic Competition Law, her decision on cancellation of the demand to receive 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 examine their lawfulness will be imposed on the Tamar Partners and their customers, while the Competition Commissioner will be able to examine the agreements in retrospect and also not close to the signing thereof, and to take steps for enforcement insofar as it transpires that arrangements which harm the competition have been made.[169]

Following the Competition Commissioner's Decisions, the said agreements were amended accordingly, and all of the new agreements signed by the Tamar Partners were drawn up in keeping with the Competition Commissioner's Decisions.

4. For details on disputes that erupted between the remaining Tamar Partners who are not holders of the Leviathan project and Noble and the Partnership regarding, *inter alia*, the ability of Noble and the Partnership to prevent the making of amendments to the IEC-Tamar Agreement, the exercise of veto rights in relation to decisions on marketing of the gas produced from the Tamar reservoir, and with regard to a balancing agreement signed between the Tamar Partners on separate marketing of the gas, see Section 7.11.4(a)6.b above.

   The force and effect of the settlement agreements in Tamar and Leviathan were made contingent, *inter alia*, on the approval of an agreed order signed by Noble and published for public comment by the Competition Commissioner on January 31, 2021 (the "**Agreed Order**").[170]

   Pursuant to the Agreed Order, 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 the fulfillment of Noble's undertakings, and in view of the settlement agreement signed between the Tamar Partners and the IEC, the Commissioner shall not continue treatment and shall not take steps for enforcement against anyone in the Noble group due

[169] https://www.gov.il/he/departments/legalInfo/decisions8856-0620
[170] https://www.gov.il/he/departments/legalInfo/draftord-nobleenergy

to the acts specified in the complaints lodged by the Other Tamar Partners and the IEC in relation to the agreement signed between them on October 4, 2020, as described in Section 7.11.4(a)6.b7.11.4(a)6.a above. The Agreed Order is subject to approval by the Competition Court. As of the report approval date, such approval has not yet been received.

5. For details on an action and a class certification motion filed in February 2020 with the Tel Aviv District Court by an electricity consumer, claiming, *inter alia*, that the Partnership and Noble that have cross ownership of the Tamar and Leviathan reservoirs cannot prevent the other Tamar reservoir partners from engaging with the IEC in an agreement that reduces the cost of the natural gas it supplies to the IEC, see Section 7.26.5 below.

7.23.3 The activity is subject to specific legislation

The exploration, development and production of oil and/or natural gas ("**Petroleum**") in Israel is regulated mainly under the Petroleum Law, including the amendments incorporated therein, and the regulations promulgated thereunder, the principles of which are as follows:

(a) The Petroleum Law (in this section: the "**Law**")

1. The Law provides, *inter alia*, that a person shall not explore for Petroleum except under a "preliminary permit", "license" or "lease deed" (as defined therein) and a person will not produce petroleum except for under a license or lease deed.

2. Preliminary testing (that does not include test drilling) in any area, in order to ascertain the prospects for discovering Petroleum in such area, including the conducting of seismic surveys, is subject to the receipt of a preliminary license. The Law permits the granting of priority rights to the holder of the preliminary rights for petroleum interests in the area in which the preliminary permit was granted, if same will undertake to do preliminary tests and invest in the exploration for Petroleum as determined by the State's competent representatives to 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 Petroleum in the area of the license in accordance with the plan submitted to the Petroleum Commissioner under the Law, and the exclusive right to conduct test and development drilling in the license area and to recover Petroleum therefrom. In general the License will be granted for an initial period of 3 years

and is subject to extension, under conditions provided for by Law, for an additional term not to exceed 4 years.

4. If a licensee makes a Petroleum discovery, it is entitled to an extension of the license period for such time, not exceeding two years, as will give it sufficient time to define the borders of the Petroleum field, and the licensee is entitled to receive in a certain area within the license area, a "lease" which granting exclusivity to explore and to produce Petroleum in the leased area, for the term of the Lease. The lease is given for a period of up to 30 years from issuance, but if a lease is given pursuant to a license that was extended after a discovery in the license area, the license term will commence upon the original termination date of the license, prior to extension. A lease may be extended, under the provisions of the Law, for an additional period of up to 20 years. A lease may expire following a suitable prior notice given by the Minister of Energy, if the lease holder fails to produce or ceases to produce Petroleum in commercial quantities.

5. The Law provides, *inter alia*, that the lessee pay the State royalties of one eighth of the quantity of Petroleum produced from the leased area and utilized (excluding Petroleum used by the lease holder for operating the leased area), but in any event no less than the minimal royalty provided for by Law.

6. A lease might expire following a suitable prior notice given by the Minister of Energy if the lease holder fails to produce or ceases to produce Petroleum in commercial quantities.

7. In addition, the Law provides that the Commissioner may cancel a petroleum interest or a priority right if the rights holder thereof has not complied with the provisions of the Law or fails to comply with any condition of its petroleum interest or preliminary permit, or has not performed in accordance with the work plan submitted by it or is late in its performance or fails to invest in Petroleum exploration the sums undertaken to invest, notwithstanding written notice given to the petroleum interest holder or preliminary permit holder sixty days previously.

8. The Commissioner will maintain a Petroleum register which will be open to the public for review (the "**Petroleum Register**"). The Petroleum Register will list all requests, grants, extensions, revisions or expirations and transfers, pledges of petroleum interests or benefits therein or grant of a lease deed. No such transaction shall be in force until it is registered therein.

9. The Law provides that no one person shall have more than twelve licenses, and that it will not have licenses for a total area exceeding four million thousand sqm, except upon 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 the pledge or transfer of a license or of a lease other than after consulting with the Council.

11. A leaseholder may build pipelines for the transport of oil and oil products. A leaseholder shall not build an oil pipeline, other than collection pipelines which lead to tanks in or around the areas of the lease wells, other than according to a line approved by the Commissioner. An oil pipeline will be constructed according to detailed drawings in accordance with the law; the drawings will first require the approval of the Commissioner, which shall not be unreasonably withheld.

(b) <u>The Petroleum Regulations, 5713-1953</u> (the “**Petroleum Regulations**”)

The Petroleum Regulations deal with, *inter alia*, preliminary permits and priority rights, in the licenses and the leases (collectively: the “**Rights**”) and set forth the manner in which applications for rights should be submitted, reports filed, fees paid, conditions with regard to the shape of the area, provisions with regard to the grant of rights by way of a competition and provisions with regard to payment of royalties pursuant the Petroleum Law.

(c) <u>The Petroleum Regulations (Principles for Offshore Petroleum Exploration and Production), 5777-2017</u> (the “**Offshore Regulations**”)

1. On November 15, 2016, the Offshore Regulations, which replaced the Petroleum Regulations (Principles for Offshore Petroleum Exploration and Production), 5766-2006, came into effect. The Offshore Regulations prescribe, *inter alia*, proof of qualification of the applicant seeking operator certification.

2. Below is a description of the principles of the Offshore Regulations:

   a. The Petroleum Commissioner will not certify an applicant as operator unless the following principal conditions are fulfilled:

1. The operator will be the lease holder with at least 25% of the rights in the Petroleum asset.

2. The operator or control holder therein (subject to the conditions in the Offshore Regulations) will have at least five years of experience in the ten-year period preceding the filing of the application, in the performance of 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 activities for preservation of health, safety, and environmental protection relating to activities in petroleum interests.

3. Furthermore, the Petroleum Commissioner will not certify a corporation as operator, unless it directly employs employees that have qualification and 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 he decides to certify a corporation as an 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, according to the stage and characteristics of the right and according to the scope of the demand for receipt of the right in that area or according to the composition of the entire group, certify a corporation as an operator even if it fails to comply with the above requirement of necessary experience in offshore oil or natural gas development and production.

5. The Petroleum Commissioner may require a certain corporation, for certification thereof as operator, greater experience than the one prescribed, if it finds it necessary according to the stage and characteristics of the right, and considering 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 the control holder thereof (subject to the conditions in the Offshore Regulations) is financially sound (as defined in the Offshore Regulations) and has financial capacity that is

deemed sufficient if the total assets in the balance sheet are at least $200 million and the total equity in the balance sheet is $50 million.

b. The applicant for a petroleum interest must prove appropriate financial capacity by fulfillment of both of the following:

1. The total assets in the balance sheet of the applicant (or of all holders of the petroleum interest jointly, including a member of the group approved as the operator with respect to the petroleum interest) are at least $400 million.

2. The total equity in the balance sheet of the applicant (or of all holders of the petroleum interest jointly, including a member of the group approved as the operator with respect to the petroleum interest) is at least $100 million.

An applicant for a petroleum interest may rely on the control holder thereof in order to prove financial capacity, subject to the conditions prescribed by the Offshore Regulations.

The aforesaid financial capacity, financial strength,[171] total assets and total equity will be examined according to the data in the audited financial statement as of December 31 of the year preceding the submission of the application, or according to an average of the data in the audited financial statements as of December 31 of the two years preceding the submission of the application, according to the discretion of the Petroleum Commissioner.

c. The Petroleum Commissioner may, with approval from the Minister of Energy, withhold approval from an application to receive a petroleum interest or an application to serve as an operator, even if all the aforesaid conditions are fulfilled, if he is convinced that reasons of national security, foreign relations 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 provisions above, it is possible to approve an operator or grant a petroleum interest even if not all of the details which appear above are fulfilled, provided that under the circumstances the non-fulfillment of the conditions is

[171] Financial strength will be proven upon fulfillment of the conditions specified in the Regulations.

immaterial and the Commissioner was convinced that there are special grounds which justify so doing.

e. The Offshore Regulations include additional provisions on the details to be included in the application for approval of an operator and reports which an operator and a holder of a petroleum interest are required to submit to the Petroleum Commissioner

(d) <u>The Natural Gas Sector Law</u>

The Natural Gas Sector Law and the regulations promulgated thereunder set forth provisions with regard to the construction of the transmission system, 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 according to its terms:

   - the construction and operation of a transmission system or part thereof;

   - the construction and operation of a distribution network or part thereof;

   - the construction and operation of an LNG facility ("**LNG License**");

   - the construction and operation of a storage facility.

   - The construction and operation of an export pipe by a person who is not a lease holder.

2. Transmission license will only be given to a company established in Israel under the Companies Law.

3. The holder of the transmission license or an electricity provider may not deal in the sale or marketing of natural gas, nor may a holder of control or a link in any of them.

4. The occupation of selling and marketing of natural gas does not require a license, however the Minister has the discretion under certain conditions set forth in the Natural Gas Sector Law, to determine, upon agreement with the Minister of Finance and upon approval of the Knesset's Economic Affairs Committee, that for a certain determined term, natural gas marketing activity will be subject to a license.

5. In the event that a person applies for more than one license, the Minister may, upon consultation with the Director General of the Natural Gas Authority appointed under the Law (in this section: the "**Director**") make the licenses conditional 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 ("**Natural Gas Authority Council**"), may, *inter alia,* in accordance with the Government's policy, provide to a corporation, without a tender, 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 the LNG license will be granted under a tender or another upon a 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 the storage license or the LNG facility license be granted without a tender or said public proceeding, to the holder of the transmission license. Notwithstanding the foregoing, a lease holder, for as long as a lease is in force, may 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 lease holder, without a tender or another public proceeding and for as long as the lease is in force, a license to store gas which is not produced by the reservoir in the lease area; the term of the license will be set forth therein and will not exceed the balance of the lease term. The Minister may instruct the lease holder, for as long as the lease is in force, to provide storage facilities to others in the reservoir that is in the area of the lease and to determine the conditions of the services, after giving the lease holder an opportunity to state its claims; if such an instruction is given, the lease holder will be deemed a holder of a storage license and the provisions of the Natural Gas Sector Law will apply to it.

8. Restrictions were placed on additional activities by a license; however the Minister, after consultation with the Natural Gas Sector Council, may give the license holder a permit to engage in additional activities under conditions prescribed in the Natural Gas Sector Law.

9. The term of a license not exceed 30 years, and not be extended; however this provision does not prevent the license holder from participating in a tender that takes place for the granting of a new license. Notwithstanding the foregoing, the Minister may decide not to limit the term in a transmission license, and if limited in term, it may be extended or the term limitation cancelled and to set forth 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 forth conditions in the license to

ensure the aims of the Natural Gas Sector Law and compliance with its instructions, including conditions that need to be met prior to commencing activity 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 subtract conditions of a license if there is a vital need therefor in order to realize the objectives of the Natural Gas Sector Law or to fulfill a relevant international treaty to which Israel is a party, and considering technological, market-related and environmental changes that have occurred since the license was issued, and after the license holder shall have been given an opportunity to voice its claims.

11. The Minister, upon the consent of the Minister of Finance, may set forth mandatory royalty payment conditions in a license given under a tender, or license fees to the State Treasury, and the manner of their calculation and payment, and if any of those are subject to bidding in the tender – in accordance with the results of the tender; the Minister, upon the consent of the Minister of Finance, and subject to approval of 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, after consultation with the Natural Gas Sector Council and with the Minister's approval, and after giving the license holder an opportunity to state its claims, may cancel a license at any time, if one of the following conditions is fulfilled: (a) the license holder failed to disclose to the tender committee or to the Minister material information that is required to be disclosed in connection with participation in the tender or the license application, or provided incorrect information; (b) the license holder fulfills one of the exceptions to receipt of the license or ceases to fulfill any of the required eligibility conditions, and does not remedy the same within a period that was determined by the manager in notice that he sent to the license holder; (c) an order was issued for the dissolution of the license holder or a receiver was appointed therefor, and the order or the appointment were not cancelled within a period that was determined by the manager in notice that he sent to the license holder; (d) the license holder failed to fulfill an instruction to correct deficiencies or breached a material regulation in the license, which breach was not remedied within the period determined by the manager or the Commissioner or is irremediable; (e) the license holder committed an ongoing breach of a provision according to this law or in the license or a condition in the license, which breach was not remedied as stated in Section

(d) above; (f) other grounds exist which are determined in the license as grounds for cancellation thereof.

13. A license or any part thereof cannot be transferred, pledged or attached, in any manner. Gas facilities of the license holder and assets that were determined in the license as required for the performance of the activity 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 manager, and under such conditions as he shall determine. An action that is taken contrary to the provisions of this section is null and void.

14. Guaranties and undertakings provided by a license holder or a control holder thereof, and money received from enforcement thereof, may not be attached or pledged.

15. No person shall 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 shall not transfer the same to another. Generally, for the purpose of such a transfer or purchase, the Minister's approval is required, after consultation with and the consent of the Council.

16. A license holder shall not condition the provision of service on the purchase of another service or gas therefrom or from another person or on the non-purchase of a service or gas from another person. 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 the condition, the said Council may approve the condition.

17. The tariffs that will be charged by the license holder, and any update thereto, will be determined by the Natural Gas Sector Council, in accordance with the rules set forth in the license, and with regard to activity that was granted under a tender, the Natural Gas Sector Council will determine the tariffs according to the conditions of the tender; the Natural Gas Sector Council may determine standards or instructions with regard to the level, quality and quantity of the services that the license holder has to provide to its consumers, and to ensure continuity during the term of the license.

18. Gas that is sold by a natural gas supplier to a Private Electricity Producer (as defined in the Electricity Sector Law, 5746-1996) is a commodity that is subject to the Supervision of Prices of Commodities and Service Law 1996-5756 (the "**Supervision**

Law") and the level of supervision that will apply is in accordance with Section E of the Supervision Law.

19. The Minister, in consultation with the Council, may grant a corporation, without a tender, a license for an export pipeline of a non-leaseholder, for a period prescribed by him in the license, upon the fulfillment of 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 fulfills 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 the lease under the Petroleum Law, with the pipeline for which the license is granted being connected to the facilities used for the operation under the lease;

        3. The Minister has preapproved the engagement.

    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 control holder 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, insofar as it did;

    c. If the control holder 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 the facilities used for the operation the pipeline will be connected, holds the approvals required for the purpose of export via the pipeline.

(e) Natural Gas Sector Regulations (Management of the Natural Gas Sector in a State of Emergency), 5777-2017 (the "**Emergency Regulations**")

1. The Emergency Regulations are under Section 91 of the Natural Gas Sector Law, which authorizes the Minister of Energy, with

approval from the Government, to announce a state of emergency in the natural gas sector and promulgate regulations applicable to the operation of the natural gas sector in a state of emergency.

2. The Emergency Regulations distinguish between a situation in which 90% of all of the natural gas supply in the sector comes from one field and one transmission system (a "**Significant Field**"), and a situation in which the natural gas supply in the sector comes from at least two fields connected to INGL through at least two separate transmission systems, as is currently customary in the Israeli sector:

   a. <u>Provisions when one Significant Field exists</u>

      Whenever the aggregate hourly demand for natural gas by the consumers of the gas supplier which is unable to supply all or part of the natural gas in the field (the "**Defaulting Supplier**") exceeds the maximum quantity that can be supplied to them, the Defaulting Supplier and INGL will allocate the existing gas quantity according to the following provisions:

      1. The first allocation of natural gas will be to the distribution consumers (as defined in the Emergency Regulations). Such allocation will be performed according to the maximum quantity per hour of the natural gas that was consumed by the distribution consumers in the 12 months preceding the declaration date (as defined in the Emergency Regulations):

         a) A quantity of up to 3,600 MMBTU per hour will be reserved for distribution consumers (the Director of the Gas Authority may determine how the quantity will be distributed between the distribution consumers amongst themselves);

         b) A quantity of at least 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 the distribution consumers that are not included in the subsection above.

      2. The remaining quantity will be divided between electricity producing consumers (consumers of a defaulting gas supplier who are producers of electricity using natural gas at a capacity exceeding 45 MW) and consumers which are

not electricity producers, proportionately according to the aggregate daily consumption average of each one of the said types of consumers in the same month in the previous calendar year;

3. The quantity that shall be distributed to consumers who are not electricity producers (out of the quantity allocated to consumers who are not electricity producers as aforesaid) will be determined according to their share in the hourly capacity ordered for each one of them according to the transmission agreement that they signed with the holder of the transmission license, and the total hourly capacity ordered for such consumers according to the transmission agreement that they signed with the holder of the transmission license.

4. The IEC will offer LNG for sale to consumers who are not electricity producers, at the price for which it purchased the LNG plus up to 10%.

b. Provisions when at least two fields exist

Non-defaulting gas suppliers will be obligated to offer their surplus gas, if any, for sale (the available daily quantity after the supply of the quantity ordered by such supplier's consumers, provided that the ordered quantity does not exceed the maximum quantity that may be nominated under the agreements with them) to the defaulting gas supplier. If the parties fail to reach an agreement as to the price of the surplus gas, The price will be in accordance with the average market price (to be determined according to the total income from natural gas sales to consumers in Israel from all of the fields that was received in the quarter preceding the quarter that preceded the declaration date divided by the aggregate quantity of natural gas in MMBTU units that was supplied to consumers in Israel in the quarter preceding the quarter that preceded the declaration date, as published by the Natural Gas Authority from time to time on its website). Whenever the aggregate hourly demand for natural gas by the consumers of the defaulting gas supplier exceeds the maximum quantity that can be supplied to them, the Defaulting Supplier and INGL will allocate the excess gas quantity purchased to consumers in the Israeli sector only, according to the following provisions:

1. The first allocation of natural gas will be to the distribution consumers. Such allocation will be performed according to the maximum quantity per hour of the natural gas that was

consumed by the distribution consumers that consume gas from the defaulting gas supplier in the 12 months preceding the declaration date, as specified below:

A quantity that does not exceed the outcome of 3,600 MMBTU per hour minus the quantity supplied to the distribution consumers supplied by the non-defaulting gas suppliers per hour, shall be reserved for the distribution consumers;

A maximum quantity that exceeds the product of 3,600 MMBTU per hour minus the quantity supplied by the non-defaulting gas suppliers to the distribution consumers, a quantity shall be allocated of 3,600 MMBTU per hour minus the quantity supplied by the non-defaulting gas suppliers the distribution consumers in the following manner:

(1) First to the household consumers;

(2) The remainder of the allocation will be allocated to the distribution consumers that are not included in Subsection (a).

2. The remaining quantity will be divided between electricity producing consumers and consumers who are not electricity producers, proportionately according to the aggregate daily consumption average of each one of the said types of consumers in the same month in the previous calendar year;

3. If surplus gas remains for supply, the defaulting gas supplier may supply natural gas from the field (the "**Additional Quantity**"), such that the daily surplus gas quantity remaining for supply shall be allocated to electricity producing consumers and consumers who are not electricity producers, proportionately according to the aggregate daily consumption average of each one of the said types of consumers in the same month in the year preceding the year in which the allocation is performed, net of the Additional Quantity that was allocated to each one of the types.

4. The quantity that shall be distributed to consumers who are not electricity producers (out of the quantity allocated to consumers who are not electricity producers as aforesaid) will be determined according to their share in the hourly

capacity ordered for each one of them according to the transmission agreement that they signed with the holder of the transmission license and the total hourly capacity reserved for such consumers according to the transmission agreement that they signed with the holder of the transmission license, net of the Additional Quantity, if allocated, for each one of the consumers who are not electricity producers.

c. General

If the Minister finds, after consultation with the Director General of the Natural Gas Authority and the Director General of the Electricity Authority, that the natural gas shortage continuously or extensively compromises the orderly functioning of the sector or the orderly supply of electricity to the Israeli market, which cannot be overcome by use of other fuels, or if the Minister of Environmental Protection shall have notified the Minister of Energy that the prolonged shortage of natural gas is significantly harming the environment in a manner that will be damaging to the public's health, the Minister may deviate from the provisions of the Regulations and prescribe a different allocation of the gas and LNG quantities, provided that the deviation is not excessive.

The Regulations do not exempt the defaulting gas supplier from any legal duty imposed thereupon, nor do they derogate from any and all of the remedies and reliefs included in the agreement between the defaulting gas supplier and the gas consumer.

(f) Decision of the Natural Gas Authority Council on the regulation of the use of the capacity of the gas pipeline from the production platform of the Tamar Project to the natural gas exit at the Terminal in Ashdod (the "**Regulation of Pipeline Capacity Allocation**")

On December 9, 2012 the Natural Gas Authority in the Ministry of Energy (in this section: the "**Authority**") published a decision regarding the Regulation of Pipeline Capacity Allocation, including with regard to the maintenance of gas capacity for consumers and marketers in the distribution network and in connection to the regulation of the matter of the Tamar Project shortage of supply capacity. It should be noted that it is the Authority's position that Tamar Partners should not refuse to sign contracts for the sale or marketing of natural gas with consumers that wish to engage with them, just because of the fact that the significance of the engagement is that the total quantity of hourly natural gas to pass through the pipeline deviates from the maximum capacity estimated as of that date at 40,000 MMBTU an hour.

(g) Decision of the Natural Gas Authority Council on the regulation of criteria and rates regarding the operation of the transmission system in a flow control regime

On January 3, 2021, the Natural Gas Authority Council released an amendment to the Council's decision on criteria and rates regarding the operation of the transmission system in a flow control regime decision no. 5/2020 (Amendment No. 2)[172] (in this section: the "**Decision**").[173] The Decision stipulates that the costs for the UFG in the transmission system deriving from reasons that cannot be attributed to malfunction of the transmission system, but to factors that cannot be prevented or controlled such as measurement timing, pressure differences and temperature differences, will be borne by the gas suppliers. The Decision further stipulates that the UFG-T ranges from 0%-0.5% (positively or negatively). The costs for UFG-T will be divided equally between the gas suppliers and the gas consumers. The Decision will take effect on April 1, 2021.

After the release of the Decision, INGL contacted Noble with 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 also forwarded for the inspection of Noble, a notice in this spirit which it provided to its customers. Further to the above notice, Noble turned 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 of the report approval date, Noble is considering its steps in regards to the Decision.

In the Partnership's estimation, the aforesaid Decision entails costs in immaterial amounts. As of the report approval date, the Partnership is examining the implications of the Decision before taking legal action.

(h) Decision of the Natural Gas Authority Council regarding the financing of export projects via the national transmission system (in this section: the "**Decision**")

On September 7, 2014, the Natural Gas Authority Council released its decision regarding the financing of export projects via the national transmission system (Decision no. 2/2014). The Decision determines the transmission rates that will apply to the transportation of Israeli natural gas via the national transmission system to neighboring countries or to the Palestinian Authority, as well as the financing of the construction of those segments of the transmission system designated for export of natural gas as aforesaid. The Decision sets forth the following principles:

1. The exporter (the entity selling or marketing the natural gas for export) shall enter into a transmission agreement with the transmission license holder, which agreement shall be approved in

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[172] Decision no. 5/2020 amends decision no. 4/2020 of the Natural Gas Authority Council of May 27, 2020, which amended the Council's decision no. 8/2019.

[173] https://www.gov.il/BlobFolder/generalpage/ng_council_decisions/he/board_decision_5_20.pdf

advance and in writing by the Director General of the Natural Gas Authority. The exporter shall pay the transmission license holder the transmission tariff that will be the regular transmission tariff applicable to Israeli consumers, as in effect from time to time.

2. The exporter shall bear the full costs of constructing the segment of the transmission system designated for export only (the "**Segment Designated for Export**") as well as the construction costs of an additional transmission line in immediate proximity to an existing segment ("**Duplicated Segment**"), in addition to management fees at a rate of 2%.

3. For as long as the transmission agreement between the exporter and the transmission license holder is in effect, and an additional consumer shall join the Segment Designated for Export in the future, the Director General of the Natural Gas Authority will determine the cost attributed to the additional consumer out of the total cost of construction of the Segment Designated for Export, according to the ratio of the capacity of the additional consumer out of the total capacity that may be transported in the Segment Designated for Export. The exporter shall be credited by the amount of such cost that shall be attributed to the additional consumer.

4. If a certain segment of the Transmission System leading to a Segment Designated for Export shall also serve Israeli consumers in the future, but the segment leading to the Segment Designated for Export would not have been duplicated at the time of its construction had it not been for the export of the natural gas via the Transmission System, the exporter shall pay (in addition to the cost of construction of the Segment Designated for Export as aforesaid) the pro rata portion in respect of the duplication of the Segment Designated for Export. The Council shall determine the allocation of the cost between the exporter and the transmission license holder.

5. In the event that the Director General of the Natural Gas Authority is in the opinion that there is sufficient capacity in the Transmission System at the time of signing the agreement between the transmission license holder and the exporter, but that it is likely that in the ten years after the commencement date of the initial natural gas flow, there will be a shortage in the capacity of the Transmission System to the Israeli consumers in a segment leading to a Segment Designated for Export, then at the date of signature of the transmission agreement, the exporter shall choose between one of the following alternatives: (1) to pay the transmission license holder 50% of the budget of the future duplication of the

relevant segment of the Transmission System, and such amount shall not be repaid to the exporter even if such segment shall eventually not be duplicated; (2) not to pay said amount and in the event of duplication of the segment as aforesaid, the provisions of Section 4 above shall apply.

6. The Director General of the Natural Gas Authority shall determine, in each case, the point in the Transmission System from which the beginning of the segment leading to a Segment Designated for Export be calculated, and such point will be explicitly indicated in the transmission agreement.

7. Despite the fact that the construction cost is imposed (in whole or in part) on the exporter, the exporter shall not own the segment and shall not have any type of link in such segment.

8. This Decision shall not apply to export transmission agreements signed with the transmission license holder before November 2, 2014 (including the transmission agreement signed in connection with an agreement dated February 19, 2014, for the export of gas from the Tamar Project to consumers in Jordan (as specified in Section 7.11.5(a) above).

9. Note that in the Dolphinus Agreements specified in Sections 7.11.5(a)2 and 7.11.5(b)2 above, it was agreed that the Tamar Partners and the Leviathan Partners, as the case may be, would bear the costs of the gas piping in the INGL transmission system.

On March 26, 2020, the Natural Gas Authority Council published an addendum to the Decision of September 7, 2014 regarding the financing of export projects through the Israeli transmission system and division of the cost of construction of the Ashdod-Ashkelon combined section (decision no. 3/2020). The addendum to the decision determines the following principles:

1. In addition to the categories which were defined in the Decision of September 7, 2014, as described above, the Council may define a section which is a section designated for export and which allows for the closing of a loop in the system or creates redundancy and a backup for natural gas which is piped to the Israeli transmission consumers as a “combined section”.

2. Insofar as a section is defined as a “combined section”, the Council shall define the ratio of allocation of the costs of construction of such section, and insofar as necessary, the Council shall determine additional conditions and obligations of either of the parties.

With respect to division of the costs of the Ashdod-Ashkelon combined section, the addendum to the Decision determined that:

1. The offshore section of the transmission system to be constructed in the future, such that it begins the Terminal in Ashdod and end at the facility connecting to the export facilities of Prima Gas Ltd., shall be defined as a combined section (the "**Combined Section**").

2. The cost of the Combined Section and the manner of allocation of the cost between the exporter and the holder of the transmission license will be established in a transmission agreement to be entered into between the holder of the transmission license and the exporter (the "**Transmission Agreement**"), in accordance with the following principles:

   a. The cost of the section shall be determined in accordance with the Council's decision which was released in September 2014. If the holder of the transmission license and the exporter fail to reach an agreement 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 announced his determination that the cost of the Ashdod-Ashkelon Combined Section will be estimated at a sum total of ILS 738 million (of which the Partnership's share is estimated at approx. ILS 159 million) and will be updated according to an update and accounting mechanism between the parties as set forth in the Transmission Agreement with INGL.

   c. 43.5% of the section's cost, as shall be determined in accordance with Paragraph a. above, will be financed by the holder of the transmission license.

   d. 56.5% of the section's cost shall be financed by the exporter in accordance with the milestones that shall be determined in the Transmission Agreement.

   e. In addition, the exporter shall pay the holder of the transmission license ILS 27 million against its share in the cost deriving from the bringing forward of the doubling of the Dor-Hagit and Sorek-Nesher sections (the "**Doubling Cost**"), which is estimated at approx. ILS 48 million, after the doubling of the said Dor and Sorek sections are included in Annex A to the license for the construction and operation of the transmission system of the holder of the transmission license, and before the construction thereof begins.

f. The exporter will provide the holder of the transmission license with an independent financial guarantee on behalf of an Israeli bank, in the sum of 110% of the aggregate amount of the cost stated in Paragraph b. above (the share of the holder of the transmission license in the cost of construction of the Combined Section plus ten percent), and of the sum of ILS 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 quantity of natural gas determined in the Transmission Agreement will be transported via the transmission system of the holder of the transmission license and not via a section outside of the Israeli transmission system.

h. Insofar as the exporter shall have ceased to export to Egypt, it will be required to pay the holder of the transmission license the difference, if any, between 110% of the aggregate total cost of that stated in Paragraph b. and the total Doubling Cost (i.e. ILS 48 million), and the aggregate capacity and piping fees that the exporter paid the holder of the transmission license from the date of completion of the Combined Section and of the payments that the exporter paid the license holder in accordance with Paragraphs c. and d. above.

As specified in Section 7.12.2(b)3.b above, on January 18, 2021 Noble engaged with INGL in a binding Transmission Agreement for purposes of piping natural gas from the Tamar reservoir and from the Leviathan reservoir to EMG's terminal in Ashkelon for purposes of transmission thereof to Egypt.

On February 23, 2021, the Natural Gas Authority released a decision regarding the reduction of the transmission tariff as a result of the expansion of the system by approx. 5%. Such reduction shall take effect from March 1, 2021.

(i) <u>The Petroleum Law Legislative Memorandum (Amendment no. 7) (Regulation of Specific Export Pipelines and Liquefaction Facilities), 5780-2020</u>

On August 9, 2020 the Ministry of Energy released the Petroleum Law Legislative Memorandum (Amendment no. 7) (Regulation of Specific Export Pipelines and Liquefaction Facilities), 5780-2020 (in this section, the "**Memorandum**"). The purpose of the Memorandum is to regulate the construction of pipelines for export of natural gas and facilities for export of natural gas, also by entities that are not lease holders pursuant to the Petroleum Law. As of the report approval date, this matter is regulated in Section 10A of the Natural Gas Sector Law. The purpose of the Memorandum is, *inter alia*, to replace the regulation set forth in the Natural Gas Sector Law. The Memorandum further proposes to regulate the construction 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, which is designed to enable export of liquefied natural gas.

In addition, the proposed amendment to the Petroleum Law requires an indirect amendment to the Natural Gas Sector Law for the purpose of adaptation of the Natural Gas Sector Law to the proposed amendments to the Petroleum Law.

(j) <u>The Promotion of Competition and Reduction of Concentration Law, 5774-2013</u> (the "**Concentration Law**")

On December 11, 2013 (in this section: the "**Commencement Date**") the Concentration Law was published in the Official Gazette, which prescribed, *inter alia*, that the regulators have the authority to consider sectorial competition considerations and economy-wide concentration considerations, in the framework of allocation of public assets by the State, in order to ensure an increase in sectorial competition and decentralization of the economy-wide concentration.

Under the Concentration Law, a regulator may choose to not allocate to an entity listed on the published list of concentration entities, determined on the basis of criteria set forth in the Concentration Law, a right (including a contract) in a business sector that uses critical infrastructure or a public resource, or in the framework of which a utility is provided to the public, listed in the Concentration Law (the "**Critical Infrastructure Sector**"), until having found that no actual damage will be caused to the sector in which the right is allocated and to the regulation of the said sector due to non-allocation, and after having taken into account considerations of prevention of the expansion of the operations of the concentration entity, bearing in mind the relevant business sectors and the link between them (the "**Economy-Wide Concentration Considerations").**

Therefore, prior to the allocation of a right in any Critical Infrastructure (including a business sector with respect to which a petroleum interest is granted or a business sector with respect to which a storage license or an LNG facility license is required under the

Natural Gas Sector Law) to the Partnership, the regulator will have to weigh Economy-Wide Concentration Considerations.

Notwithstanding the foregoing, the aforementioned provisions with regard to Economy-Wide Concentration Considerations will not apply to the allocation of a petroleum interest to anyone having another petroleum interest in respect of the same area on the allocation date.

In addition, when allocating a right (within the above meaning thereof) including a license required for activity business sector that is not in an Critical Infrastructure Sector, the regulator is required to take into account considerations of promotion of the sectorial competition, in addition to any other consideration he is required to weigh under law for such purpose.

On December 25, 2017, the Committee for the Reduction of Concentration published, according to the provisions of the Concentration Law, a list of the concentration entities in the market, a list of the significant financial corporations and a list of the significant real corporations which were recently updated on March 2, 2020.[174] From the Partnership's perusal, in proximity to the report approval date, of the lists published by the Concentration Committee (including the updates thereto), it transpires that the Partnership appears on the list of the concentration entities and on the list of the significant real corporations.

As of the report approval date, the Partnership is unable to assess the scope of the effect of the Concentration Law on the oil and gas exploration sector in general and on its operations in particular.

(k) Regulation of Security in Public Entities Law, 5758-1998 (in this section: the "**Law**")

1. The Law applies to a "public entity", which is, as defined by the Law, an entity listed in any of the schedules to the Law.

2. The Law imposes various duties on a "public entity": (a) Appointment of a security officer who will report directly to the

[174] See records on the concentration entities in the market, the financial corporations and significant real corporations, as published:
https://www.gov.il/BlobFolder/unit/centralization_decrease_committee/he/Vaadot_ahchud_CentralizationDecreaseCommittee_GormimRikuzim_List-new.pdf (list of the concentration entities).
https://www.gov.il/BlobFolder/unit/centralization_decrease_committee/he/Vaadot_ahchud_CentralizationDecreaseCommittee_GofimFinansim_List-new.pdf (list of the financial entities).
https://www.gov.il/BlobFolder/unit/centralization_decrease_committee/he/Vaadot_ahchud_CentralizationDecreaseCommittee_Taagidim_List-new.pdf (list of the significant real entities).

director of the entity, in order to ensure the security level required for the activity of the public entity; (b) Appointment of an officer in charge of the security of essential computerized systems; (c) Appointment of a security guard in accordance with the requirements of an authorized officer.

3. The Law confers vast powers upon the security officer of a public entity, and *inter alia*: The authority to conduct a search and seize an object; the authority to require a person entering a public entity to identify himself; detainment powers (in certain circumstances specified in the Law); the authority to prohibit entry into the public entity with weapons (and, under certain circumstances specified in the Law, also while using reasonable force).

4. In accordance with the Sixth Schedule to the Law, a public entity listed in the Sixth Schedule to the Law will also be required to carry out offshore security activities. The offshore security activities are defined as activities required for the protection of a person's safety or the protection of property, in a building or on the premises of a public entity located in the maritime zone, as well as actions for the prevention of harm to any of the above.

5. In accordance with the provisions of the Sixth Schedule to the aforesaid Law, the holder of a license under the Natural Gas Sector Law, 5762-2002, which owns an offshore facility, or which operates an offshore facility, is deemed a public entity for the purpose of imposition of the duties listed in Section 2 above as well as the conduct of offshore security activities.

6. The IDF is the guiding authority on offshore security and its representative is deemed by the Law as an "authorized officer" for the purpose of offshore security activities.

7. Under the law, an offshore facility is a facility situated in the maritime zone, including a vessel as defined in the Shipping (Vessels) Law, 5720-1960, which is used for the performance of a petroleum discovery survey or for a production well, for transmission, for liquefaction or for gasification of petroleum, or for the processing, storage or transportation 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 also includes, other than the band of Israel's territorial waters, the "continental shelf" as defined in the Shipping Law (Offences against the Security of International Sea Travel and Offshore Facilities), 5768-2008.

8. Other than offshore facilities that are listed, as aforesaid, in the Sixth Schedule to the Law, Section 21 of the Second Schedule includes an "operator of an onshore facility for the processing of natural gas received by pipeline from the sea or from a foreign country, by virtue of a license or by law." Such operator is subject to requirements of physical security activities and information security activities (but not activities for the security of computerized systems or offshore security activities).

9. In accordance with the law, the holders of the lease in the Tamar and Leviathan reservoirs (in this section: the "**Reservoirs**"), including the Partnership, are responsible, *inter alia*, for the security of vital automated systems in the Reservoirs, in accordance with the instructions of the Israel National Cyber Directorate (the "**INCD**"). Since it is the operator that is responsible for the operation of the production system of the Reservoirs, it is the operator that actually implements the instructions of the INCD on the 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 in connection with performance 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 the Leviathan reservoir's full compliance with the security requirements.

10. As of the report approval date, and as the Partnership was informed by the operator in December 2020, in connection with operation of the Reservoirs, the operator meets the provisions of the Regulation of Security in Public Entities Law and the sections concerning regulation of security in the lease deeds, including the directives on security matters issued thereto by the professional functions in the navy pursuant to law.

7.23.4 Directives of the Petroleum Commissioner

(a) Provision of collateral in connection with petroleum interests

1. On September 17, 2014 the Petroleum Commissioner published, in accordance with Section 57 of the Petroleum Law, language of directives for the provision of collateral in connection with petroleum interests, which were updated on July 18, 2019, the main principles of which are as specified below. However, it is noted that in addition to these directives, the Commissioner demanded insurance confirmations in the language determined by him, based on insurance plans that were submitted to him on the

issue of insurance which pertain to the various leases. Below are the main directives for the provision of collateral in connection with the petroleum interests:

a. Entities applying for new onshore licenses shall deposit a base guaranty in an amount equal to $500 thousand. Rules regarding submission of base guaranties in new offshore licenses shall be determined in the framework of proceedings for the granting of offshore licenses.

b. Prior to performing drilling license holders will be required to provide an additional guarantee in a sum that the Petroleum Commissioner will determine in accordance with the character of the drilling and the drilling plan, which sum of the additional guarantee and the offshore license shall be no less than an amount equal to $5 million, while the sum of the additional guaranty for onshore licenses shall be no less than an amount equal to $250 thousand.. In the event that the Petroleum Commissioner believes that the drilling characteristics justify it, he will be entitled to demand a guarantee of a lower sum than aforementioned.

c. The initial validity of the base guaranty for new onshore licenses will be for a period of one year, and the right holder shall renew the guaranty each time until the Commissioner’s notice that there is no need therefor. In addition, the base guaranty and the additional guaranty for existing onshore and offshore licenses will be valid for a period of one year until the Commissioner’s notice that there is no need therefor. The Commissioner may increase the amount of the guaranty after giving the right holder a possibility to present his arguments on the matter.

d. In the petroleum leases, the Petroleum Commissioner will determine the sum of the guarantee taking into account, *inter alia*, the development plan, the characteristics of the lease, the stage it is at, the size of the petroleum field, but in any event the guarantee shall be no less than an amount equal to $7.5 million for an offshore lease, and from an amount equal to $1.5 million for an onshore lease. Guarantees in respect of new leases shall be deposited upon the grant of the lease, for a term to be determined by the Petroleum Commissioner. Furthermore, the Petroleum Commissioner reserves the right to update the amount of the guarantee consequently to a change of circumstance.

e. The aforesaid guarantees will be in force even after the right for which they were given terminates, until the Commissioner advises otherwise, but no more than 7 years after expiration of the right for which they had been provided.

f. In the event that, in the opinion of the Petroleum Commissioner, a petroleum interest holder did not act in due diligence in respect of the petroleum interest or caused damage in his actions due to the petroleum interest or did not incur expenses or failed to fulfill obligations that he was due to incur or fulfill under the Petroleum Law, and the Petroleum Commissioner, during the period of the right, instructed the petroleum interest holder by way of written notice to take actions or incur expenses or fulfill obligations pertaining to the petroleum interest, and the petroleum interest holder failed to follow such instruction and did not provide a proper reason for such failure, the Petroleum Commissioner may order the forfeiture of the guarantees or any part thereof, after hearing the arguments of the rights holder regarding the forfeiture of the guarantee.

g. The petroleum interest holder shall make and maintain, at its expense, and throughout the entire term of the petroleum interest, all of such insurances, which are customary among international companies for exploration or production of oil or gas.

h. Should a petroleum interest holder fail to comply with the directives, or if it is found that the guarantee or insurance that were made were revoked or terminated for any reason whatsoever, prior to their renewal, extension or replacement by another guarantee or insurance, the Petroleum Commissioner shall be entitled to forfeit the existing guarantee in connection with the right and may act to mitigate the possible damage, at the expense of the right holder. In addition, the Petroleum Commissioner may be entitled to view such as non-compliance with the work plan and with the provisions of the right and to act in accordance with the provisions of the Petroleum Law.

i. In addition, the directives include, *inter alia*, provisions regarding applicants of new onshore licenses, existing onshore licenses, updates of guarantee amounts and extensions thereof, as well as general provisions regarding guarantees.

In accordance with such directives and the terms and conditions of the Partnership's petroleum assets, as of the report approval date, the Partnership, together with its partners in the various enterprises, deposited autonomous bank guarantees for the Ashkelon, Noa, Tamar, Dalit, Leviathan North, Leviathan South leases and also for the Alon D license and the Ofek and Yahel licenses.[175] The Partnership's share in such guarantees totals approx. $60.4 million.

(b) Directives on the method of calculation of the royalty value at the wellhead

1. In May 2020, the Director of Natural Resources at the Ministry of Energy released the final version of the directives on the method of calculation of the royalty value at the wellhead according to Section 32(b) of the Petroleum Law, 5712-1952 (in this section: the "**Directives**").

   a. The Directives state that the value of the royalty at the wellhead shall be equal to 12.5% of the price of sale to customers at the point of sale, net of costs deemed essential 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 purposes of calculation of the royalty value at the wellhead shall be expenses actually incurred by the lease holder between the wellhead and the point of sale specified above, provided that the Commissioner deems them essential for the sale of the petroleum: (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 transmission system; and (2) operating expenses (opex) arising directly from the types of capital expenses.

   b. The Commissioner shall from time to time determine, for each lease holder, specific directives for each lease, listing the deductible expenses for purposes of calculation of the royalty, according to the specific characteristics of the lease.

   c. Expenses due to assets will be recognized in such a way that the depreciation rate in respect of the fixed assets will be calculated according to the depletion method, starting from the

[175] With respect to additional guarantees that the Partnership provided, together with its partners in the Tamar Project, see Sections 7.3.2(m) and 7.24.5(a) above, and with respect to additional guarantees that the Partnership provided together with its partners in the Leviathan project, see Section 7.2.2(n) above. With respect to guaranties that the Partnership provided for the customs in connection with the Tamar and Leviathan projects, see Note 12J5 to the financial statements (Chapter C of this report).

date on which the fixed asset started to operate (i.e., only when the fixed asset reached the location and condition required for its operation, and started to operate). The total depreciation expenses to be recognized shall not exceed the cost of the fixed asset. The depreciation expenses in respect of the fixed asset will be recognized such that at the end of the "asset's life", 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.

Insofar as an agreement is signed, which grants third parties ownership interest in the fixed asset or the right of use of a fixed asset, either for or without consideration, or an agreement is signed which includes the receipt of payment from third parties for petroleum transportation or treatment, the assessment of the fixed asset value will be adjusted in the year in which an 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 purposes of calculation of the royalty value at the wellhead.

The assessment will be adjusted in the year in which the transaction in the relevant asset was made, in accordance with the "disposal principle". The lease holder may be required to pay royalties to the State for such value, even if it generated no income in that year.

The economic value for purposes of adjustment of the assessment will be limited to the amount recognized and depreciated for royalty purposes, in respect of the fixed asset sold or the rights of use in which were transferred.

d. The Directives determine additional provisions, including a specification of the types of expenses which will not be recognized, the method of recognition of abandonment costs and the method of treatment of transactions that are affected by the existence of special relations between the parties to the transaction.

2. On September 6, 2020, the Director of Natural Resources at the Ministry of Energy released the "Directives of the Petroleum Commissioner on the method of calculation of the royalty value at

the wellhead – Tamar Lease".[176] It is noted that as of the date of approval of the report, no specific directives have yet been received from the Petroleum Commissioner with respect to the method of calculation of the royalties to the State from the Leviathan reservoir.

Below is a summary of the directives received regarding the method of calculation of the royalty value at the wellhead in the Tamar Lease:

a. Capex that will be recognized for purposes of calculation of 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 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 up to the entrance to the Terminal in Ashdod will be recognized at a rate of 100%.

b. Operating expenses arising directly from the types specified in paragraph (a) above, will be recognized at a rate of 82%: salary expenses of the worker 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 consulting; insurance expenses.

c. In the event that the contract sale price includes a component of a transmission tariff that is paid to INGL, all of the transmission expenses paid by the lease holder will be recognized.

d. Abandonment costs will be recognized for calculation of the royalty according to the provisions set forth in the general directives, and provided that at least 170 BCM in the aggregate were produced from the Tamar Lease and the Abandonment Plan has been approved by the Commissioner.

3. From the start of production of natural gas from the Tamar reservoir, the Tamar Partners, including the Partnership, pay

[176] https://www.gov.il/BlobFolder/policy/oil_search_publications/he/tamar_royalty.pdf

royalties at the rate determined and updated from time to time by the Petroleum Commissioner. For details on this matter, see Section 7.25.10(b) below.

Throughout the years, the Tamar Partners clarified to the Petroleum Commissioner, in proximity to the commencement of production from the Tamar reservoir, that they were paying the aforesaid royalties under protest, and that they disagreed with the method in which the royalty rate was calculated by the Petroleum Commissioner, which they claim does not properly weight the expenses for the transmission and treatment of the petroleum from the wellhead to the transmission system.

Following the release of the Directives and the determination of specific guidelines regarding the calculation of the State's royalty rate in the Tamar project, in the Partnership's estimation, 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 rate paid to the State at its request since 2013. When the effective royalty rate in the Tamar project will be determined, whether in agreement with the State or in a legal proceeding, and insofar as this rate will be lower than the rate of royalties actually paid, the Tamar Partners will be entitled to reimbursement for the overpayments 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 in order to reserve their rights against statute of limitations claims with respect to the royalties which they claim have been overpaid over the years (the "**Overpayments**"), the Tamar Partners applied on this matter to the State, which confirmed that insofar as the Tamar Partners take legal action with respect to the Overpayments within a reasonable period of time (several months) from the date of determination of the Directives regarding the calculation of the royalties which the holders of the rights are required to pay, the State would not raise claims relating to the lapse of time. For details regarding agreements reached by the Partnership in this context with all of the parties to which it paid royalties from the Tamar project over the years, see Section 7.25.10(d)6 below.

(c) <u>The transfer and pledge of a petroleum asset interest and benefit in a petroleum asset interest</u>

On December 28, 2020 the Petroleum Commissioner published the new directives for purposes of Section 76 of the Petroleum Law, which replace the directives of December 31, 2015, the objective of which is to regulate the procedure and conditions for the transfer and pledge of a petroleum interest (preliminary permit, license and lease) and a benefit (including a right to contract royalties) in a petroleum interest[177] (in this Section: the "**Directives**"). The principles of the Directives are as follows:

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) a voting right at 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" – each one of the following: (1) a voting right at a general meeting of a company or at 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;

[177] 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.

"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. At 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 fulfilled:

    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 fulfills 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 fulfills 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-b above and certain additional conditions are fulfilled.

3. The Petroleum Commissioner may approve a transfer of petroleum interests, as stated above, even if not all the above specified conditions are fulfilled, 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 fulfilled:

    a. The transfer may delay or harm the performance of the duties of the holder of the petroleum interests for exploration or production of petroleum according to the license or lease or according to the Petroleum Law, as the case may be.

    b. The transfer may significantly harm the competition in the field of exploration and production.

    c. The transfer may significantly harm the payment of the royalties which are due to the State Treasury according to the Petroleum Law and the law.

    d. The transferee or the control holder thereof breached the provisions of the Petroleum Law, or instructions and requirements made by the Petroleum Commissioner thereunder, in relation 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.

e. The transferor or transferee have not yet paid an amount they are required to pay to the State Treasury with regards to a petroleum interest which they have or had.

6. In addition, the Petroleum Commissioner may not approve a transfer, even if all the condition for providing the approval which are detailed in these Directives are fulfilled, 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. Permission for a pledge does not constitute permission to transfer the pledged right, and if the conditions for realizing the pledge are fulfilled, 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:

    1. Transfer of a petroleum interest between group members up to a rate of 10%, other than the transfer of rights of an operator;

    2. 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%;

    3. Transfer of benefit that is not a contractual royalty, other than the following cases:

        a. The benefit pertains to a producing lease and may have a material effect on the activity under the lease;

        b. A benefit in an operator or group member holding 40% or more of a petroleum interest;

    4. 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;

    5. Pledge of an existing right to a contractual royalty, other than a royalty, the transfer of which is required by Government Resolution No. 476 of August 16, 2015;

    6. 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.

(d) Export permit applications

On December 31, 2015, the Petroleum Commissioner published directives concerning the submission of applications for the receipt of a permit to export natural gas, which determine, *inter alia*, the date and the manner for submission of the application for receipt of a permit to export natural gas from the lease area, the details to be included in such application and the documents to be attached thereto, and in addition, clarifications pertaining to such export permit. It is emphasized that an export permit will be granted in accordance with the conditions specified in the Gas Framework, as specified in Section 7.23.1(c)2 above, and subject to any law.

It is noted that as of the report approval date, export permits have been received for the export agreements that were signed by the Partnership, and which are specified in Sections 7.11.5(a) and 7.11.5(b) above. On December 16, 2019, the Petroleum Commissioner’s approval was received for the export of natural gas from the Leviathan and Tamar leases to Egypt. For details see Sections 7.11.5(a)2 and 7.11.5(b)2 above.

7.23.5 Additional regulatory restrictions

(a) Government resolutions regarding adoption of recommendations of the committees for examination of the government policy on the natural gas sector

In October 2011, a committee was formed to examine the government's policy with regard to the natural gas sector in Israel and its future development, headed by Mr. Shaul Tzemach, the Director General of the Ministry of Energy at such time (in this section: the "**Tzemach Committee**"). On September 12, 2012 the Tzemach Committee published a final report. On June 23, 2013 the Israeli Government adopted the principal recommendations of the Tzemach Committee, with certain changes (in this Section: the "**Government Resolution Regarding the Tzemach Committee**"). On December 17, 2015, the Gas Framework, which is described in Section 7.23.1 above, took effect, in which several clarifications and amendments were made to the Government Resolution as aforesaid. On January 21, 2018, the Ministry of Energy announced the formation of an interministerial professional team headed by the Director General of the Ministry of Energy, Udi Adiri (the "**Adiri Committee**") for a periodic examination of the recommendations of the Tzemach Committee. The Adiri Committee examined the developments that had taken place in the natural gas sector during the five years that had passed since the adoption of the recommendations of the Tzemach Committee and reexamined the matter of natural gas supply and demand in 2018. On December 18, 2018, the Adiri Committee published its final conclusions, and on January 6, 2019 the Israeli Government adopted the principal recommendations of the Adiri Committee (the "**Government Resolution Regarding the Adiri Committee**"). The key points of the Government Resolution Regarding the Adiri Committee that may affect the Partnership's operations are as follows:

1. The quantity of natural gas that should be secured in favor of the domestic market shall remain as approved by the Government Resolution Regarding the Tzemach Committee (540 BCM), after an update due to the consumption of approx. 40 BCM to date, and will amount to 500 BCM (the "**Minimum Quantity for the Domestic Market**"), which shall allow for the supply of natural gas for the market's needs over the next 25 years. In this section: the "Natural gas Quantity" – the quantity of natural gas in the 2P and 2C categories in the aggregate, according to PRMS, in the discoveries recognized by the Petroleum Commissioner, with respect to which leases have been granted and for which the connection of the leases to the shore has been completed according to a development plan in a manner allowing for the supply thereof to the Israeli market.

2. The duty to supply the Minimum Quantity for the Domestic Market in respect of discoveries recognized prior to the approval of the Government Resolution Regarding the Adiri Committee shall remain as determined in the Government Resolution Regarding the Tzemach Committee, as specified below:

Amount of Natural Gas in Reservoir	**Rate of Minimum Supply to Domestic Market out of Natural Gas Amount in Reservoir**
Exceeding 200 BCM (inclusive)	50%
Exceeding or equaling 100 BCM, but lower than 200 BCM	40%
Exceeding or equaling 25 BCM, but lower than 100 BCM	25%
Lower than 25 BCM	To be determined by the Petroleum Commissioner

The duty to supply the Minimum Quantity for the Domestic Market in respect of discoveries recognized after approval of the Government Resolution Regarding the Adiri Committee will be as specified below:

Amount of Natural Gas in Reservoir	**Rate of Minimum Supply to Domestic Market out of Natural Gas Amount in Reservoir**
For every additional 1 BCM exceeding 200 BCM	55%
For every additional 1 BCM from 50 BCM to 200 BCM	50%
Lower than 50 BCM	No duty to supply to the domestic market shall apply

It is noted that in respect of reservoirs shared by Israel and other countries, the Petroleum Commissioner shall determine specific arrangements and conditions.[178] In addition, it was determined that the export facilities will be located in an area that is controlled by Israel which is in its exclusive economic zone, unless determined otherwise in a bilateral agreement between Israel and another country.

[178] It is noted that the permitted export quota from the Karish and Tanin reservoirs in the amount of 47 BCM was replaced, against the obligation to supply to the domestic market that applies to the holders of the Leviathan Leases, from the date of the Petroleum Commissioner's approval of the transfer of the interests in Karish and Tanin. For details, see Section 7.23.1(b)1.b above.

3. The export of natural gas will require approval from the Petroleum Commissioner,[179] and the amount of gas permitted for export will be in accordance with the relative part of quantities authorized for export in the reservoirs at that time, subject to ensuring the minimum amount for the domestic market, as aforesaid.

4. Notwithstanding the aforesaid, a reservoir developed prior to the Government Resolution regarding the Tzemach Committee (i.e. the Yam Tethys project and the Tamar Project), may export 50% of the amount for which the lease holders have not yet committed to the domestic market as of the date of the Government Resolution regarding the Tzemach Committee and no more, with immediate effect, provided that export approval is given. It is clarified that if a consumer exercises the option to reduce quantities granted thereto by an agreement signed with the lease holders prior to the said date, the quantity of natural gas for which the option to reduce quantities was exercised, will be deemed as part of the quantity of natural gas for which the lease holders have not yet committed to the domestic market.

5. A lease holder in a developed reservoir may substitute his export quota in exchange for mandatory supply to the domestic market in accordance with the size thereof and the rates determined, and subject to the approval of the Petroleum Commissioner and the Competition Commissioner, after weighing all the relevant considerations.

6. It has been decided to impose an obligation to connect reservoirs to the domestic market according to the size of the reservoir, as follows: (a) Reservoirs exceeding 200 BCM shall be obligated to connect to the domestic market upon their development and prior to the date of commercial piping of the natural gas; (b) Reservoirs ranging between 50 BCM and 200 BCM that commence commercial production of natural gas by January 1, 2028 shall be obligated to connect to the domestic market by December 31, 2032, according to the discretion of the Petroleum Commissioner; such reservoirs that commence commercial production after January 1, 2028 shall be obligated to connect to the domestic market upon their development and prior to the date of commercial piping of the natural gas; (c) Reservoirs up to 50 BCM shall not be obligated to connect to the domestic market. In the case of fields that produce by means of a single production system, with at least two of the leases, in whose area such fields are situated, having an

[179] For details regarding the Petroleum Commissioner's directives with respect to the submission of applications for receipt of a natural gas export permit, see Section 7.23.4(d) below.

identical entity approved as the operator or holder of more than 50% of the interests, the calculation of the gas quantity in such fields for purposes of the duty to connect to the domestic market shall be made in the aggregate. Notwithstanding the aforesaid, the Commissioner may, in a reasoned decision, not calculate the natural gas quantity in the fields in the aggregate.

7. In order to encourage the connection of additional natural gas fields to the domestic market, to task the Commissioner, the Director of the Natural Gas Authority and the Budget Director at the Ministry of Finance, with examining the State's participation in the construction of an additional offshore complex in the southern polygon approved under NOP 37/H, which includes an offshore terminal and connection thereof to the shore, insofar as, in the Commissioner's opinion, exploration activity in Israel's southern offshore area shall have developed. In addition to the aforesaid, to task the Commissioner with examining additional measures to encourage the full realization of the potential economic benefit deriving from the natural gas fields, and, *inter alia*, to encourage the connection to the domestic market of fields which are not subject to the connection obligation or whose connection obligation has been postponed according to the aforesaid.

   In view of a projected shortage in supplying demand on an hourly basis mid-decade between 2030 and 2040, it is proposed to formulate a mix of solutions, including the imposition of a duty on the Petroleum Commissioner to address, in the export permits, the issue of demand in the domestic market on an hourly basis, to act to encourage the connection of additional fields to the domestic market (particularly toward the middle of the next decade (2030-2040)), and to examine the termination of the agreement with the LNG carrier only in 2021 (at present, the agreement is effective until 2022). In such context it is noted that on December 29, 2020, the Ministry of Energy released a notice whereby the Minister of Energy has decided that the agreement with the LNG carrier will not be extended beyond 2022.

8. To task the Minister of Energy, in consultation with the Minister of Finance and the Minister of Economy and Industry, with formulating the principles of the regulation required in relation to the sale of natural gas to consumers in the domestic market, which gas is designated for the production of follow-on products that are primarily designated for export. Further to the aforesaid, the subcommittee was established for purposes of formulating the principles of the regulation as aforesaid (in this subsection: the

"**Subcommittee**"). On October 7, 2020, the Subcommittee published[180] a summary report of the principles of the regulation with respect to the export of natural gas follow-on products, the main principles of which are:

a. Natural gas follow-on products were defined as natural gas-based products whose production involves a chemical change of a methane molecule from natural gas into a different compound or compounds, other than by oxidation (including methanol, ethylene, propylene, ammonia, GTL and DME).

b. The Subcommittee stated that the determination that the sale of natural gas to the follow-on product industry will be deemed as export has many repercussions, and primarily: repercussions deriving from the government's policy in relation to the natural gas sector, including the requirement for an export permit; inclusion of the gas in the total quantity guaranteed to the domestic market; calculation of the gas for purposes of the obligation of minimal supply from a natural gas field to the domestic market; the natural gas price and financing of the transmission system pipeline. It was further determined that the aforesaid does not define the sale as export for purposes of other aspects, such as for purposes of taxation, including for purposes of the Encouragement of Capital Investments Law, 5719-1959.

c. The Subcommittee recommended that a fixed quantity of up to 5 BCM per year of the sale of natural gas to the follow-on product industry be classified as sale in Israel and not for export, in order to allow the industry's existence without distorting the calculation of the demand in the domestic market.

d. The allocation mechanism will be on a "first-come first-served" basis, while the condition to receipt of the allocation will be presentation of an agreement, or at the very least a signed MOU, regarding the relevant plant. The allocated quantity relates to all of the follow-on products with no internal division or restrictions with respect to certain follow-on products. The allocating entity will be the Director General of

[180] The Subcommittee's summary report 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)+

the Ministry of Energy, in consultation with the Director General of the Ministry of the Economy.

e. It was further determined that if applications are submitted, during the two years after the date of adoption of the government resolution on this issue, for the allocation of natural gas to the follow-on product industry at a scope exceeding 5 BCM per year, both the quantity allocated for such purpose and the policy in respect thereof will be examined.

f. The Subcommittee stated 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 specified in Subsection 11 below).

9. To task the Minister of Energy, in consultation with the Minister of Finance, with initiating regulation amendments, including legislative amendments, to the extent necessary, for the purpose of regulating secondary trade in natural gas, which may be directed toward export. In this context, to task the Minister of Energy, in consultation with the Minister of Finance, with ensuring, through such regulation amendments, that secondary trade in natural gas which may be directed toward export will be allowed in a quantity limited to 3% of the total sales of natural gas to the Israeli market in the past year. Such quantity will not be counted for the purpose of calculation of the total quantity secured for the domestic market, but will be counted for the purpose of the minimum supply duty of a natural gas field to the domestic market; it is clarified that the export of such limited quantity shall not require an export permit.

10. The Government Resolution Regarding the Adiri Committee shall be examined by the Government five years after the date of approval thereof for the purpose of revisions, insofar as necessary, with respect to the policy on discoveries to be recognized by the Commissioner five years after the date of approval of the Government Resolution Regarding the Adiri Committee, according to the needs of the domestic market and considering the natural gas supply.

11. A government resolution dated October 25, 2020, dealing with the promotion of renewable energies, approved the second amendment to a government resolution of June 23, 2013, in which it was decided that the government would examine, already during 2021, the restrictions on permitted export quotas in order to increase them. The interim recommendations of the team are expected to be published in the near future. Considering the government policy on natural gas export and given the objective of increasing the targets of renewable energy use, the Partnership does not expect a

restriction that will reduce the scope of the permitted export of natural gas to overseas customers.

(b) Natural gas price control

On May 25, 2011, the Ministry of Energy requested the Joint Prices Committee at the Ministry of Finance and the Ministry of Energy (the "**Prices Committee**") to examine the need for the imposition of control on the prices of natural gas sold in Israel.

Further to the recommendation by the Prices Committee, Control of Prices of Commodities and Services Order (Application of the Law to Natural Gas and Determination of the Control Level), 5773-2013, was published on April 24, 2013. Such order imposes control on the gas sector in terms of reporting on profitability and prices. Such reporting duty is separately imposed in respect of every project. The need to control natural gas prices in Israel in terms of price fixing will be examined based on information to be received. According to the Gas Framework, as long as the Partnership and Noble comply with all of the terms of the Gas Framework, such reporting duty will remain as is. Such reporting duty applies to the Partnership together with its partners in the Yam Tethys project, in the Tamar Project and in the Leviathan project, and also applies to each project separately.

For details regarding a risk factor pertaining to the possible effect of the imposition of price control on natural gas prices in Israel, see Section 7.29.19 below.

(c) The Marine Zones Bill

On November 6, 2017, a government bill, the Marine Zones Bill, 5778-2017 was put before the Knesset (the "**Marine Zones Bill**"). The proposed law seeks to set forth the legal framework applying to the offshore areas (including the areas that are beyond the borders of the State), the rights that the State of Israel has in such areas and the limits of authority that it is entitled to enforce with regard to activities undertaken therein.

Insofar as the bill shall be approved, it may affect the Partnership's operations and the costs thereof, whose scope cannot be estimated as of the report approval date. In this context, it should be noted that in January 2013 an opinion was provided by the Deputy Attorney General (Economics-Fiscal), which provided that in accordance with Israeli law and bearing in mind the instructions of international law, the laws relating to regulation of the natural gas and petroleum sector in Israel can be applied in the offshore areas beyond the State borders, as well as the laws with regarding to environmental protection of the

State of Israel and the fiscal laws of Israel. This opinion did not negate the applicability of additional laws.

(d) <u>The decision of the Minister of Energy to reduce the use of coal and the reform at the IEC and in the electricity sector</u>

On June 3, 2018, government resolution no. 3859 was adopted regarding a reform in the electricity sector and at the IEC (the "**Reform**"). The Reform includes, *inter alia*, the following steps: the IEC will reduce its activity in the electricity production sector by selling five production sites with a total maximum capacity of approx. 4,000 MW, which constitute approx. one half of its electricity production capacity, and in addition the IEC will build two modern production units using natural gas 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 the conversion of the coal-fired power plants in Hadera and Ashkelon to natural gas could be shortened to 2025, and in such 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 the timetable, which he previously determined, by 4 years. In addition, the decision determines that the production plant units at the Rotenberg Power Plant will be converted from coal to natural gas, and units 5-6 at the Orot Rabin Power Plant in Hadera will be converted – by the end of 2025.

On June 8, 2020 a joint notice was released by the Ministry of Energy and the Ministry of Environmental Protection[181] on the Ministers' decision to instruct the IEC to expand the planned shutdowns of the polluting coal-fired units 1-4 at the Orot Rabin site in Hadera, commencing from H2/2020 until the final shutdown thereof in 2022, thus, as stated in the notice, bringing about another significant reduction of air pollutant emissions.

On June 24, 2020, the Ministry of Energy released a notice regarding the Minister of Energy's decision to reduce approx. 20% more of the rate of coal use at the IEC's power plants relative to 2019, and therefore, coal use in 2020 will not exceed 24.9% (compared with 30% in 2019). The Minister of Energy instructed the IEC to take the

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[181] Ministry of Energy website, Spokesman's notice dated June 8, 2020
https://www.gov.il/he/departments/news/press_080620

necessary steps in order to meet the new target, while maintaining the survivability of the electricity generation system.[182]

On February 8, 2021, it was published that the Minister of Energy has directed the IEC to reduce the use of coal such that it will not exceed 22.5% of the total electricity production in 2021, as part of the policy to end the age of coal in Israel by 2025.

(e) The plan to save Israel from polluting energy

On October 9, 2018, the Energy Minister released the "Plan to save Israel from polluting energy", which mainly concerns reduction of the use of polluting fuel products by 2030, and further thereto, in March 2019, the Ministry of Energy released a principles of policy document entitled 'The energy sector's targets for 2030'.[183] The plan set goals for 2030, specifying concrete steps and determining timetables in five main sectors, as follows:

The electricity production section – a gradual reduction of electricity production using coal until the use of coal in the production of electricity at all of the coal-fired power plants will be completely stopped, and electricity production will be based on natural gas and renewable energies only. As aforesaid, on November 13, 2019 the Ministry of Energy announced a further shortening of the timetable for ending the use of coal for the production of electricity, in the context of which it had been decided to convert the coal-fired plants in Hadera and Ashkelon to natural gas by the end of 2025.

a. The transportation sector – cessation of the consumption of polluting fuel products in land transportation, and transition to use of electric vehicles and compressed natural gas-powered vehicles. 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[184] for the establishment of approx. 2,500 electric car charging stations nation-wide, and in June 2019 it released the list of winners of the tender. Toward the deployment of the new charging stations, the Ministry of Energy is promoting the creation of a map and an app that will include all of

[182] Ministry of Energy website, Spokesman's notice dated June 24, 2020: https://www.gov.il/he/departments/news/press_240620
[183] https://www.gov.il/BlobFolder/rfp/target2030/he/energy_2030_final.pdf.
[184] https://www.gov.il/he/departments/general/electric_vehicle_ac_dc.

Israel's stations. Establishment of the system is expected to be completed by the end of 2021.[185]

b. The industrial sector - discontinuation of the use of fuel oil, LPG and diesel oil and replacement thereof with cleaner and more efficient sources of energy commencing 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 issued grants to the distributing companies for purposes of accelerating deployment of the distribution network.[186]

c. Promotion of energy streamlining through use of various mechanisms, including mechanisms to encourage decreasing electricity production among suppliers, producers and consumers of electricity and other license holders in the electricity sector; steps to require zero-energy building; promotion of a model city for smart and efficient energy use; streamlining governmental bodies in order to already reach a target of 20% in 2025 and implementing energy rating targets according to actual consumption for existing buildings in Israel.

d. Ensuring energy security in the market through ensuring redundancy in natural gas supply to the market, in the transportation, industry and electricity sectors.

(f) <u>Government Resolution on "Promotion of renewable energy in the electricity sector and amendment of government resolutions</u>"

On October 25, 2020, a government resolution 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. An update was also determined for the intermediate target, setting it at 20% electricity generation from renewable energies by December 31, 2025, and modifying the policy regarding the promotion of conventional power generation facilities. The government resolution included a series of decisions aimed at facilitating the promotion of renewable energy. In addition, the government's resolutions regarding the adoption of the main points of the Tzemach Committee were amended, such that

[185] https://www.gov.il/he/Departments/General/electric_vehicle_ac_dc

[186] https://www.gov.il/he/departments/news/electric_car_110619.

during 2021 the government will examine the restrictions on the natural gas export quotas.[187]

It was further determined, as part of the adoption of the Minister of Energy's policy and as part of his notice of August 11, 2020 as specified above, that Government Resolution No. 2592 will be amended. Therefore, by July 31, 2023, additional power generation capacity of 4,000 MW is required, fired by natural gas and backed up by diesel oil in approved plans, in response to the needs of electricity consumers until 2030 including at least 4 plans that will enable power production in a combined cycle with the available state-of-the-art technology.

On November 10, 2020, the Natural Gas Authority announced[188] that as part of the plan to save Israel from polluting energy, it was promoting the connection of 16 hospitals to the natural gas network, at a cost of ILS 40 million. In this context, it announced a call for grants to the distribution companies for connecting additional hospitals to the natural gas distribution network. On January 12, 2021,[189] the Ministry of Energy announced that a grant had been awarded for the purpose of connecting five additional hospitals across Israel to the natural gas distribution network in about three years. The plan and the call that had been released promote a step upon the completion of which, as of the date of the update, 18 governmental and non-governmental hospitals will have been connected to the natural gas distribution network.

(g) Energy sector targets for 2050

On November 29, 2020, the Ministry of Energy announced, for public comments, the proposed targets for reduction of emissions in the energy sector in 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 sub-targets: a 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 annual improvement of 1.3% in the energy intensity index,

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[187] https://www.gov.il/he/departments/policies/dec465_2020

[188] 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)

[189] https://www.gov.il/he/departments/news/ng_120121

and an additional examination of the export policy in the natural gas sector and full transition to natural gas in the industrial sector.[190]

(h) The Excise on Fuel (Exemption and Refund) (Tax Amendment and Temporary Provision) Order, 5778-2018 (Green Taxation); the Excise on Fuel (Imposition of Excise) (Amendment no. 2 and Temporary Provision no. 3) Order, 5778-2018 (Amendment), 5779-2019; the Customs Tariff and Exemptions and Sales Tax on Goods (Amendment no. 8) Order, 5778-2018 (Coal) (collectively: the "**Orders**")

On March 14, 2018, and in accordance with the amendment of February 21, 2019, the Finance Committee of the Knesset, and subsequently the Plenum of the Knesset, approved the Orders, in which it was determined, *inter alia*, that from January 1, 2021, the excise tax on coal will increase by approx. 125%, in view of the government's policy to gross-up external costs of fuels and to encourage expansion of uses of natural gas.

In addition, it was decided that, from January 1, 2024, the excise tax on compressed natural gas (CNG) will increase gradually, subject to the existence of no less than 25 compressed natural gas fueling stations that shall receive all of the approvals required for activity. It was further determined that from January 1, 2021, refund of the excise on diesel oil, which is mainly used for transportation purposes, will gradually be cancelled.

On January 1, 2021, the excise tax increase took effect.

In the Partnership's estimation, these Orders may lead to a material reduction in the use of coal for the production of electricity and to reduction of the use of diesel oil for transportation purposes, and accordingly, to increased demand for natural gas in the economy, over and above the natural growth in demand for natural gas and for electricity in the Israeli economy.

(i) Environmental directives for offshore oil and natural gas exploration and development

In September 2016, the Ministry of Energy, jointly with the Ministry of Environmental Protection and other government ministries, published directives designated to regulate the environmental aspects of the operations of offshore oil and natural gas exploration, development and production. 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 Land

[190] https://www.gov.il/he/departments/publications/Call_for_bids/energy_2050_public

Authority, release environmental directives to which the Partnership may be directly or indirectly subject. Such directives are updated from time to time, and they are intended to instruct the holders of offshore petroleum interests as to the actions and documents they are required to prepare in the context of their operation in the areas of their rights, in order to prevent, or minimize to the greatest extent possible, environmental hazards that might be created during the operations of offshore oil and natural gas exploration, development and production. Such directives constitute an integral part of the petroleum interest and the work plan therefor, and deviation therefrom might lead to the revocation of the right. Therefore, the Ministry of Energy specifies, *inter alia*, the following directives:

1. <u>Environmental directives for the performance of a seismic survey</u>: in view of the level and the consequences of the noise created as a result of the performance of a seismic survey, it is required to report to the Commissioner on the noise level, the routes and dates planned for the seismic survey, and to receive approval from the Commissioner for the performance thereof. In cases in which the activity is carried out in reservations or in proximity to infrastructure facilities, the activity is required to be coordinated vis-à-vis the competent entities or authorities. In addition, it is required that a plan for the performance of the survey be prepared, and the Commissioner's approval be obtained as a condition for the performance thereof.

2. <u>Environmental directives for licenses</u>: At the stage of grant of the license, the right is granted for petroleum exploration by means of exploration wells and appraisal wells, in the area of the license. Insofar as findings are discovered, further tests are carried out, with the purpose of examining the quantity and the quality of the findings. As a condition for the receipt of a drilling permit, the license holder will submit an application for the Commissioner's approval, which includes the following documents: (1) An environmental document that includes an environmental impact assessment plan for the marine environment; (2) An enterprise emergency plan for the treatment of sea pollution by oil, approved by the National Marine Environment Protection Division; in addition, the license holder is also required to obtain the following permits: a permit for discharge into the sea and a poison permit.

3. <u>Environmental directives for post-discovery licenses and for leases</u>: As a condition for the receipt of approval for the development plan and the operation permit, the lease holder will submit the following documents to the Commissioner: (1) An environmental document that includes environmental impact assessment for the marine environment, which refers to the

planned development plan and production; (2) An enterprise emergency plan for the treatment of incidents of sea pollution by oil. In addition, the lease holder is also required to obtain the following permits: a permit for discharge into the sea, a poison permit and an emission permit.

(j) National Outline Plan 37/H for the Reception and Processing of Natural Gas

In order to create the zoning infrastructure for the connection of the natural gas reservoirs to the national transmission system and construct the facilities required for such purpose, the National Planning & Building Council (in this section: the "**National Council**") and the Israeli Government approved the "detailed partial national outline plan on the reception and processing of natural gas from discoveries to the national transmission system" (in this section: the "**Plan**" or "**NOP 37/H**").

The Plan designates areas (onshore and offshore) for the construction of the facilities required in the process of production and transmission of natural gas, which include, *inter alia*, natural gas reception and processing terminals, pipelines for transmission of the gas etc. The development plan of the Leviathan reservoir in the format specified in Section 7.2.2(j) above, is in keeping with NOP 37/H.

(k) The decision of the Electricity Authority – principles for recognition of the gas costs for private producers operating with natural gas and principles for recognition of costs for a utility provider (the system management unit) in respect of agreements for the purchase of natural gas (in this section: the "**Decision**")

March 6, 2019 saw the release of the Decision, which specifies the manner of calculation of the seller's price per MMBTU in ILS to a producer that has signed a gas agreement in which the gas price is linked to the production component. The Decision shall only apply to license holders that are entitled to recognition of the gas agreement cost according to the Authority's decision applicable to them (upon satisfaction of two cumulative conditions which are stipulated in the Decision).[191]

The notes to the Decision state, *inter alia*, as follows:

- A private producer that signs a gas agreement that supersedes a previous gas agreement which was recognized by the Authority will benefit from 25% of the price difference between the

[191] https://www.gov.il/BlobFolder/policy/55511/he/Files_Hachlatot_55511_1337.pdf

agreements, provided that the price under the new agreement is lower.

- A private producer that signs a gas agreement that does not supersede a gas agreement which was recognized by the Authority will benefit from 25% of the difference between the maximum gas price under the Gas Framework and the contractual gas price.

The Decision sets a mechanism that incentivizes the private power producers to engage in agreements for the sale and purchase of gas, in which the gas price is lower than the maximum price specified in the Gas Framework, by means of recognizing a price higher than the actual gas price. Furthermore, the Decision incentivizes the private power producers to engage in agreements with gas suppliers that are not related to the Tamar partners, insofar as the gas price under such agreements is lower than the maximum gas price specified in the Gas Framework. It is clarified that, as concerns the IEC, the of the Electricity Authority of June 12, 2017[192] applies, which establishes the principles the IEC is required to fulfill in order for the costs to be recognized, but does not set a similar mechanism.

(l) <u>Permits and licenses for the facilities of the Yam Tethys project, the Tamar Project and the Leviathan project</u>

1. In the framework of the development of the Yam Tethys project, the Yam Tethys Partners received an approval to construct a permanent rig for the production of natural gas and oil and also an approval for the operation of a production system of natural gas under the Petroleum Law, and in addition the Minister of Energy granted Yam Tethys Ltd. (a company owned by the Yam Tethys Partners) a license to construct and operate a transmission system for the transfer of natural gas of the Yam Tethys Partners or other natural gas suppliers from the production platform to the Terminal, provided certain conditions are fulfilled and subject to the conditions of the license and the Natural Gas Sector Law .

2. In addition, in the framework of the Tamar Project development plan, the Tamar Partners received approval to construct a permanent platform for the production of natural gas and oil, and also an approval for the operation of a production system of natural gas and condensate from the Tamar Project under the Petroleum Law, according to which the Tamar Partners were required, *inter*

[192] https://www.gov.il/BlobFolder/policy/51813d/he/Files_Hachlatot_13518.pdf

alia, to provide guarantees in the amount of ILS 100 million (in 100% terms).[193]

Furthermore, on August 29, 2016, the Minister of Energy granted Tamar 10-Inch Pipeline Ltd. (a company owned by the Tamar Partners according to their rate of interest in the lease) a temporary transmission license for the operation of a pipeline to be used for the transfer of natural gas from the Tamar Lease, via the Tamar rig to the entry point of the natural gas processing terminal in Ashdod, all subject to the conditions of the license. The pipeline was constructed as part of the production system, as defined in the operation approval for Tamar, mainly in order to serve for the transfer of condensate, and its operation for the purpose of natural gas transmission is for a limited period, following which it will go back to being used for the transfer of condensate.

3. In the Phase 1A development plan for the Leviathan project, the Leviathan Partners received approval for the construction of a permanent rig for the production of natural gas and oil, as well as approval for the operation of a system for production of natural gas and condensate from the Leviathan project, according to which the Leviathan Partners were obligated, *inter alia*, to submit guaranties, as specified in Section 7.2.2(n) above.

   On February 21, 2017, the Minister of Energy granted Leviathan Transmission System Ltd. (a company owned by the Leviathan Partners) a license for the construction and operation of a transmission system to be used for the transfer of natural gas of the Leviathan Partners originating from the Leviathan Leases, or of other natural gas suppliers, upon the fulfillment of certain conditions, all subject to the conditions of the license.

4. In addition, many additional permits and approvals were received under various laws which are required for the different projects (Yam Tethys, Tamar and Leviathan).

7.23.6 <u>Applicability of Cypriot legislation to the Partnership's activity</u>

Gas and oil exploration activity in Cyprus is subject to regulation that includes, *inter alia*, the obligation to receive permits, licenses or franchise arrangements to perform the activity, requirements in connection with the scope of investment and schedules for performance of exploration, payment of royalties to the State (under the franchise agreement detailed in Section 7.4.3 above), safety and the environment.

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[193] The Tamar Partners furnished a guarantee in the sum of $35 million to secure the said undertaking and also to secure the terms and conditions of the Tamar Lease deed.

Exploration activity and the production of hydrocarbons in territorial waters and in the economic waters of the Cyprus Republic are regulated mainly in laws and local regulations that were promulgated under primary legislation (the “**Cyprus Legislation**”). In addition, the Republic of Cyprus is a full member of the European Community and the European Community directive with regard to the granting and use of authorizations for exploration and production of hydrocarbons (Directive 94/22/EC) and other relevant European legislation also regulates the exploratory activity and the production of hydrocarbons in the Republic of Cyprus and in the Republic of Cyprus EEZ.

In 1988 the Republic of Cyprus adopted the United Nations Convention on the Law of the Sea (UNCLOS 82) and as far as is known, signed agreement with neighboring states (Israel, Egypt and Lebanon) with regard to the definition of the Cyprus EEZ.

Under the Cyprus Legislation, a license is required for the purpose of performing seismic surveys 2D and 3D, which is granted for a period of up to one year, a license for the exploration of hydrocarbons is given for an initial period of 3 years which can be extended by two additional periods of two years each and a production (exploitation) license is given for a period of 25 years and can be extended for an additional period of 10 years, subject to meeting the conditions of the license. A production license, in connection with a commercial discovery during exploration will be given after approval of the development and production plan.

The relations between the Republic of Cyprus and the license holder are set forth in the Production Sharing Contract (the “**Production Sharing Contract**”). The Production Sharing Contract sets forth the relationship, the obligations and rights of the license holder and the fiscal conditions to which the license holder is subject. For further details with respect to the Production Sharing Contract in Block 12, see Section 7.4.3 above.

During 2014, the Republic of Cyprus decided to establish a designated government company, the Cyprus Hydrocarbons Company Ltd., owned by the Cypriot government which is its arm in all matters regarding exploration activity in the EEZ of Cyprus, and the production and export of oil and natural gas from Cyprus.

7.24 **Pledges**

With regard to pledges the Partnership has given on its assets, see Notes 10 and 12J to the financial statements (Chapter C of this report).

7.25 **Material Agreements**

The Partnership has entered into material agreements that were in effect during the period from January 1, 2020 until the report approval date, as specified below:

7.25.1 <u>Agreements for the sale of natural gas from the Tamar and Leviathan projects to the domestic market</u> (for details, see Sections 7.11.4(a) and 7.11.4(b)2 above).

7.25.2 Agreement for the balancing of the gas produced from the Tamar reservoir (for details, see Section 7.11.4(a)6 above).

7.25.3 <u>Engagements for the export of natural gas from the Tamar and Leviathan projects</u> (for details, see Section 7.11.5 above).

7.25.4 <u>Financing agreements</u> (for details, see Section 7.20 above).

7.25.5 <u>Production Sharing Contract in respect of Block 12</u> (for details, see Section 7.4.3 above).

7.25.6 <u>Agreements for the purchase of EMG shares and for the purchase of rights in the EMG pipeline</u>

With the aim of realizing the two agreements between the Partnership and Noble and Dolphinus for the export of natural gas to Egypt from the Tamar and Leviathan reservoirs specified in Sections 7.11.5(a)2 and 7.11.5(b)2 (in this Section 7.25.6: the "**Dolphinus Agreements**" or the "**Export to Egypt Agreements**"), on September 26, 2018, EMED signed agreements for the purchase of 39% of the share capital of EMG (the "**EMG Transaction**").

On November 6, 2019, the EMG Transaction was closed, on January 15, 2020, the flow of natural gas from the Leviathan reservoir to Egypt began, and on June 30, 2020 the flow of natural gas from the Tamar reservoir to Egypt began.

The closing of the EMG Transaction was contingent, *inter alia*, on the signing of a Capacity, Lease & Operatorship Agreement – CLOA, between EMED and EMG, in which EMG shall grant EMED the exclusive right to lease and operate the EMG pipeline for the flow of natural gas from Israel to Egypt (in this Section 7.25.6: the "**CLOA**"), which was signed on June 30, 2019, all as specified below:

(a) <u>General background</u>

EMG is a private company registered in Egypt which owns a submarine pipeline of a diameter of 26 inches and approx. 90 km long, which connects between the Israeli transmission system in the Ashkelon area and the Egyptian transmission system in the el Arīsh area, and related facilities (collectively: the "**EMG Pipeline**"). The EMG Pipeline was planned for a capacity of approx. 7 BCM per year, with an option to increase the capacity to approx. 9 BCM per year through the installation of additional systems. The flow of gas in the EMG Pipeline from Egypt to Israel was stopped in 2012, and to the best of the Partnership's knowledge, as of the date of the signing of the agreement, EMG had no commercial activity, and it remained exposed to lawsuits[194] and debts to authorities, finance providers, suppliers and customers in significant amounts.[195] It is noted that in the framework of the transaction, the Partnership was not required to provide collateral or guaranties in relation to the existing debts of EMG.

On the date of the signing of the agreement, EMG's shareholders were:

(1) EGI-EMG LP – 12%;

(2) Merhav MNF Ltd. – 8.2%;

(3) Merhav Ampal Energy Holdings, Limited Partnership – 8.6%;

(4) Merhav Ampal Group Ltd. – 8.2% (the "**Merhav Ampal Group**");

(5) PTT – 25%;

(6) MGPC – 28%;

(7) EGPC – 10%.

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[194] In addition, to the best of the Partnership's knowledge, on December 30, 2018, ORL filed with the International Chamber of Commerce a Request for Arbitration against EMG in accordance with the natural gas sale agreement that was signed between them on December 12, 2010 (the "**EMG-ORL Agreement**"). ORL's primary claim is that due to the non-supply of natural gas during the term of the EMG-ORL Agreement, and termination of the agreement, it suffered estimated damage of approx. $350 million. In addition, ORL's secondary claim is that contractual limitations on liability apply, estimated at approx. $45 million plus interest. EMG claims that ORL is not entitled to compensation at all since the EMG-ORL Agreement was suspended due to *force majeure* events, and that ORL's claims are time-barred. EMG further claims that even if it is found that ORL is entitled to compensation for its damage, the amount of the compensation is limited to approx. $20 million in accordance with the terms and conditions of the EMG-ORL Agreement. The arbitration hearings were held on October 12, 2020 to October 16, 2020 and included written filings which continued until December 18, 2020. The arbitration judgement was issued to the parties on March 5, 2021, in the context of which all of the claims against EMG were rejected and ORL was charged with costs.

[195] In accordance with EMG's financial statements as of December 31, 2019 and December 31, 2018, EMG's assets total approx. $402 million and approx. $105 million, respectively; the liabilities total approx. $390 million and approx. $520 million, respectively; the equity totals approx. $12 million and negative equity totals approx. $415 million, respectively. In addition, in 2019 and 2018, EMG did not recognize income from operations, but in 2019 the company recorded income from an asset write-off reversal and a debt arrangement with an Egyptian bank which generated profit therefor in the sum of approx. $427 million, and conversely it accrued in 2019 losses in the sum of approx. $25 million. EMG's financial statements are presented in U.S. dollars and are prepared according to Egyptian GAAP. It is noted that the said financial statements do not include a provision for possible claims on the part of customers.

(Shareholders (1)-(4) above shall hereinafter be referred to collectively in this section as: the "**Sellers**").

(b) Agreements for the purchase of 39% of EMG's share capital

On September 26, 2018, EMED signed four separate, mainly 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 (collectively in this section: the "**Share Purchase Agreements**"), as well as another agreement for the purchase of shares at a rate of 2% from MGPC (the "**MGPC Agreement**").

1. The main principles of the Share Purchase Agreements

a. Upon fulfillment of the conditions precedent, the main ones of which are mentioned in Paragraph e. below, and the conditions to the closing of the EMG Transaction, the Sellers sold and transferred to EMED the EMG shares held thereby, at a total rate of 37% of EMG's share capital (in this section: the "**Purchased Shares**"), including all of the rights attached to the Purchased Shares.

b. The Sellers, the shareholders of the Sellers and the companies affiliated with the Sellers shall waive any claim, lawsuit, award, decision, order or remedy that are available to them against the Egyptian government and companies owned thereby in the framework of the Arbitration Proceedings.[196]

c. In consideration for the Purchased Shares, for waiver of their rights in the framework of the Arbitration Proceedings, and other rights in accordance with the Share Purchase Agreements, as aforesaid, EMED paid the Sellers, on the date of the closing of the EMG Transaction, the sum total of approx. U.S. $527 million (in this section: the "**Consideration**"), out of which each one of the Partnership and Noble paid a sum of approx. U.S. $188.5 million, and the balance was paid by the Egyptian Partner.

d. The law that governs the Share Purchase Agreements is English law. Disputes between the parties shall be heard in

[196] It is noted that some of the Sellers, the shareholders of the Sellers and companies affiliated with the Sellers, conducted several arbitration proceedings at international arbitration institutes against the Egyptian government and companies owned thereby in connection with the cessation of the flow of the gas from Egypt to Israel (collectively in this Section 7.25.6: the "**Arbitration Proceedings**"). In addition, EMG is a party to arbitration proceedings against companies owned by the Egyptian government.

arbitration in London (according to the arbitration rules of The London Court of International Arbitration).

e. Performance of the EMG Transaction contemplated in the Share Purchase Agreements was contingent on fulfillment of standard conditions precedent, including: receipt of all of the approvals and the consents required for the transfer of the Purchased Shares from the Sellers and registration thereof in EMED's name; receipt of the approvals and the consents required pursuant to any law in Egypt and Israel for fulfillment of the transactions contemplated in the Share Purchase Agreements and for the flow of the gas in the EMG Pipeline from Israel to Egypt (including approval of the Competition Authority); signing of the CLOA and elimination of any material impediment to performance thereof; completion of the engineering due diligence process in relation to the EMG Pipeline, including the performance of continuous gas flow tests from Israel to Egypt via the EMG Pipeline, in accordance with the quantities and the period determined; modification of the existing debt structure of EMG in favor of an Egyptian bank and rescheduling thereof to EMED's satisfaction; receipt of all of the formal approvals required by the Sellers, including in relation to the controlling shareholder of the Merhav Ampal Group, which is in dissolution proceedings, court approvals,[197] and the closing of all of the Share Purchase Agreements.

f. On July 31, 2019, the decision of the Competition Commissioner[198] was issued in accordance with Section 20(b) of the Competition Law, which allows the purchase of the interests in the EMG Pipeline under the following main conditions:

1. The Partnership (and any affiliate, as defined in the decision: "**Affiliate**"), Noble (and any Affiliate), EMG and EMED (EMG and EMED shall hereinafter be referred to, jointly and severally, as the "**Parties**") shall not refuse a gas swap application and shall supply natural gas to a customer in Israel who has signed a natural gas supply contract with a supplier of natural gas in Egypt in a quantity and of a quality that is no less than the quality to which the natural gas

[197] On November 16, 2018, the approval required from the Bankruptcy Court in New York was received.
[198] https://www.gov.il/BlobFolder/legalinfo/decisions037056/he/decisions_037056.pdf.

supplier in Egypt committed vis-à-vis the customer in Israel (a "**Gas Swap Arrangement**"). In this context, they will make every reasonable effort, including by exercising their rights in the Tamar and Leviathan projects in order to grant such an application, all provided that the Egyptian supplier supplies natural gas to the customer of the Israeli supplier (i.e. the Tamar partners and the Leviathan partners) (the "**Israeli Supplier**") in a quantity and of a quality that is no less than the quality that the Israeli Supplier undertook to sell to the customer in Egypt.

2. The obligation of the Partnership, Noble and the Parties as stated in Subsection 1 above is up to the gas quantities set forth in the take-or-pay clauses 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 agreements for transmission in the EMG Pipeline (i.e. any agreement for use of capacity of the transmission infrastructure of the pipeline in the direction from Ashkelon to el-ʻArīsh).

3. An Egyptian supplier (i.e. a supplier that meets the requirements of the Egyptian law for the export of natural gas to Israel, if any) shall not be charged by EMG with an amount that exceeds one half of the transmission fees in the EMG Pipeline for natural gas that is swapped in a Gas Swap Arrangement.

4. The Partnership, Noble and the Parties shall not refuse to provide transmission services in the EMG Pipeline to an entity seeking to transport natural gas that does not originate from an Israeli Supplier in the EMG pipeline from Ashkelon to el-ʻArīsh (the "**Other Entity**") who wishes to receive transmission services in the EMG Pipeline up to the scope of the available capacity (i.e. capacity in the EMG Pipeline which is not reasonably required by the Tamar partners or the Leviathan partners).

5. The aforesaid notwithstanding, the obligation to provide the transmission services shall not apply in any of the following cases: (a) the Other Entity shall have refused to sign a transmission agreement with the Parties, despite the Director of the Natural Gas Authority having confirmed that the transmission

agreement contains no conditions that are unnecessarily burdensome on the Other Entity; (b) the Other Entity shall have refused to meet conditions required by the Director of the Natural Gas Authority with respect to such transmission agreement.

6. EMED shall not exercise the option to extend the Capacity, Lease & Operatorship Agreement by another ten years without receiving a permit in advance from the Competition Commissioner.

With respect to the petition that was filed with the Competition Court at the Jerusalem District Court with respect to the Competition Commissioner's approval as aforesaid, see Section 7.26.8 below.

g. With respect to the signing of an agreement between Noble and INGL regarding the transmission of natural gas to the EMG Pipeline via the INGL System, see Section 7.12.2(b)3.b. above.

2. The main principles of the MGPC Agreement

Concurrently with the signing of the Share Purchase Agreements, an agreement was signed between EMED and MGPC whereby MGPC transferred to EMED, without financial consideration, upon the closing of the Share Purchase Agreements, 2% of EMG's shares which are held thereby, against the conclusion of disputes between some of the Sellers and MGPC.

After the closing of the EMG Transaction, and as of the date of this report, EMG's shareholders are:

(1) EMED – 39%;

(2) PTT – 25%;

(3) MGPC – 17% (controlled by Dr. Ali Evsen);

(4) The Egyptian Partner – 9%;[199]

(5) EGPC – 10%.

(c) The Capacity Lease & Operatorship Agreement

As aforesaid, the closing of the EMG Transaction was contingent, *inter alia*, on the signing of the CLOA between EMED and EMG, in which EMG shall 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, shall be borne by EMED (collectively in this section: the "**Operation Costs**"), while EMG will be entitled to receive the current transmission fees which Dolphinus shall pay for use of the pipeline (in this section: the "**Transmission Fees**"), net of the Operation Costs. As of December 31, 2020, Noble and the Partnership have invested in the refurbishment of the EMG Pipeline, through EMED, approx. $124 million, [200] most of which will be repaid from the cash flow deriving from the payment for the transport of the gas to EMED.

[199] To the best of the Partnership's knowledge, MGPC has transferred the said shares to the Egyptian Partner.
[200] Of which approx. $72 million were invested in financing the Michal Matan and Ratio-Yam joint ventures in the context of the Capacity Allocation Agreement.

Concurrently with the signing of the Export to Egypt Agreements, on September 26, 2019 an agreement was signed between the Partnership and Noble and the Tamar Partners and the Leviathan Partners in connection with allocation of the capacity (in this section: the "**Capacity Allocation Agreement**") in the transmission system from Israel to Egypt. The capacity division 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:

1. First layer – up to 350,000 MMbtu per day will be allocated to the Leviathan Partners.

2. Second layer – the capacity above the first layer, up to 150,000 MMbtu per day until 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.

3. Third layer – any additional capacity above the second layer will be allocated to the Leviathan Partners.

On the date of the closing of the EMG Transaction, the Leviathan Partners paid the sum of $200 million[201] ("**Leviathan's Participation**") and the Tamar Partners paid the sum of $50 million[202] ("**Tamar's Participation**"), in consideration for an undertaking to allow the transport of natural gas from the Leviathan and Tamar reservoirs and guaranteed capacity in the EMG Pipeline, all for the purpose of consummation of the Export to Egypt Agreements. It is noted that the final amounts of Leviathan's Participation and Tamar's Participation 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 via the EMG Pipeline until such date (including gas quantities not yet supplied and paid for by virtue of a take-or-pay undertaking).

In addition, the Capacity Allocation Agreement determined arrangements for participation in the costs of the EMG Transaction, additional costs in connection with the transport of the gas, and investments which will be required for maximum utilization of the capacity of the EMG Pipeline, payment of which shall be divided between the Leviathan Partners and the Tamar Partners. For details regarding an agreement that was signed according to these principles, see Section 7.11.4(a)6 below.

[201] The Partnership's share is $90.7 million.
[202] The Partnership's share is $11 million.

The Capacity Allocation Agreement further determines principles for a "backup" arrangement between the Tamar Partners and the Leviathan Partners, according to which, from June 30, 2020 until the Capacity Increase Date, insofar as the Tamar Partners shall be unable to supply the quantities which they undertook to supply to Dolphinus, the Leviathan Partners shall supply the Tamar Partners with the required quantities.

The term of the Capacity Allocation Agreement is until the conclusion of the Export to Egypt Agreements, unless it shall have ended prior thereto in the following cases: a breach of a payment undertaking which was not remedied by the party in breach; in a case where the Competition Authority shall not have approved extension of the Capacity Lease and Operatorship Agreement according to the decision of the Competition Commissioner, as specified in Section 7.25.6(b)f above. In addition, each party shall be entitled to end its part in the Capacity Allocation Agreement insofar as its export agreement shall have been terminated.

To the best of the Partnership's knowledge, on August 26, 2019, PTT, which holds 25% of EMG's shares, filed a claim with the Economic Court in Port Sa'id, Egypt, against EMG and other parties. In the complaint, PTT seeks cancelation of resolutions of EMG's general meeting of June 10, 2019, including cancelation of the resolution regarding approval of the signing of the Capacity & Operatorship Agreement. PTT asserts that these resolutions constitute oppression of minority shareholders and contradict the best interests of the company, contrary to the provisions of the Egyptian companies law, to which EMG is subject. As of the report approval date, the hearing of the claim was postponed to April 2021.

(d) EMED's shareholders' agreement

In proximity to the date of the signing of the Share Purchase Agreements, EMED's shareholders signed a shareholders' agreement which regulates the relationship between them as shareholders of EMED, including provisions regarding material resolutions that shall be adopted unanimously. In addition, right of first refusal arrangements were determined for the transfer of shares of EMED.

(e) Term sheet for use of additional infrastructures

Concurrently with the signing of the Share Purchase Agreements, as described above, a term sheet was signed between the Partnership and Noble and the Egyptian Partner (which holds the Arab Gas Pipeline in the segment between el Arish and Aqaba, and an affiliate of Dolphinus, whereby 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 flow of gas in additional quantities over and above the gas quantities that would flow via the EMG Pipeline (in this section: the "**Additional Infrastructure**"), for the purpose of implementation of the Dolphinus agreements and other agreements for the sale of natural gas to Egypt. In addition, the parties agreed to look into other projects for the transmission of natural gas from Israel to potential customers and facilities in Egypt.

(f) <u>Agreement between EMG and EAPC and Eilat-Ashkelon Infrastructure Services Ltd.</u>

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 "**EAPC Agreement**" or the "**Agreement**", respectively) for regulation of a sublease of areas in the EAPC site at the Ashkelon port, rights of way at the port and use by EMG and EMED of the natural gas facility situated on this site, for the purpose of the transport of the natural gas in the EMG Pipeline.

In consideration for these rights, the EAPC Companies are entitled to payments as specified 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 Export to Egypt Agreements are terminated 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 the provisions thereof (including extension of the lease agreement between Eilat-Ashkelon Infrastructure Services Ltd. and the Israel Land Authority), EMG will be entitled to 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 guaranty (renewable over the term of the Agreement) in the sum of U.S. $4 million (in this section: the "**Guaranty Amount**"). As of the report approval date, EMG has not provided the bank guaranty, and in its stead EMED provided a company guaranty up to the sum of the Guaranty Amount, which is backed by two bank guaranties in the sum of U.S. $2 million each, which were provided by the Partnership and Noble (in this section:

the "**Bank Guaranties**"). The guaranty provided by EMED shall expire and be null and void in the event that: (a) all of EMG's undertakings vis-à-vis the EAPC Companies shall have been cancelled; (b) the EAPC Companies shall have received payment in the sum of the Guaranty Amount due to enforcement of the Bank Guaranties; (c) the Bank Guaranties shall have been replaced with a bank guaranty provided by EMG; or (d) the Bank Guaranties shall have expired or been cancelled. It is further noted that according to the terms and conditions of the guaranty provided by EMED, the EAPC Companies will be obligated to first enforce the Bank Guaranties and only in the case of non-payment will they be entitled to use EMED's guaranty.

Alongside the signing of the Agreement, the Tamar and Leviathan partners provided a release letter, according to which each one of the partners releases the EAPC Companies from any future lawsuit in respect of damage that shall be caused thereto (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 exception of damage caused with malicious intent).

The EAPC Companies provided a similar letter to the Tamar and Leviathan partners.

7.25.7 Joint operating agreement in Tamar and Dalit leases

(a) General

The exploration and production activity in the framework of the Tamar Project lease are done under a joint operating agreement (JOA) of November 16, 1999 (as amended from time to time) to which party to currently are the Partnership and the Other Tamar Partners as detailed in Section 7.2 above (in this section: the "**Agreement**" or the "**JOA**").

The purpose of the Agreement is to set forth the mutual rights and obligations of the parties in connection with activities in the areas of the Tamar Project leases (in this section: the "**Petroleum Assets**").

(b) Manner of accounting

Unless otherwise provided for in the JOA, all the rights and interests in the Petroleum Assets, in the joint property and in all the hydrocarbons produced from them, will be subject to the terms and conditions of the Petroleum Assets and the rules that apply to them, and in accordance with the participation rates of the parties in the Petroleum Assets. Furthermore, unless otherwise provided for in the JOA, the undertakings of the parties under the JOA and the terms and conditions of the Petroleum Assets and all the liability and expenses incurred or undertaken by the operator in connection with the joint activity[203], and all the credits to the joint account[204], will be borne by the parties, between themselves, in accordance with their participation share in the Petroleum Assets, and each party will pay when due in accordance with the Accounting Procedure instructions set forth in the JOA (the "**Accounting Rules**") its share, in accordance with its participation share, of all expenses of the joint account including advances and interest owed according to the JOA. The dates of payment are of the essence. Payment by a party of another party's obligation under the JOA does not negate its right to dispute such liability at a later stage.

According to the Accounting Rules, Noble is entitled to reimbursement of all direct expenses expended thereby in connection with the fulfillment of its function as operator. The amendment of June 30, 2016 to the JOA, provides for the accounting method also in respect of Noble's indirect expenses, and determines that as of January 1, 2016, Noble will be entitled to payment of indirect expenses at the rate of 1% of the total direct expenses, other than with respect to marketing activities and fees, which are specified in the amendment to the agreement as aforesaid.

(c) <u>The identity, rights and obligations of the operator</u>

Noble serves as the operator of the Tamar Project leases (in this section: the "**Operator**")

Subject to the conditions of the JOA, the Operator is granted all the authorities and obligations with regard to the management of joint venture, under the supervision and instructions of the joint operating committee. The Operator's position may not be assigned without the prior written consent of the parties to the JOA (which are not operator) as well as any consent that is required on behalf of the Petroleum Commissioner, with the exception of an assignment to an affiliate of the Operator, as defined in the agreement.

The Operator is exclusively responsible, for the management of the joint activity. The Operator may employ contractors and/or agents (which could be related companies of the Operator) to perform said joint activities. The Operator will be responsible, *inter alia*, for preparing a work plan, the budgets and the authorizations for payment, for the performance of the work plan according to the authorization of

[203] In accordance with the definitions of the JOA – the "joint activity" is the activity performed by the operator according to the provisions of the JOA and the costs for which each of the parties to the JOA may be billed.
[204] In accordance with the definitions of the JOA – the "joint account" are accounts held by the operator in favor of the joint project in accordance with rules set forth in the JOA and the accounting rules.

the joint operating committee, for the planning and getting of all approvals and material required to perform them, giving of advisory services and technical services as required for efficient performance of the joint operation.

In the joint management of the activity the Operator will be required, *inter alia*, to perform the joint activities in accordance with the terms and conditions of the Petroleum Assets and their applicable rules, the JOA and the instructions of the operational committee. The Operator will perform its role with due diligence and in accordance with the customary procedures in the petroleum industry.

The JOA sets forth various instructions regarding the manner of engagement of the Operator in contracts with third parties (according to approved budgets), and depending on the sum of the offered contract, may be required to consult with the other parties with regard to the criteria according to which the candidates for the tender will be chosen, to report to the parties with regard to the offers received and to get the operating committees' approval for the choice of candidate in a tender.

The Operator is required to take out and maintain the insurances detailed in the JOA in accordance with the general instructions therein. It is also provided that each of the parties to the JOA must take care of itself and of additional insurance on its account to cover the risks in connection with the joint activity.

The Operator is also required, after receipt of reasonable prior notice, to permit representatives of each party, at any reasonable time and on their own expense and responsibility, access to the joint activity including the right to observe the joint activity, to examine all joint property and to audit the finances in accordance with the Accounting Rules set forth in the JOA.

Subject to the terms and conditions of the Petroleum Assets and the approved budget, the Operator will determine the number of employees and the number of contractors, choose them and determine their hours of work and the consideration to be paid to them in connection with the joint activity.

The Operator will immediately advise the parties of any material actions and other actions filed as a result of the joint activity and/or are related to the activity of the Partnership, as shall be instructed by the operating committee. The Operator will represent the parties and defend said claims. The Operator may, at its sole discretion, settle any claim or series of claims in a sum that does not exceed $75,000 (including legal expenses), and will ask for permission from the operating committee for any sum(s) that exceed the aforementioned sum. No party will settle with regard to its proportionate share of any claim without first proving to the operating committee that this can be done without harming the interests of the joint activity.

Each party which is not the Operator will immediately notify the other parties regarding any action filed against it by a third party and that relates from the joint activity or could affect the joint activity, and the party that is not an operator will defend or settle the aforementioned claim in accordance with instructions that will be given by the operating committee. The costs and damages caused in connection with the defense or settlement which can be related to the joint activity will be debited from the joint account.

The Operator will not be responsible vis-à-vis the other parties to the agreement for any action, debt, loss or damage, direct or indirect, whether under the agreement or tort (including negligence) or other that derives from the joint operation or in connection thereto unless the action, debt, loss or damage derives from willful misconduct of the Operator or the failure of the Operator to obtain the required insurance cover (unless the Operator took all reasonable means to get such insurance coverage and advised the other parties of such) and in any event will not be liable for consequential damages, including but not only the inability to produce petroleum, production loss or loss of profits. The foregoing does not exempt the Operator from responsibility for its share in accordance with its participation share, for any damage, loss or other liability.

(d) Operating committee

A joint operating committee (the "**Committee**") was formed for the supervision and giving of directions in all matters related to the joint activity in the lease area. The Committee's authority includes, *inter alia*, the making of decisions with regard to policy, processes and operating practice, approval of all notices to the public relating to the agreement or the joint operation, approval of all plans and budget requests, the determining of schedules, place and depth of drilling of wells and everything related thereto, making decisions with regard to application for licenses and leases and replacing the Operator. Each partner has a representative in the joint operating committee, whose voting rights are relative to the holdings of the partner that appointed him. The Operator's representative serves as the Committee's chairman.

The joint operating committee's decisions are passed by a vote of two or more partners that hold collectively at least 68% of the rights in the lease (related parties as defined in the agreement will be considered one party). In order to approve a decision related to the termination of a lease or waiver of any part of a lease area, unanimous agreement is required. A positive decision of any one party to the JOA is sufficient to approve any license or license renewal or lease application.

(e) Work plans and budgets

The JOA sets forth procedures and processes for the submission and approval of work plans, budgets and authorizations for expenditure (AFE) for activities in the areas to which the JOA applies. It should be noted that the Operator can deviate from the approved AFE for the work plan in a rate that does not exceed 10% of the approved sum or 1 million dollars, whichever is lower.

Exploration plan and budget – the work plan and budget will be approved by the operating committee. Authorization for expenditure (AFE) within the work plan and budget will be approved in accordance with the provisions stipulated by the JOA, unless at least 20% of the parties to the JOA deliver a notice to the Operator of their objection to the approval of the AFE. Prior an expenditure or the giving of an undertaking in a sum exceeding $250,000 for any item in the approved work plan and budget, the Operator will send all the other parties a request for an authorized expenditure approval (AFE). In the event that the Operator anticipates a deviation from the AFE for administrative purposes and for geological or geophysical operations that are not exclusive to a particular project, no AFE will be required, provided that the deviation does not exceed $50,000.

Development plan and budget – In the event that the committee should decide after a full discussion on the economic merit of the development of each offer presented to it, the Operator will provide the parties, as soon as possible after the making of such decision, a development plan and budget for the applicable discovery, which will include, inter alia, the works required in connection with the development, all the information required to submit it in accordance with the agreement, the manner of management required for the development including details with regard to the number of workers and manpower required, an estimate of the production commencement date and of the annual production volume and any other information required by the committee. Prior to expenditure or the giving of an undertaking, in any amount, with regard to the preparation of a development plan and budget or with regard to any item in the approved development plan and budget, the Operator will send all the other parties a request for an AFE. In the event that the Operator anticipates a deviation from the AFE for administrative purposes and for geological or geophysical operations that are not exclusive to a particular project, no AFE will be required, provided that the deviation does not exceed $50,000.

Production plan and budget – each year the Operator will provide the parties with the proposed production plan for the following year. The proposed production plan must include, *inter alia*, the projects, and works that need to be performed, any information required to be provided in accordance with the JOA, details regarding the number of workers and required manpower and an estimation of the total production by quarter and the maximum daily rate of production for each quarter and all other information required by the committee. Before expenditure or the giving of an undertaking in a sum that exceeds $250,000 for each item in the work plan and approved budget, the Operator will send all the other parties a request for authorized expenditure (AFE).

The development or production plan and the proposed budgets will be subject to reconsideration, revision, amendment and approval by the committee that will be done so as soon as possible and in accordance with the schedule specified in the JOA.

In the event that the Operator anticipates a deviation from the AFE for administrative purposes and for geological or geophysical operations that are not exclusive to a particular project, no AFE will be required, provided that the deviation does not exceed $50,000 as pertains to the exploration, development and discovery stage, and that the deviation does not exceed $1 million as pertains to the production stage.

(f) Sole risk operations

Operations in which not all the parties take part (defined in the agreement as “Exclusive Operations” and known in the oil exploration industry as “Sole Risk” operations) will not be performed if they contradict joint operations in which all the partners participate. The agreement sets forth rules for the performance of said “Sole Risk” operations.

The agreement includes various instructions relating to Sole Risk operations - i.e. the performance of drilling, tests and development not unanimously agreed upon by all the partners in the leases , which under certain conditions specified in the agreement can be performed by some of the partners. Parties that do not join the Sole Risk operation have been given the possibility, subject to conditions and payments set forth in the agreement, to get back their share in such operation and everything deriving therefrom. Furthermore, parties who had not joined the Sole Risk activities, but decided to join after the joining date, will bear the fines and the interest specified in the JOA.

(g) <u>Resignation and removal of the Operator</u>

The Operator may resign by written notice of 180 days in advance or upon shorter notice upon the agreement of the operating committee. In addition, subject to the provisions of the agreement the committee can terminate the Operator in the following situations: (1) if the Operator ceases to hold at least 10% of the working interest in the Tamar and Dalit leases; (2) an application was made for a court order or a valid decision for reorganization of the Operator, under the bankruptcy laws; (3) if the Operator is liquidated or ceases its existence in another manner; (4) if the Operator becomes insolvent, makes an arrangement in favor of creditors or if a receiver is appointed for a significant part of its assets.

In addition, the Operator will be removed from its position upon receipt of a notice from the Petroleum Commissioner with regard to cancellation of the approval that was given to the Operator, to the extent that such an approval is required.

Furthermore, the operating committee may remove the Operator from its position by written notice to the Operator of 90 days in advance, if the Operator, in the reasonable opinion of the other parties to the JOA (that are not the Operator) shall have committed a fundamental breach of the agreement and shall not have remedied the breach within 28 days from the date it received notice detailing the occurrence of said breach. Any decision of the other parties to the JOA (that are not an operator) to give a notice of breach to the Operator requires a vote in favor of the decision of parties, excluding the Operator and which are not related thereto, holding collectively at least 68% of the total working interests.

In the event that the Operator resigns or is removed from its position, the operating committee shall elect, as soon as possible but in any event within 30 days from the date of provision of the notice regarding the Operator's resignation or its removal from its position as aforesaid, one of the parties to the JOA (which are not the Operator) who shall agree to assume the position of operator, subject to any approval that shall be required on behalf of the Petroleum Commissioner. In the event that the Operator is removed from its position, if the outgoing operator decides not to vote for one of the parties to the JOA (which are not the Operator) as the new operator, but rather to vote for itself or for a party affiliated with the outgoing operator, its vote shall not be counted. In the event that the parties do not elect a new operator, the party to the JOA (which is not the Operator) which holds the largest percentage out of the total working interests shall be appointed as operator, insofar as it agrees to assume the position and subject to any approval that shall be required on behalf of the Petroleum

Commissioner. In the event that there are two parties that hold the largest percentage of the total working interests, the decision between the two will be made by a vote of the operating committee.

(h) Sanctions applicable to the partners and the conditions for imposition thereof

A party that shall have failed to timely pay its proportionate share in the joint expenses, including advances and interest, will be deemed as a party in breach ("**Party in Breach**"). The delinquent amount shall bear cumulative interest on a daily basis. Any party that is not a Party in Breach (a "**Party Not in Breach**") must bear its proportionate share (its share versus the share of all of the other Parties Not in Breach) in the amount in breach (excluding interest), and pay this amount to the Operator on the first day after a period of 6 days in which the Party in Breach is in breach, and if it fails to do so, it itself shall become a Party in Breach.

So long as the breach is ongoing, the Party in Breach shall not be entitled to participate or vote in the operation committee meetings and shall not be entitled to receive data and information pertaining to the joint operations. If the breach lasts more than 6 Business Days, as such term is defined in the JOA, from the date on which the breach notice is given to the Party in Breach, and for as long as it continues, the Party in Breach will not be entitled to receive the portion to which it is entitled of the output, and this portion will be the property of the Parties Not in Breach and they will be entitled, while taking the steps detailed in the JOA, to collect from it what is due to them, until the payment of the sum subject to breach.

If the Party in Breach does not remedy the breach within 90 days from the date of the notice of the breach, then without derogating from any other rights the Parties Not in Breach may have under the JOA, each party that is not in breach will have the option (that can be exercised at any time until full remedy of the breach) to require the Party in Breach to resign completely from the JOA and the Petroleum Asset. If the aforementioned option is realized the Party in Breach will be deemed as having transferred, all of its rights under the JOA and the Petroleum Asset to the Parties Not in Breach, and it will be obliged, upon first demand, to sign any document and take all action required by law in order to give validity to said transfer of shares, and to remove any attachment or pledge applicable to said rights. Rights and remedies of the Parties Not in Breach as a result of said breach are in addition to any right or other remedy at the disposal of the Parties Not in Breach, under law.

(i) Manner of dilution of partners' holdings – transfer of rights

A party may transfer its rights to a third party, subject to approval by the other parties to the JOA, which approval shall not be unreasonably withheld.

Transfer of the working interests of a party in a Petroleum Asset, in whole or in party, will only be valid if it meets the conditions of the JOA, including *inter alia* the following conditions:

1. Notwithstanding the transfer, the transferor will remain liable vis-à-vis the other parties to the JOA for all liabilities, financial or other, that were either vested, had matured or accrued under the terms of the Petroleum Asset or the JOA prior to the date of the transfer including without limitation, any expenses approved by the operating committee prior to the transferor giving notice with regard to the transfer of the rights to other parties to the agreement.

2. The transferee will have no rights with regard to the terms of the Petroleum Asset, the area of the Petroleum Asset or under the JOA, for as long as, and until the required government approval has been received, and it has undertaken specifically in a written document to the satisfaction of the other parties, to perform the transferor's undertakings under the conditions of the Petroleum Asset and the JOA with regard to the working interest being transferred to it, and the transferor will provide the guarantees required by the government or according to the Petroleum Asset.

3. The foregoing does not preclude a party under the JOA from pledging or otherwise encumbering, all or part of its interest in the area of the Petroleum Asset or under the JOA as collateral for finance, subject to such party retaining responsibility for all undertakings relating to the said interest; the pledge will be subject to any government approval that may be required and will be specifically subordinated to the rights of the other parties under the JOA.

(j) Withdrawal from the JOA

The JOA includes provisions regulating the matter of withdrawal, full or in part, of a party from any Petroleum Asset in which it is a participant (and from the applicable JOA) and determines the situations when such withdrawal is possible, and the rights and obligations of the withdrawing party vis-à-vis the other partners in the license.

A party that wishes to withdraw from the JOA or Petroleum Assets, must notify the other parties of its decision, such notice must be unconditional and irrevocable immediately upon delivery, subject to the conditions set forth in the JOA (a "**Withdrawal Notice**"). Within 30 days from the day of delivery of a Withdrawal Notice the other parties to the JOA will be entitled to also give a Withdrawal Notice. In the event that all the parties provide a Withdrawal Notice, they will act to terminate the JOA and their remaining undertakings relating to the project and the Petroleum Asset. In the event that not all the parties decide to withdraw as aforesaid, the withdrawing party will act in order to transfer his rights to the partners that chose not to withdraw (the "**Remaining Partners**") as soon as possible. Transfer of rights as aforementioned will be for no consideration, with the withdrawing partner bearing all the expenses arising from its withdrawal as aforesaid, unless otherwise agreed. The transfer of the rights to the Remaining Partners will be in proportion to their relative holdings.

(k) Rights and obligations with respect to production

Each party has the right and the obligation to take its share in the hydrocarbons produced from the leases, in accordance with the terms of the JOA.

The JOA does not regulate the joint sale of natural gas or LNG that shall be produced from the leases.

(l) The governing law and settlement of disputes

The JOA is subject to the laws of England and Wales. In addition, any dispute shall be decided in an arbitration proceeding in accordance with the arbitration rules of the International Chamber of Commerce. In the framework of the arbitration proceeding, a single arbitrator will be appointed who shall not be a resident or citizen of Israel or England.

7.25.8 Joint Operating Agreement in respect of the Leviathan Leases[205]

(a) General

The activity in the framework of the Leviathan Leases is carried out under a joint operating agreement of August 31, 2008 (as amended from time to time), the present parties to which are the Partnership and the other partners in the Leviathan Leases as specified in Section 7.2.1 above (in Section 7.25.8: the "**Agreement**" or "**JOA**").

[205] It is noted that until January 1, 2012, the activity in the Leviathan Leases was carried out in the framework of a single joint operating agreement.

The purpose of the Agreement is to set forth the mutual rights and obligations of the parties in connection with activities in the areas of the Leviathan Leases (in Section 7.25.8: the "**Petroleum Asset**").

According to the aforementioned operating agreements, Noble was appointed as the operator.

(b) Manner of accounting

Unless otherwise provided for in the JOA, all the rights and interests in the Petroleum Asset, in the joint property and all the hydrocarbons produced from them, will be subject to the terms and conditions of the Petroleum Asset and the applicable rules, and in accordance with the participation rates of the parties therein. Furthermore, unless otherwise provided for in the JOA, the party's undertakings under the Petroleum Asset conditions and the JOA and all the liabilities and expenses incurred or undertaken by the operator in connection with the joint activity,[206] and all the credits to the joint account,[207] will be borne by the parties, amongst themselves, in accordance with their participation rate in the Petroleum Asset, and each party will pay, when due, in accordance with the Accounting Procedure instructions of the JOA (the "**Accounting Rules**") its share in accordance with its participation rate of all the expense of the joint account. Payment dates are of the essence of the JOA. Payment by a party of another party's obligation under the JOA does not negate its right to dispute such liability at a later stage. According to the Accounting Rules, Noble is entitled to be reimbursed for of all direct expenses paid in connection with it fulfilling its position as operator and to be reimbursed for the indirect costs derived from its shares of the expenses of the joint venture at the exploration state as follows:

Direct expenses (on an annual basis)	Rate of payment to operator (as a percentage of direct expenses
Up to $4 million -	4%
$4-7 million -	3%
$7-12 million -	2%
Above $12 million -	1%

The rate of indirect expenses for the development and production stage was not provided by the Agreement, and on June 30, 2016 an amendment to the JOA in the Leviathan project was signed, whereby

[206] In accordance with the definitions of the JOA – the "joint activity" is the activity performed by the operator according to the provisions of the JOA and the costs for which each of the parties to the JOA may be billed.
[207] In accordance with the definitions of the JOA – the "joint account" are accounts held by the operator for the joint project in accordance with rules set forth in the JOA and the Accounting Rules.

the operator will be entitled to receive indirect expenses at the rate of 1% of all of the direct expenses in connection with development and production operations, subject to certain exceptions, such as marketing activity.

(c) Rights and obligations of the operator

Under the JOA the operator is exclusively responsible, for the management of the joint activity, which includes, *inter alia*, preparation of work plans, budgets and payment authorizations, performance of the work plan according to the joint operating committee's approval, planning and obtaining all of the approvals and materials required for performance thereof, and provision of consulting services and technical services as required for the efficient performance of the joint operation. The operator may employ contractors and/or agents (which could be related companies/affiliates of the operator[208] or one of the parties to the JOA or a related party/affiliate to one of the parties to the JOA) to perform said joint activities.

In managing the joint activities the operator must, *inter alia*, perform the joint activities in accordance with the terms and conditions of the Petroleum Asset and the rules applicable thereto, the laws, the JOA and the instructions of the operating committee (which roles are specified below); to manage all the joint activity with diligence and in a safe and efficient manner in accordance with the acceptable principles in the international petroleum industry in similar situations. In addition, the operator is required to take out the insurances detailed in the JOA, in accordance with the instructions set forth therein.

In addition, the operator is required, after receipt of reasonable prior notice, to permit the representatives of all the parties at any reasonable time and at their expense and responsibility access to the joint activity including the right to observe the joint activity, to inspect the joint equipment and to conduct a financial audit in accordance with the provisions of the Accounting Rules set forth in the JOA.

Subject to the terms and conditions of the Petroleum Asset, the conditions applicable to it and the JOA, the operator will determine the number of workers, will select them and determine their hours of work and the consideration to be paid to them in connection with the joint activity. The operator will only employ the manpower reasonably required to perform the joint activity.

[208] In this regard, "a related/associated party" is defined in the JOA as a legal entity that controls or is controlled by a party to the JOA (directly or indirectly); and "control" means the ownership (directly or indirectly) of more than 50% of the voting rights or the ability to control the decision-making at the said legal entity.

The operator will provide the other parties with information and data as detailed in the JOA and will enable them access at all reasonable times to all aforementioned information.

The operator, as shall be instructed by the operating committee, will immediately advise the parties of any significant actions and other actions that were filed as a result of the joint activity and/or related thereto. The operator will represent the parties and defend them from said actions. The operator may, at its sole discretion, settle any claim or series of claims for a sum that does not exceed $50,000 plus legal expenses, and will ask for permission from the operating committee for any sum(s) that exceed that. Each party will be entitled, at its own expense, to be represented by its own lawyer at any compromise arrangement or defense in said actions. No party will settle with regard to its proportionate share of any claim without first proving to the operating committee that this can be done without harming the interests of the joint activity.

Each party that is not an operator will immediately advise the other parties of any action against it by a third party that derives from the joint activity or may impact the joint activity, and the non-operator party will defend or compromise on the said claim, in accordance with instructions given by the operating committee. Costs and damages which will be caused in connection with the defense or compromise and that can be attributed to the joint activity will be charged to the joint account.

Unless otherwise provided for in this section: the operator (and in this regard – including the directors and officers therein, its related companies and the directors and officers therein, collectively: the "**Indemnified Parties**") will not bear (except as a party in the participation rate of a Petroleum Asset) any damage, loss, cost, expense or liability deriving from the joint activity, even if caused, in whole or in part, by a prior defect, negligence (sole, joint or parallel), gross negligence, strict liability or any other legal culpability of the operator or of any indemnified party as aforesaid.

Unless otherwise provided for in this section: the parties to the JOA in accordance with their participation rate in the Petroleum Asset will defend and indemnify the operator and the Indemnified Parties for all damages, losses, costs, expenses (including legal expenses and reasonable legal fees) and liability, deriving from actions demands or causes of action that were filed by any person or legal body and that are the result of or derive from the joint activity, even if caused in full or in part, by a prior defect, negligence (sole joint or parallel), gross negligence, strict liability or any other legal culpability of the operator or any other said Indemnified Party.

Notwithstanding the foregoing, if the operator's officers in senior supervisory positions or in its related parties is involved in gross negligence which proximately causes the parties damages, loss, cost, expense or other liability for actions, claims or claims of action as aforesaid, then in addition to its liability as a party in accordance with its participation rate, the operator will bear only the first $5,000,000 in aggregate of such damages, losses, expense, costs and debts.

Notwithstanding the foregoing, in no event will an Indemnified Party (except as a party with rights in the Petroleum Asset according to the percentage of its working interests therein) in the debt for damages or environmental or consequential losses.

(d) The operating committee

In the framework of the JOA the parties established an operating committee, which has the authority and responsibility to approve and supervise the joint activities required or necessary to meet the conditions of the Petroleum Asset and the JOA, for exploration and exploitation of Petroleum Asset areas in accordance with the JOA and in an appropriate manner according to the circumstances. The operating committee is made up of representatives of the parties (and their alternates) and each representative of a said party will have the right to an opinion equal to the working interest which it represents. The JOA determines the order of processes and proceedings for convening meetings of the operating committee and the discussion at them and includes processes and arrangements for making decisions in writing.

Unless otherwise provided for specifically in the JOA, all decisions, approvals and other activities of the operating committee with regard to the proposals presented before it, will be decided by the vote in favor of at least 2 parties or more (that are not related parties/affiliates, as defined above) jointly holding at the time of the vote at least 60% of all of the working interests in the area of the applicable Petroleum Asset.

It is further noted that in order to approve a decision to end the lease or waive any part of the area of the lease, a positive vote of all of the parties is required. A positive decision of any one party to the JOA is sufficient in order to approve any application for a license or renewal of a license or a lease.

(e) Work plans and budgets

The JOA sets forth procedures and processes to submit and approve work plans, budgets and authorizations for expenditure (AFE) for activities in the areas to which the JOA applies.

On or prior to the first day of October of each calendar year, the operator will present the parties with a proposed production work plan and budget, which will specify the joint activity that will be performed in the production area as well as the planned production timetables for the next calendar year, and the operating committee is required to make a decision, within 30 days of the submission of the proposal as aforesaid, about the production work plan and budget.

Engagement of the operator in contracts in the framework of the exploration and evaluation activity and also in the production activity, that the consideration thereof exceeds $2.5 million and also development activity that consideration thereof exceeds $5 million, will be subject to the approval of the operating committee

Prior to expenditure or the giving of an undertaking in a sum that exceeds $500,000 for any item in the work plan and approved budget for exploration, evaluation and production activity, or in a sum that exceeds $1,000,000 for any item in the work plan and approved budget for development activity, the operator will send an authorization for expenditure request (AFE) which will include, *inter alia*, an evaluation of the sums and schedule required to perform said work, and all the additional information required to support the aforementioned application all of the other parties. Notwithstanding the foregoing, the operator will not be obliged to submit an AFE to parties prior to undertaking any expenditure with regard to operational expenditure, general and ongoing management activity, classified as separate items in the work plan and the approved budget.

The operator may deviate, without operating committee approval, at a rate that does not exceed 10% per item from the sum that was approved for such item and subject to the aggregate total deviations in calendar year not exceeding 5% of the work plan total and approved budget. Where the operator believes that the deviation shall exceed such aforementioned limits, it shall submit another AFE for the operating committee’s approval for issuance of a permit. These limitations do not derogate from the right of the operator to deviate from the expenditure for urgent operational matters and emergencies as detailed in the JOA.

It is noted that the JOA permits the other parties who are not the operator to submit different work plans and budgets to those that were submitted by the operator, for the operating committee’s approval. In the event that the work plans and the budgets that were submitted by the parties shall not be approved by the operating committee by an effective majority as aforesaid, the work plan that received the most assenting votes will be approved, insofar as it meets the obligations required by the minimum work terms determined in regards to the Petroleum Asset.

(f) <u>Sole Risk operations</u>

Activities in which not all the parties participate (defined in the agreement as “Exclusive Operations” and known in the oil exploration industry as “Sole Risk” operations) will not be performed if they contradict joint operations in which all the parties participate. The agreement determines rules with respect to the framework of performance of such operations.

The JOA includes various provisions relating to Sole Risk operations, namely the drilling of wells, tests and development, other than with the consent of all of the parties and which, under certain conditions specified in the agreement, may be performed by some of the parties. Parties that did not join such activity were given a possibility, subject to conditions and payments determined in the agreement, to receive back their share in such activity and everything deriving therefrom. In addition, parties which did not join the Sole Risk operations but decided to join after the joining date will bear the penalties and interest set forth in the joint operating agreement.

(g) Resignation and removal of the operator

Subject to the provisions of the JOA, the operator may, at any time, resign from its position as operator, upon prior notice of at least 120 days.

Subject to the provisions of the JOA the operator will be removed from its position upon the occurrence of any one of the following events: (1) if it becomes insolvent, bankrupt or if it has made an arrangement with its creditors; (2) if a notice was provided by a party to an agreement in the event of a court order or valid decision for reorganization under the bankruptcy laws; (3) if a receiver is appointed to a significant portion of its assets; or (4) if the operator is liquidated or ceases to exist in another manner.

Furthermore, the operator may be removed from its position by a decision of other parties to the JOA (that are not the operator) if it materially breached the JOA and did not commence the remedy of said breach within 30 days from the date upon which it received notice detailing said breach, or if it did not act to complete the remedy of the breach. Any decision of other parties to the JOA (that are not the operator) to give a notice of breach to the operator or to remove the operator will require an affirmative vote in favor of the decision of one or more of the parties that are not the operator (or that are not a related party or an affiliate of the operator) that represent collectively at least 65% of the total working interests of the parties that are not an operator.

When there is a change in the identity of the operator as aforesaid, then the operating committee will convene as soon as possible in order to appoint an operator, however no party to the JOA will be appointed as operator against its will. The operator that was removed from office against its will or the related party/affiliate will not be permitted to vote in favor of itself or to be a candidate for the position of operator.

(h) Operating committee

Under the JOA, the parties have established an operating committee, which is authorized and holds the function of approving and supervising the joint activities required or necessary for the fulfillment of the conditions of the petroleum assets to which the JOA applies, for exploration and use of the areas of the petroleum assets in accordance with the agreement and in an appropriate manner according to the circumstances. The operating committee consists of the parties' representatives (and their successors) and every such party representative has a vote equal to the working interest of the party he represents. The JOA specifies the processes and the procedures for calling meetings of the operating committee and the discussion thereby, and includes procedures and arrangements for the adoption of written resolutions.

Unless the JOA expressly stipulates otherwise, all decisions, approvals and other activities by the operating committee with respect to all of the proposals presented thereto shall be decided by an affirmative vote in favor of the proposal by two or more parties (other than related/associated parties, as defined above), holding together, at the time of the vote, at least 60% of all working interests in the petroleum assets.

It is further noted that an affirmative vote by all parties is required in order to approve a resolution to terminate the lease or a waiver of any part of the area of the lease. In order to approve a license or license renewal or lease application, the affirmative decision of any party to the JOA is sufficient.

(i) <u>Sanctions applicable to the parties and the conditions for imposition thereof</u>

A party that fails to timely pay its proportionate share in the joint expenses (including advances and interest) or that fails to obtain or maintain the collateral required thereof, will be deemed a party in breach (the "**Party in Breach**").

As of 5 days from the date a Party in Breach was provided with a notice of breach and the breach persists, the Party in Breach will not be entitled, *inter alia*, to participate in meetings of the operating committee or to vote at them, receive information regarding the joint activity and to transfer its working interests or any part thereof, except to parties in breach.

Any party that is not a Party in Breach (a "**Party Not in Breach**") must bear the proportionate share (its share relative to the share of the other Parties Not in Breach) of the sum that is in breach (excluding interest), and to pay this sum to the operator within 10 days from the date of receipt of a notice with regard to the breach, and if it does not do so will itself be deemed a Party in Breach.

As long as the breach is ongoing, the Party in Breach will not be entitled to receive its portion of the output, and this portion will be the property of the Parties Not in Breach and they will be entitled, while following the proceedings detailed in the JOA, to collect from it what is due to them until the full payment of the breached sum (including setting up a reserve fund). Any surplus sum will be paid to the Party in Breach and any shortage will remain as a debt of the Party in Breach to the Parties Not in Breach.

If the Party in Breach does not remedy the breach within 90 days from the date of the notice of the breach, then without derogating from any other rights the Parties Not in Breach may have under the JOA, each party that is not in breach will have the option (that can be exercised at any time until full remedy of the breach) to require the Party in Breach to resign completely from the JOA and the Petroleum Asset. If such option is realized on the date a notice of realization of the option was sent, the Party in Breach will be deemed as having assigned all of its working interests to the Parties Not in Breach, and it will be required to sign, without delay, any document and take any action required by law in order to give force and effect to the said transfer of shares, and to remove any attachment or pledge that apply to the said rights.

Rights and remedies of the Parties Not in Breach as a result of said breach are in addition to any right or other remedy at the disposal of the Parties Not in Breach, under law.

A fundamental principle of the JOA is that each party is required to pay its relative portion (according to its participation rate in the Petroleum Asset) of all sums it owes under the JOA when due. Therefore each party that becomes a Party in Breach waives any offset claims and will not be entitled to raise such vis-à-vis the Parties Not in Breach which instituted the proceedings set forth in the JOA against it, for non-payment of the sums owed by it on time.

(j) <u>Transfer of rights</u>

Transfer of working interests of a party to a Petroleum Asset, in whole or in part, will be in force if it meets all the conditions set forth in the JOA, including *inter alia* the following conditions:

1. Except for in the case where a party transfers all of its working interests in a Petroleum Asset, no transfer of rights will occur where as a result the transferor retains or the transferee has

received a working interest in a Petroleum Asset and in the JOA of less than 10%.

2. Notwithstanding the transfer, the transferor will retain liability vis-à-vis the other parties to the JOA for all financial and other liabilities, that were vested, had matured or accrued under the Petroleum Asset and the JOA prior to the date of the transfer including any and all expenses approved by the operating committee prior to the transferor's notice with regard to the transfer of the offered rights to the other parties under the JOA.

3. The transferee will have no rights with regard to the Petroleum Asset or under the JOA, for as long as and until: (a) it receives the required government approval and provides the guarantees required by the government or according to the terms and conditions of the Petroleum Asset; (b) it specifically undertakes, in a written document, to the satisfaction of the other parties, to perform the transferor's undertakings under the terms and conditions of the Petroleum Asset and the JOA with regard to the working interest being transferred to him; and (c) all other parties have given their written consent to the transfer. Furthermore, the parties may withhold their approval only if the transferee fails to demonstrate, to their reasonable satisfaction, that it has the ability to satisfy its payment obligations under the leases and the JOA and the technical ability to contribute to the planning and execution of the joint activity. However, in the event of transfer to a related party, the consent of the other parties is not required, subject to the transferor remaining responsible for the transferee's performance of all of its obligations.

4. The foregoing does not preclude a party to the JOA from pledging any or part of its working interests as collateral for financing, subject to such party remaining responsible for all undertakings relating to said interest. The said pledge or encumbrance will be subordinate to any government approval that will be required and will be done specifically as subordinate to the rights of the other parties under the JOA.

5. The transfer of a party's working interests in the petroleum assets, in whole or in part (with the exception of a transfer to a related party or encumbrance of the interests as specified above), shall be subject to the giving of a notice to the other parties, in which the transferor discloses to the other parties the final terms and conditions of the transaction and grants them the right of first refusal. Upon the delivery of such notice, each of the other parties shall have the right to acquire the working interests to which the transaction pertains from the transferor, on the same terms and

conditions (and without any reservation), by giving a counter-notice within 30 days of the delivery of the notice. In the event that more than one party notifies of its intention to exercise the right of first refusal, the sale of the rights shall be conducted *pro rata* according to such parties' rate of working interests.

(k) <u>Change of control</u>

In the event of change of control of any of the partners, such party shall provide the other parties with: (a) all of the required governmental approvals, as well as the guarantees required by the Government; (b) will provide the other parties with collateral with respect to the financial ability to comply with the obligations under the agreement. In addition, the party undergoing such change, the partner is required to give notice of the change of control to the other partners (the "**Notice**"). In this section, "change of control" means any direct or indirect change of control of a party (including by way of merger, sale of shares, other interests or otherwise), the value of the Leviathan Leases held by which constitutes more than 50% of the market value of all of the assets of such party. The Notice shall include, *inter alia*, the market value of the partner's rights according to the JOA, based on the amount that the entity acquiring the control is prepared to pay in an arm's length transaction. Upon delivery of the Notice as aforesaid, each one of the other parties shall be entitled to purchase all of the rights of the partner at which the change of control is performed, within a period of 30 days from delivery of the Notice, and the purchase will be according to the conditions and the sum of the purchase amount stated. It is also noted that according to the terms and conditions determined in the JOA, the other parties may challenge the value stated in the Notice of the change of control.

In a case where more than one party gives notice of its desire to exercise its right to purchase the rights as aforesaid, the division will be made proportionately to the share of the parties' working interests.

(l) <u>Withdrawal from the JOA</u>

The JOA includes provision regulating the matter of withdrawal, full or in part, of a party from any Petroleum Asset in which it is a participant (and from the JOA applicable) and determines the cases when withdrawal is possible, and the rights and obligations of the withdrawing party vis-à-vis the other partners for the Petroleum Asset and the JOA.

A party that wishes to withdraw from a Petroleum Asset, must provide a notice of its decision to the other parties ("**Withdrawal Notice**"). Said notice will not be unconditional and irrevocable upon delivery, subject to the conditions set forth in the JOA. Within 30 days from the day of delivery of the Withdrawal Notice the other parties to the JOA will be entitled to also present a Withdrawal Notice. In the event that all the parties present a Withdrawal Notice, they will act to terminate the JOA and the remaining undertaking connected to the Petroleum Asset and the JOA. In the event that not all the parties will decide to withdraw, all the withdrawing parties will act in order to assign as soon as possible the said rights to the partner/partners that chose not to withdraw. Transfer of said rights will be without consideration, with each of the withdrawing partners bears all expenses with regard to its withdrawal, unless otherwise resolved. The transfer of the rights to the remaining partners will be in proportion to their relative holdings.

(m) Rights and obligations with respect to production

Each party has the right and obligation to take its share in the hydrocarbons produced from the leases, unless it is agreed otherwise.

(n) Governing law and dispute settlement

The JOA is subject to the laws of England and Wales. A dispute shall be decided in an arbitration proceeding in accordance with the arbitration rules of the London Court of International Arbitration (LCIA).

7.25.9 Joint operating agreement in Block 12

The joint operating agreement as aforesaid covers the same issues as and is in a format similar to the joint operating agreement that applies to the Leviathan project (for details see Section 7.26.8 above), whereby decisions are made by an “effective majority”, which is affirmative votes in favor of the decision by at least two participants that are not related parties and collectively hold at least 65% of the total rights in the license. Noble Cyprus serves as operator.

7.25.10 Royalties to the State and to related and third parties

(a) General

The Petroleum Law prescribes that a lease holder must pay the State royalties at the rate of one-eighth (12.5%) of the quantity of oil and natural gas produced from the area of the lease and utilized, according to the market value of the royalty at the wellhead (the "**State Royalties**").

In addition to State Royalties, the Partnership pays royalties, according to the market value of the royalties at the wellhead, to related and third parties (the "**Royalty Interest Owners**") according to undertakings originating from the agreement for the transfer of rights in petroleum assets to the Partnership, as shall be specified in this section below, and undertakings originating from Avner's Limited Partnership Agreement.

(b) Calculation of the market value of the royalties at the wellhead

As aforesaid, pursuant to the Petroleum Law, the leaseholder will pay the State the "market value of the royalty at the wellhead". A determination of a method for calculating the market value of the royalty at the wellhead is required, since 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 determined, had the gas been delivered at the wellhead. Consequently, the effective rate of the State Royalties is actually lower than one-eighth (the "**Effective Rate**").

For details regarding directives published by the Ministry of Energy regarding the method of calculation of the market value of the State Royalties at the wellhead, see Section 7.23.4(b) above.

Below are details regarding the method of calculation of the Effective Rate of the State Royalties in projects of the Partnership and on the discussions with the State on this matter.

(c) Calculation of the market value of the State Royalties in projects of the Partnership[209]

1. The State Royalties in the Yam Tethys project

In 2004, the partners in the Yam Tethys project and the Petroleum Commissioner reached an agreement regarding the method of calculation of the Effective Rate of the State Royalties, whereby the State recognized certain types of expenses that would be deducted from the total sales.

In February 2019, an agreement was signed between the Yam Tethys Partners and the Ministry of Energy regarding final royalty reports for 2011-2013. The agreement determined that the Yam Tethys Partners are entitled to a refund of approx. $4.4 million (100%) which was offset against monthly royalty payments in the Yam Tethys project.

It is noted that the Ministry of Energy's audit of the royalty reports for 2014-2020 has not yet been completed, but in view of the fact that the scope of the revenues from the project in 2014-2020 was immaterial, the differences deriving from the rate of the advances for such years and the effective royalty

[209] It is noted that the method of calculation of the market value at the wellhead of the royalties paid to the Royalty Interest Owners was made in accordance with the calculation of the Effective Rate of the State Royalties in respect of the Tamar Project.

rate used by the Partnership in its financial statements is immaterial.

It is noted that production from the Mari-B reservoir ended in May 2019.

2. The State Royalties in the Tamar Project

a. According to the position of the Ministry of Energy, the agreement regarding the method of calculation of the value of the State Royalties at the wellhead in the Yam Tethys project, does not apply 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 the wellhead in the Tamar Project, the Tamar Partners paid the State advance payments, in accordance with 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. The position of the operator and the Other Tamar Partners is 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 entailed thereby and the amount of the investments in the project, and that the average Effective Rate of the State Royalties in 2013-2020 should be lower.

b. 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 approx. 11.16%, approx. 11.3% and approx. and 11.34%, respectively.[210]

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 is approx. $16.8 million.

For further details in this regard, see Note 15 to the Financial Statements.

[210] It is 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%.

c. For details regarding a claim for restitution of royalties that were paid to the State by the Partnership, Avner and Noble in respect of their revenues deriving from the supply of natural gas from their share in the Tamar Project to their customers, under the Yam Tethys project's agreements, see Section 7.26.2 below.

d. On September 6, 2020, the Natural Resources Administration at the Ministry of Energy released the directives of the Petroleum Commissioner regarding calculation of the royalty value at the wellhead in the Tamar Lease[211] (in this section: the "**Directives**"). The Directives specified, *inter alia*, the following principles:

The expenses which shall be recognized for purposes of calculation of the royalty value at the 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 for the Platform and 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%: salary expenses of the worker 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 consulting; insurance expenses.

In addition, should the contract sale price include a component of a transmission tariff that is paid to INGL, all of the transmission expenses paid by the lease holder will be recognized. Abandonment costs will be recognized for purposes of calculation of the royalty according to the general directives, see Section 7.23.3(b) above. However, the cumulative conditions applying to the Tamar Lease shall be: at least 170 BCM of the gas in the reservoir were produced in the aggregate and the Abandonment Plan has been approved by the Commissioner.

3. The State Royalties in the Leviathan project

From the date of commencement of supply of the gas from Leviathan reservoir, the Leviathan Partners are making advance payments to the State on account of the State's royalties in respect of the revenues from the Leviathan project at the rate of approx. 11.3%, in accordance with a letter of demand received from the Ministry of Energy in January 2020.

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 approx. 11.81%.[212]

The difference between the royalties actually paid to the State by the Partnership and the effective royalty rate on which the Partnership relied in its financial statements for 2020 amounts to approx. $2.6 million.

For further details on this matter, see Note 15 to the financial statements.

(d) Payment of royalties to related and third parties[213]

1. General

In addition to the State royalties, the Partnership pays, as aforesaid, royalties to related and third parties, in accordance with undertakings that the Partnership and Avner assumed in the past, as shall be specified below.

2. Royalties of Delek Group and Delek Energy:[214,215,216] These royalties originate from an interest transfer agreement of 1993

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[212] It is noted that in the discounted cash flow figures for the Leviathan project, the Partnership assumed that the effective rate of State royalties was 11.5%.

[213] Following the merger of the partnerships, all of the undertakings to pay royalties to the said royalty interest owners now apply with respect to all of the Partnership's (existing and future) petroleum assets, although the royalty rate in respect thereof was reduced by 50% relative to the royalty rate on the eve of the merger, since the Partnership and Avner held the said petroleum assets in equal shares, apart from the Ashkelon and Noa leases, in which the Partnership held 25.5% and Avner 23%, and in respect of which the royalty rate was reduced by 47.42% relative to the royalties that were paid by the Partnership prior to the merger to Delek Group and Delek Energy, and by 52.58% relative to the royalties that were paid by Avner prior to the merger, and all as specified above.

[214] On June 17, 2018, Delek Energy and Delek Royalties notified the Partnership that Delek Energy's right to receive royalties from the Partnership's share (22%) in the oil and/or gas and/or other valuable substances that shall be produced and utilized from the Tamar and Dalit leases had been transferred to Delek Royalties, and that the registration in the Petroleum Register had been amended accordingly. In view of the aforesaid, from June 1, 2018 the Partnership pays all of the said royalties directly to Delek Royalties.

[215] On December 26, 2019, Delek Group notified the Partnership that its right to receive royalties from the Partnership's share (22%) in the oil and/or gas and/or other valuable substances that shall be produced and utilized

between Delek Energy and Delek Israel[217] (in this section: the "**Transferors**") and the General Partner of the Partnership, under which the Transferors transferred to the Partnership interests in several licenses and the Partnership undertook to pay the Transferors (Delek Energy – 75% and Delek Israel – 25%) royalties at the rates specified below from the entire share of the Partnership in oil and/or gas and/or other valuable substances that shall be produced and used from the petroleum assets, in which the Partnership has or shall have any right (prior to deduction of any kind of royalties, but after deduction of the petroleum used for the production itself) (the "**Interest Transfer Agreement**").

The royalty rates that were set forth in the Interest Transfer Agreement (after an adjustment following the merger of the partnerships) are as follows: until the Partnership's Investment Recovery Date (as defined below), royalties shall be paid at a rate of 2.5% from onshore petroleum assets and 1.5% from offshore petroleum assets, and after the Partnership's Investment Recovery Date, royalties shall be paid at a rate of 7.5% from onshore petroleum assets and 6.5% from offshore petroleum assets (the "**Royalties of Delek Group and Delek Energy**").

According to the terms and conditions of the royalties, as determined in the Interest Transfer Agreement and the deed of royalties signed between the Partnership and the Transferors, the following provisions shall apply with respect to determination of the Investment Recovery Date:

The term "**Investment Recovery Date**" shall mean the date after the execution of the Interest Transfer Agreement, on which the (Net) Value of the Revenues (as defined below) that the Partnership received or is entitled to receive for the oil and/or gas and/or other valuable substances that were produced and exploited from the petroleum asset (i.e. a license or lease) in

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from the Tamar and Dalit leases had been transferred to Study Funds for Teachers and Kindergarten Teachers – Managing Company Ltd. and to Study Funds for High School Teachers, Seminary Teachers and Supervisors – Managing Company Ltd. (collectively: the "**Teacher and Kindergarten Teacher Funds**"), and that the registration in the Petroleum Register had been amended accordingly. In view of the aforesaid, from December 1, 2019, the Partnership pays all of the said royalties directly to the Teacher and Kindergarten Teacher Funds.

[216] On October 28, 2020, Delek Group and Delek Energy notified the Partnership that their right to receive royalties from the Partnership's share (45.34%) in the oil and/or gas and/or other valuable substances that shall be produced and utilized from the Leviathan North and Leviathan South leases had been transferred to Delek Overriding Royalty Leviathan Ltd ("**Delek Overriding Royalty**"), and that the registration in the Petroleum Register had been amended accordingly. In view of the aforesaid, from October 2020, the Partnership pays all of the said royalties income directly to Delek Overriding Royalty.

[217] Following the reorganization that was carried out in the past, the royalty right as aforesaid of Delek Israel was transferred at the time to Delek Group.

which the discovery is found, calculated in Dollars (according to the representative rate published by the Bank of Israel), shall reach the sum equal to the Value of All of the Partnership's Expenses on that petroleum asset (as defined below), calculated in Dollars (according to the representative rate as aforesaid).

The term "**(Net) Value of the Revenues**" shall mean the value of all of the revenues, as certified by auditors of the Partnership, for oil and/or gas and/or other valuable substances that were produced and exploited from the petroleum asset (i.e. a license or lease) (the "**(Gross) Value of the Revenues**"), after deduction of all of the expenses for the production thereof and the royalties paid therefor.

The term "**Value of All of the Partnership's Expenses**" shall mean all of the expenses that the Partnership incurred on the petroleum asset (i.e. a license or lease), in which the oil and/or gas and/or other valuable substances are produced, except for expenses (**up to the (Net) Value of the Revenues**) that were deducted from the (Gross) Value of the Revenues for determining the sum of the (Net) Value of all of the Revenues and as shall be certified by the Partnership's auditors.

<u>Expert arbiter decision regarding the definition of the "Investment Recovery Date"</u>

In 2002, an expert arbiter was appointed by consent between the Partnership and the Transferors in order to determine the correct meaning of certain definitions and terms regarding the determination of the Investment Recovery Date in connection with the royalties for which the Partnership is liable by virtue of the Interest Transfer Agreement.

In his decision, the expert who was appointed opined and determined, *inter alia*, the method of calculation and the various elements that should and should not be taken into account for the purpose of determining the "Investment Recovery Date", and in this context decided that:

- Only revenues/receipts that were received for oil and/or natural gas and/or other valuable substances (collectively: "**Oil and/or Gas**") that were produced and utilized from the petroleum assets (and certified as such by the Partnership's auditors) should be taken into account; and

- Only the value of the Partnership's expenses incurred in the petroleum asset (the license or the lease) in which the Oil and/or Gas were produced (and were certified as such by the Partnership's auditors) should be taken into account; and if the expense was incurred in more than one petroleum asset as aforesaid, it should be split between the petroleum assets in which it was incurred and/or which it was intended to serve. Thus, where the expense was incurred in petroleum asset A, from which ultimately no Oil and/or Gas was produced, this expense shall not be taken into account for determining the Investment Recovery Date in petroleum asset B, from which the Oil and/or Gas are produced; and

- The expense for exploration activities (including dry holes) shall be taken into account as an expense in the petroleum asset in the area of which such activities were performed, for the purpose of determining the Investment Recovery Date, and the same applies to development activities and actions for identifying the field's boundaries; and

- Expenses in respect of facilities (onshore and on the continental shelf), including for production, processing, transmission, measurement, storage, operation, maintenance and operating expenses and marketing and sales expenses (including the sale agreements) of the Gas should be taken into account; and

- With respect to expenses that are taken into account for determining the Investment Recovery Date, fully-incurred expenses (without depreciation) and financial expenses should be taken into account; and

- The determination of the Investment Recovery Date is a one-time irreversible determination, even if a situation subsequently arises in which the expenses in the petroleum asset exceeded the revenues received from the Oil and/or Gas output from such petroleum asset.

<u>Investment Recovery Date in the Tamar Project</u>

In view of the fact that the entities entitled to royalties that originate from the Interest Transfer Agreement (in this section: the "**Royalty Interest Owners**") also include the control holders of the Partnership, the board of directors of the General Partner of the Partnership decided to authorize the audit committee (which comprises independent and outside directors only) to handle everything relating to determination of the Investment Recovery Date in the Tamar Project, and, *inter alia*, to examine issues that arise from a report prepared at the request of the Supervisor of the Partnership by an outside economic consultant (in this section: the "**Consultant on behalf of the Supervisor**" and the "**Consultant's Report**", respectively), to clarify the various issues vis-à-vis the Royalty Interest Owners, and to take any other measure as the committee shall deem fit, at its discretion, and all in accordance with the Partnership's best interests. According to the same board resolution, the audit committee was authorized to retain the services of outside and independent professional consultants, according to its discretion and at the Partnership's expense, for the purpose of supporting the proceeding legally and economically, and to determine the terms and conditions of compensation of the said consultants.

The report of the Consultant on behalf of the Supervisor summarizes checks that he carried out with respect to the calculation of the Investment Recovery Date that was included in the draft calculation report prepared by the Partnership, whereby the Investment Recovery Date occurred in December 2017 (in this section: the "**Draft Calculation**). The main issue mentioned in the Consultant's Report is the treatment of the levy on gas and petroleum profits under the Taxation of Profits from Natural Resources Law, with respect to which the Consultant on behalf of the Supervisor noted, *inter alia*, that his conclusions do not necessarily represent flaws in the Draft Calculation and are subject to legal and economic interpretation of the royalty agreement.

On September 4, 2018, the Audit Committee and subsequently the Board (without directors who hold office in the control holder) approved a calculation of the Investment Recovery Date in the Tamar Project, whereby the date of commencement of payment of royalties to the Royalty Interest Owners at an increased rate of 6.5% (instead of a rate of 1.5%), falls in January 2018 (in lieu of December 2017 according to the draft calculation), such that from this date, the Partnership pays the Royalty Interest Owners royalties at the increased rate. It is noted that the calculation was approved by the Audit Committee and the Board after completion of the auditors' audit of the Partnership, and based on independent legal advice given to the Audit Committee.

The change to the Investment Recovery Date as aforesaid (to January 2018 in lieu of December 2017) derived from the correction of a calculation error that was included in the Draft Calculation in respect of the financial expenses. In this context, it is noted that further to the Partnership's request of the Royalty Interest Owners for restitution of $2 million that had been overpaid to them, on September 20, 2018, the said Royalty Interest Owners repaid the Partnership the said amount.

For details regarding the legal proceedings that are being conducted in connection with calculation of the Investment Recovery Date in the Tamar Project, see Section 7.26.7 below.

3. Royalties by Virtue of the Avner Partnership Agreement:[218] According to the Avner Partnership agreement, the Partnership pays Cohen Development and other parties that are not affiliated with the Partnership (the "**Royalties by Virtue of the Avner Partnership Agreement**" and the "**Entities Entitled to Royalties by Virtue of the Avner Partnership Agreement**", respectively) after completion of the merger of the Partnerships, royalties at the rate of 3% of the Partnership's entire share of the oil and/or gas and/or other valuable substances which shall be produced and utilized from the petroleum assets in which the Partnership has or shall in the future have an interest (before deduction of royalties of any kind but after reduction of the petroleum which shall serve for the purpose of the production itself).

4. Additional terms:

The following additional terms and conditions apply to all of the royalties that the Partnership pays to related and third parties (which originate both from the Interest Transfer Agreement and the Avner Partnership Agreement) (in this section: the "**Royalties**"):

[218] A limited partnership agreement of August 6, 1991 (as amended from time to time) which was signed between Avner Oil & Gas Ltd., as the general partner of Avner of the first part, and Avner Trusts Ltd., as limited partner of Avner of the second part (above and below: the "**Avner Partnership Agreement**"). Accordingly, the difference between the royalties actually paid by the Partnership to the Royalty Interest Owners and the effective royalty rate used by the Partnership in its financial statements for 2013-2020 is approx. $5.6 million.

a. The Royalty Interest Owners or any of them shall be entitled to receive all or part of the Royalties in kind, i.e. to receive in kind a part of the oil and/or gas and/or other valuable substances that will be produced and used from the petroleum assets, in which the Partnership has an interest (up to the amount of the aforesaid rate). If any of the Royalty Interest Owners shall have chosen to receive the royalties in kind, the parties shall regulate the manner of and dates on which the Royalty Interest Owners shall receive the royalties. Should either of the Royalty Interest Owners not choose to receive the royalties in kind, the Partnership shall pay such Royalty Owner the market value, in Dollars or (if payment under law may not be made but in Israeli currency) in Israeli currency, calculated in Dollars according to the Dollar's representative rate upon the actual payment, at wellhead price, of the royalties due to the Royalty Owner. Such payment shall be made once every month. The measurement of the quantities of oil and/or gas and/or other valuable substances that shall be produced and exploited from the petroleum assets, for the purpose of calculating the royalties due to the Royalty Interest Owners, shall be made in accordance with accepted principles in the petroleum industry.

b. The Partnership shall keep full and accurate records concerning its share in the oil and/or gas and/or other valuable substances that shall be produced and exploited from the petroleum assets in which it has an interest. Each of the Royalty Interest Owners shall be entitled to appoint an accountant who shall be entitled to inspect, examine and copy, during normal work hours, the Partnership's books and other documents and records regarding the Transferors' right to the royalties under the Interest Transfer Agreement.

c. The aforesaid right to royalties shall be linked to the Partnership's share in each of the petroleum assets in which it has an interest. Should the Partnership transfer its rights in a petroleum asset in which it has an interest, the Partnership shall ensure that the transferee assume all of the undertakings to pay the royalties as aforesaid. The aforesaid shall not apply at the event of asset forfeiture due to the Partnership being behind on payments. Regarding the Royalties by Virtue of the Avner Partnership Agreement, the aforesaid shall also not apply in the event of a transfer to partners who are continuing operations by some of the participants (sole risk).

5. Additionally, the Partnership pays Dor Chemicals Ltd. royalties from its share of the Tamar and Dalit leases, as specified in Sections 7.3.7 and 7.3.8 above.

6. In view of the dispute that has arisen between the Tamar Partners and the State regarding the royalty value at the wellhead in the Tamar Project as described in Section 7.25.10(b) above (the "**Royalty Value at the Wellhead Dispute**") 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 Section 7.26.2 below (the "**Yam Tethys Customer Gas Dispute**"), in November 2020, the Partnership reached agreements with all of the parties to which it had paid royalties from the Tamar Project over the years (including Delek Group and its affiliated corporations) (in this section: the "**Royalty Interest Owners**"), whereby:

    a. In reference to the Royalty Value at the Wellhead Dispute, it was agreed that after said dispute with the State shall be decided, and should it be found that the Royalty Interest Holders received Overpayments from the Partnership, then the Royalty Interest Owners shall be required to return said Overpayments to the Partnership, as shall be determined regarding the Overpayments made by the Partnership in respect of the State Royalties, plus linkage differentials and interest according to the Adjudication of Interest and Linkage Law, 5721-1961. It was further clarified that should it be found, after the determination of a binding method of calculation, that the Royalty Interest Holders received underpayments, then the Partnership shall be required to return said Overpayments to the Royalty Interest Owners, plus linkage differentials and interest as aforesaid. It was further agreed that until the expiration of 18 months from the date of determination of the binding method of calculation, none of the parties shall raise claims relating to the lapse of time.

    b. In reference to the Yam Tethys Customer Gas Dispute, it was agreed that the ruling in the claim conducted in such regard by the Partnership and Noble against the State shall apply, *mutatis mutandis*, also to the Royalty Interest Holders, and that should it be found that the Partnership underpaid royalties, then it shall be required to pay the Interest Royalty Owners the underpaid royalties plus linkage differentials and interest and should it be found that the Partnership overpaid royalties, then the Royalty Interest Owners shall be required to return such overpaid royalties, plus linkage differentials and interest as aforesaid. It was further agreed that until the expiration of 18 months from the date the claim against the State shall be decided, none of the parties shall raise claims relating to the lapse of time.

7.25.11 <u>Agreement for granting usage rights in the facilities of the Yam Tethys project</u>

According to an agreement of July 23, 2012, between the Partnership together with the other Yam Tethys Partners, and the Partnership together with the Other Tamar Partners (the "**Usage Agreement**"), it was agreed, *inter alia*, as follows:

(a) The Yam Tethys Partners shall grant the Tamar Partners usage rights in the existing facilities at the Yam Tethys project, including the wells, the platform of Mari-B, the compression system, the pipes and the Terminal, and the Tamar Partners were granted the right to upgrade and/or construct facilities for transportation and storage of natural gas from the Tamar Project (the "**Yam Tethys Facilities**"). The usage rights in the Yam Tethys Facilities shall be given subject to maintaining capacity for the gas produced from the Yam Tethys project in the pipes and the Terminal.

(b) The term of the Usage Agreement shall expire on the earlier of: (a) the expiration or termination of the Tamar Lease, and in case that the Dalit field is developed such that use is made of the Yam Tethys Facilities, the expiration or termination of the Dalit Lease; (2) giving of notice by the Tamar Partners of permanent discontinuation of commercial production of gas from the Tamar Project; (3) the abandonment of the Tamar Project.

(c) In consideration for the use of the Yam Tethys Facilities, the Tamar Partners have paid the Yam Tethys Partners the total sum of $380 million in installments that ended on December 31, 2015.

(d) The transfer of the rights in the Tamar Lease, in the joint operating agreement of the Tamar Lease, in the Yam Tethys lease or in the operating agreement of Yam Tethys, of each specific party to the Usage Agreement, is subject to the assignment of its rights and undertakings according to the Usage Agreement in accordance with the proportionate share that was transferred as aforesaid. The transferee is required to agree to assume the transferor's undertakings according to the Usage Agreement.

(e) Fundamental breaches

If the Tamar Partners:

1. Shall have failed to pay the Yam Tethys Partners any amount that is required according to the Usage Agreement within 10 days from the date of receipt of an invoice from the Yam Tethys Partners;

2. Shall fail to supply to the Yam Tethys Partners the capacity for gas that is produced from the Yam Tethys project that is reserved for them in the pipeline and at the Terminal according to the Usage Agreement, which breach is not remedied within 60 days from the date of receipt of notice of the breach from the Yam Tethys Partners;

3. Shall have breached the Usage Agreement (except in connection with management of the Yam Tethys Facilities by the Tamar Partners), which breach is not remedied within 60 days from the date of receipt of notice of the breach from the Yam Tethys Partners.

The sole remedy available to the Yam Tethys Partners with respect to these breaches by the Tamar Partners is the filing of a claim with a payment demand, or a motion for an enforcement order or an injunction, as the case may be.

If any one of the Yam Tethys Partners or the operator of Yam Tethys:

1. Shall have failed to pay the Tamar Partners any amount that is required according to the Usage Agreement within 10 days from the date of receipt of an invoice from the Tamar Partners;

2. Shall have denied the rights to use the Yam Tethys Facilities in any manner whatsoever;

3. Shall have breached the Usage Agreement (except in connection with management of the Yam Tethys Facilities by the Yam Tethys Partners), which breach is not remedied within 60 days from the date of receipt of notice of the breach from the Tamar Partners.

The sole remedy available to the Tamar Partners with respect to these breaches by the Yam Tethys Partners is the filing of a claim with a payment demand, or a motion for an enforcement order or an injunction, as the case may be.

(f) In addition, the agreement contains, *inter alia*, provisions that regulate the relationship between the Tamar Partners and the Yam Tethys Partners throughout the entire period of use of the Yam Tethys Facilities, including with respect to the management of the Yam Tethys Facilities, and a mechanism for the distribution of the operating expenses of the Yam Tethys Facilities and distribution of the capital expenses of the Yam Tethys Facilities in connection with the preparation and upgrade of the Yam Tethys Facilities for receiving natural gas from the Tamar Project, which is based on the ratios of the gas output volume between the Yam Tethys project and the Tamar Project.

(g) This agreement is subject to English law. All of the disputes between the parties in connection with this agreement or the performance thereof shall be heard in arbitration before three arbitrators according to the arbitration rules of the London Court of International Arbitration. Disputes of a technical nature may be referred to an independent expert with appropriate qualifications.

(h) The ownership of the upgraded Yam Tethys Facilities shall remain with the Yam Tethys Partners, and provisions were determined in the Usage Agreement regarding a mechanism of accounting in respect of the value of the upgrades to the said facilities at the end of the period of production from the Tamar Project. Within 90 days after the end of the Tamar period, the Yam Tethys operator is required to provide each one of the Tamar Partners with a calculation of the market value of the upgrades to the Yam Tethys Facilities. This calculation shall take into account the condition of the facilities and their lifespan, the planned use of the facilities by the Yam Tethys Partners and the Yam Tethys group, the decommissioning and abandonment costs and any other matter that the Yam Tethys operator deems relevant. The parties to the agreement shall conduct negotiations on the issue and shall agree on a final market value, with any dispute on the matter being referred to be decided by an expert. The payment of the Yam Tethys Partners to the Tamar Partners for the upgraded Yam Tethys Facilities (or vice versa if the value is negative) shall be made within 60 days from the date of determination of a final market value for the upgraded facilities of Yam Tethys.

7.25.12 <u>Agreement for the purchase of an interest in the New Ofek and New Yahel licenses</u>

On March 19, 2019, the Partnership entered into an agreement with SOA (in this section: the "**Seller**") for the purchase of a 25% interest (out of 100%) in each of the New Ofek License and the New Yahel License, which are onshore licenses, in the center and the north of the State of Israel, respectively (in this section: the "**Petroleum Assets**", the

"**Licenses**", the "**Purchased Interest**", the "**Purchase Agreement**" and the "**Transaction**", respectively). Upon fulfillment of the conditions precedent in the Purchase Agreement, on October 10, 2019, the Transaction contemplated in the Purchase Agreement was closed, and on November 5, 2019, the Petroleum Commissioner announced that the transfer of the Purchased Interest had been registered in the Petroleum Register.

Set forth below is a concise description of the main principles of the Purchase Agreement:

(a) On the Transaction closing date (the "**Effective Date**"), the Seller transferred to the Partnership the Purchased Interests, their being free and clear of any pledge, royalty,[219] liability, claim and third party rights, apart from certain exceptions that were defined, such as the State's royalties, other mandatory payments and statutory restrictions, and from this date the Partnership shall assume and bear all of the rights and liabilities in connection with the Purchased Interests, apart from certain exceptions that were defined, such as liability for bodily injury and property damage and environmental damage in respect of the period preceding the Effective Date.

(b) On the Effective Date, the Partnership paid the Seller U.S. $1 million as reimbursement for past expenses which were borne by the Seller, until the Effective Date, in the framework of its activity in the Petroleum Assets.

(c) The Partnership undertook to bear the costs of production tests in the New Ofek License up to a sum total that shall not exceed U.S. $6,500,000. If the cost of the production tests exceeds the said amount, each one of the partners in the New Ofek License, including the Partnership, shall pay its proportionate share in the additional cost as aforesaid, in accordance with the provisions of the Joint Operating Agreement (JOA) which was signed between the Partners on the Effective Date.

(d) The Partnership shall provide guaranties in the sum of 50% of the guaranties required in connection with the Licenses, according to the directives of the Petroleum Commissioner for provision of collateral, provided that if the Seller does not provide the remaining guaranties (50%), the Partnership shall be released from its said obligation. The Purchase Agreement includes additional

[219] It is clarified that the Purchased Interests shall be subject to the Partnership's commitment to pay overriding royalties to interested parties of the Partnership and to third parties.

provisions which pertain to tax duties, confidentiality, dispute resolution, representations, undertakings and indemnification arrangements between the parties in respect of a breach of the representations or undertakings that were made in the agreement, as is accepted in transactions of this type.

7.25.13 Agreement for the sale of the Partnership's interests in the Tanin and Karish Leases

On August 16, 2016, the Partnership and Avner (in this section: the "**Sellers**") signed an agreement with Energean Israel (in this section: the "**Buyer**"), whereby Energean Israel purchased all of the interests of the Sellers and Noble in the I/16 "Tanin" and I/17 "Karish" leases (the "**Leases**"). In consideration for the purchase of the interests in the Leases, the agreement provides that Energean Israel will pay the Sellers a sum total of $148.5 million (in equal shares between them), which represents the reimbursement of past expenses invested in the Leases by the Sellers and Noble, plus royalties in respect of the natural gas and condensate to be produced form the Leases, as follows: (1) The Sellers were paid $40 million in cash on the transaction closing date; (2) The balance of the consideration, in the total amount of $108.5 million (in this section: the "**Balance of the Consideration**"), will be paid to the Sellers in ten equal annual installments plus interest according to the mechanism and at the rate specified in the agreement, which will commence on the date on which a final investment decision (FID) is made with respect to the development of the Leases or on the date on which the total expenses of the Buyer in connection with the development of the Leases exceeds $150 million, whichever is earlier (3) The sold interests were transferred to the Buyer along with the existing royalties in the Leases, which the Sellers had borne in respect of their original share in the Leases (26.4705%) for each of the Sellers, and accordingly, the duty to pay the same to the royalty holders will be imposed on Energean Israel as of the transaction closing date; (4) The Buyer will transfer to each of the Sellers a royalty right in respect of the natural gas and condensate to be produced from the Leases at the rate of 3.75% (for 100% of the interests in the Leases) – prior to the payment of the petroleum profit levy under the Taxation of Profits from Natural Resources Law (the "**Levy**") in respect of the Leases, and at the rate of 4.125% (for 100% of the interests in the Leases) – immediately upon commencement of the payment of the Levy, net of the rate of the existing royalties in respect of such Seller's share in the Leases, as specified in Subsection (3) above. Furthermore, in accordance with the provisions of the Gas Framework, the Buyer transferred to the Sellers and to the other Leviathan Partners the Leases' export quota, according to the conditions specified in the agreement and its annexes.

On March 27, 2018, the Partnership received Energean's notice whereby, on March 22, 2018, Energean adopted a final investment decision (FID) in connection with development of the Leases. Therefore, in accordance with the terms and conditions of the agreement, the Partnership is entitled, from the date of adoption of such FID, to payment of the Balance of the Consideration in ten equal annual installments, plus interest according to the mechanism and at the rate determined in the agreement. For details regarding the consideration that was received upon adoption of such FID and with respect to a very material valuation regarding the Partnership's royalties from the sale of the leases, see Note 8B to the financial statements and Section 8B of Chapter D of this report.

7.25.14 The agreement for the sale of the interests to Tamar Petroleum

As aforesaid, on July 2, 2017, a sale agreement was signed by and between the Partnership, as seller, on the first part, and Tamar Petroleum, as buyer, on the second part (in this section: the "**Sale Agreement**"), pursuant to which Tamar Petroleum purchased interests from the Partnership at a rate of 9.25% (out of 100%) of the Tamar and Dalit leases. On July 20, 2017, all of the conditions precedent specified in the Sale Agreement were met, including the receipt of the Petroleum Commissioner's approval of the transfer of the interests in the Tamar and Dalit leases and the registration thereof in the Petroleum Register, and pursuant thereto, the interests in the Tamar and Dalit leases, at a rate of 9.25% (out of 100%) were transferred.

The main points of the Sale Agreement are as follows:

(a) The Partnership undertook to sell and transfer to Tamar Petroleum, working interests at the rate of 9.25% (of 100%) in the Tamar and Dalit leases, subject to the existing undertakings for payment of overriding royalties to affiliated parties and third parties, and the proportionate share (9.25%) of the rights and undertakings pursuant to the JOA, agreements for sale of gas from Tamar Lease, the agreement for use of the Yam Tethys facilities, shares of Tamar 10-Inch Pipeline, the Tamar Platform operation approval, and the approvals to export from Tamar (in this section: the "**Object of Sale**").

(b) The consideration for the Object of Sale that was paid to the Partnership included an amount of approx. $837 million in cash (approx. ILS 3 billion), and the allotment to the Partnership of 19,990,000 ordinary shares of ILS 0.1 par value each of Tamar Petroleum.

(c) Tamar Petroleum undertook to act to allow the Partnership to make a shelf (sale) offering if the Partnership will seek to sell its shares in

Tamar Petroleum to the public, subject to certain qualifications and limitations.

(d) The effective date for the purpose of calculating the consideration amount and the transfer of the rights and obligations for the Object of Sale to Tamar Petroleum is July 1, 2017.

(e) The Partnership shall continue to bear responsibility with respect to the following issues also subsequently to the date of completion of the transaction: arbitration regarding the production component tariff in the matter of OPC that concluded in July 2019, the appeal in the matter of the royalties with respect to the sale of gas from the Tamar Project to customers of the Yam Tethys project, including with respect to any and all liabilities in connection with these proceedings which shall be caused in the period following the effective date; the motion for certification of a class action that was filed by an IEC consumer against the Tamar Partners (for details see Section 7.26.1 below), with respect to the amounts that were received by the Partnership during the period before the effective date; liability due to taxes and royalties to the State with respect to the period before the effective date, or with respect to any profit, income or revenue of the Partnership in connection with the Object of Sale (including if said tax assessment was made after the effective date), except for taxes that relate to reports that were filed before the effective date to the tax authorities with respect to the Taxation of Profits from Natural Resources Law; taxes which apply to the Partnership in connection with the transfer of the Object of Sale to Tamar Petroleum; liabilities to the Partnership's suppliers or customers due to the Object of Sale which relate to the period until the effective date, except if provisions were made for such liabilities in Tamar Petroleum's financial statements; and liabilities, if any, with respect to Delek and Avner (Tamar Bond) Ltd.

(f) The Partnership made various representations in the Sale Agreement, as is customary in such transactions, including an indemnification undertaking for the breach of representations. Additionally, additional provisions were set forth as is customary in such agreements, including regarding a dispute resolution mechanism, interpretation and delivery of notices.

(g) It was further prescribed in the framework of the Sale Agreement that insofar as the Partnership shall hold Tamar Petroleum shares after the completion of the issuance of the shares, then the Partnership unilaterally waives all of the voting rights attached to all of the shares held thereby over and above shares in a quantity equal to 12% of the Tamar Petroleum shares following the completion of the issuance. For the avoidance of doubt, it was clarified that all of the equity rights attached to the shares held by the Partnership shall remain in full force, including: the right to receive dividends, bonus shares, rights, and the right to receive surplus assets upon the Company's liquidation. The shares that are in excess, above 12% (the "**Surplus Shares**") shall be deposited thereby with a trustee that shall act pursuant to an irrevocable letter of instructions that shall set forth, *inter alia*, the following: the Surplus Shares shall also include bonus shares or rights, or shares deriving from such rights, that shall be allotted to the Partnership due to the Surplus Shares as part of an issuance of bonus shares and/or rights to all of Tamar Petroleum's shareholders. With respect to a future issuance of rights, if any, the Partnership shall instruct the trustee whether to exercise or sell the right. The trustee shall transfer to the Partnership any and all dividends that it will receive due to the Surplus Shares. Whenever the Partnership will seek to sell the Surplus Shares, in whole or in part, to a third party, the trustee shall transfer such shares to whomever the Partnership instructs it, in writing, against receipt of full consideration therefor (unless the Partnership shall have instructed it to transfer the shares before receipt of the consideration), provided that the Partnership shall inform the trustee, in writing, of the transferee's details and sign any document that will be required for such transfer. Upon the sale or transfer of the Surplus Shares from the Partnership to a third party as aforesaid, they shall be entitled to all of the rights that are attached to ordinary shares in Tamar Petroleum.

The Partnership undertook to first sell the Surplus Shares (which, following their sale, shall confer on the buyer all of the rights that are attached thereto, including voting and capital rights as aforesaid) and also undertook that so long as it shall not have sold the Surplus Shares it shall not purchase additional Tamar Petroleum Shares. It is clarified in this context that shares that will be allotted to the Partnership in the context of issuance of bonus shares and/or rights shall not be deemed as a purchase for purposes of this undertaking.

Additionally, the Partnership undertook not to propose more than one director in the framework of the general meetings that convene for the purpose of appointing directors at Tamar Petroleum. The articles of association of Tamar Petroleum determine provisions that establish the Partnership's aforesaid waiver of voting rights that are attached to the shares that will be held thereby at a rate exceeding 12% of the issued capital.

7.26 **Legal proceedings**

7.26.1 On June 18, 2014, a motion for class certification was filed with the District Court in Tel Aviv by a consumer of the IEC against the Tamar Partners[220] (in this section: the "**Petitioner**"[221] and the "**Certification Motion**", respectively). The issue addressed in the said Motion is the price for which the Tamar Partners sell natural gas to the IEC.

The Certification Motion claims that the gas price for the IEC is an unfair price which constitutes abuse of the Tamar Partners' position as the holders of a monopoly in the Israeli natural gas supply sector in violation of Section 29A of the Economic Competition Law.

The remedies sought by the Certification Motion are: compensation for all of the electricity consumers in the sum of the difference between the price that the IEC paid for natural gas supplied by the Tamar Partners and the fair price thereof, which was estimated, on the date of the filing of the Certification Motion, at a total sum of ILS 2.456 billion (in terms of 100%), as well as declaratory orders, according to which the Tamar Partners are obligated to avoid selling the natural gas from the Tamar Project in an amount exceeding the amount stated in the Motion for Certification, and the sale thereof at a higher price constitutes abuse of their monopoly power.

On July 7, 2016, a court hearing was held on the motion for summary dismissal, which had been filed by the Tamar Partners on April 20, 2016, after the Attorney General had filed his position whereby the Certification Motion should be summarily dismissed. In his position, the Attorney General argued that there was no call for adjudication of the class action, on the grounds that price regulation (which is one component of the Gas Framework) may not be challenged separately from the Gas Framework as a whole, and judicial review of the Gas Framework belongs with the High Court of Justice, rather than in a class action. The Attorney General further argued that adjudication of the class action might hinder the execution of the Gas Framework.

On November 23, 2016 a decision was issued denying the motion for summary dismissal of the Certification Motion, and on December 15, 2016, the Tamar Partners filed a motion for leave to appeal this decision.

On September 28, 2017, the Supreme Court's judgment was issued on the motion for leave to appeal. The Supreme Court heard such motion as if leave had been granted and an appeal filed, and on the merits ruled that there was no room to intervene in the decision of the District Court and

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[220] On December 8, 2017, Tamar Petroleum's motion to join the aforesaid legal proceeding was granted.
[221] On April 12, 2018, counsel for the late Petitioner filed an agreed motion to replace him with his widow, subject to the filing of a supplementary affidavit on her behalf, and on the same day, the motion was approved by the court.

that the appeal should be denied. However, it ruled that it was necessary to carry out an additional factual investigation, and therefore ordered that the hearing be remanded to the District Court for it to hear the Certification Motion on the 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 granted the motion of the Tamar Partners to submit the position of the Attorney General regarding his interpretation of Section 29A(b)(1) of the Economic Competition Law, 5748-1988, 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.

In the Partnership's estimation, based on the opinion of the legal advisors, the chances of the class certification motion's being granted are lower than 50%.

7.26.2 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 (in this section: the "**Defendant**"), which mainly includes the restitution of royalties overpaid by the Plaintiffs, and under protest, to the Defendant, for revenues that derive from gas supply agreements which were signed between third party customers (in this section: the "**End Customers**") and the Yam Tethys Partners, some of the gas contemplated in which agreements was supplied from the Tamar Project, according to the accounting mechanism, according to which the consideration that was received from the End Customers, together with the consideration reflecting the share of Delek Group, which is a right holder in Yam Tethys and does not hold direct rights in Tamar, was divided such that the Tamar Partners which are not Yam Tethys Partners too (i.e. Isramco, Dor Gas, Tamar Petroleum and Everest), received a natural gas price equal to the monthly average price of natural gas supplied during that month by virtue of agreements signed between the Tamar Partners and their customers, and the remaining monetary balance was divided between the Yam Tethys Partners that also have rights in the Tamar Project (i.e. the Plaintiffs), according to their share in the Tamar Project. This accounting mechanism allowed the maintaining of a balance of the gas quantities in the Tamar Project between the partners therein according to their share. The restitution remedy sought by the Plaintiffs, as of the date of the filing of the claim, was approx. $15.3 million, and reflects the royalties which the Plaintiffs shall overpay from May 2013 until the date of filing of the claim (in this section: the "**Restitution Amount**"). Underlying the claim is the Plaintiffs' argument whereby, as distinguished from the Defendant's argument, the Plaintiffs, as the holders of the rights in both the Yam Tethys project and the Tamar Project are taking from the gas in their possession such that no sale was made between the "Tamar Project" and the "Yam Tethys project", and 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. Consequently, the Defendant is overcollecting royalties from the Plaintiffs, in respect of amounts that exceed the amounts received from the End Customers, which reflect the market value of the gas, in view of the End Customers' being an unaffiliated party. As of December 31, 2020, the restitution remedy due to the Plaintiffs' primary argument as aforesaid is approx. $28 million (the overpaid royalties restitution principal amount for the period between May 2013 and September 2017, and for the period between May 2019 and December 2020, according to the Plaintiffs) (in this section: the "**Updated Restitution Amount**"), with the Partnership's share in the principal being approx. $13 million. Update of the Updated Restitution Amount is subject to payment of additional fees by the Plaintiffs.

Alternatively, the Plaintiffs' argument is that also if there had been any kind of a sale, the sale that was performed was with respect to the share of the holders of the rights in the Tamar Project that are not the holders of the rights in the Yam Tethys project (Isramco and Dor – 32.75% and in part of the period also Tamar Petroleum and Everest – 45.5%) and the holders of the rights in the Yam Tethys project, while the balance of the gas that is supplied to the End Customers by the Plaintiffs (67.25% and in part of the period in which Tamar Petroleum and Everest hold rights – 54.5%) is gas that is in the Plaintiffs' possession, which they are entitled to use for the purpose of supplying gas to the End Customers as aforesaid (in this section: the "**Partial Sale Approach**").

As of December 31, 2020, the restitution remedy with respect to the Partial Sale Approach as aforesaid is approx. $19.3 million (the overpaid royalties restitution principal amount 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 approx. $9 million.

The trial hearings were held on June 21, 2020. On February 23, 2021 the Plaintiff filed summations on their behalf. Accordingly, the Defendant may file responding summations on its behalf by May 31, 2021 and the Plaintiffs may file responding summations on their behalf, in reference to the Defendant's summations, by June 30, 2021.

The Partnership estimates, based on the opinion of the legal advisors, that there is a possible chance, i.e. above 20% but below 70%, that the Plaintiffs' primary argument will be accepted, and they will thus be entitled to the Updated Restitution Amount, and the chances that the Partial Sale Approach will be accepted are greater than the chances that it will be rejected.

7.26.3 On December 25, 2016 a motion for class certification was filed (in this section: the "**Certification Motion**") based on the argument that the Merger transaction between the Partnership and Avner was approved in an unfair proceeding, and the consideration that was paid to the holders of the minority units in Avner, as determined in the Merger agreement, is unfair. The motion was filed against Avner, the general partner of Avner and the members of the board of directors thereof, Delek Group as the holder of control in Avner (indirectly), and against PricewaterhouseCoopers Consulting Ltd. (PwC) as the economic consultants of an independent board committee that was established by Avner (in this section: the "**Respondents**"). According to the motion, *inter alia*, the committee members, the board of Avner and the General Partner breached the duty of care vis-à-vis Avner, and Avner conducted itself in a manner that was oppressive to the minority. The total damage was estimated by the petitioners to be in the amount of ILS 320 million. On February 13, 2017 the court approved a stipulation whereby the motion for class certification will be amended by adding an argument of minority oppression by Delek Group. On July 6, 2017, the court ordered to add the Partnership as a respondent in accordance with the Partnership's motion. Trial hearings were held on March 9, 2021 and March 10, 2021, at the conclusion of which it was determined that by March 17, 2021, the parties will file a stipulation regarding the method of conduct of the summations stage .

The Partnership estimates, based on the opinion of the legal advisors, that the chances that the Certification Motion will be accepted are lower than 50%.

7.26.4 On February 4, 2019, a class action and a motion for certification thereof (in this section: the "**Certification Motion**") was filed with the Tel Aviv District Court (Economic Department) by a shareholder of Tamar Petroleum and the Public Representatives Association (in this section collectively: the "**Petitioners**"), against Tamar Petroleum, the Partnership, the CEO of the General Partner of the Partnership and the Chairman of the Board of Tamar Petroleum on the date of the offering, the CEO of Tamar

Petroleum, the CFO of Tamar Petroleum and Leader Issues (1993) Ltd. (in this section collectively: the "**Respondents**"), in connection with the issue of the shares of Tamar Petroleum in July 2017 (in this section: the "**IPO**").

According to the Petitioners, in essence, the Respondents misled the investing public in the IPO with respect to the ability of Tamar Petroleum to distribute a dividend to its shareholders, for the period commencing on the IPO date and ending at the end of 2021 (in this section: the "**Period**"), and breached duties under various laws, *inter alia* a breach of the duty of care of the said officers and breach of the Partnership's duties as shareholder and holder of control of Tamar Petroleum before the IPO.

The remedies sought in the said class action mainly include a financial remedy in the sum of at least $53 million which is, according to the Petitioners, the difference between the total dividend which Tamar Petroleum was expected to distribute for the Period, as stated in the offering to institutional investors document of July 12, 2017, and the total dividend which, according to an expert opinion that was attached to the Certification Motion, Tamar Petroleum is expected to distribute for the Period.

On August 13, 2019, the court ordered the Petitioners to deliver the pleadings in the file to the Attorney General in order that he give notice by September 15, 2019 of whether he wishes to be joined to 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 Petitioners filed a motion to amend the Certification Motion (in this section: the "**Amendment Motion**"), in which they sought adding to the Certification Motion an additional petitioner who participated in the IPO, unlike the current Petitioners who did not participate therein. In addition, the Amendment Motion included a motion to increase the amount of the argued damage to $153 million.

The parties' responses were submitted to the Court and as of the report approval date, a decision has not yet been issued regarding the Amendment Motion.

In the Partnership's estimation, based on the opinion of its legal counsel, the chances of the Certification Motion being granted are lower than 50%.

7.26.5 On February 27, 2020 the Partnership learned of the filing of a class action and a motion for class certification (in this section: the "**Certification Motion**"), which was filed with the Tel Aviv District Court by an electricity consumer (in this section: the "**Petitioner**") against the Partnership and Noble and against the other holders in the Tamar Project and the Leviathan project (as parties against which no remedy is sought), in connection with the competitive process for the supply of natural gas conducted by the IEC (see Section 7.11.4(b)2 above) and in connection with a possible amendment to the agreement for the supply of gas from the Tamar Project to the IEC, as agreed by Isramco, Tamar Petroleum, Dor and Everest (collectively in this section: the "**Other Holders in the Tamar Project**"), without involvement on the part of the Partnership and Noble (in this section: the "**Amendment to the Tamar Agreement**").

The Petitioner's principal arguments are, in brief, that the bids made by the Other Holders in the Tamar Project and the holders in the Leviathan project in the competitive process amount to abuse of monopoly power and to a restrictive arrangement, as defined in the Economic Competition Law; the Partnership's and Noble's not signing the Amendment to the Tamar Agreement also amounts to abuse of monopoly power; the price determined 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 made and which shall be made by the Partnership and Noble under this agreement, while harming competition, amount to unjust enrichment. The Petitioner alleges that such actions of the Partnership and Noble have caused and are expected to cause damage to the classes he seeks to represent in the sum of approx. ILS 1.16 billion, which he seeks for the classes he seeks to represent, and according to which the Court is moved to award compensation and fees. The main remedy that is sought in the said 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.

A pretrial in the Certification Motion was scheduled for November 17, 2021.

The other holders in Tamar and in Ratio and the other holder in Leviathan were also added to the Certification Motion as respondents, with no remedy being sought against them. On December 22, 2020 the other holders in Tamar filed a motion for summary omission thereof (in this section: the "**Omission Motion**"), the Petitioner filed an objection, and the Partnership, Noble and Ratio did not object thereto.

On January 31, 2021 the Court determined that a hearing in the Omission Motion shall be held on May 5, 2021.

The deadline for filing responses to the Certification Motion has not yet been determined.

In the Partnership's estimation, based on the opinion of its legal counsel, the chances of the Certification Motion being granted are lower than 50%.

7.26.6 On January 6, 2019, the supervisor on behalf of the holders of the Participation Units in the Partnership, filed with the Tel Aviv District

Court (Economic Department) a complaint and an urgent motion for a provisional injunction (in this section: the "**Complaint**" or the "**Supervisors' Claim**" and the "**Motion for a Provisional Injunction**", respectively) pursuant to Section 65W(b) of the Partnerships Ordinance, against the Partnership, the Partnership's general partner, Delek Group, Delek Energy and Delek Royalties (Delek Group, Delek Energy and Delek Royalties, jointly in this section: the "**Royalty Interest Owners**").

In the Complaint, the supervisor moves the court to declare that the calculation of the "Investment Recovery Date" in the Tamar Project must include the payments that the Partnership is required to make to the State by virtue of the Taxation of Profits from Natural Resources Law; to declare that the Investment Recovery Date in the Tamar Project has not yet arrived; to determine from what date the Royalty Interest Owners are entitled to receive the overriding royalty at the increased rate (a rate of 6.5% in lieu of a rate of 1.5%); and to declare that the Royalty Interest Owners are required to return the amounts that they were overpaid to the Partnership, plus linkage differentials and interest. In addition, in the Motion for a Provisional Injunction, the supervisor moves the court to issue an order that will prevent any action which may deprive the rights of the holders of the Participation Units, such that it order the Partnership and the Partnership's general partner to refrain from transferring to the Royalty Interest Owners the overriding royalty at the increased rate, and to transfer the same to an escrow account held by the Partnership, and order Delek Group and Delek Royalties to return the increased overriding royalty that they received until now from the Partnership and deposit it in the escrow account.

On February 26, 2019, a hearing was held at the Court on the motion for a provisional remedy, at which the Court clarified that no provisional remedy will be granted with respect to a date earlier than the date of the hearing of the motion. The Court requested that the parties hold talks in an attempt to reach agreements regarding the provisional remedy. On April 2, 2019, the court entered a decision on an arrangement between the Royalty Interest Owners and the supervisors, whereby Delek Energy shall give the supervisor a letter of undertaking to make payment, insofar as it is ruled that the Royalty Interest Owners were overpaid royalties. This decision obviated the supervisors' motion for a provisional injunction.

On February 6, 2019, the Partnership and the General Partner filed a motion for a stay of proceedings in the claim, due to the existence of a binding arbitration clause in the transfer of rights agreement between the Partnership and the Royalty Interest Owners of August 2, 1993. On June 23, 2019, a hearing was held on the motion, in which the supervisor, Adv. Gissin, was examined. On June 24, 2019, the motion was denied, and the claim will consequently continue to be heard by the Court, rather than by an arbitrator.

On April 4, 2019, the Royalty Interest Owners filed an answer and a counter-complaint against the Partnership, the General Partner of the Partnership and the supervisor (in this section: the "**Counterclaim**"). In the Counterclaim, the Royalty Interest Owners argue, *inter alia*, that the Partnership's calculation of the Investment Recovery Date in respect of the Tamar project included expenses that were "loaded" onto the calculation, and *inter alia*, financial expenses of the Partnership itself, future expenses of uncertain amount with respect to the retirement and disposal of facilities, headquarter expenses of the Partnership and any expense intended for stages of the project that are subsequent to the "wellhead". The Royalty Interest Owners argue that, discounting such expenses, the Investment Recovery Date in respect of the Tamar project had already occurred in August 2015, or alternatively – in 2016, or further alternatively – in 2017. Accordingly, the Royalty Interest Owners move the Court to declare which expenses should be taken into account in the calculation of the Investment Recovery Date and to order the Partnership to recalculate the Investment Recovery Date based on the aforesaid, as well as the royalties that the Royalty Interest Owners are entitled to receive and to deliver the calculation to the Royalty Interest Owners.

On October 2, 2019, the answers were filed on behalf of the Partnership and the General Partner – both an answer in relation to the Supervisors' Claim and a counter-answer in relation to the Counterclaim – in which it was asserted that both of the claims should be simultaneously dismissed with prejudice. The answers were supported by the opinion of an economic expert on behalf of the Partnership and the General Partner. On December 15, 2019, the Royalty Interest Owners filed a counter-replication in relation to the counter-answer filed by the Partnership.

On May 12, 2020, the supervisors filed an urgent motion for provisional remedies (in this section: the "**Motion**"), moving the Tel Aviv-Jaffa District Court (Economic Department) to order the Partnership and the General Partner of the Partnership to cease and desist from transferring the increased overriding royalty[222] to the Royalty Interest Owners or, alternatively, to order them to transfer the increased overriding royalty to an escrow account owned by the Partnership at least until a decision is made in the Supervisors' Claim. According to the supervisors, the Motion is filed in view of an extreme and dramatic change of circumstances that has resulted in the Royalty Interest Owners being on the verge of insolvency. The Supervisors moved the court to schedule an urgent hearing of the Motion in order to prevent and save the need for a

[222] It is noted that from June 1, 2018, December 1, 2019 and October 28, 2020, the Partnership is paying the increased overriding royalty to Delek Royalties (in lieu of Delek Energy), to the Teacher and Kindergarten Teacher Funds (in lieu of Delek Group) and to Delek Overriding Royalty (in lieu of Delek Energy and Delek Group), respectively.

preliminary order until a hearing is held *inter partes*. The court did not grant the Motion, and ruled on that date that the Partnership, the General Partner of the Partnership and the Royalty Interest Owners shall file their responses to the Motion within 7 days.

On May 19, 2020, responses to the Motion were filed by the Partnership, the General Partner of the Partnership and the Royalty Interest Owners. The response of the Partnership and the General Partner of the Partnership argued that the Motion should be denied, *inter alia*, because in a situation where any of the Royalty Interest Owners falls into a state of insolvency, the Partnership has a right of setoff according to insolvency law, which guarantees any amount that will be ruled in its favor in the Supervisors' Claim. On June 23, 2020, the supervisors filed with the court a motion and notice which was agreed with the Royalty Interest Owners, according to which an agreement was reached between the supervisors and the Royalty Interest Owners, which obviates, at this time, the need to decide on the matters in dispute between the parties to the Motion. On the same date, the court approved the aforesaid agreement, canceled the scheduled hearing, and ordered the parties to give notice within 10 days on whether they had reached a comprehensive agreement and the method in which they seek to advance the hearing in the Supervisors' Claim.

On July 9, 2020, an agreed notice was filed on behalf of the parties, whereby the supervisors and the Partnership completed the preliminary proceedings between them, while the supervisors and the Royalty Interest Owners moved to extend the time frame for completion of the preliminary proceedings between them until July 23, 2020. On July 12, 2020, the Court granted this motion. After the parties did not reach agreements between them, the Court ordered, on August 18, 2020, that evidence on behalf of the supervisors regarding their claim and evidence on behalf of the Royalty Interest Owners regarding the Counterclaim shall be submitted within 45 days. Evidence on behalf of the defendants' in the claim and in the Counterclaim shall be submitted 45 days later. Dates for hearing the evidence in the case shall be scheduled thereafter. In addition, the Court scheduled a pretrial hearing for December 20, 2020.

On September 2, 2020, the Royalty Interest Owners filed an agreed stipulation whereby the evidence of the supervisors in the claim and the evidence of the Royalty Interest Owners in the counterclaim will be filed by November 24, 2020, and the defendants' evidence in the Supervisors' Claim and the counterclaim will be filed by January 10, 2021. On September 2, 2020, the Court approved the aforesaid stipulation and postponed the pretrial to January 26, 2021. On November 19, 2020, the Court granted the motion of the Plaintiffs and the Counter-Plaintiffs and postponed the date for submission of their evidence until December 6, 2020, and the date for submission of the Defendants' evidence until January 19, 2021. In accordance with the Court's decision, the Plaintiffs and the Counter-Plaintiffs filed their evidence on December 6, 2020. On January 12, 2021, the Court granted the Partnership's motion and postponed the pretrial hearing to March 25, 2021, and also extended the date for submission of the Defendants' evidence in the Supervisors' Claim and the counterclaim up to 14 days prior to the date of the hearing, i.e., until March 11, 2021. On March 10, 2021, the Court granted another motion for a brief extension of the date for submission of evidence by the Partnership, such that on March 14, 2021, an expert opinion was submitted regarding the common practice in the oil and gas industry for determination of the investment recovery date, which supports the position of the Partnership, and on March 17, 2021, an affidavit *in lieu* of direct testimony will be submitted on behalf of the Partnership, as well as a supplemental economic opinion on its behalf.

7.26.7 Further to Section 7.11.4(a)5 above, with respect to the Leviathan partners' bid being chosen as the winner in the Competitive Process conducted by the IEC, on April 18, 2019 the Partnership was served with an administrative petition that was filed with the District Court in Tel Aviv by some of the Tamar partners (Isramco, Tamar Petroleum, Dor Gas and Everest (jointly in this section: the "**Petitioners**")), against the Israel Electric Corp. (IEC) and the Leviathan partners (the Partnership, Noble and Ratio) (the IEC and the Leviathan partners jointly in this section: the "**Respondents**") (in this section: the "**Petition**"), whereby the Court was moved to declare that the decision of April 4, 2019 by the IEC's tenders committee (in this section: the "**Committee**"), which had announced that the Leviathan's partners won the Competitive Process, was wrongful and in violation of the law and therefore null and void; alternatively, to remand the decision to the Committee and order it to consider other options, as specified in the Petition; and further alternatively, to order that the Competitive Process be cancelled. Simultaneously with the filing of the Petition, a motion was filed with the Court, seeking an interim order that would prohibit the Respondents from carrying out any action for the promotion or execution of the results of the Competitive Process the said Petition was decided and a motion was filed for an urgent hearing on the motion for interim order and on the Petition (in this section: the "**Motion**"). On July 7, 2019, the Court handed down a judgment that dismissed the said administrative petition and imposed the IEC's expenses on the Petitioners.

On August 19, 2019, the Petitioners filed an appeal from the judgment with the Supreme Court (the "**Appeal**"), whereby the Court was moved to overturn the judgment and rule as sought in the Petition. On December 4, 2019, the appellants filed a summary of their arguments, which reiterated their original arguments as presented at the District Court, and on the basis of which they claimed that the judgment which denied the Petition cannot stand, and in particular that the circumstances of the bids submitted in the competitive process included an identical price on behalf of both of the groups that participated therein, cannot justify the imposition of new conditions for determination of the winning bid that were neither stated nor mentioned at the beginning of the competitive process, whereby the selection of the winning bid would be based solely on price. On April 23, 2020, the IEC and the Leviathan partners filed a summary of their arguments, whereby the Appeal should be denied, first and foremost since, in the Competitive Process documents, the IEC had reserved the right to consider the overall advantages of each bid over and above the price. On May 21, 2020, a hearing was held on the Appeal, in which the parties informed the court that they were conducting advanced settlement negotiations, and at the parties' request, the court decided to grant an extension in order to reach agreements. On August 12, 2020, the appellants informed the court that in light of the lapse of time from the date of the hearing and in the absence of a binding agreement being signed, it will not be possible to obviate a decision in the proceeding, and that the appellants will update the court insofar as an agreement is signed until the date of receipt of the judgment.

On August 24, 2020, the judgment of the Supreme Court was rendered, which denied the Appeal and charged the appellants with the IEC's expenses and legal fees in the sum total of ILS 50,000. For further details, see the immediate report of the Partnership of August 25, 2020 (Ref. no. 2020-01-093126), the information in which is incorporated herein by reference.

7.26.8 Further to Section 7.25.6 above, following the decision of the Competition Commissioner (in this section: the "**Commissioner**"), pursuant to Section 20(b) of the Economic Competition Law, to approve, conditionally, the merger between EMG and EMED, in the framework of which a series of agreements were signed in order to allow the export of gas to Egypt from the Leviathan and Tamar gas reservoirs (in this section: the "**Merger**"), on September 8, 2019, Lobby 99 Ltd. (CIC) and Hatzlacha – For Promotion of a Fair Society (R.A.), filed an administrative appeal with the Competition Court at the Jerusalem District Court. The administrative appeal was filed against the Commissioner (as a respondent) and against EMED and EMG. In summary, the administrative appeal asserts that the Merger will enable the Partnership and Noble to block any possibility of importing natural gas from Egypt that will compete with the gas produced from the Tamar and Leviathan reservoirs that they own, and that the conditions imposed in the context of the approval for the Merger are not implementable and do not remedy the competitive damage that may be caused, according to them, by approval of the Merger. In the administrative appeal, the court was moved to revoke or modify the Commissioner's decision. On December 15, 2020 a preliminary hearing was held in the administrative appeal. As of the report date, dates for trial hearings have not yet been scheduled.

The Partnership estimates, based on the opinion of its legal counsel, that the chances of the administrative appeal being accepted are lower than 50%.

7.26.9 On April 23, 2020, a holder of participation units of the Partnership (in this section: the "**Petitioner**") filed a class action and motion for class certification against the Partnership, the General Partner of the Partnership, Delek Group Ltd., Yitzhak Sharon (Tshuva), the directors of the General Partner of the Partnership (including the former chairman of the board) and the CEO of the General Partner of the Partnership (in this section: the "**Certification Motion**" and the "**Respondents**", respectively), with the Economic Department of the Tel Aviv District Court.

The Certification Motion alleges that the Respondents refrained from disclosing, in the Partnership's reports, the existence of a clause in the agreements for the sale of natural gas from the Leviathan and Tamar reservoirs to Dolphinus Holdings Limited (in this section: the "**Sale Agreements**" and the "**Buyer**", respectively), according to which in a year in which the average daily Brent barrel price (as defined in the Sale Agreements) is lower than $50 per barrel, the Buyer is entitled to reduce the minimum annual quantity purchased under the Sale Agreements, to 50% of the annual contract quantity. According to the Petitioner, the alleged non-disclosure in the Partnership's reports establishes causes of action by virtue of various sections of the Securities Law, by virtue of the tort of breach of statutory duty, and by virtue of the tort of negligence.

The main remedy sought in the Certification Motion is compensation of the class which the Petitioner intends to represent, for the alleged damage incurred thereby, which is assessed, according to the opinion attached to the Certification Motion, at approx. ILS 55.5 million. The Petitioner also moved for 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 Certification Motion, accompanied by an expert opinion. In summary, the response argues that during the period relevant to the Certification Motion, the reduction clause was never material, and therefore was not required to be disclosed to the public. It was further argued in this context, *inter alia*, that the probability of a drop in Brent barrel prices below the annual average of $50 was very low at least until March 2020 with the outbreak of the Covid-19 Crisis 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, *inter alia*, 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 quantities that Dolphinus actually consumes, and warned that this was forward-looking information, that there is evidence that there is no proximate cause between the disclosure of the reduction clause and the decrease observed 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. According to the decision of the Court, the Petitioner is required to file a replication to the response by March 31, 2021.

In the Partnership's estimation, based on an opinion of its legal counsel, the chances of the motion being granted are lower than 50%.

In such context it is noted, in reference to the possibility given to the buyer under the agreements for export 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 vis-à-vis the Partnership. On November 10, 2020, the Partnership filed a response to the said request.

7.26.10 On June 18, 2020, the partners in the Alon D license filed a petition with the Supreme Court, sitting 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. A motion was also made for an interim order preventing the expiration of the license, and alternatively prohibiting the launch of a competitive process for a new license for the license area (or part thereof) or the granting of such license to a third party pending decision of the petition, and a preliminary order pending decision of the motion for the interim order. On the same day, a decision was issued ordering the Minister of Energy and the Petroleum Commissioner to file their answer to the motion for an interim order 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 announced a competitive process for a license for natural gas and oil exploration in Block 72, the area of which was covered by the license. On June 24, 2020, the partners in the license filed a notice to the court in which they updated that the Ministry of Energy had initiated a competitive 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 answer to the motion for an interim order, claiming that the motion for an interim order 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 proximity to the date of commencement of the competitive process). The Minister and the Commissioner further claimed that the chances of the petition being granted are not high since, as they argue, the petition is aimed, in practice, against a decision of the Minister from 2017, such that its filing at the present time constitutes *laches*. On July 6, 2020, the partners in the license filed a response to the answer of the Minister and the Commissioner to the motion for an interim order, in which they specified the reasons why the claims of the Minister and the Commissioner should be denied. On July 7, 2020, the motion for an interim order was denied. The hearing of the petition was scheduled for May 19, 2021.

7.27 **Goals and business strategy**

7.27.1 General

The Partnership's strategy and goals are, exhaustion of the economic potential of the petroleum assets held thereby alongside examination of acquisition of additional petroleum assets. The strategy is realized mainly through promotion of further development of the producing petroleum assets owned thereby, and primarily the Leviathan reservoir, promotion of the development of non-producing petroleum assets owned thereby, and primarily the Aphrodite reservoir, improvement of the production and operation of the producing petroleum assets owned thereby, as well as promotion of possibilities for the use, ownership, development and expansion of infrastructure for natural gas transmission from the Partnership's petroleum assets to the domestic market and to the export markets including in LNG form.

For this purpose, the Partnership acts, *inter alia*, for the increase of the demands for natural gas, both by means of expansion and assimilation of the use of natural gas in the domestic market and by means of natural gas export to neighboring countries through pipelines and/or through the liquefaction and/or compression thereof and the marketing thereof to global markets.

In addition, the Partnership is acting to exhaust the potential for additional gas and/or oil discoveries in its petroleum assets and/or in new licenses, in and/or outside of Israel, if and to the extent that it will engage in transactions for the purchase of petroleum assets and/or that they will be granted thereto. It is noted that the Partnership is examining business opportunities that are connected to its business sector, in and outside of Israel, including the possibility of joining as a partner in petroleum assets in various stages of exploration, development and production, and is also examining technological developments that are connected to its business sector.

Considering the provisions of the Gas Framework that require the Partnership to transfer all of its interests in the Tamar and Dalit leases to a third party by December 2021, as described in Section 7.23.2(b) above, the Partnership intends to focus its efforts in the near future on finding an optimal solution for compliance with the requirements of the Gas Framework, and, in this context, intends to primarily act for promoting the possibility of selling such interests to a third party.

Simultaneously, as part of the Partnership's strategy to promote the possibility of listing its principal assets on a foreign exchange, the Partnership has acted in the last year to promote a possible outline for a split of its assets, whereby all of the Partnership's assets, barring its interests in the Tamar and Dalit leases and in the Yam Tethys project, will be transferred to a new U.K. corporation (the "**U.K. Corporation**") against an allocation of shares to be distributed to the participation unit holders, subsequently to which, the U.K. Corporation will issue shares to foreign investors and list its shares on the London Stock Exchange and on the Tel Aviv Stock Exchange (the "**London Transaction**"). In the context of promoting the London Transaction, the Partnership has prepared a draft offering prospectus which was recently submitted on behalf of the U.K. Corporation for approval by the U.K. regulator (the FCA). As of the date of approval of the report, the Partnership continues acting for promotion of 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, *inter alia*, the receipt of regulatory approvals in Israel and abroad, and is subject, *inter alia*, to approval by the meeting of the participation unit holders, the procurement of various approvals and the completion of other actions the feasibility of which is uncertain, and there is consequently no certainty that the transaction will be consummated.

The scope and diversity of the Partnership's activity necessitate the investment of significant financial means, *inter alia* in order to substantiate and broaden the commercial, technical, financial, legal, regulatory and other capabilities and knowledge. The Partnership intends to consider using the variety of means available thereto for raising money, by way of debt and/or equity, in addition to using the surplus future revenues from the Leviathan project, and the excess cash available thereto, and the proceeds received and to be received from the sale of assets in accordance with the Gas Framework, as specified in Section 7.20.1 above.

7.27.2 The Tamar Project

The Partnership is promoting alternatives to the implementation of the Gas Framework (as specified in Section 7.27.1 above. Until the sale of its other interests in the project, the Partnership is acting to maximize the Project's value *inter alia*, through the continued assurance of the supply of natural gas and condensate from the Project in accordance with the signed agreements and the conduct of negotiations and engagement in additional agreements for the sale of natural gas and condensate to the various potential consumers in Israel and in the region.

7.27.3 The Leviathan project

(a) Continued assurance of the supply of natural gas and condensate from the project in accordance with agreements that have been signed, and the conduct of negotiations and engagement in additional agreements for the sale of natural gas and condensate to the various potential consumers in Israel and in the region (primarily Jordan, Egypt and the Palestinian Authority).

(b) Promotion of additional development phases of the Leviathan reservoir (beyond Phase 1A) to a scope of production of approx. 16 BCM per year and/or a scope of production of approx. 21 BCM per year and/or a scope of production of approx. 24 BCM per year, as specified in Section 7.2.5(a)3 above, for the purpose of supplying natural gas to additional customers and target markets, including the Egyptian market, the liquefaction facilities in Egypt (ELNG and/or SEGAS), and according to the present and expected demand in other target markets.

(c) Examination of the techno-economic feasibility of construction of a FLNG facility based on natural gas from the Leviathan reservoir. For further details, see Section 7.12.2(c) above.

(d) Promotion of the consideration of forming an exploration prospect to oil targets in the Leviathan Leases, as specified in Section 7.2.4 above.

7.27.4 Block 12 – Cyprus

Promotion of development of the Aphrodite reservoir, as stated in Section 7.4.6 above, and marketing of the gas to the Egyptian market and to the Cypriot domestic market. At the same time, the Partnership is examining other development options, including the option of combining the development thereof with development plans for adjacent reservoirs located in the EEZ of Israel, including the Leviathan reservoir.

7.27.5 Optimization of infrastructures

The Partnership is examining, jointly with its partners in the various petroleum assets and other owners of infrastructures, the possibilities for optimization of existing infrastructures in the various projects, including the joint transmission infrastructure for export of natural gas to the various target markets and *inter alia* for the purpose of reducing transmission costs and increasing the feasibility of advancing various projects. For instance, the Partnership is examining, together with its partners in the Leviathan project and the Aphrodite reservoir, the possibility of constructing a joint pipeline for transmission of natural gas to consumers in Egypt. For details regarding the possibilities of piping the gas to Egypt which are being examined by the Partnership, see Section 7.12.2(b)2.b above.

7.27.6 Oil and gas exploration

The Partnership is acting for continued natural gas and/or oil exploration activity in the areas of its petroleum assets and in new licenses, in and outside of Israel, while focusing on prospects with the greatest economic potential, including drilling to petroleum targets, and chiefly promotion of drilling to petroleum targets in the Leviathan Leases. Furthermore, the Partnership is acting to identify business opportunities in new petroleum assets, in the context of participation in tenders and/or joining existing partnerships that hold oil and/or gas assets, mainly in and around the Mediterranean Basin.

7.27.7 Increasing the demand for natural gas

The Partnership is working to increase demand for natural gas, *inter alia*, in the following methods:

(a) Transportation: The Partnership is working to promote projects to increase the use of natural gas for transportation, including public transport vehicles and trucks powered by compressed natural gas, as well as electric transportation, such as electric buses and passenger cars in the Israeli transportation market. In the Partnership's estimation, since the consumption of liquid fuels for transportation in Israel in 2019 was equivalent to approx. 3.6 BCM of natural gas per year, such projects may lead to an increase in the potential demand for natural gas.

In this context it is noted that on October 29, 2020, the Partnership signed a (non-binding) cooperation agreement with Italian energy company Snam S.p.A. and with Dan Public Transportation Co. Ltd. for the promotion of technology and its implementation in the field of clean energy for transportation, and especially propulsion using LNG for transportation. In the Partnership's estimation, the implementation of the technology underlying the aforesaid cooperation (if and insofar as implemented), may lead to an increase in the potential demand for natural gas.

(b) <u>Conversion of coal-fired power plants to use of natural gas</u>: In the Partnership's estimation, the continuation of the Government's policy to reduce the use of polluting coal for the production of electricity, including discontinuation of all coal-fired electricity generation by 2025, in favor of transition to natural gas in power generation, may increase the use of natural gas in Israel in significant quantities, estimated at up to approx. 4.8 BCM per year compared to 2019.

(c) <u>Residential</u>: The Partnership is examining the promotion of projects that encourage the residential use of natural gas in new neighborhoods.

(d) <u>Additional industries</u>: To the best of the Partnership's knowledge, projects are being examined and promoted in Israel by various entrepreneurs, both in industries in which natural gas is used as a raw material, such as the production of ammonia and methanol, and in energy-intensive industries. In the Partnership's estimation, the establishment in Israel of plants in these areas, if established, may lead to a significant increase in the domestic use of natural gas.

7.27.8 <u>Options for entering the field of renewable energies</u>

To the best of the Partnership's knowledge, as of the date of approval of the report, The TASE and ISA are promoting an amendment to the TASE rules that will allow oil and gas partnerships to incorporate projects in the field of renewable energy into their activities. Subject to the approval of the aforesaid amendment and its terms and subject to the receipt of any and all required approvals, the Partnership intends to examine, during the coming year, options for entering the field of renewable energies and investment in technologies in the field of energy.

It is clarified that the Partnership's strategy and goals as specified above constitute general intentions and goals and as such there is no certainty that they will be realized, *inter alia*, due to changes in the various projects, changes in the market conditions, geopolitical changes, changes in regulation and in tax laws, changes in priorities resulting from the results of the drillings and surveys that will be performed and due to unpredicted events and the risk factors specified in Section 7.29 below.

7.28 **<u>Insurance coverage</u>**

From time to time, the Partnership takes out the insurance policies generally accepted in Israel for the energy sector for natural gas exploration, development and production, *mutatis mutandis* to the requirements of the law, the regulation (in Israel and overseas), the conditions of the license, the requirements of the financing entities and the scopes of the Partnership's operations and its exposures in Israel and overseas.

Some of the insurance policies are taken out in group insurance policies that cover several insured, which cover the assets and liabilities in the Partnership's various activities, only against some of the possible risks, as is the common practice in the industry of exploration, development and production of natural gas, all subject to the provisions of this section. The insurance system covers, *inter alia*, expenses for loss of control of well, certain coverage for political risks, property damage and certain consequential damage related to the insured property damage at the production phase, risks to construction work in the development of the assets (including during the maintenance period pertaining to the development of the Leviathan reservoir) as well as liabilities for third party bodily and property damage due to the activity of drilling, construction and production, including pollution damage resulting from accidental events.

It is noted that the Partnership and Noble have taken out insurance coverage for physical damage to EMG's property in an 'all risks' policy, as well as in a policy for insurance of war and terror risks. In addition, the Leviathan Partners have taken out insurance coverage for interruptions in the supply of gas, caused by physical damage to the Egyptian transmission network in Sinai, due to acts of war and/or terror.

The insurance policies specified above have been taken out partly independently and partly in the framework of the operator's insurance system. The insurance policies are subject to the agreements of pledge and assignment of rights in accordance with financing agreements that are signed from time to time.

It is noted that the Partnership monitors, from time to time, changes in the value of the insured property, and the amounts of the consequential damage that is entailed by damage to the insured property and/or to the property of a customer and/or of a supplier, in order to adjust the scope of the purchased insurance according to the exposure subject to the insurance costs and the global supply of insurance for the energy sector. Consequently, the Partnership can decide on a decrease of the purchased coverage and/or a reduction of the sum of the purchased insurance and/or decide not to purchase any insurance at all for this risk or another.

It is further noted that the Partnership engaged with Delek Group (in this section: the "**Guarantor**") in an agreement, whereby the Guarantor granted a performance guarantee in favor of the Republic of Cyprus with respect to the Partnership's activity in Block 12 as specified in Section 7.4.3(c)(2)(k) above. As a condition for granting the aforesaid guarantee, the Partnership was required to take out additional insurance to the Guarantor's satisfaction, beyond the insurance system applicable thereat, so as to cover, within higher liability caps at the stage of performing the drilling work, with respect to the insurance of liabilities to third parties as well as expenses for regaining control over an out-of-control well, including coverage of bodily and property damage and cleaning expenses resulting from the risks of accidental pollution.

For details with respect to the risk in the absence of sufficient insurance coverage, see Section 7.29.12 below.

7.29 **Risk factors**

Below is a concise summary of the threats, weaknesses and other risk factors of the Partnership, which derive from the general environment ("**Macro Risks**"), the business sector ("**Sectoral Risks**") and the unique characteristics of the Partnership's operations ("**Special Rusks**"). It is clarified that the following risk factors are not an exhaustive list of the risks related to the Partnership and its operations, and that the Partnership has other risks that derive from the Partnership's business and assets as described in this Chapter A, as well as risks which, as of the date of approval of the report, are not yet known to the Partnership.

7.29.1 Transfer of the interests in the Tamar and Dalit leases and compliance with the conditions of the Gas Framework

As specified in Sections 7.23.1 and 7.27.1 above, according to the conditions of the Gas Framework, the Partnership is required to transfer, by December 2021, all of its interests in the Tamar and Dalit leases to a third party which is not related to the Partnership or to anyone holding means of control in the Leviathan reservoir or in the Karish and Tanin reservoirs, subject to approval by the Petroleum Commissioner (in this section: the "**Transfer of Rights**" and the "**Effective Date**", respectively).

According to the provisions of the Gas Framework, in the event that the Transfer of Rights is not effectuated by the Effective Date, the right to the Transfer of Rights that were not sold will be transferred to a trustee (as defined in the Gas Framework), who will act to find buyers and receive the most proposals for sale of the rights being transferred in Tamar, and all in accordance with the provisions of the Framework and the instructions that he will receive from the Competition Commissioner. The trustee will sell the rights being transferred in Tamar in reference to the market value and to the highest price to be offered to him, and in any case, no later than the lapse of 12 months of the date of Transfer of Rights in Tamar (even if the price is not representative of the real value of the rights being transferred in Tamar).

7.29.2 COVID-19 Crisis

The outbreak of the COVID-19 Crisis in the beginning of 2020 caused a significant drop in the demand for natural gas in 2020. As of the report approval date, the development of the COVID-19 Crisis and its possible effects on the global and domestic economic activity remain shrouded in uncertainty. Insofar as the crisis continues, it may lead, *inter alia*, to the imposition of movement restrictions and adverse effect on the economic activity, as well as to a drop in the levels of demand and prices of energy products in general, and the natural gas marketed by the Partnership in particular. For further details, see Section 6.9 above, Section 3G of Part One of the Board of Directors' Report and Note 1 to the financial statements (Chapter C of this report).

7.29.3 Natural gas price formulas and linkage components in the supply contracts

The gas price is determined in the natural gas supply contracts according to price formulas which include various linkage components, including linkage to the Electricity Production Tariff, linkage to the U.S. CPI, linkage to the Brent barrel price and linkage to the ILS/$ exchange rate. A considerable portion of the natural gas supply agreements signed by the Partnership also specify, along with the price formulas, price floors that limit, to a certain extent, the exposure to fluctuations in the linkage components, but there is no certainty that the Partnership will also be able to determine such price floors in new contracts to be signed thereby in the future. For further details with respect to the linkages set forth in the natural gas sale agreements, see Section 6.10.1 above.

A decrease in the Electricity Production Tariff (*inter alia* as a result of an adjustment that the IEC shall request, if any, of the price in accordance with the mechanism determined in the IEC-Tamar Agreement as stated in Section 7.11.4(a)4 above) and/or a decrease in the Brent prices and/or a decrease in the U.S. CPI and/or a rise in the ILS/$ exchange rate (depreciation of the ILS versus the dollar) may adversely affect the Partnership's income from the existing and future gas sale agreements.

It is noted that the frequent methodological changes made by the Electricity Authority in the method of calculation of the Electricity Production Tariff render it difficult to predict, and may lead to between the gas suppliers and the customers disputes in relation to the method of calculation thereof. It is noted in this context that, for some of the private power plants (including plants sold by the IEC in the context of the reform as stated in Section (d) above), the Electricity Authority has applied regulation referred to as SMP (System Marginal Price), whereby, 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 Electricity System Manager between the various electricity producers, every day. Such pricing method may have an effect on the prices of natural gas to be sold by the Partnership to electricity producers in the domestic market, in the event that the gas prices in future contracts are linked to such pricing.

7.29.4 Changes in demand or in the prices of the fuels and other energy sources in the international markets

The demand for natural gas from the Partnership's customers and the price thereof are affected, *inter alia*, also by significant changes in the prices of oil, natural gas, including LNG, and the prices of other sources of energy, including coal and other alternatives to the natural gas produced from the Tamar and Leviathan reservoirs, both in the domestic market and in the international markets. Thus, for example, low LNG prices in the international markets may lead to increased import of LNG to Israel and/or to the regional markets, reduce the 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, a decrease in demand or a decrease in the prices of energy sources alternative to natural gas (including coal and other products) in the domestic market or in the international markets may reduce demand by existing and potential customers and lead to a decrease in the price of the natural gas sold by the Partnership, which may adversely affect the Partnership, its financial position and results of operations.

Reforms and decisions relating to the electricity sector, as specified in Section 7.24.6(f) above, and in the energy sector generally, including changes in the environmental laws, may also reduce the demand for the 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 Covid-19 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 the existing and future gas sale agreements, as well as the making of decisions on investment in new natural gas projects and/or expansion of existing projects. For details regarding the effect of the Covid-19 Crisis on energy prices and demand, see Section 6.9 above.

7.29.5 <u>Global macroeconomic factors</u>

The Partnership's ability to sell the natural gas produced, as well as the signing of new long-term agreements for the sale of natural gas, and the making of investment decisions with respect to new natural gas production projects and/or expansion of existing projects, is dependent, *inter alia*, on various global macroeconomic factors or on major events in the large economies, such as the U.S., China and the European Union. Among the macroeconomic factors that may have a significant impact on the Partnership's business are, *inter alia*, changes in the growth rate or a global economic slowdown, a global recession, global inflation, irregular volatility in foreign exchange rates, the global trade situation, a rise in interest margins, 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, 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 Covid-19, and global political and social processes that may destabilize regimes. Global macroeconomic factors of this type, which in the majority of cases are unforeseeable, may cause significant harm to the global economy, increase uncertainty in the markets, damage 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 a global impact of this type, and it is difficult to assess and estimate how factors of this type may evolve and affect the Partnership's business.

7.29.6 <u>Geopolitics</u>

The general security, economic and political situation in the Middle East, and specifically in Israel, Egypt and Jordan, may affect the willingness of foreign entities and countries, including in the Middle East, to enter into business relationships with Israeli bodies, including the Partnership, together with its partners in the different projects. Therefore, any deterioration in the geopolitical situation in the Middle East and/or deterioration in the relations between Israel and its neighbors in the relevant target markets, for security and/or political and/or economic reasons, may materially impair the Partnership’s revenues from contracts of export of gas to Egypt and to Jordan, i.e. to Dolphinus and to NEPCO, which are key customers of the Partnership, as well as its ability to promote its business with countries and additional entities in the neighboring countries.

7.29.7 Difficulties in obtaining financing

For the promotion of additional development phases in the development plan of the Leviathan reservoir or the development of additional reservoirs in the future, such as the Aphrodite reservoir, if it is decided to drill the same, the Partnership will need additional significant financial sources, and the Partnership may be required to raise capital or additional financing, including through a future raising of bank debt or a private or public bond offering.

Raising of additional financing may be difficult, particularly in the event of an economic crisis that is expressed in a reduction of the available credit sources and the tightening of requirements of the finance providers for provision of the financing. As of the report approval date, against the backdrop of the Covid-19 Crisis, a grave global economic crisis may develop which will adversely affect the Partnership's ability to raise capital. In addition, the possibility of raising additional debt is subject to the other undertakings and covenants determined in the bonds, as specified in Section 7.20 above.

7.29.8 Competition in gas supply

The Partnership is exposed to competition in the supply of natural gas to the domestic market and to export markets, which competition has recently intensified significantly, including competition with existing competing has reservoirs, or new reservoirs that may be discovered in the future in Israel or in neighboring countries, and 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 energy). The intensification in competition has led to a drop in the natural gas prices determined 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 another drop in its price, which may lead to a material negative effect on the Partnership's revenues and business.

In recent years a number of considerable gas reservoirs have been discovered in Israel, in scopes that materially exceed the Ministry of Energy's estimates with respect to the demand for gas in the domestic market. For details on competitive proceedings for oil and natural gas exploration in Israel's EEZ which may lead to new gas discoveries, see Section 7.14.1 above. In Egypt and in 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 by reservoirs that have been discovered (such as the Zohr natural gas field in Egypt) or new reservoirs to be discovered in the future, and also by suppliers of alternative energy products.

As of the report approval date, in addition to the Tamar and Leviathan reservoirs, which are presently producing in Israel, the Karish, Karish North and Tanin reservoirs, which are owned by Energean, are in advanced development stages and the first is expected, to the best of the Partnership's knowledge and based on Energean's releases, to commence gas supply in Q1/2022. These reservoirs, which are organized under one 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 Karis and Tanin reservoirs are intended to supply natural gas to the domestic market only.

In accordance with the Gas Framework, the Partnership is required to sell all of its holdings in the Tamar and Dalit reservoirs to unrelated third parties (as specified in Section 7.23.1(b)2 above). Upon completion of such sale, the Tamar reservoir will be a competitor of the Partnership's remaining petroleum assets.

Until the date of this report, the gas produced from the Tamar reservoir was jointly marketed by all of the Tamar partners. For details with respect to a balancing agreement for the separate marketing of gas from the Tamar reservoir, see Section 7.11.4(a)6.b above. The separate sale of natural gas by the partners in a petroleum asset may increase competition and lead to a decrease in the prices of natural gas. As of the date of this report, the gas from the Leviathan reservoir is jointly marketed by all of the Leviathan partners, but under the JOA each partner is entitled, subject to certain conditions, to take its share of the gas produced from the reservoir and market the same separately from the other partners, which, if and to the extent it occurs, may lead to increased competition.

In view of the limited scope of the demand for natural gas in the domestic market, the entry of additional competitors to the domestic gas market, the restrictions on the scope of exportable gas, and incentives granted to the development of new sources of renewable energy, the Partnership may face considerable competition in selling the gas reserves that are attributed to its petroleum assets.

For further details regarding the competition in gas supply, see Section 7.14 above. For details with respect to an option granted to natural gas purchasers to reduce the quantities under the gas agreements signed therewith, see Sections 7.11.4(a)3 and 7.11.4(b)1.b above. For details on the Electricity Authority's decision that incentivizes the independent power producers to engage in gas sale and purchase agreements at a price which is lower than the maximum price set forth in the Gas Framework, and in addition incentivizes independent power producers to engage in agreements to purchase natural gas with new gas suppliers that are not Tamar Partners, see Section 7.25.5(k) above.

7.29.9 Restrictions on export

The results of the Partnership's activity 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 the regional and international market. The Government Resolution on Export, which is specified in Section 7.23.1(c)2.a above, limits the quantity of gas that may be exported. Should a decision be adopted regarding a further reduction of the quantities of natural gas permitted for export, this may lead to significant damage to the Partnership's business. In addition, the possibility of exporting and selling the gas depends on many highly uncertain factors, such as the foreign relations between the State of Israel and the Republic of Cyprus with countries that are potential target markets for gas export, construction of an export and transportation system and receipt of the relevant regulatory authorizations and the functioning thereof, the economic merit of constructing such a system, identifying potential customers in the international market, finding sources for financing the investments required for the development and construction of the export system, and competition with local and international suppliers in the relevant target markets.

7.29.10 Dependence on the development and functioning of the transmission system

The Partnership's ability to supply the gas produced from its assets to the existing customers and to additional potential customers in and outside of Israel, is contingent, *inter alia*, on the development and functioning of the national transmission system for gas supply, the regional distribution networks, and transmission pipelines to consumers in neighboring countries (in this section collectively: the "**Transmission Systems**"). Any significant malfunction of or disruption to the Transmission Systems that are used and/or shall be used by the Partnership 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 which may have an adverse effect on the Partnership's business and its results of operations. In addition, a delay in implementation of the development and expansion plan for the gas transmission system may impair the Partnership's ability to meet its forecasts in connection with natural gas sales.

7.29.11 Operational risks

Oil and natural gas exploration, development and production activity in deep water entails considerable operating risks. Drilling in deep water requires use of advanced drilling technologies, and generally takes longer and its costs are higher than its onshore equivalent, due to the considerable complexity of the activity and due to the need to hold and maintain long supply systems. Development and production of natural gas from reservoirs in deep water entails a range of risks which include, *inter alia*, an uncontrolled outburst of liquids and gas from a well, explosion, collapse and combustion of a well, breakdowns, accidents and other events that may disrupt the functioning of the production and transmission system. Performance below the expected or efficient level may also be caused, *inter alia*, as a consequence of contractor or operator errors, work disputes or disruptions, injuries, a delay or non-receipt of permits, approvals or licenses, a breach of requirements of permits or the licenses, a shortage of manpower, equipment or spare parts, delays in the delivery of equipment or spare parts, security breaches, cyberattacks, acts of terrorism, and natural disasters.

The occurrence of any one of the events as aforesaid may significantly reduce or halt the production or supply of the natural gas, prejudice the timetable and the budget for the activity, damage the quality of the sold hydrocarbons, and consequently lead to the imposition of penalties due to non-supply and even to termination of the existing gas sale agreements of the Partnership.

7.29.12 Lack of sufficient insurance coverage

Even though the Partnership is insured with coverage of various kinds of damage that may be caused in connection with its operations, not all of the possible risks are or can be fully covered by the various insurance policies that were taken out, and therefore, the insurance payments, if received, will not necessarily cover the entire scope of the damage and/or all of the possible losses (with respect to third party damage (including during the crossing of infrastructures), with respect to possible loss of income, with respect to the costs of the construction and restoration of the production system in the case of an event due to which damage is caused to the production system, including due to terror, war, cyber and loss of control of the well, and with respect to damage to any kind of property in the well). In addition, there is no certainty that suitable policies may be purchased in the future on reasonable commercial terms or 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 activity in Jordan (as specified in Section 7.12.5(b)1 above) and in Egypt (as specified in Section 7.25.6 above) exposes the Partnership to risks that cannot be insured at all or can only by partially insured, including, *inter alia*, consequential damage associated with damage of any type to property and/or associated with damage to property of a supplier and/or a customer and/or a breach of agreements and termination of agreements for a reason that is not permitted by the agreement and/or modification of legislation and/or directives of competent authorities in Jordan and in Egypt, which may damage the Partnership's business and property.

In the case of large-scale loss or damage, the insurance policies taken out may be insufficient for covering all of the damage to the Partnership and/or third parties, including with respect to environmental pollution damage. These risks, if they materialize, may cause postponements and delays in the Partnership's exploration, development and production activities, damage the Partnership's business or have a material adverse effect on the Partnership's business, financial position, results of operations or its forecasts, and in an extreme case may even lead the Partnership to insolvency.

It shall be noted that the decision on the type and scope of the insurance is usually made separately for each activity, taking into consideration, *inter alia*, the insurance costs, type and scope of the offered coverage, the regulatory requirements, the ability to obtain suitable coverage in the insurance market, the capacity available to the Partnership in the insurance market and the foreseeable risks.

7.29.13 <u>Construction risks, dependence on contractors and on professional service and equipment suppliers</u>

In Israel there are currently no contractors qualified to perform most of the actions performed in the Partnership's assets, and therefore the Partnership engages through the operator with foreign contractors for the performance of such work. Moreover, the number of drilling rigs that are capable of drilling and performing development activities offshore, in general, and in deep-water, in particular, is relatively small and there is no certainty that a suitable facility will be found for performing the aforesaid actions on the dates to be scheduled therefor. Consequently, the aforesaid actions may entail high costs and/or considerable delays may be caused in the schedule that is determined for the performance of the work. In addition, most of the equipment and manpower that are suitable for the performance of the aforesaid actions may not be ordered within short periods of time and therefore it is necessary to order professional equipment and manpower services from overseas a considerable time in advance, which significantly increases the costs of and delays the activities. The engagement with foreign contractors for the performance of offshore oil and/or natural gas exploration, development and production (including contractors for the performance of maintenance and repair work) may encounter difficulties also due to the political and security situation of the State of Israel. The price of the services and the costs of exploration, development and production activities are determined according to the supply and demand in the markets that are affected *inter alia* by the commodity prices, regulation changes, supply of alternative products and level of activity in the industry.

7.29.14 <u>Risks of exploration activity and reliance on partial and estimated data, estimates and evaluations</u>

Oil and gas exploration activity entails a high level of risk, *inter alia*, in the event of failure in exploration and appraisal wells, and may result in a total loss of the entire investment. The geological and geophysical means do not provide an exact projection of the location, form, characteristics or size of oil or gas reservoirs, such that the determination of the exploration goals and the estimates concerning the size of the reservoirs and the gas and/or petroleum resources therein are based to a great extent on partial or estimated data and assumptions. It is of course impossible to guarantee that as a result of this exploration any oil or gas will be discovered, or such that may be commercially produced and exploited. Furthermore, there is a lack of direct geological and geophysical information regarding some of the areas of the Partnership's petroleum assets, *inter alia* due to the small number of wells drilled in relevant depths and/or areas.

The estimation of the quantity of resources in the producing petroleum assets Tamar and Leviathan is examined on a continuous basis, and may be updated based on an opinion of independent reserve evaluators and additional information accrued regarding the reservoirs. An estimate of the quantities of resources attributed to the petroleum assets of the Partnership is a subjective process which is based on various assumptions and estimates and on partial information, and therefore estimates regarding the same reservoirs that are carried out by different experts may sometimes be materially different. In view of the aforesaid, it is noted that the information appearing in the report regarding the quantities of resources that are attributed to the petroleum assets of the Partnership is an estimate only, and should not be deemed as information on exact quantities of natural gas and petroleum liquids that will be recoverable from the various reservoirs. It is further noted that an estimate of the quantity of natural gas reserves is used to determine the rate of amortization of the producing assets in the Partnership's financial statements, and in view of the significance of the amortization of the assets, the above-described changes may have a material effect on the Partnership's results of operations and financial position.

In addition, the discounted cash flow figures that are attributed to the Tamar and Leviathan projects are based on various assumptions many of which are not controlled by the Partnership, *inter alia* in relation to the quantities of gas and condensate that shall be produced, the rate of production and sales and the sale prices, which there is no certainty will materialize. For details regarding the main assumptions underlying the Tamar Project cash flows included herein, see Section 7.3.11(a)3 above. For details regarding the main assumptions underlying the Leviathan project cash flows, see the Partnership's immediate report of March 10, 2021 (Ref. no. 2021-01-030942), the information included therein is incorporated herein by reference.

7.29.15 Merely estimated costs and timetables and the eventuality of lack of means

Estimated costs for performing exploration, development, operation and maintenance activities, and estimated timetables for performance thereof, are based on past experience and general estimates, and thus considerable deviations may occur therein, including due to events that are beyond the Partnership's control. Development and exploration plans may change considerably, *inter alia*, following findings arising from such activities, and cause considerable deviations in the estimated timetables and costs of such activities. Faults during exploration, development, operation or maintenance activities as well as other factors may cause the timetable to be extended far beyond the plan, and the actual expenditure required for completion of the activities to be considerably higher than the costs planned therefor.

7.29.16 Forfeiture of the Partnership's rights in its petroleum assets and the financial strength of the partners in the petroleum assets

The activities of exploration, development and expansion/maintenance of the capability to supply gas in the Partnership's petroleum assets, entail considerable financial expenses, which the Partnership may not have the means to cover. According to the joint operation agreements, failing to pay on time the Partnership's share in an approved budget for the performance of an approved work plan constitutes a breach that may lead to the loss of the Partnership's share in the petroleum asset/s to which the operation agreement and/or agreements applies and/or apply.

In addition, in a situation where other parties to the joint operating agreements shall not have paid amounts that they were supposed to pay, the Partnership may be required to pay amounts that considerably exceed its proportionate share in such petroleum assets. Due to the especially high cost of development expenses and offshore drillings, these additional costs may lead to the Partnership's being unable to meet its financial obligations and as a result, it will lose its rights in the petroleum assets.

In view of the aforesaid, *inter alia*, the financial strength of the partners in the Partnership's petroleum assets may have repercussions on its cash flow.

7.29.17 Dependence on obtaining regulatory and other approvals

Exploration, development and production activity in the Partnership's petroleum assets requires receipt of many regulatory approvals are required in the Partnership's field of business in Israel, mainly from the entities authorized pursuant to the Petroleum Law and the Natural Gas Sector Law, as well as related approvals from the state authorities, including the Ministry of Defense, the environmental protection authorities, the tax authorities, the various planning authorities, the Ministry of Agriculture, the Ports Authority, and the Ministry of Transportation (in this section: the "**Approvals**"). The Approvals required for the activity of the partners in the petroleum assets prescribe validity conditions, a considerable number of which are not controlled by the partners. A breach of such conditions may lead, *inter alia*, to cessation of the production activity from the producing reservoirs, imposition of restrictions on the various activities, and exposure of the partners in the petroleum assets to financial, administrative or criminal sanctions. The partners in the petroleum assets have no control over the conditions that will be prescribed in new Approvals that shall be required in the future, and thus there is no certainty that the required Approvals will be obtained or that the conditions thereof shall be complied with.

7.29.18 Regulatory changes

In general, the scope of regulation applying to the field of business of the Partnership is constantly growing. For details with respect to the regulation applicable to the Partnership's operations as of the report approval date, see Section 6.10.2 above. The tightening of the regulation applying, *inter alia*, to activity of exploration, development and production of gas and petroleum, the terms of natural gas supply, natural gas export, taxation of oil and gas profits, rules for the allocation of new petroleum interests, insurance and guaranties, transfer and pledge of petroleum interests, antitrust, control of gas prices, planning regulation and so forth, may adversely affect the Partnership's business. In addition, if additional changes occur in any relevant law, regulation according to the Gas Framework, or any relevant regulation or policy, or a delay in the receipt of any regulatory approval, or the Partnership or its customers do not receive the regulatory approvals required or do not fulfill the terms and conditions thereof, the Partnership or its customers may not be able to fulfill their undertakings according to the existing agreements for the sale of natural gas.

7.29.19 Potential control of natural gas prices

As stated in Section 7.23.5(a)11 above, on April 22, 2013, the Control of Prices of Commodities and Services Order (Application of the Law to Natural Gas and Determination of the Control Level), 5773-2013, was published, which imposes control on the gas sector in terms of profitability and price reporting. Such reporting duty is separately imposed in respect of every project, while it is necessary to report semiannually on the prices and on the profit margins of the sold natural gas. According to information to be received, the need to impose control on natural gas prices in Israel at the level of fixing a maximum price for the sale of natural gas, will be examined. In the event that price control is imposed and a maximum price is determined, which is lower than the prices set forth in the Partnership's natural gas sale agreements, and insofar as such determination withstands judicial review, this may adversely affect the Partnership's business, the scope of which shall be derived from the maximum price to be determined.

The Gas Framework included binding provisions pertaining to the price of the gas and the linkage alternatives of the price which may be presented to the customers of the Tamar and Leviathan reservoirs, as specified in Section 7.23.1(c)1 above. In accordance with the Gas Framework, the Price Control Committee was approached, and it decided that for as long as the Partnership and Noble comply with all of the conditions of the Framework, control should be kept on the level of reporting on profitability and prices for the duration of the transition period which is expected to end in December 2021.

7.29.20 <u>Class certification motion regarding the price in the agreement between the Tamar Partners and the IEC</u>

On June 18, 2014, a class certification motion 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 which constitutes abuse of the Tamar Partners' position as the holders of a monopoly in the Israeli natural gas supply sector in violation of Section 29A of the Economic Competition Law (in this section: the "**Certification Motion**"). Insofar as the Certification Motion is granted, and thereafter a final and non-appealable judgment is received against the Tamar Partners, this may have a material adverse effect on the Partnership's business, including on the discounted cash flow figures as specified in Section 7.3.11(a)3 above and in the Partnership's immediate report of March 10, 2021 (Ref. no. 2021-01-030942), as well as on the prices at which the Partnership shall sell natural gas to its customers, the scope of which will be derived from the outcome of the action. In the Partnership's estimation, such a decision may have a negative effect on all of the oil and gas activity in Israel. For further details regarding this proceeding, see Section 7.26.1 above.

7.29.21 <u>Applicable environmental regulation</u>

The Partnership, in its field of business, is subject to various laws, regulations and guidelines concerning environmental protection, relating to various issues, such as: leakage of petroleum, natural gas or other pollutants into the sea, emission into the sea of pollutants and waste of different kinds (wastewater, remains of drilling equipment, drilling mud, mortar and so forth), chemical substances used in various stages of the work, emission of pollutants into the air, light and noise nuisances, construction of pipe infrastructure on the seabed and related facilities. In addition, the Partnership is required, through the operator of the projects, to obtain approvals for the activity of the operator as aforesaid from the competent entities under the Petroleum Law, the Natural Gas Sector Law and other laws (such as environmental protection laws).

Non-compliance with the provisions of such environmental regulation may expose the operator, the Partnership and its partners in the various petroleum assets to various enforcement measures, which also include lawsuits, penalties and various sanctions, including criminal, as well as to delays and even the discontinuation of the Partnership's activity. In addition, the Partnership may be responsible for the acts of others such as the operator or third-party contractors that are affiliated with the operator, and for pollution relating to the Partnership's facilities or deriving from their activity.

Oil and natural gas exploration and production in deep water entail various risks, including the emission of hazardous waste and substances into the environment, and exposure of humans to such hazardous waste and substances. Consequently, the Partnership may be responsible for some or all of the repercussions deriving from the risks of exposure or emission of such hazardous waste and substances.

As stated in Section 7.23.5(i) above, in September 2016, the Ministry of Energy, together with the Ministry of Environmental Protection and other government ministries, published directives that regulate the environmental aspects of the offshore oil and natural gas exploration, development and production activity. Such directives may have an effect on the costs and manner of the Partnership's activity, the scope of which cannot be estimated as of the report approval date. There is no certainty that the costs that will be required from the Partnership in connection with the existing and foreseeable laws, regulations and guidelines in the field of environmental protection, and in connection with the repercussions deriving from the emission of substances into the environment, will not exceed the amounts allocated 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 its results of operations. It is further noted that the interpretation and enforcement of the environmental regulations and laws change from time to time and may be stricter in the future.

For details regarding an administrative financial penalty imposed by the Ministry of Environmental Protection see Section 7.22.6(c) above.

7.29.22 Climate changes

The public discourse on climate changes and the impact of humans thereon may lead to regulatory intervention and additional developments that may have a material effect on the Partnership's business sector. International agreements, legislation and other regulatory measures to be taken with the aim of decreasing greenhouse gas emissions, if and insofar as 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 activity 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.

7.29.23 Dependence on weather and sea conditions

Offshore activity is exposed to a variety of operating risks that are unique to the marine environment such as capsize, collision and damage or loss that are caused by harsh weather conditions and the sea conditions. Such conditions may cause significant damage to the facilities and disrupt the activity.

Stormy sea conditions and unusual weather conditions may cause damage to the production and transmission system and to the (existing or under construction) exploration equipment as well as delays in the timetable planned for the work plan of the offshore projects and the prolongation of its execution period. Such delays may cause the increase of the projected costs and even non-compliance with timetables to which the Partnership is committed. See Section 7.1.3(b) above regarding the effects of weather on demand.

7.29.24 Cyber and information security risks

The partners in the Partnership's petroleum assets, including the Partnership and the operator thereof (directly and via subcontractors) (in this section: the "**Corporations**"), rely in their activity on IT systems. Thus, for example, in the context of the production from the Tamar and Leviathan reservoirs, use is made of industrial control systems, which are used for supervision, control and data collection in industry ("**ICS**"), which monitor and control large-scale processes which include, *inter alia*, monitoring of the natural gas and condensate transmission pipeline. ICS-based systems are exposed to a risk of cyberattacks. In addition, the Partnership and the operator are dependent on IT systems, including information systems and infrastructures with respect to the processing and documentation of financial and operating data, engagement with workers, consultants and business partners, analysis of seismic, geological and engineering information, estimate of oil and gas reserves and other activities relating to the Partnership's business. The Partnership's business partners, including suppliers, customers and financial institutions, are also dependent on IT systems, including information and infrastructure systems. As the dependency thereon increases, the potential exposure to cyber threats, both intentional and unintentional, also increases. In addition, there has been an increase in the severity of the cyber threats worldwide in terms of their sophistication and complexity, particularly at this time when, against the backdrop of the Covid-19 Crisis, many organizations have transitioned to activity that is primarily via remote connection to organizational networks, which create exposure to unauthorized access.

Faults and/or failures in IT systems, including in infrastructure and information systems, in the security of the information, hacking into the IT systems of the corporations or of outside entities or internal entities that have, *inter alia*, remote access to systems, infrastructures and information, may allow unauthorized access for the purpose of misuse of the Partnership's assets, and deliberate harm to IT systems, the infrastructure and information systems of the corporations, which may cause damage to the administration networks of the Partnership and the operator, the leak of information to unauthorized entities, disruption of the information in the systems and damage to the integrity of the information. Damage to the current operation of the systems that support the business activity, in extreme cases, may even cause disruption or discontinuation of the supply of natural gas, loss of information, and material costs for restoration of the information systems, thus having a material adverse effect on the Partnership's business, financial position, results of operations or capabilities.

The Partnership is acting for implementation of 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 its position with respect to the Partnership's defense system in terms of cyber and information security, and is acting for implementation of this position in organizational procedures and procurement of systems, infrastructures and services.

The Partnership acts, in normal times, to increase the level of the employees' awareness of aspects of cyber and information security, including phishing attacks and remote work rules. In addition, the Partnership receives from a third party 24/7 monitoring and control services, 365 days a year, 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 petroleum assets, and in this context, does not have control over the central ICS systems which monitor and control the production activity, that are under the operator's responsibility and control. To the best of the Partnership's knowledge, the operator is closely supervised by the National Cyber Directorate and implements adequate procedures and measures for effective management of information security and cyber protection in relation to these systems.

7.29.25 <u>Tax risks</u>

Tax issues related to the Partnership's operations, including in regards to the manner of calculation of the mandatory payment under the Taxation of Profits from Natural Resources Law, have not yet been discussed in the case law of the courts in Israel and it is impossible to foresee or determine how the courts will rule if and when the aforesaid legal issued are brought to their decision. In addition, with respect to some of the legal issues, it is impossible to foresee the position of the tax authorities. Since the Partnership's business is subject to a unique tax regime, changes that result from changes in legislation, case law or a change in the position of the Tax Authority, as aforesaid, may have material repercussions on the tax regime that shall apply to the Partnership and its Unit Holders.

For details regarding legal proceedings conducted with respect to the appropriate balancing arrangement that the Partnership should implement in connection with tax payments pursuant to Section 19 of the Taxation of Profits from Natural Resources Law (both with respect to the tax years 2015-2016 and with respect to assessment differences which may transpire in the future), see Section 7.21.2 above.

For details regarding disputes with the Tax Authority regarding tax assessments for 2016 and onwards see Section 7.21.6 to 7.21.10 above.

For details regarding the draft Income Tax Regulations (Rules for the Calculation of Tax due to the Holding and Sale of Participation Units in Oil Exploration Partnerships) (Amendment), 5781-2020 which was released on October 12, 2020, see Section 7.21.2 above.

7.29.26 <u>Financing-related undertakings</u>

As specified in Section 7.20 above, the terms of the bonds (issued by the Partnership and special purpose subsidiaries established thereby, define events of default and determine financial covenants and restrictions (see Note 10 to the financial statements and Part Five of the Board of Directors' Report (Chapter B of this report)). The Partnership's non-fulfillment of undertakings that it has assumed in connection with the terms of the bonds or the existence of conditions, some of which are beyond the Partnership's control, which give the bondholders grounds for acceleration of the debt, may lead to acceleration of the amounts due under such bonds, to the raising of the rates of the interest on the Partnership's liabilities and/or to enforcement of the collateral provided by the Partnership.

For details with respect to financial covenants with which the Partnership is required to comply, see Section 7.20.2 above.

7.29.27 Dependence on customers

The IEC, NEPCO and Dolphinus are presently the Partnership's key customers, and in regards thereto, the Partnership is exposed to risks that are not under its control, including changes in the economic and political conditions in Egypt and Jordan which may affect Dolphinus and NEPCO or their ability to meet their obligations under the gas supply contracts. For details regarding the Partnership's revenues from these customers, see Section 7.11.3 above. The Partnership cannot foresee the changes that these customers will experience (if any), and how such changes will affect their regulatory, economic and financial condition.

In the IEC-Tamar Agreement and in agreements signed with Dolphinus, dates were determined on which each party to the agreement may request adjustment of the price. Insofar as the IEC and/or Dolphinus request an adjustment of the price of the gas that is purchased thereby in accordance with the mechanism set forth in the agreements therewith, this may have a negative effect on the Partnership's business and results of operations.

The Partnership is exposed to risks that are not under its control pertaining to the financial strength of its customers and their ability to meet their obligations under the gas supply contracts. Insofar as its customers in general, and its key customers in particular, fail to meet their obligations under the supply contracts, and if the Partnership shall be unable to sell the contract quantity determined in the supply contracts to other customers, this will have a material adverse effect on the Partnership's revenues and financial results.

7.29.28 Reliance on the operator

The Partnership relies to a great extent on Noble in the petroleum interests, in which it serves as operator, including in the projects Tamar, Leviathan, Block 12 in Cyprus, and Yam Tethys, in accordance with the provisions of the joint operating agreements. The operator's resignation and/or removal, for whatever reason as specified in the operating agreement, from the Tamar Project and/or the Leviathan project, or any change in its status and/or rights, such that it ceases to be the operator of these projects, may impair the Partnership's ability to fulfill its undertakings according to the work plans of the petroleum assets and/or according to the gas sale agreements. In such a case, the Partnership cannot guarantee that a substitute operator will be found, or that a substitute operator will be found under the current terms and conditions. The Partnership's failure to find a substitute operator may adversely affect the activity of the various projects as aforesaid and the partnerships' undertakings to supply gas in accordance with the existing gas sale agreements, and consequently may lead to a decline 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 acts (or omissions).

7.29.29 <u>Risk in development and production in the case of a discovery</u>

The process of making a decision to make an investment in the development of a field for the purpose of commercial production therefrom, and interim actions until commercial production, and to perform the development and commercial production (if it is decided that there is room therefor) may take long periods of time and require the Partnership to invest considerable amounts. It is noted that there is no certainty that in every case of a discovery which was defined as a commercial discovery, the acts of development of the oil or gas field will be economic for the Partnership and financeable, *inter alia* due to the duty to pay royalties to third parties. It is further noted that development and production in deep water (such as the water depth in the Tamar, Leviathan and Aphrodite natural gas discoveries) is complex, high-risk activity that requires the establishment of special production facilities at significant cost.

7.29.30 <u>Revocation or expiration of petroleum interests and assets</u>

Petroleum interests are granted under the Petroleum Law for a limited period of time and the validity thereof is contingent on fulfillment of obligations on dates set forth in the terms of the petroleum asset. In a case of non-compliance with the terms, the petroleum interest may be revoked, subject to the Petroleum Law Non-compliance with the terms set forth in the petroleum interests may lead to the loss of the interests, and all of the money invested in such interests may be lost. In such context it is noted that the development plan of the Aphrodite reservoir prescribes, *inter alia*, that the partners are required to perform the A-3 appraisal drilling by November 2021, as specified in Section 7.4 above. The partners in the petroleum asset applied to the Cypriot Government with a request to approve changes in the work plan, including a postponement of the performance date of such drilling. As of the approval date, the Cypriot authorities have not yet approved said request.

7.29.31 Overflow of reservoirs

Oil or natural gas reservoirs discovered or to be discovered in areas in which the Partnership holds rights, may "overflow" (in terms of spreading of the geological structure of the reservoir) into other areas in which the Partnership does not hold rights, and vice versa. In the event that the reservoir overflows into areas in which other parties hold rights, there may possibly be a need to reach agreements regarding joint utilization and production from the reservoir or an alternative indemnification arrangement, in order to achieve efficient utilization of the oil or natural gas resources, which may cause delays in various activities that the Partnership is due to perform.[223]

7.29.32 Security risks

The production facilities of the Yam Tethys project and the Tamar project, which are located at sea, as well as INGL's gas transmission facilities, the EMG Pipeline and other infrastructures used for the supply of gas to Egypt, are relatively close to the offshore and onshore border between Israel and the Gaza Strip, in consequence of which they are exposed to security risks, including terrorist attacks and sabotage. Furthermore, the facilities of the Leviathan project, the Ashdod terminal, the pipeline, the infrastructures and the facilities used for the supply of gas to Jordan are also exposed to security risks, including terrorist attacks and sabotage.

Such security risks, if and insofar as they materialize, may, *inter alia*, 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 also lead to the revocation of the gas supply agreements or the reduction of the sums the customers are required to pay due to a "*force majeure*" argument. In addition, such risks may limit the ability of service and equipment providers to provide their services or the items 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 negative effect on the Partnership's revenues and business, including its ability to execute activities that are contingent on prior coordination with the defense forces.

7.29.33 Fluctuations in the dollar exchange rate

[223] In this regard, see Section (d) above in relation to the runoff of a small part of the Tamar SW reservoir into the area of the Eran license, and see Footnote 84 in connection with the runoff of the Aphrodite reservoir into the area of the Yishai license.

Changes in the ILS/Dollar exchange rate may affect the Partnership's results in several ways, as follows: (a) The Partnership's functional currency is the U.S. dollar. Since some of the Partnership's expenses are stated in ILS or affected by the ILS/Dollar exchange rate, a decrease in the ILS/Dollar exchange rate (a strengthening of the ILS against the Dollar) increases such expenses in Dollar terms; (b) Since the gas prices in the agreements for the sale of gas from the reservoirs in which the Partnership is a partner, are determined by price formulas that include various linkage components, and, *inter alia*, linkage to the ILS/Dollar exchange rate and linkage to the PUA's tariff, which is partly affected by the ILS/Dollar exchange rate. A weakening of the ILS against the Dollar may have an immaterial negative effect on the Partnership's revenues; (c) Since the Partnership reports its taxable income in ILS and pays the tax advances for the holders of the Partnership's participation units in ILS, changes in the ILS/dollar exchange rate affect the amount of the Partnership's taxable income and the amount of the cash flow which is used for payment of such tax advances.

7.29.34 <u>The Partnership's belonging to Delek Group and to the control holder thereof</u>

The Partnership's belonging to Delek Group and to the controlling shareholder thereof, and the financial position thereof, may have a material adverse effect on the Partnership and its business.

The Partnership's belonging to Delek Group affects the Partnership's ability to raise credit, *inter alia*, due to the "single borrower" limitation, as a result of which the Partnership's credit sources in Israel may be limited, as well as other regulatory restrictions imposed on the banking system and on institutional bodies by the Ministry of Finance and the Bank of Israel. In addition, a deterioration in the financial position of Delek Group may make it difficult for the Partnership to raise credit and/or adversely affect the commercial conditions according to which the credit required by the Partnership is provided.

In addition, according to the Petroleum Commissioner's directives, a change in or transfer of control of the Partnership requires receipt of the Commissioner's approval (for further details in this regard, see Section 7.23.4 above).

It is further noted that according to the Production Sharing Contract that was signed with the Republic of Cyprus in the context of the Aphrodite project, as specified in Section 7.4.3 above, a change in the control of Delek Group or the Partnership, directly or indirectly, requires prior approval of the Republic of Cyprus. In addition, according to the terms and conditions of the Production Sharing Contract and the requirement of the Republic of Cyprus, Delek Group has provided a performance guaranty for the Partnership's undertakings under the Production Sharing Contract.

7.29.35 The Partnership's status as a monopoly in natural gas supply in Israel

The Partnership and together the Tamar Partners were declared in 2012 as monopoly holders in natural gas supply in Israel. Due to this declaration, limitations may be imposed on the Partnership's activity, including a prohibition on unreasonably refusing to supply natural gas as well as a prohibition on abusing its market position in a manner that may undermine business competition or damage the public (for example, by a determination of an unfair price level or by determining different engagement terms for similar transactions which may grant certain customers an unfair advantage over their competitors). Restrictions on the Partnership in light of its monopoly in natural gas supply in Israel may affect its ability to expand its activity in Israel. For further details regarding the restrictive trade practices and economic competition law, see Section 7.23.2 above.

7.29.36 "*Force majeure*" events clause under the existing natural gas sale agreements

In most of the Partnership's natural gas sale agreements (the "**Agreements**"), the customers are obligated to take or pay for a minimum annual quantity of natural gas, in accordance with the mechanisms set forth in the Agreements. However, the customers may be exempt from this obligation upon the occurrence of "*force majeure*" events, which prevent them from fulfilling their undertakings, 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 in the circumstances. The Agreements specify a list of cases that shall not be deemed as a "*force majeure*" event, also where they are beyond the customer's control. It is noted that the Partnership may also be exempt from its obligations according to the natural gas sale agreements upon the occurrence of a "*force majeure*" event which prevents it from fulfilling its undertakings according to the Agreements.

If a "*force majeure*" event lasts for a prolonged period as determined in a natural gas sale agreement (usually between one and three years), and it has a material effect on the ability of a party to the agreement to fulfill its undertakings as aforesaid, this may constitute grounds for termination of the agreement. Therefore, the occurrence of a "*force majeure*" event for a long 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 following table presents the above-described risk factors according to their nature (macro-risks, industry risks and risks specific to the Partnership), which were rated based on the estimates of the Partnership's General Partner, according to the magnitude of the effect thereof on the Partnership:

	Degree of Risk Factor's Effect on Partnership's Business		
	Significant Effect	**Medium Effect**	**Small Effect**
Macro Risks			
Covid-19 Crisis		X	
Natural Gas Price Formulas and Linkage Components in the Supply Contracts		X	
Changes in Demand or in the Prices of the Fuels and Other Energy Sources in the International Markets	X		
Global Macroeconomic Factors	X		
Geopolitics	X		
Industry Risks			
Difficulties in Obtaining Financing		X	
Competition in Gas Supply	X		
Restrictions on Export		X	
Dependence on the Development and Functioning of the Transmission System	X		
Operational Risks		X	
Lack of Adequate Insurance Coverage		X	
Construction Risks, Dependence on Contractors and on Professional Service and Equipment Suppliers		X	
Risks of exploration activity and reliance on partial and estimated data, estimates and evaluations		X	
Only Estimated Costs and Timetables and the Eventuality of Lack of Means		X	
Forfeiture of the Partnership's Rights in its Petroleum Assets and the Financial Strength of the Partners in the Petroleum Assets			X
Dependence on Obtaining Regulatory and Other Approvals		X	
Regulatory Changes	X		
Potential Control of Natural Gas Prices		X	
Motion for Class Certification in connection with the price in the agreement between the Tamar Partners and the IEC	X		
Applicable Environmental Regulation	X		
Climate Changes			X
Dependence on Weather and Sea Conditions			X
Cyber and Information Security Risks		X	
Risks Specific to the Partnership			

	Degree of Risk Factor's Effect on Partnership's Business		
	Significant Effect	**Medium Effect**	**Small Effect**
Transfer of the Interests in the Tamar and Dalit Leases and Fulfillment of the Terms of the Gas Framework	X		
Tax Risks		X	
Financing-related Undertakings		X	
Dependence on Customers		X	
Reliance on the Operator	X		
Risk in Development and Production in the case of a Discovery			X
Sale of Interests in Petroleum Assets without Obtaining Full Consideration therefor		X	
Revocation or Expiration of Petroleum Interests and Assets			X
Overflow of Reservoirs			X
Security Risks	X		
Fluctuations in the Dollar Rate		X	
The Partnership's Belonging to Delek Group and the Controlling Shareholder thereof		X	
The Partnership's Status as a Monopoly in Natural Gas Supply in Israel		X	
"*Force majeure*" events clause under the existing natural gas sale agreements		X	

The extent of the effect of the aforesaid risk factors on the Partnership's operations is based on estimation only and the actual extent of the effect may be different.

Glossary

Set forth below is a glossary of professional terminology, in alphabetical order. The explanations and interpretations are provided for readers' convenience. The official definitions may be found in the PRMS and in regulations of the Israel Securities Authority, as updated from time to time.

Professional terminology

Appraisal/confirmation well	A well that is designed to confirm the size, quality and continuity of a natural gas/oil field, that was discovered by a successful exploration well. Appraisal drilling is performed during the field evaluation stage, which formally culminates at FID for the field development. Depending on the size and complexity of the field, there may be more than one appraisal well in a field.
Commercial	According to the PRMS, a project is considered commercial when there is evidence for firm intent to develop a reservoir within a reasonable timeframe, and firm evidence that all contingencies (including technical, environmental, economic, social, political, legal, contractual and regulatory) are met.
Compressed natural gas (CNG)	Natural gas compressed at high pressure by a factor of 100 to 300 of its original volume, depending on the compression pressure. Compressing the gas enables its storage and transportation. CNG is mainly used as a fuel for natural gas-powered vehicles.
Condensate	Hydrocarbon mixture that is found in a gas state at reservoir conditions, but condenses to a liquid on its way to the surface, as a consequence of the decrease in pressure and temperature.
Contingent resources	Defined by the PRMS as the quantities of hydrocarbons estimated, as of a given date, to be potentially recoverable from known accumulations, but which commerciality is contingent on one or more contingencies. Such contingencies may be, inter alia, technical, commercial and/or regulatory. Contingent resources are reported based on the certainty associated with the estimates, to low estimate (1C), best estimate (2C) and high estimate (3C).
Development	All activities required to facilitate production of gas/condensate/oil from a reservoir, including drilling and completing of production wells, installing of a transmission system to a processing facility, installing of processing facilities as required, and installing of a transmission system from the processing facility to the clients.
Dry gas	Natural gas composed primarily of methane, and in general contains less than 10 barrels of condensate per million cubic feet

	of gas.
Exploration well	A well that is designed to prove the existence of natural gas/oil in a prospect, and the verification of the geological model that led to its drilling. It is the peak of the exploration activity. Depending on the size and complexity of the field, there may be more than one exploration well in a field.
Floating production, storage and offloading (FPSO)	A floating processing and storage facility for oil and/or gas, which generally resembles a ship. Equipped with facilities for processing and separation of oil and/or gas and/or water and other liquids, that are produced from subsea wells and are connected to the facility through dedicated pipes (risers). The facility has a storage capacity of tens or hundreds of thousands of barrels of fluids, which are offloaded by tankers periodically.
Gas/oil initially in place (GIIP/OIIP)	the total volume of gas or oil in the reservoir, prior to production, commonly reported at standard pressure and temperature. The actual volume of ”in place” gas is independent of the development plan, and does not change, though estimates pertaining to it might change. They quantity of in-place gas is always greater than the quantity of recoverable gas (see also “recovery factor” and “recoverable gas/oil).
Hydrocarbons	Compounds composed of hydrogen and carbon. In this report, this term is used to refer mainly to natural gas and/or oil and/or condensate.
Jacket	Structure fixed to the seabed and extending above the sea level, on to which the platform topsides are installed.
Lean natural gas	In the context of the production systems of Tamar and Leviathan, the term refers to the processed natural gas stream, *after* removal of liquids (e.g., water and MEG)
Liquefied natural gas (LNG)	Natural gas condensed by cooling to approximately 160°C below zero to a liquid state, and thus shrunk by a factor of 600. Liquifying natural gas enables its transportation to distant clients, without the need for a pipeline.
Logs	1) Different types of tests and measurements conducted during drilling operations, to continuously characterize and record the properties of the drilled rocks and the fluids within them. 2) The tools utilized for the aforementioned tests and measurements. Logs are divided to those utilized while drilling (Logging While Drilling, LWD) and installed on the drill string, and to those utilized when the drill string is removed

	from the borehole, and are carried by wireline (wireline logging).
Low/ Best/ High estimate	according to the PRMS, the low estimate is defined as a value where there is a 90% probability that the actual volume will be equal or greater than it; the best estimate is defined as the value where there is a 50% probability that the actual volume will be equal or greater than it; the high estimate is defined as the value where there is a 10% probability that the actual volume will be equal or greater than it.
Manifold	A structure consisting of pipes and valves, used for controlling, routing and monitoring flow of various products. In Tamar and Leviathan, the manifold is subsea, and routes the flow from pipelines arriving from several wells into the long tie-back pipelines that connect it to the production platforms.
Natural gas	Gaseous mixture of hydrocarbons, generated by natural processes.
Oil/gas exploration	All activities geared to identifying oil/gas reservoirs and proving their existence, including, inter alia, geological, geophysical, engineering, geochemical surveys and analyses. By convention, the exploration phase terminates following a successful exploration well, and after the explorationists succeeded in proving the economic viability of the discovery, which sometimes requires drilling additional wells.
Oil/gas field	A subsurface accumulation or accumulations of oil, often consisting of a reservoir rock capped by a sealing layer. This term usually refers to reservoirs that are likely economic.
Petroleum	Natural mixture of hydrocarbons in solid, liquid or gas state. Petroleum may also contain components which are not hydrocarbons, such as carbon dioxide, nitrogen and sulfur. In this report, this term is used to refer mainly to natural gas and/or oil and/or condensate
Petroleum asset	Possession, whether directly or indirectly, of a preliminary permit, license or lease. Outside Israel, a possession, whether directly or indirectly, of an interest with an equivalent essence, granted by an authorized entity. Among petroleum rights are the right to benefit based on the possession, whether directly or indirectly, of a petroleum asset or of a right with an equivalent essence.
Petroleum Resources Management System (PRMS)	The guiding document for reliable and standard definition, classification and reporting of petroleum resources, developed and promulgated by the major professional associations in the industry.

	The most recent edition was released in 2018, replacing that of 2007.
Production and processing platform	A facility that is used for processing of produced fluids (natural gas/condensate/associated water, etc.), and sometimes also for remote control on the production wells and the connecting pipelines array. In the Yam Tethys, Tamar and Leviathan projects, the production and processing platforms are located offshore.
Prospective resources	Defined by the PRMS as the quantities of hydrocarbons estimated, as of a given date, to be potentially recoverable from *undiscovered* accumulations. Prospective resources are reported based on the certainty associated with the estimates, to low estimate (1U), best estimate (2U) and high estimate (3U).
Recoverable gas/oil	The volumes of gas/oil that can be produced through commercial or sub-commercial development projects, as of a given day.
Recovery factor	The ratio of recoverable to initially in-place oil or gas, as defined here. The recovery factor ranges from 0 to 1, generally lower for oil than for gas.
Reserves	Defined by the PRMS as quantities of hydrocarbons anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must satisfy four criteria: discovered, recoverable, commercial, and remaining based on the development project(s) applied. Reserves are reported, in accordance with the range of uncertainty associated with the estimates, as proven (P1), probable (P2) and possible (P3) quantities. The low estimate (1P) consists of P1; the best estimate (2P) of P1 and P2; and high estimate (3P) of P1, P2 and P3.
Rich natural gas	In the context of the production systems of Tamar and Leviathan, the term refers to the processed natural gas stream, *before* removal of liquids (e.g., water and MEG)
Seismic survey	Methodology based on sound waves, that enables imaging of the subsurface and detection of geological structures, and is the main tool in petroleum exploration. Generally, seismic surveys are divided into those that provide a two-dimensional (2D) image of the subsurface, and to those that provide a three-dimensional (3D) image. The raw data are processed in various techniques. The geological interpretation is commonly performed on the processed products.
Topsides	A structure that contains the production and processing facilities,

	as well as other related facilities, situated above sea level, and installed on top of a jacket in the case of a fixed-leg platform, or on top of a floating facility in the case of an FPSO.
Umbilical cables	In the context of the production systems of Tamar and Leviathan, the term refers to control and command cables through which the wells are operated, as well as conduits of liquids to the wells. In Tamar and Leviathan, there are umbilical cables connecting the production platform to the subsea distribution assembly (SDA), and in-field cables, connecting the SDA to the production wells.
Wet gas	Natural gas consisting of, compared to dry gas, less light hydrocarbons (mainly methane and ethane) and more heavier hydrocarbons. By convention, gas is considered "wet" where methane content is below 85%.
Working interest	The interest in a petroleum asset granting its owner the right to participate, proportionally to its stake in a joint venture, in utilization of the asset for petroleum exploration, development and production subject to proportional participation in whatever expenditures, following the acquisition of the working interest.

Preliminary permit, priority right to receive a license, petroleum right, petroleum, license	As defined in the Petroleum Law.
Discovered; Discovery; On Production; Approved for Development; Justified for Development; Development Pending; Development Unclarified or on Hold; well abandonment; Development not Viable; Dry Hole	As defined in the PRMS.

Units

BCF - Billion Cubic Feet

BCM - Billion Cubic Meters

MMCFD - Million Cubic Feet Per Day

TCF - Trillion Cubic Feet

MMCF - Million Cubic Feet

MMBBL - Million Barrels

MMBTU - Million British Thermal Units

Below are conversion coefficients used in this report:

BCM	BCF	MMCF
1	.353147	35,314.7

BCF	MMCF	BCM
1	1000	0.0283

MMCF	BCF	BCM
1	0.001	0.00003

Abbreviations, partial list

AFE – Authority for expenditure

AOT– Ashdod onshore terminal

ACQ – Annual Contract Quantity

EGAS – Egyptian Natural Gas Holding Company

EMG – Eastern Mediterranean Gas Company S.A.E

FEED – front-end engineering design

FID – final investment decision

FLNG – Floating LNG

FPSO – Floating Production, Storage and Offloading

IEC – Israel Electric Corp.

JOA – Joint operating agreement

JV – Joint Venture

MEG – monoethyleneglycol (anti-freeze liquid)

NEPCO – Natural Electric Power Company (Jordanian national electric company)

NSAI – Netherland Sewel and Associates Inc.

PRMS – Petroleum Resources Management System

SPC – Special Purpose Company

TCQ – Total Contract Quantity

TEG – triethylen glycol (Water-annexing liquid, used to dry natural gas)

Geological ages and periods, appearing 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

March 14, 2021

Delek Drilling Limited Partnership
19 Abba Eban Boulevard
Herzliya 4612001
Israel

Ladies and Gentlemen:

As independent consultants, Netherland, Sewell & Associates, Inc. (NSAI) hereby grant permission to Delek Drilling Limited Partnership (Delek Drilling) to use the following NSAI reports in the 2020 Annual Report of Delek Drilling to be published in March 2021 and in public reports to be filed with the Israel Securities Authority and the Tel Aviv Stock Exchange (including by way of reference):

- The report dated March 14, 2021, which sets forth our estimates of the proved, probable, and possible reserves and future revenue, as of December 31, 2020, to the Delek Drilling interest in certain gas properties located in Tamar and Tamar Southwest Fields, Tamar Lease I/12, offshore Israel.
- The report dated March 14, 2021, which sets forth our estimates of the unrisked contingent and prospective resources, as of December 31, 2020, to the Delek Drilling working interest in discoveries and prospects located in the Aphrodite Field Area, Block 12, offshore Cyprus.
- The report dated March 10, 2021, which sets forth our estimates of the proved, probable, and possible reserves and future revenue, as of December 31, 2020, to the Delek Drilling interest in certain gas properties located in Leviathan Field, Leases I/14 and I/15, offshore Israel. The March 10 report also sets forth our estimates of the contingent resources and cash flow, as of December 31, 2020, to the Delek Drilling interest in these properties.
- The report dated January 21, 2020, which sets forth our estimates of the unrisked prospective resources, as of December 31, 2019, to the Delek Drilling working interest in two Leviathan Deep prospects located in Leases I/14 and I/15, offshore Israel.
- The report dated March 19, 2018, which sets forth our estimates of the unrisked contingent and prospective resources, as of December 31, 2017, to the Delek Drilling working interest in discoveries and prospects located in the Dalit Discovery area, offshore Israel.

Since our March 10 report, we have received daily well production data for Leviathan Field through March 14, 2021. This daily well production data has been reviewed by NSAI and it is our opinion that there are no material changes to the production profile for each category or the proved, proved plus probable, and proved plus probable plus possible reserves referenced in our March 10 report.

As of the date hereof, nothing has come to our attention regarding the Leviathan Deep prospects and Dalit Discovery area that could cause us to make any revisions in our January 21 and March 19 reports or in our conclusions based on data available when our reports were prepared. It is our opinion that there are no material changes to the unrisked prospective resources referenced in our January 21 report and unrisked contingent and prospective resources referenced in our March 19 report.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: Richard B. Talley, Jr.
Richard B. Talley, Jr., P.E.
Senior Vice President

RBT:MDK

ESTIMATES

of

RESERVES AND FUTURE REVENUE

to the

DELEK DRILLING LIMITED PARTNERSHIP INTEREST

in

CERTAIN GAS PROPERTIES

located in

TAMAR AND TAMAR SOUTHWEST FIELDS
TAMAR LEASE I/12, OFFSHORE ISRAEL

as of

DECEMBER 31, 2020

BASED ON PRICE AND COST PARAMETERS

specified by

DELEK DRILLING LIMITED PARTNERSHIP

NETHERLAND, SEWELL & ASSOCIATES, INC.

WORLDWIDE PETROLEUM CONSULTANTS

ENGINEERING • GEOLOGY
GEOPHYSICS • PETROPHYSICS

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.
WORLDWIDE PETROLEUM CONSULTANTS
ENGINEERING • GEOLOGY • GEOPHYSICS • PETROPHYSICS

EXECUTIVE COMMITTEE
ROBERT C. BARG
P. SCOTT FROST
JOHN G. HATTNER
JOSEPH J. SPELLMAN
RICHARD B. TALLEY, JR.

CHAIRMAN & CEO
C.H. (SCOTT) REES III

PRESIDENT & COO
DANNY D. SIMMONS

March 14, 2021

Delek Drilling Limited Partnership
19 Abba Eban Boulevard
Herzliya 4612001
Israel

Ladies and Gentlemen:

In accordance with your request, we have estimated the proved, probable, and possible reserves and future revenue, as of December 31, 2020, to the Delek Drilling Limited Partnership (Delek Drilling) interest in certain gas properties located in Tamar and Tamar Southwest Fields, Tamar Lease I/12, offshore Israel. It is our understanding that Delek Drilling owns a 22 percent direct working interest in these properties. As requested, this report does not include the Delek Drilling indirect working interest in these properties. Reserves in Tamar Southwest Field that extend into the Eran License have not been included in this report. We completed our evaluation on or about the date of this letter. This report has been prepared using price and cost parameters specified by Delek Drilling, as discussed in subsequent paragraphs of this letter. The estimates in this report have been prepared in accordance with the definitions and guidelines set forth in the 2018 Petroleum Resources Management System (PRMS) approved by the Society of Petroleum Engineers (SPE) and in accordance with internationally recognized standards, as stipulated by the Israel Securities Authority (ISA). Definitions are presented immediately following this letter. This report has been prepared for Delek Drilling's use in filing with the ISA; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

We estimate the gross (100 percent) reserves and the Delek Drilling working interest reserves for these properties, as of December 31, 2020, to be:

	Gas Reserves (BCF)		Condensate Reserves (MMBBL)	
Category	Gross (100%)	Working Interest	Gross (100%)	Working Interest
Proved (1P)	7,726.2	1,699.8	10.0	2.2
Probable	2,755.0	606.1	3.6	0.8
Proved + Probable (2P)	10,481.2	2,305.9	13.6	3.0
Possible	2,468.3	543.0	3.2	0.7
Proved + Probable + Possible (3P)	12,949.5	2,848.9	16.8	3.7

We estimate the future net revenue after levy and corporate income taxes, discounted at 0, 5, 10, 15, and 20 percent, to the Delek Drilling interest in these properties, as of December 31, 2020, to be:

	Future Net Revenue After Levy and Corporate Income Taxes (MM$)				
Category	Discounted at 0%	Discounted at 5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
Proved (1P)	2,434.0	1,541.8	1,068.7	796.0	626.9
Probable	955.9	336.5	134.1	62.1	34.4
Proved + Probable (2P)	3,389.9	1,878.3	1,202.8	858.1	661.3
Possible	881.5	223.4	64.9	22.9	10.7
Proved + Probable + Possible (3P)	4,271.4	2,101.7	1,267.6	881.0	672.0

Totals may not add because of rounding.

We estimate the gross (100 percent) reserves for these properties by field, as of December 31, 2020, to be:

	Tamar		Tamar Southwest		Total	
Category	Gas (BCF)	Condensate (MMBBL)	Gas (BCF)	Condensate (MMBBL)	Gas (BCF)	Condensate (MMBBL)
Proved (1P)	6,929.8	9.0	796.4	1.0	7,726.2	10.0
Probable	2,595.9	3.4	159.1	0.2	2,755.0	3.6
Proved + Probable (2P)	9,525.7	12.4	955.6	1.2	10,481.2	13.6
Possible	2,366.0	3.1	102.2	0.1	2,468.3	3.2
Proved + Probable + Possible (3P)	11,891.7	15.5	1,057.8	1.4	12,949.5	16.8

Totals may not add because of rounding.

Gas volumes are expressed in billions of cubic feet (BCF) at standard temperature and pressure bases. Condensate volumes are expressed in millions of barrels (MMBBL); a barrel is equivalent to 42 United States gallons. Monetary values shown in this report are expressed in United States dollars ($) or millions of United States dollars (MM$). For reference, the March 11, 2021, exchange rate was 3.31 Israeli New Shekels per United States dollar.

Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. The 1P reserves are inclusive of proved developed producing and proved undeveloped reserves. Our study indicates that as of December 31, 2020, there are no proved developed non-producing reserves for these properties. The project maturity subclass for these reserves is on production. The estimates of reserves and future revenue included herein have not been adjusted for risk. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated.

Working interest revenue shown in this report is Delek Drilling's share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for Delek Drilling's share of royalties, capital costs, abandonment costs, operating expenses, and Delek Drilling's estimates of its oil and gas profits levy and corporate income taxes. The future net revenue has been discounted at annual rates of 0, 5, 10, 15, and 20 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties. Tables I through V present revenue, costs, and taxes by reserves category. Table VI presents Delek Drilling's historical production and operating expense data.

As requested, this report has been prepared using gas and condensate price parameters specified by Delek Drilling. Gas prices are based on a weighted average of all sales contracts according to their relative volumes and Delek Drilling's expected future sales contracts. These contract prices are derived mainly from various formulae that include indexation to the Consumer Price Index, the Power Generation Tariffs published by The Electricity Authority, or an average of long-term forecasts for Brent Crude prices provided by various institutions. Condensate prices are based on Brent Crude prices and are adjusted for quality, transportation fees, and market differentials.

Operating costs used in this report are based on operating expense records of Delek Drilling. Operating costs are limited to direct project-level costs, insurance costs, workover costs, indirect headquarters general and administrative overhead expenses, and Delek Drilling's estimate of the portion of the operator's headquarters general and administrative overhead expenses that can be directly attributed to this project; Noble Energy Mediterranean Ltd. is the operator of the properties. Based on a review of the records provided to us and our knowledge of similar properties, we regard these estimated operating costs to be reasonable. Operating costs have been divided into field-level costs and per-unit-of-production costs and, as requested, are not escalated for inflation.

Capital costs used in this report were provided by Delek Drilling and are based on estimates of future expenditures for the purpose of preserving and expanding the production capacity. Capital costs are those amounts of expenditures already authorized by the partners and amounts forecasted by Delek Drilling that are required for the above purpose, including new development wells, additional infrastructure, and production equipment. It is our understanding that Tamar and Tamar Southwest Fields are being developed under the Tamar Development Plan. Based on our understanding of this future development plan, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Abandonment costs used in this report are Delek Drilling's estimates of the costs to abandon the wells, platform, and production facilities, net of any salvage value. As requested, capital costs and abandonment costs are not escalated for inflation.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; however, we are not currently aware of any possible environmental liability that would have any material effect on the reserves estimated in this report or the commerciality of such estimates. Therefore, our estimates do not include any costs due to such possible liability.

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the Delek Drilling interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on Delek Drilling receiving its net revenue interest share of estimated future gross production.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be commercially recoverable; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. There is a 10 percent chance that the quantities will be equal to, or greater than, the quantities of the proved plus probable plus possible reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with the current development plan as provided to us by Delek Drilling, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report. The near-term gas sales forecasts used in this report were provided by Delek Drilling. It should be noted that the actual production profile for each category may be lower or higher than the production profile used to calculate the estimates of future net revenue used in this report, and no sensitivity analysis was performed with respect to the production profile of the wells.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, seismic data, core data, well test data, production data, historical price and cost information, and property ownership interests. We were provided with all the necessary data to prepare the estimates for these properties, and we were not limited from access to any material we believe may be relevant. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with generally accepted petroleum engineering and evaluation principles set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the SPE (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, analogy, and reservoir modeling, that we considered to be appropriate and necessary to classify, categorize, and estimate reserves in accordance with the 2018 PRMS definitions and guidelines. Certain parameters used in our volumetric analyses are summarized in Tables VII and VIII. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

Netherland, Sewell & Associates, Inc. (NSAI) was engaged on December 15, 2020, by Mr. Yossi Abu, Chief Executive Officer of Delek Drilling, to perform this assessment. The data used in our estimates were obtained from Delek Drilling, Noble Energy Mediterranean Ltd., other interest owners, public data sources, and the nonconfidential files of NSAI and were accepted as accurate. Supporting work data are on file in our office. We have not examined the contractual rights to the properties or independently confirmed the actual degree or type of interest owned. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis. Furthermore, no limitations or restrictions were placed upon NSAI by officials of Delek Drilling.

QUALIFICATIONS

NSAI performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. We provide a complete range of geological, geophysical, petrophysical, and engineering services, and we have the technical expertise and ability to perform these services in any oil and gas producing area in the world. The staff are familiar with the recognized industry reserves and resources definitions, specifically those promulgated by the U.S. Securities and Exchange Commission, by the Alberta Securities Commission, and by the SPE, Society of Petroleum Evaluation Engineers, World Petroleum Council, and American Association of Petroleum Geologists. The technical persons primarily responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards.

This assessment has been led by Mr. Richard B. Talley, Jr. and Mr. Zachary R. Long. Mr. Talley is a Senior Vice President and Mr. Long is a Vice President in the firm's Houston office at 1301 McKinney Street, Suite 3200, Houston, Texas 77010, USA. Mr. Talley is a Licensed Professional Engineer (Texas Registration No. 102425). He has been practicing consulting petroleum engineering at NSAI since 2004 and has over 5 years of prior industry experience. Mr. Long is a Licensed Professional Geoscientist (Texas Registration No. 11792). He has been practicing consulting petroleum geoscience at NSAI since 2007 and has over 2 years of prior industry experience.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

By: C.H. Scott Rees

C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

By: Richard B. Talley, Jr.

Richard B. Talley, Jr., P.E. 102425
Senior Vice President

Date Signed: March 14, 2021

STATE OF TEXAS
R. B. TALLEY, JR.
102425
LICENSED
PROFESSIONAL ENGINEER

By: Zach Long

Zachary R. Long, P.G. 11792
Vice President

Date Signed: March 14, 2021

STATE OF TEXAS
Z. R. LONG
GEOLOGY
11792
LICENSED
PROFESSIONAL GEOSCIENTIST

RBT:MDK

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the Petroleum Resources Management System Approved by
the Society of Petroleum Engineers (SPE) Board of Directors, June 2018

This document contains information excerpted from definitions and guidelines prepared by the Oil and Gas Reserves Committee of the Society of Petroleum Engineers (SPE) and reviewed and jointly sponsored by the SPE, World Petroleum Council, American Association of Petroleum Geologists, Society of Petroleum Evaluation Engineers, Society of Exploration Geophysicists, Society of Petrophysicists and Well Log Analysts, and European Association of Geoscientists & Engineers.

Preamble

Petroleum resources are the quantities of hydrocarbons naturally occurring on or within the Earth's crust. Resources assessments estimate quantities in known and yet-to-be-discovered accumulations. Resources evaluations are focused on those quantities that can potentially be recovered and marketed by commercial projects. A petroleum resources management system provides a consistent approach to estimating petroleum quantities, evaluating projects, and presenting results within a comprehensive classification framework.

This updated PRMS provides fundamental principles for the evaluation and classification of petroleum reserves and resources. If there is any conflict with prior SPE and PRMS guidance, approved training, or the Application Guidelines, the current PRMS shall prevail. It is understood that these definitions and guidelines allow flexibility for entities, governments, and regulatory agencies to tailor application for their particular needs; however, any modifications to the guidance contained herein must be clearly identified. The terms "shall" or "must" indicate that a provision herein is mandatory for PRMS compliance, while "should" indicates a recommended practice and "may" indicates that a course of action is permissible. The definitions and guidelines contained in this document must not be construed as modifying the interpretation or application of any existing regulatory reporting requirements.

1.0 Basic Principles and Definitions

1.0.0.1 A classification system of petroleum resources is a fundamental element that provides a common language for communicating both the confidence of a project's resources maturation status and the range of potential outcomes to the various entities. The PRMS provides transparency by requiring the assessment of various criteria that allow for the classification and categorization of a project's resources. The evaluation elements consider the risk of geologic discovery and the technical uncertainties together with a determination of the chance of achieving the commercial maturation status of a petroleum project.

1.0.0.2 The technical estimation of petroleum resources quantities involves the assessment of quantities and values that have an inherent degree of uncertainty. These quantities are associated with exploration, appraisal, and development projects at various stages of design and implementation. The commercial aspects considered will relate the project's maturity status (e.g., technical, economical, regulatory, and legal) to the chance of project implementation.

1.0.0.3 The use of a consistent classification system enhances comparisons between projects, groups of projects, and total company portfolios. The application of PRMS must consider both technical and commercial factors that impact the project's feasibility, its productive life, and its related cash flows.

1.1 Petroleum Resources Classification Framework

1.1.0.1 Petroleum is defined as a naturally occurring mixture consisting of hydrocarbons in the gaseous, liquid, or solid state. Petroleum may also contain non-hydrocarbons, common examples of which are carbon dioxide, nitrogen, hydrogen sulfide, and sulfur. In rare cases, non-hydrocarbon content can be greater than 50%.

1.1.0.2 The term resources as used herein is intended to encompass all quantities of petroleum naturally occurring within the Earth's crust, both discovered and undiscovered (whether recoverable or unrecoverable), plus those quantities already produced. Further, it includes all types of petroleum whether currently considered as conventional or unconventional resources.

1.1.0.3 Figure 1.1 graphically represents the PRMS resources classification system. The system classifies resources into discovered and undiscovered and defines the recoverable resources classes: Production, Reserves, Contingent Resources, and Prospective Resources, as well as Unrecoverable Petroleum.

1.1.0.4 The horizontal axis reflects the range of uncertainty of estimated quantities potentially recoverable from an accumulation by a project, while the vertical axis represents the chance of commerciality, P_c, which is the chance that a project will be committed for development and reach commercial producing status.

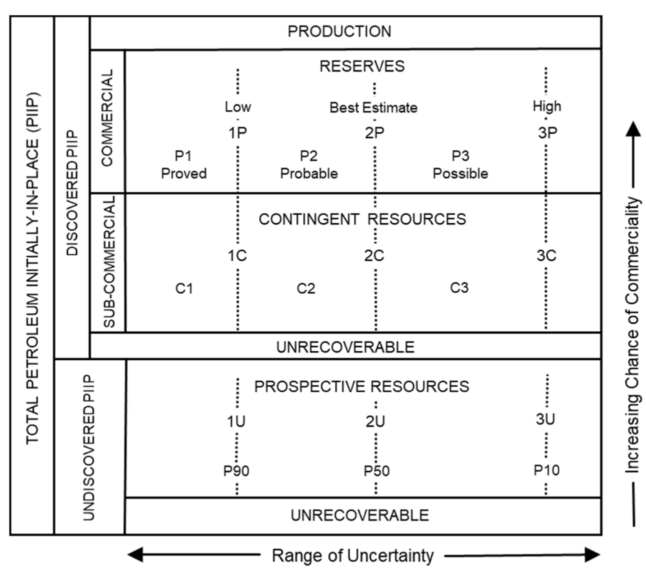

Figure 1.1—Resources classification framework

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1.1.0.5 The following definitions apply to the major subdivisions within the resources classification:

A. **Total Petroleum Initially-In-Place** (PIIP) is all quantities of petroleum that are estimated to exist originally in naturally occurring accumulations, discovered and undiscovered, before production.

B. **Discovered PIIP** is the quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations before production.

C. **Production** is the cumulative quantities of petroleum that have been recovered at a given date. While all recoverable resources are estimated, and production is measured in terms of the sales product specifications, raw production (sales plus non-sales) quantities are also measured and required to support engineering analyses based on reservoir voidage (see Section 3.2, Production Measurement).

1.1.0.6 Multiple development projects may be applied to each known or unknown accumulation, and each project will be forecast to recover an estimated portion of the initially-in-place quantities. The projects shall be subdivided into commercial, sub-commercial, and undiscovered, with the estimated recoverable quantities being classified as Reserves, Contingent Resources, or Prospective Resources respectively, as defined below.

A. 1. **Reserves** are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must satisfy four criteria: discovered, recoverable, commercial, and remaining (as of the evaluation's effective date) based on the development project(s) applied.

2. Reserves are recommended as sales quantities as metered at the reference point. Where the entity also recognizes quantities consumed in operations (CiO) (see Section 3.2.2), as Reserves these quantities must be recorded separately. Non-hydrocarbon quantities are recognized as Reserves only when sold together with hydrocarbons or CiO associated with petroleum production. If the non-hydrocarbon is separated before sales, it is excluded from Reserves.

3. Reserves are further categorized in accordance with the range of uncertainty and should be sub-classified based on project maturity and/or characterized by development and production status.

B. **Contingent Resources** are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, by the application of development project(s) not currently considered to be commercial owing to one or more contingencies. Contingent Resources have an associated chance of development. Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the range of uncertainty associated with the estimates and should be sub-classified based on project maturity and/or economic status.

C. **Undiscovered PIIP** is that quantity of petroleum estimated, as of a given date, to be contained within accumulations yet to be discovered.

D. **Prospective Resources** are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of geologic discovery and a chance of development. Prospective Resources are further categorized in accordance with the range of uncertainty associated with recoverable estimates, assuming discovery and development, and may be sub-classified based on project maturity.

E. **Unrecoverable Resources** are that portion of either discovered or undiscovered PIIP evaluated, as of a given date, to be unrecoverable by the currently defined project(s). A portion of these quantities may become recoverable in the future as commercial circumstances change, technology is developed, or additional data are acquired. The remaining portion may never be recovered because of physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

1.1.0.7 The sum of Reserves, Contingent Resources, and Prospective Resources may be referred to as "remaining recoverable resources." Importantly, these quantities should not be aggregated without due consideration of the technical and commercial risk involved with their classification. When such terms are used, each classification component of the summation must be provided.

1.1.0.8 Other terms used in resource assessments include the following:

A. **Estimated Ultimate Recovery (EUR)** is not a resources category or class, but a term that can be applied to an accumulation or group of accumulations (discovered or undiscovered) to define those quantities of petroleum estimated, as of a given date, to be potentially recoverable plus those quantities already produced from the accumulation or group of accumulations. For clarity, EUR must reference the associated technical and commercial conditions for the resources; for example, proved EUR is Proved Reserves plus prior production.

B. **Technically Recoverable Resources (TRR)** are those quantities of petroleum producible using currently available technology and industry practices, regardless of commercial considerations. TRR may be used for specific Projects or for groups of Projects, or, can be an undifferentiated estimate within an area (often basin-wide) of recovery potential.

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1.2 Project-Based Resources Evaluations

1.2.0.1 The resources evaluation process consists of identifying a recovery project or projects associated with one or more petroleum accumulations, estimating the quantities of PIIP, estimating that portion of those in-place quantities that can be recovered by each project, and classifying the project(s) based on maturity status or chance of commerciality.

1.2.0.2 The concept of a project-based classification system is further clarified by examining the elements contributing to an evaluation of net recoverable resources (see Figure 1.2).

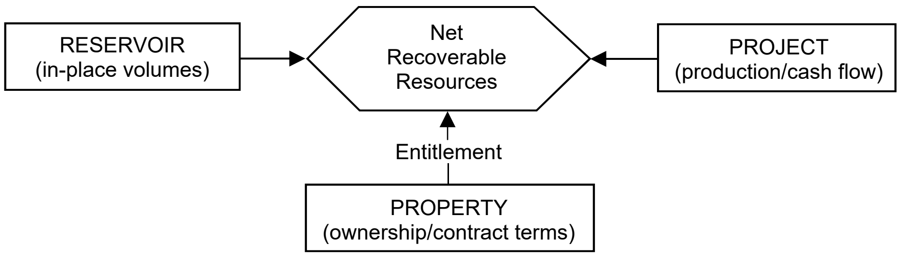

Figure 1.2—Resources evaluation

1.2.0.3 **The reservoir** (contains the petroleum accumulation): Key attributes include the types and quantities of PIIP and the fluid and rock properties that affect petroleum recovery.

1.2.0.4 **The project:** A project may constitute the development of a well, a single reservoir, or a small field; an incremental development in a producing field; or the integrated development of a field or several fields together with the associated processing facilities (e.g., compression). Within a project, a specific reservoir's development generates a unique production and cash-flow schedule at each level of certainty. The integration of these schedules taken to the project's earliest truncation caused by technical, economic, or the contractual limit defines the estimated recoverable resources and associated future net cash flow projections for each project. The ratio of EUR to total PIIP quantities defines the project's recovery efficiency. Each project should have an associated recoverable resources range (low, best, and high estimate).

1.2.0.5 **The property** (lease or license area): Each property may have unique associated contractual rights and obligations, including the fiscal terms. This information allows definition of each participating entity's share of produced quantities (entitlement) and share of investments, expenses, and revenues for each recovery project and the reservoir to which it is applied. One property may encompass many reservoirs, or one reservoir may span several different properties. A property may contain both discovered and undiscovered accumulations that may be spatially unrelated to a potential single field designation.

1.2.0.6 An entity's net recoverable resources are the entitlement share of future production legally accruing under the terms of the development and production contract or license.

1.2.0.7 In the context of this relationship, the project is the primary element considered in the resources classification, and the net recoverable resources are the quantities derived from each project. A project represents a defined activity or set of activities to develop the petroleum accumulation(s) and the decisions taken to mature the resources to reserves. In general, it is recommended that an individual project has assigned to it a specific maturity level sub-class (See Section 2.1.3.5, Project Maturity Sub-Classes) at which a decision is made whether or not to proceed (i.e., spend more money) and there should be an associated range of estimated recoverable quantities for the project (See Section 2.2.1, Range of Uncertainty). For completeness, a developed field is also considered to be a project.

1.2.0.8 An accumulation or potential accumulation of petroleum is often subject to several separate and distinct projects that are at different stages of exploration or development. Thus, an accumulation may have recoverable quantities in several resources classes simultaneously.

1.2.0.10 Not all technically feasible development projects will be commercial. The commercial viability of a development project within a field's development plan is dependent on a forecast of the conditions that will exist during the time period encompassed by the project (see Section 3.1, Assessment of Commerciality). Conditions include technical, economic (e.g., hurdle rates, commodity prices), operating and capital costs, marketing, sales route(s), and legal, environmental, social, and governmental factors forecast to exist and impact the project during the time period being evaluated. While economic factors can be summarized as forecast costs and product prices, the underlying influences include, but are not limited to, market conditions (e.g., inflation, market factors, and contingencies), exchange rates, transportation and processing infrastructure, fiscal terms, and taxes.

1.2.0.11 The resources being estimated are those quantities producible from a project as measured according to delivery specifications at the point of sale or custody transfer (see Section 3.2.1, Reference Point) and may permit forecasts of CiO quantities (see Section 3.2.2., Consumed in Operations). The cumulative production forecast from the effective date forward to cessation of production is the remaining recoverable resources quantity (see Section 3.1.1, Net Cash-Flow Evaluation).

1.2.0.12 The supporting data, analytical processes, and assumptions describing the technical and commercial basis used in an evaluation must be documented in sufficient detail to allow, as needed, a qualified reserves evaluator or qualified reserves auditor to clearly understand each project's basis for the estimation, categorization, and classification of recoverable resources quantities and, if appropriate, associated commercial assessment.

2.0 Classification and Categorization Guidelines

2.1 Resources Classification

2.1.0.1 The PRMS classification establishes criteria for the classification of the total PIIP. A determination of a discovery differentiates between discovered and undiscovered PIIP. The application of a project further differentiates the recoverable from unrecoverable resources. The project is then evaluated to determine its maturity status to allow the classification distinction between commercial and sub-commercial projects. PRMS requires the project's recoverable resources quantities to be classified as either Reserves, Contingent Resources, or Prospective Resources.

2.1.1 Determination of Discovery Status

2.1.1.1 A discovered petroleum accumulation is determined to exist when one or more exploratory wells have established through testing, sampling, and/or logging the existence of a significant quantity of potentially recoverable hydrocarbons and thus have established a known accumulation. In the absence of a flow test or sampling, the discovery determination requires confidence in the presence of hydrocarbons and evidence of producibility, which may be supported by suitable producing analogs (see Section 4.1.1, Analogs). In this context, "significant" implies that there is evidence of a sufficient quantity of petroleum to justify estimating the in-place quantity demonstrated by the well(s) and for evaluating the potential for commercial recovery.

2.1.1.2 Where a discovery has identified potentially recoverable hydrocarbons, but it is not considered viable to apply a project with established technology or with technology under development, such quantities may be classified as Discovered Unrecoverable with no Contingent Resources. In future evaluations, as appropriate for petroleum resources management purposes, a portion of these unrecoverable quantities may become recoverable resources as either commercial circumstances change or technological developments occur.

2.1.2 Determination of Commerciality

2.1.2.1 Discovered recoverable quantities (Contingent Resources) may be considered commercially mature, and thus attain Reserves classification, if the entity claiming commerciality has demonstrated a firm intention to proceed with development. This means the entity has satisfied the internal decision criteria (typically rate of return at or above the weighted average cost-of-capital or the hurdle rate). Commerciality is achieved with the entity's commitment to the project and all of the following criteria:

A. Evidence of a technically mature, feasible development plan.
B. Evidence of financial appropriations either being in place or having a high likelihood of being secured to implement the project.
C. Evidence to support a reasonable time-frame for development.
D. A reasonable assessment that the development projects will have positive economics and meet defined investment and operating criteria. This assessment is performed on the estimated entitlement forecast quantities and associated cash flow on which the investment decision is made (see Section 3.1.1, Net Cash-Flow Evaluation).
E. A reasonable expectation that there will be a market for forecast sales quantities of the production required to justify development. There should also be similar confidence that all produced streams (e.g., oil, gas, water, CO2) can be sold, stored, re-injected, or otherwise appropriately disposed.
F. Evidence that the necessary production and transportation facilities are available or can be made available.
G. Evidence that legal, contractual, environmental, regulatory, and government approvals are in place or will be forthcoming, together with resolving any social and economic concerns.

2.1.2.2 The commerciality test for Reserves determination is applied to the best estimate (P50) forecast quantities, which upon qualifying all commercial and technical maturity criteria and constraints become the 2P Reserves. Stricter cases [e.g., low estimate (P90)] may be used for decision purposes or to investigate the range of commerciality (see Section 3.1.2, Economic Criteria). Typically, the low- and high-case project scenarios may be evaluated for sensitivities when considering project risk and upside opportunity.

2.1.2.3 To be included in the Reserves class, a project must be sufficiently defined to establish both its technical and commercial viability as noted in Section 2.1.2.1. There must be a reasonable expectation that all required internal and external approvals will be forthcoming and evidence of firm intention to proceed with development within a reasonable time-frame. A reasonable time-frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While five years is recommended as a benchmark, a longer time-frame could be applied where justifiable; for example, development of economic projects that take longer than five years to be developed or are deferred to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented.

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2.1.2.4 While PRMS guidelines require financial appropriations evidence, they do not require that project financing be confirmed before classifying projects as Reserves. However, this may be another external reporting requirement. In many cases, financing is conditional upon the same criteria as above. In general, if there is not a reasonable expectation that financing or other forms of commitment (e.g., farm-outs) can be arranged so that the development will be initiated within a reasonable time-frame, then the project should be classified as Contingent Resources. If financing is reasonably expected to be in place at the time of the final investment decision (FID), the project's resources may be classified as Reserves.

2.2 Resources Categorization

2.2.0.1 The horizontal axis in the resources classification in Figure 1.1 defines the range of uncertainty in estimates of the quantities of recoverable, or potentially recoverable, petroleum associated with a project or group of projects. These estimates include the uncertainty components as follows:

A. The total petroleum remaining within the accumulation (in-place resources).
B. The technical uncertainty in the portion of the total petroleum that can be recovered by applying a defined development project or projects (i.e., the technology applied).
C. Known variations in the commercial terms that may impact the quantities recovered and sold (e.g., market availability; contractual changes, such as production rate tiers or product quality specifications) are part of project's scope and are included in the horizontal axis, while the chance of satisfying the commercial terms is reflected in the classification (vertical axis).

2.2.0.2 The uncertainty in a project's recoverable quantities is reflected by the 1P, 2P, 3P, Proved (P1), Probable (P2), Possible (P3), 1C, 2C, 3C, C1, C2, and C3; or 1U, 2U, and 3U resources categories. The commercial chance of success is associated with resources classes or sub-classes and not with the resources categories reflecting the range of recoverable quantities.

2.2.1 Range of Uncertainty

2.2.1.1 Uncertainty is inherent in a project's resources estimation and is communicated in PRMS by reporting a range of category outcomes. The range of uncertainty of the recoverable and/or potentially recoverable quantities may be represented by either deterministic scenarios or by a probability distribution (see Section 4.2, Resources Assessment Methods).

2.2.1.2 When the range of uncertainty is represented by a probability distribution, a low, best, and high estimate shall be provided such that:

A. There should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate.
B. There should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate.
C. There should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

2.2.1.3 In some projects, the range of uncertainty may be limited, and the three scenarios may result in resources estimates that are not significantly different. In these situations, a single value estimate may be appropriate to describe the expected result.

2.2.1.4 When using the deterministic scenario method, typically there should also be low, best, and high estimates, where such estimates are based on qualitative assessments of relative uncertainty using consistent interpretation guidelines. Under the deterministic incremental method, quantities for each confidence segment are estimated discretely (see Section 2.2.2, Category Definitions and Guidelines).

2.2.1.5 Project resources are initially estimated using the above uncertainty range forecasts that incorporate the subsurface elements together with technical constraints related to wells and facilities. The technical forecasts then have additional commercial criteria applied (e.g., economics and license cutoffs are the most common) to estimate the entitlement quantities attributed and the resources classification status: Reserves, Contingent Resources, and Prospective Resources.

2.2.2 Category Definitions and Guidelines

2.2.2.1 Evaluators may assess recoverable quantities and categorize results by uncertainty using the deterministic incremental method, the deterministic scenario (cumulative) method, geostatistical methods, or probabilistic methods (see Section 4.2, Resources Assessment Methods). Also, combinations of these methods may be used.

2.2.2.2 Use of consistent terminology (Figures 1.1 and 2.1) promotes clarity in communication of evaluation results. For Reserves, the general cumulative terms low/best/high forecasts are used to estimate the resulting 1P/2P/3P quantities, respectively. The associated incremental quantities are termed Proved (P1), Probable (P2) and Possible (P3). Reserves are a subset of, and must be viewed within the context of, the complete resources classification system. While the categorization criteria are proposed specifically for Reserves, in most cases, the criteria can be equally applied to Contingent and Prospective Resources. Upon satisfying the commercial maturity criteria for discovery and/or development, the project quantities will then move to the appropriate resources sub-class. Table 3 provides criteria for the Reserves categories determination.

2.2.2.3 For Contingent Resources, the general cumulative terms low/best/high estimates are used to estimate the resulting 1C/2C/3C quantities, respectively. The terms C1, C2, and C3 are defined for incremental quantities of Contingent Resources.

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2.2.2.4 For Prospective Resources, the general cumulative terms low/best/high estimates also apply and are used to estimate the resulting 1U/2U/3U quantities. No specific terms are defined for incremental quantities within Prospective Resources.

2.2.2.5 Quantities in different classes and sub-classes cannot be aggregated without considering the varying degrees of technical uncertainty and commercial likelihood involved with the classification(s) and without considering the degree of dependency between them (see Section 4.2.1, Aggregating Resources Classes).

2.2.2.6 Without new technical information, there should be no change in the distribution of technically recoverable resources and the categorization boundaries when conditions are satisfied to reclassify a project from Contingent Resources to Reserves.

2.2.2.7 All evaluations require application of a consistent set of forecast conditions, including assumed future costs and prices, for both classification of projects and categorization of estimated quantities recovered by each project (see Section 3.1, Assessment of Commerciality).

Table 1—Recoverable Resources Classes and Sub-Classes

Class/Sub-Class	Definition	Guidelines
Reserves	Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.	Reserves must satisfy four criteria: discovered, recoverable, commercial, and remaining based on the development project(s) applied. Reserves are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by the development and production status. To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability (see Section 2.1.2, Determination of Commerciality). This includes the requirement that there is evidence of firm intention to proceed with development within a reasonable time-frame. A reasonable time-frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While five years is recommended as a benchmark, a longer time-frame could be applied where, for example, development of an economic project is deferred at the option of the producer for, among other things, market-related reasons or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented. To be included in the Reserves class, there must be a high confidence in the commercial maturity and economic producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.
On Production	The development project is currently producing or capable of producing and selling petroleum to market.	The key criterion is that the project is receiving income from sales, rather than that the approved development project is necessarily complete. Includes Developed Producing Reserves. The project decision gate is the decision to initiate or continue economic production from the project.
Approved for Development	All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is ready to begin or is under way.	At this point, it must be certain that the development project is going ahead. The project must not be subject to any contingencies, such as outstanding regulatory approvals or sales contracts. Forecast capital expenditures should be included in the reporting entity's current or following year's approved budget. The project decision gate is the decision to start investing capital in the construction of production facilities and/or drilling development wells.

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Class/Sub-Class	Definition	Guidelines
Justified for Development	Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals/contracts will be obtained.	To move to this level of project maturity, and hence have Reserves associated with it, the development project must be commercially viable at the time of reporting (see Section 2.1.2, Determination of Commerciality) and the specific circumstances of the project. All participating entities have agreed and there is evidence of a committed project (firm intention to proceed with development within a reasonable time-frame). There must be no known contingencies that could preclude the development from proceeding (see Reserves class). The project decision gate is the decision by the reporting entity and its partners, if any, that the project has reached a level of technical and commercial maturity sufficient to justify proceeding with development at that point in time.
Contingent Resources	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable owing to one or more contingencies.	Contingent Resources may include, for example, projects for which there are currently no viable markets, where commercial recovery is dependent on technology under development, where evaluation of the accumulation is insufficient to clearly assess commerciality, where the development plan is not yet approved, or where regulatory or social acceptance issues may exist. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by the economic status.
Development Pending	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.	The project is seen to have reasonable potential for eventual commercial development, to the extent that further data acquisition (e.g., drilling, seismic data) and/or evaluations are currently ongoing with a view to confirming that the project is commercially viable and providing the basis for selection of an appropriate development plan. The critical contingencies have been identified and are reasonably expected to be resolved within a reasonable time-frame. Note that disappointing appraisal/evaluation results could lead to a reclassification of the project to On Hold or Not Viable status. The project decision gate is the decision to undertake further data acquisition and/or studies designed to move the project to a level of technical and commercial maturity at which a decision can be made to proceed with development and production.
Development on Hold	A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay.	The project is seen to have potential for commercial development. Development may be subject to a significant time delay. Note that a change in circumstances, such that there is no longer a probable chance that a critical contingency can be removed in the foreseeable future, could lead to a reclassification of the project to Not Viable status. The project decision gate is the decision to either proceed with additional evaluation designed to clarify the potential for eventual commercial development or to temporarily suspend or delay further activities pending resolution of external contingencies.
Development Unclarified	A discovered accumulation where project activities are under evaluation and where justification as a commercial development is unknown based on available information.	The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are ongoing to clarify the potential for eventual commercial development. This sub-class requires active appraisal or evaluation and should not be maintained without a plan for future evaluation. The sub-class should reflect the actions required to move a project toward commercial maturity and economic production.

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Class/Sub-Class	Definition	Guidelines
Development Not Viable	A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time because of limited production potential.	The project is not seen to have potential for eventual commercial development at the time of reporting, but the theoretically recoverable quantities are recorded so that the potential opportunity will be recognized in the event of a major change in technology or commercial conditions. The project decision gate is the decision not to undertake further data acquisition or studies on the project for the foreseeable future.
Prospective Resources	Those quantities of petroleum that are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.	Potential accumulations are evaluated according to the chance of geologic discovery and, assuming a discovery, the estimated quantities that would be recoverable under defined development projects. It is recognized that the development programs will be of significantly less detail and depend more heavily on analog developments in the earlier phases of exploration.
Prospect	A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.	Project activities are focused on assessing the chance of geologic discovery and, assuming discovery, the range of potential recoverable quantities under a commercial development program.
Lead	A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation to be classified as a Prospect.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to confirm whether or not the Lead can be matured into a Prospect. Such evaluation includes the assessment of the chance of geologic discovery and, assuming discovery, the range of potential recovery under feasible development scenarios.
Play	A project associated with a prospective trend of potential prospects, but that requires more data acquisition and/or evaluation to define specific Leads or Prospects.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to define specific Leads or Prospects for more detailed analysis of their chance of geologic discovery and, assuming discovery, the range of potential recovery under hypothetical development scenarios.

Table 2—Reserves Status Definitions and Guidelines

Status	Definition	Guidelines
Developed Reserves	Expected quantities to be recovered from existing wells and facilities.	Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well. Where required facilities become unavailable, it may be necessary to reclassify Developed Reserves as Undeveloped. Developed Reserves may be further sub-classified as Producing or Non-producing.
Developed Producing Reserves	Expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.	Improved recovery Reserves are considered producing only after the improved recovery project is in operation.
Developed Non-Producing Reserves	Shut-in and behind-pipe Reserves.	Shut-in Reserves are expected to be recovered from (1) completion intervals that are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

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Status	Definition	Guidelines
Undeveloped Reserves	Quantities expected to be recovered through future significant investments.	Undeveloped Reserves are to be produced (1) from new wells on undrilled acreage in known accumulations, (2) from deepening existing wells to a different (but known) reservoir, (3) from infill wells that will increase recovery, or (4) where a relatively large expenditure (e.g., when compared to the cost of drilling a new well) is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects.

Table 3—Reserves Category Definitions and Guidelines

Category	Definition	Guidelines
Proved Reserves	Those quantities of petroleum that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable from a given date forward from known reservoirs and under defined economic conditions, operating methods, and government regulations.	If deterministic methods are used, the term "reasonable certainty" is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the estimate. The area of the reservoir considered as Proved includes (1) the area delineated by drilling and defined by fluid contacts, if any, and (2) adjacent undrilled portions of the reservoir that can reasonably be judged as continuous with it and commercially productive on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, Proved quantities in a reservoir are limited by the LKH as seen in a well penetration unless otherwise indicated by definitive geoscience, engineering, or performance data. Such definitive information may include pressure gradient analysis and seismic indicators. Seismic data alone may not be sufficient to define fluid contacts for Proved reserves. Reserves in undeveloped locations may be classified as Proved provided that: A. The locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially mature and economically productive. B. Interpretations of available geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with drilled Proved locations. For Proved Reserves, the recovery efficiency applied to these reservoirs should be defined based on a range of possibilities supported by analogs and sound engineering judgment considering the characteristics of the Proved area and the applied development program.
Probable Reserves	Those additional Reserves that analysis of geoscience and engineering data indicates are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves.	It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate. Probable Reserves may be assigned to areas of a reservoir adjacent to Proved where data control or interpretations of available data are less certain. The interpreted reservoir continuity may not meet the reasonable certainty criteria. Probable estimates also include incremental recoveries associated with project recovery efficiencies beyond that assumed for Proved.

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the Petroleum Resources Management System Approved by
the Society of Petroleum Engineers (SPE) Board of Directors, June 2018

Category	Definition	Guidelines
Possible Reserves	Those additional reserves that analysis of geoscience and engineering data indicates are less likely to be recoverable than Probable Reserves.	The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high-estimate scenario. When probabilistic methods are used, there should be at least a 10% probability (P10) that the actual quantities recovered will equal or exceed the 3P estimate. Possible Reserves may be assigned to areas of a reservoir adjacent to Probable where data control and interpretations of available data are progressively less certain. Frequently, this may be in areas where geoscience and engineering data are unable to clearly define the area and vertical reservoir limits of economic production from the reservoir by a defined, commercially mature project. Possible estimates also include incremental quantities associated with project recovery efficiencies beyond that assumed for Probable.
Probable and Possible Reserves	See above for separate criteria for Probable Reserves and Possible Reserves.	The 2P and 3P estimates may be based on reasonable alternative technical interpretations within the reservoir and/or subject project that are clearly documented, including comparisons to results in successful similar projects. In conventional accumulations, Probable and/or Possible Reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from Proved areas by minor faulting or other geological discontinuities and have not been penetrated by a wellbore but are interpreted to be in communication with the known (Proved) reservoir. Probable or Possible Reserves may be assigned to areas that are structurally higher than the Proved area. Possible (and in some cases, Probable) Reserves may be assigned to areas that are structurally lower than the adjacent Proved or 2P area. Caution should be exercised in assigning Reserves to adjacent reservoirs isolated by major, potentially sealing faults until this reservoir is penetrated and evaluated as commercially mature and economically productive. Justification for assigning Reserves in such cases should be clearly documented. Reserves should not be assigned to areas that are clearly separated from a known accumulation by non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results); such areas may contain Prospective Resources. In conventional accumulations, where drilling has defined a highest known oil elevation and there exists the potential for an associated gas cap, Proved Reserves of oil should only be assigned in the structurally higher portions of the reservoir if there is reasonable certainty that such portions are initially above bubble point pressure based on documented engineering analyses. Reservoir portions that do not meet this certainty may be assigned as Probable and Possible oil and/or gas based on reservoir fluid properties and pressure gradient interpretations.

REVENUE, COSTS, AND TAXES
PROVED (1P) RESERVES
DELEK DRILLING LIMITED PARTNERSHIP INTEREST
TAMAR AND TAMAR SOUTHWEST FIELDS, TAMAR LEASE I/12, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2020

Period Ending	Working Interest Revenue (MM$)	Royalties State (MM$)	Royalties Interested Party (MM$)	Royalties Third Party (MM$)	Royalties Total (MM$)	Net Capital Costs (MM$)	Net Abandonment Costs (MM$)	Net Operating Expenses[1] (MM$)	Future Net Revenue Before Levy and Corporate Income Taxes Discounted at 0% (MM$)
12-31-2021	299.7	34.5	13.4	13.9	61.8	14.6	-	32.1	191.2
12-31-2022	337.8	38.8	15.1	15.7	69.7	6.2	-	29.1	232.9
12-31-2023	344.6	39.6	15.5	16.0	71.1	47.4	-	28.9	197.1
12-31-2024	357.4	41.1	16.0	16.6	73.7	68.6	-	28.9	186.2
12-31-2025	392.1	45.1	17.6	18.2	80.9	-	-	29.0	282.2
12-31-2026	412.6	47.4	18.5	19.2	85.1	-	-	29.1	298.4
12-31-2027	429.6	49.4	19.3	20.0	88.6	-	-	29.1	311.8
12-31-2028	440.9	50.7	19.8	20.5	91.0	35.0	-	29.6	285.3
12-31-2029	464.6	53.4	20.8	21.6	95.8	7.8	-	29.7	331.2
12-31-2030	476.5	54.8	21.4	22.1	98.3	-	-	29.7	348.5
12-31-2031	476.8	54.8	21.4	22.2	98.4	-	-	29.7	348.7
12-31-2032	474.9	54.6	21.3	22.1	98.0	-	-	29.7	347.2
12-31-2033	474.9	54.6	21.3	22.1	98.0	22.4	-	29.7	324.8
12-31-2034	475.1	54.6	21.3	22.1	98.0	42.9	-	29.7	304.5
12-31-2035	465.2	53.5	20.9	21.6	96.0	-	-	29.7	339.5
12-31-2036	430.2	49.5	19.3	20.0	88.8	-	-	29.6	311.9
12-31-2037	317.8	36.5	14.3	14.8	65.6	-	-	29.1	223.1
12-31-2038	248.7	28.6	11.2	11.6	51.3	-	-	28.9	168.5
12-31-2039	204.5	23.5	9.2	9.5	42.2	-	-	28.7	133.6
12-31-2040	173.5	20.0	7.8	8.1	35.8	-	-	28.6	109.1
12-31-2041	150.7	17.3	6.8	7.0	31.1	-	-	28.5	91.1
12-31-2042	132.7	15.3	6.0	6.2	27.4	-	-	28.4	76.9
12-31-2043	116.8	13.4	5.2	5.4	24.1	-	-	28.4	64.3
12-31-2044	102.8	11.8	4.6	4.8	21.2	-	-	28.3	53.3
12-31-2045	90.4	10.4	4.1	4.2	18.6	-	-	28.3	43.5
12-31-2046	79.2	9.1	3.6	3.7	16.3	-	-	28.2	34.7
12-31-2047	70.0	8.1	3.1	3.3	14.5	-	-	28.2	27.4
12-31-2048	61.3	7.0	2.7	2.8	12.6	-	-	28.1	20.5
12-31-2049	54.1	6.2	2.4	2.5	11.2	-	17.9	28.1	-3.1
12-31-2050	47.7	5.5	2.1	2.2	9.8	-	17.9	28.1	-8.2
12-31-2051	37.8	4.3	1.7	1.8	7.8	-	17.9	28.1	-16.0
12-31-2052	-	-	-	-	-	-	-	-	-
12-31-2053	-	-	-	-	-	-	-	-	-
12-31-2054	-	-	-	-	-	-	-	-	-
12-31-2055	-	-	-	-	-	-	-	-	-
12-31-2056	-	-	-	-	-	-	-	-	-
Total	8,640.9	993.7	387.5	401.4	1,782.7	244.9	53.8	899.4	5,660.0

Totals may not add because of rounding.

(1) Operating costs are limited to direct project-level costs, insurance costs, workover costs, indirect headquarters general and administrative overhead expenses, and Delek Drilling's estimate of the portion of the operator's headquarters general and administrative overhead expenses that can be directly attributed to this project.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

NETHERLAND, SEWELL & ASSOCIATES, INC.

REVENUE, COSTS, AND TAXES
PROVED (1P) RESERVES
DELEK DRILLING LIMITED PARTNERSHIP INTEREST
TAMAR AND TAMAR SOUTHWEST FIELDS, TAMAR LEASE I/12, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2020

Period Ending	Levy Rate[(1)] (%)	Levy[(1)] (MM$)	Future Net Revenue After Levy and Before Corporate Income Taxes Discounted at 0% (MM$)	Corporate Income Tax Rate[(2)] (%)	Corporate Income Taxes[(2)] (MM$)	Future Net Revenue After Levy and Corporate Income Taxes: Discounted at 0% (MM$)	Discounted at 5% (MM$)	Discounted at 10% (MM$)	Discounted at 15% (MM$)	Discounted at 20% (MM$)
12-31-2021	24.0	45.8	145.4	23.0	29.6	115.8	113.0	110.4	108.0	105.7
12-31-2022	30.5	71.0	161.8	23.0	31.7	130.2	121.0	112.8	105.5	99.0
12-31-2023	35.8	70.6	126.5	23.0	35.3	91.2	80.7	71.9	64.3	57.8
12-31-2024	40.0	74.4	111.8	23.0	35.2	76.6	64.6	54.9	47.0	40.5
12-31-2025	45.1	127.3	154.9	23.0	27.8	127.1	102.1	82.8	67.8	56.0
12-31-2026	46.8	139.6	158.7	23.0	29.6	129.1	98.8	76.5	59.9	47.4
12-31-2027	46.8	145.9	165.9	23.0	32.6	133.3	97.0	71.7	53.7	40.7
12-31-2028	46.8	133.5	151.8	23.0	37.9	113.9	79.0	55.7	39.9	29.0
12-31-2029	46.8	155.0	176.2	23.0	36.8	139.4	92.1	62.0	42.5	29.6
12-31-2030	46.8	163.1	185.4	23.0	37.1	148.3	93.3	60.0	39.3	26.2
12-31-2031	46.8	163.2	185.5	23.0	37.3	148.2	88.8	54.5	34.2	21.8
12-31-2032	46.8	162.5	184.7	23.0	37.3	147.5	84.1	49.3	29.6	18.1
12-31-2033	46.8	152.0	172.8	23.0	39.8	133.0	72.3	40.4	23.2	13.6
12-31-2034	46.8	142.5	162.0	23.0	43.6	118.4	61.3	32.7	17.9	10.1
12-31-2035	46.8	158.9	180.6	23.0	39.0	141.6	69.8	35.5	18.7	10.1
12-31-2036	46.8	146.0	165.9	23.0	35.6	130.3	61.2	29.7	14.9	7.7
12-31-2037	46.8	104.4	118.7	23.0	24.8	93.9	42.0	19.5	9.4	4.6
12-31-2038	46.8	78.9	89.6	23.0	18.1	71.5	30.5	13.5	6.2	2.9
12-31-2039	46.8	62.5	71.1	23.0	14.7	56.4	22.9	9.7	4.3	1.9
12-31-2040	46.8	51.1	58.1	23.0	11.9	46.2	17.8	7.2	3.0	1.3
12-31-2041	46.8	42.7	48.5	23.0	9.7	38.8	14.3	5.5	2.2	0.9
12-31-2042	46.8	36.0	40.9	23.0	7.9	33.0	11.6	4.3	1.6	0.7
12-31-2043	46.8	30.1	34.2	23.0	6.4	27.8	9.3	3.3	1.2	0.5
12-31-2044	46.8	24.9	28.3	23.0	5.5	22.8	7.2	2.4	0.9	0.3
12-31-2045	46.8	20.4	23.1	23.0	5.3	17.8	5.4	1.7	0.6	0.2
12-31-2046	46.8	16.2	18.4	23.0	4.2	14.2	4.1	1.2	0.4	0.1
12-31-2047	46.8	12.8	14.6	23.0	3.1	11.5	3.2	0.9	0.3	0.1
12-31-2048	46.8	9.6	10.9	23.0	2.2	8.7	2.3	0.6	0.2	0.1
12-31-2049	-	-	-3.1	23.0	3.1	-6.3	-1.6	-0.4	-0.1	-0.0
12-31-2050	-	-	-8.2	23.0	2.0	-10.1	-2.4	-0.6	-0.2	-0.0
12-31-2051	-	-	-16.0	23.0	0.2	-16.1	-3.6	-0.9	-0.2	-0.1
12-31-2052	-	-	-	23.0	-	-	-	-	-	-
12-31-2053	-	-	-	23.0	-	-	-	-	-	-
12-31-2054	-	-	-	23.0	-	-	-	-	-	-
12-31-2055	-	-	-	23.0	-	-	-	-	-	-
12-31-2056	-	-	-	23.0	-	-	-	-	-	-
Total		2,540.9	3,119.2		685.1	2,434.0	1,541.8	1,068.7	796.0	626.9

Totals may not add because of rounding.

(1) Oil and gas profits levy rates and estimates are provided by Delek Drilling.
(2) Corporate income tax rates and estimates of corporate income taxes are provided by Delek Drilling and are its expected corporate income taxes per year.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

NETHERLAND, SEWELL & ASSOCIATES, INC.

REVENUE, COSTS, AND TAXES
PROBABLE RESERVES
DELEK DRILLING LIMITED PARTNERSHIP INTEREST
TAMAR AND TAMAR SOUTHWEST FIELDS, TAMAR LEASE I/12, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2020

Period Ending	Working Interest Revenue (MM$)	Royalties State (MM$)	Royalties Interested Party (MM$)	Royalties Third Party (MM$)	Royalties Total (MM$)	Net Capital Costs (MM$)	Net Abandonment Costs (MM$)	Net Operating Expenses[1] (MM$)	Future Net Revenue Before Levy and Corporate Income Taxes Discounted at 0% (MM$)
12-31-2021	-	-	-	-	-	-	-	-	-
12-31-2022	-	-	-	-	-	-	-	-	-
12-31-2023	-	-	-	-	-	-41.9	-	-	41.9
12-31-2024	-	-	-	-	-	-68.6	-	-	68.6
12-31-2025	-	-	-	-	-	68.6	-	-	-68.6
12-31-2026	-	-	-	-	-	41.9	-	-	-41.9
12-31-2027	-	-	-	-	-	-	-	-	-
12-31-2028	-	-	-	-	-	-35.0	-	-	35.0
12-31-2029	-	-	-	-	-	-7.8	-	-	7.8
12-31-2030	-	-	-	-	-	-	-	-	-
12-31-2031	-	-	-	-	-	-	-	-	-
12-31-2032	-	-	-	-	-	-	-	-	-
12-31-2033	-	-	-	-	-	-22.4	-	-	22.4
12-31-2034	-	-	-	-	-	-42.9	-	-	42.9
12-31-2035	-	-	-	-	-	7.8	-	-	-7.8
12-31-2036	35.1	4.0	1.6	1.6	7.3	35.0	-	0.1	-7.3
12-31-2037	146.1	16.8	6.6	6.8	30.2	22.4	-	0.6	93.1
12-31-2038	215.6	24.8	9.7	10.0	44.5	42.9	-	0.8	127.4
12-31-2039	259.9	29.9	11.7	12.1	53.6	-	-	1.0	205.3
12-31-2040	291.2	33.5	13.1	13.5	60.1	42.9	-	1.1	187.1
12-31-2041	313.8	36.1	14.1	14.6	64.7	-	-	1.2	247.9
12-31-2042	313.3	36.0	14.1	14.6	64.6	-	-	1.2	247.5
12-31-2043	270.2	31.1	12.1	12.6	55.7	-	-	1.0	213.4
12-31-2044	231.0	26.6	10.4	10.7	47.7	-	-	0.9	182.5
12-31-2045	197.9	22.8	8.9	9.2	40.8	-	-	0.8	156.3
12-31-2046	169.6	19.5	7.6	7.9	35.0	-	-	0.7	133.9
12-31-2047	144.5	16.6	6.5	6.7	29.8	-	-	0.6	114.1
12-31-2048	124.1	14.3	5.6	5.8	25.6	-	-	0.5	98.0
12-31-2049	105.8	12.2	4.7	4.9	21.8	-	-17.9	0.4	101.5
12-31-2050	90.2	10.4	4.0	4.2	18.6	-	-17.9	0.3	89.2
12-31-2051	81.4	9.4	3.7	3.8	16.8	-	1.1	0.3	63.2
12-31-2052	102.9	11.8	4.6	4.8	21.2	-	19.0	28.3	34.4
12-31-2053	14.9	1.7	0.7	0.7	3.1	-	19.0	28.0	-35.2
12-31-2054	-	-	-	-	-	-	-	-	-
12-31-2055	-	-	-	-	-	-	-	-	-
12-31-2056	-	-	-	-	-	-	-	-	-
Total	3,107.6	357.4	139.4	144.4	641.1	42.9	3.2	67.8	2,352.7

Totals may not add because of rounding.

(1) Operating costs are limited to direct project-level costs, insurance costs, workover costs, indirect headquarters general and administrative overhead expenses, and Delek Drilling's estimate of the portion of the operator's headquarters general and administrative overhead expenses that can be directly attributed to this project.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

NETHERLAND, SEWELL & ASSOCIATES, INC.

REVENUE, COSTS, AND TAXES
PROBABLE RESERVES
DELEK DRILLING LIMITED PARTNERSHIP INTEREST
TAMAR AND TAMAR SOUTHWEST FIELDS, TAMAR LEASE I/12, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2020

Period Ending	Levy Rate[(1)] (%)	Levy[(1)] (MM$)	Future Net Revenue After Levy and Before Corporate Income Taxes Discounted at 0% (MM$)	Corporate Income Tax Rate[(2)] (%)	Corporate Income Taxes[(2)] (MM$)	Future Net Revenue After Levy and Corporate Income Taxes: Discounted at 0% (MM$)	Discounted at 5% (MM$)	Discounted at 10% (MM$)	Discounted at 15% (MM$)	Discounted at 20% (MM$)
12-31-2021	24.0	-	-	23.0	-	-	-	-	-	-
12-31-2022	30.5	-	-	23.0	-	-	-	-	-	-
12-31-2023	36.5	16.6	25.3	23.0	-3.8	29.1	25.7	22.9	20.5	18.4
12-31-2024	42.0	32.7	35.9	23.0	-5.6	41.5	35.0	29.7	25.4	21.9
12-31-2025	46.2	-28.6	-40.0	23.0	10.1	-50.1	-40.2	-32.6	-26.7	-22.1
12-31-2026	46.8	-19.6	-22.3	23.0	6.4	-28.7	-21.9	-17.0	-13.3	-10.5
12-31-2027	46.8	-	-	23.0	-	-	-	-	-	-
12-31-2028	46.8	16.4	18.6	23.0	-3.8	22.4	15.5	11.0	7.9	5.7
12-31-2029	46.8	3.7	4.2	23.0	-0.0	4.2	2.8	1.9	1.3	0.9
12-31-2030	46.8	-	-	23.0	1.0	-1.0	-0.6	-0.4	-0.3	-0.2
12-31-2031	46.8	-	-	23.0	1.0	-1.0	-0.6	-0.4	-0.2	-0.1
12-31-2032	46.8	-	-	23.0	1.0	-1.0	-0.6	-0.3	-0.2	-0.1
12-31-2033	46.8	10.5	11.9	23.0	-1.4	13.3	7.2	4.0	2.3	1.4
12-31-2034	46.8	20.1	22.8	23.0	-5.0	27.8	14.4	7.7	4.2	2.4
12-31-2035	46.8	-3.7	-4.2	23.0	-0.1	-4.0	-2.0	-1.0	-0.5	-0.3
12-31-2036	46.8	-3.4	-3.9	23.0	7.6	-11.4	-5.4	-2.6	-1.3	-0.7
12-31-2037	46.8	43.5	49.5	23.0	18.0	31.5	14.1	6.5	3.1	1.6
12-31-2038	46.8	59.6	67.8	23.0	26.4	41.3	17.6	7.8	3.6	1.7
12-31-2039	46.8	96.1	109.2	23.0	24.3	84.9	34.4	14.6	6.4	2.9
12-31-2040	46.8	87.6	99.5	23.0	31.7	67.8	26.2	10.6	4.4	1.9
12-31-2041	46.8	116.0	131.9	23.0	28.3	103.5	38.1	14.7	5.9	2.5
12-31-2042	46.8	115.8	131.7	23.0	28.3	103.4	36.2	13.3	5.1	2.1
12-31-2043	46.8	99.9	113.5	23.0	24.1	89.4	29.8	10.5	3.9	1.5
12-31-2044	46.8	85.4	97.1	23.0	19.8	77.3	24.6	8.2	2.9	1.1
12-31-2045	46.8	73.2	83.2	23.0	15.6	67.5	20.4	6.5	2.2	0.8
12-31-2046	46.8	62.7	71.3	23.0	13.1	58.2	16.8	5.1	1.6	0.6
12-31-2047	46.8	53.4	60.7	23.0	11.8	48.9	13.4	3.9	1.2	0.4
12-31-2048	46.8	45.9	52.2	23.0	10.3	41.8	10.9	3.0	0.9	0.3
12-31-2049	46.8	46.0	55.5	23.0	7.5	48.0	11.9	3.2	0.9	0.3
12-31-2050	46.8	37.9	51.3	23.0	6.5	44.8	10.6	2.7	0.7	0.2
12-31-2051	46.8	22.1	41.1	23.0	9.6	31.6	7.1	1.7	0.4	0.1
12-31-2052	46.8	16.1	18.3	23.0	8.1	10.1	2.2	0.5	0.1	0.0
12-31-2053	-	-	-35.2	23.0	-	-35.2	-7.2	-1.6	-0.4	-0.1
12-31-2054	-	-	-	23.0	-	-	-	-	-	-
12-31-2055	-	-	-	23.0	-	-	-	-	-	-
12-31-2056	-	-	-	23.0	-	-	-	-	-	-
Total		1,105.9	1,246.8		290.9	955.9	336.5	134.1	62.1	34.4

Totals may not add because of rounding.

(1) Oil and gas profits levy rates and estimates are provided by Delek Drilling.
(2) Corporate income tax rates and estimates of corporate income taxes are provided by Delek Drilling and are its expected corporate income taxes per year.

NETHERLAND, SEWELL & ASSOCIATES, INC.

REVENUE, COSTS, AND TAXES
PROVED + PROBABLE (2P) RESERVES
DELEK DRILLING LIMITED PARTNERSHIP INTEREST
TAMAR AND TAMAR SOUTHWEST FIELDS, TAMAR LEASE I/12, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2020

		Royalties							
Period Ending	Working Interest Revenue (MM$)	State (MM$)	Interested Party (MM$)	Third Party (MM$)	Total (MM$)	Net Capital Costs (MM$)	Net Abandonment Costs (MM$)	Net Operating Expenses[1] (MM$)	Future Net Revenue Before Levy and Corporate Income Taxes Discounted at 0% (MM$)
12-31-2021	299.7	34.5	13.4	13.9	61.8	14.6	-	32.1	191.2
12-31-2022	337.8	38.8	15.1	15.7	69.7	6.2	-	29.1	232.9
12-31-2023	344.6	39.6	15.5	16.0	71.1	5.6	-	28.9	239.0
12-31-2024	357.4	41.1	16.0	16.6	73.7	-	-	28.9	254.8
12-31-2025	392.1	45.1	17.6	18.2	80.9	68.6	-	29.0	213.6
12-31-2026	412.6	47.4	18.5	19.2	85.1	41.9	-	29.1	256.5
12-31-2027	429.6	49.4	19.3	20.0	88.6	-	-	29.1	311.8
12-31-2028	440.9	50.7	19.8	20.5	91.0	-	-	29.6	320.3
12-31-2029	464.6	53.4	20.8	21.6	95.8	-	-	29.7	339.0
12-31-2030	476.5	54.8	21.4	22.1	98.3	-	-	29.7	348.5
12-31-2031	476.8	54.8	21.4	22.2	98.4	-	-	29.7	348.7
12-31-2032	474.9	54.6	21.3	22.1	98.0	-	-	29.7	347.2
12-31-2033	474.9	54.6	21.3	22.1	98.0	-	-	29.7	347.2
12-31-2034	475.1	54.6	21.3	22.1	98.0	-	-	29.7	347.3
12-31-2035	465.2	53.5	20.9	21.6	96.0	7.8	-	29.7	331.6
12-31-2036	465.3	53.5	20.9	21.6	96.0	35.0	-	29.7	304.6
12-31-2037	464.0	53.4	20.8	21.6	95.7	22.4	-	29.7	316.2
12-31-2038	464.2	53.4	20.8	21.6	95.8	42.9	-	29.7	295.9
12-31-2039	464.4	53.4	20.8	21.6	95.8	-	-	29.7	338.9
12-31-2040	464.7	53.4	20.8	21.6	95.9	42.9	-	29.7	296.3
12-31-2041	464.5	53.4	20.8	21.6	95.8	-	-	29.7	339.0
12-31-2042	446.1	51.3	20.0	20.7	92.0	-	-	29.6	324.4
12-31-2043	386.9	44.5	17.4	18.0	79.8	-	-	29.4	277.7
12-31-2044	333.8	38.4	15.0	15.5	68.9	-	-	29.2	235.8
12-31-2045	288.3	33.2	12.9	13.4	59.5	-	-	29.0	199.8
12-31-2046	248.8	28.6	11.2	11.6	51.3	-	-	28.9	168.6
12-31-2047	214.5	24.7	9.6	10.0	44.3	-	-	28.7	141.5
12-31-2048	185.4	21.3	8.3	8.6	38.2	-	-	28.6	118.5
12-31-2049	159.9	18.4	7.2	7.4	33.0	-	-	28.5	98.4
12-31-2050	138.0	15.9	6.2	6.4	28.5	-	-	28.4	81.0
12-31-2051	119.2	13.7	5.3	5.5	24.6	-	19.0	28.4	47.2
12-31-2052	102.9	11.8	4.6	4.8	21.2	-	19.0	28.3	34.4
12-31-2053	14.9	1.7	0.7	0.7	3.1	-	19.0	28.0	-35.2
12-31-2054	-	-	-	-	-	-	-	-	-
12-31-2055	-	-	-	-	-	-	-	-	-
12-31-2056	-	-	-	-	-	-	-	-	-
Total	11,748.5	1,351.1	526.9	545.8	2,423.8	287.8	57.0	967.2	8,012.7

Totals may not add because of rounding.

[1] Operating costs are limited to direct project-level costs, insurance costs, workover costs, indirect headquarters general and administrative overhead expenses, and Delek Drilling's estimate of the portion of the operator's headquarters general and administrative overhead expenses that can be directly attributed to this project.

NETHERLAND, SEWELL & ASSOCIATES, INC.

REVENUE, COSTS, AND TAXES
PROVED + PROBABLE (2P) RESERVES
DELEK DRILLING LIMITED PARTNERSHIP INTEREST
TAMAR AND TAMAR SOUTHWEST FIELDS, TAMAR LEASE I/12, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2020

						Future Net Revenue After Levy and Corporate Income Taxes				
Period Ending	Levy Rate[(1)] (%)	Levy[(1)] (MM$)	Future Net Revenue After Levy and Before Corporate Income Taxes Discounted at 0% (MM$)	Corporate Income Tax Rate[(2)] (%)	Corporate Income Taxes[(2)] (MM$)	Discounted at 0% (MM$)	Discounted at 5% (MM$)	Discounted at 10% (MM$)	Discounted at 15% (MM$)	Discounted at 20% (MM$)
12-31-2021	24.0	45.8	145.4	23.0	29.6	115.8	113.0	110.4	108.0	105.7
12-31-2022	30.5	71.0	161.8	23.0	31.7	130.2	121.0	112.8	105.5	99.0
12-31-2023	36.5	87.2	151.8	23.0	31.5	120.3	106.5	94.8	84.8	76.2
12-31-2024	42.0	107.1	147.7	23.0	29.6	118.1	99.5	84.6	72.4	62.4
12-31-2025	46.2	98.7	114.9	23.0	37.9	77.1	61.9	50.2	41.1	33.9
12-31-2026	46.8	120.0	136.5	23.0	36.0	100.4	76.8	59.5	46.6	36.8
12-31-2027	46.8	145.9	165.9	23.0	32.6	133.3	97.0	71.7	53.7	40.7
12-31-2028	46.8	149.9	170.4	23.0	34.1	136.3	94.5	66.7	47.8	34.7
12-31-2029	46.8	158.7	180.4	23.0	36.8	143.6	94.8	63.9	43.8	30.5
12-31-2030	46.8	163.1	185.4	23.0	38.1	147.3	92.7	59.6	39.0	26.1
12-31-2031	46.8	163.2	185.5	23.0	38.3	147.2	88.2	54.1	33.9	21.7
12-31-2032	46.8	162.5	184.7	23.0	38.3	146.4	83.6	48.9	29.4	18.0
12-31-2033	46.8	162.5	184.7	23.0	38.4	146.3	79.5	44.5	25.5	15.0
12-31-2034	46.8	162.6	184.8	23.0	38.6	146.2	75.6	40.4	22.2	12.5
12-31-2035	46.8	155.2	176.4	23.0	38.9	137.5	67.8	34.5	18.1	9.8
12-31-2036	46.8	142.6	162.1	23.0	43.2	118.8	55.8	27.1	13.6	7.0
12-31-2037	46.8	148.0	168.2	23.0	42.8	125.4	56.1	26.0	12.5	6.2
12-31-2038	46.8	138.5	157.4	23.0	44.5	112.9	48.1	21.3	9.8	4.6
12-31-2039	46.8	158.6	180.3	23.0	39.0	141.4	57.3	24.2	10.7	4.8
12-31-2040	46.8	138.7	157.6	23.0	43.6	114.0	44.0	17.8	7.5	3.3
12-31-2041	46.8	158.7	180.4	23.0	38.0	142.4	52.4	20.2	8.1	3.4
12-31-2042	46.8	151.8	172.6	23.0	36.2	136.4	47.8	17.6	6.8	2.7
12-31-2043	46.8	130.0	147.7	23.0	30.5	117.3	39.1	13.7	5.1	1.9
12-31-2044	46.8	110.3	125.4	23.0	25.3	100.1	31.8	10.7	3.7	1.4
12-31-2045	46.8	93.5	106.3	23.0	20.9	85.4	25.8	8.3	2.8	1.0
12-31-2046	46.8	78.9	89.7	23.0	17.3	72.4	20.9	6.4	2.1	0.7
12-31-2047	46.8	66.2	75.3	23.0	14.8	60.5	16.6	4.8	1.5	0.5
12-31-2048	46.8	55.5	63.1	23.0	12.5	50.5	13.2	3.7	1.1	0.3
12-31-2049	46.8	46.0	52.3	23.0	10.6	41.7	10.4	2.8	0.8	0.2
12-31-2050	46.8	37.9	43.1	23.0	8.5	34.6	8.2	2.1	0.6	0.2
12-31-2051	46.8	22.1	25.1	23.0	9.7	15.4	3.5	0.8	0.2	0.1
12-31-2052	46.8	16.1	18.3	23.0	8.1	10.1	2.2	0.5	0.1	0.0
12-31-2053	-	-	-35.2	23.0	-	-35.2	-7.2	-1.6	-0.4	-0.1
12-31-2054	-	-	-	23.0	-	-	-	-	-	-
12-31-2055	-	-	-	23.0	-	-	-	-	-	-
12-31-2056	-	-	-	23.0	-	-	-	-	-	-
Total		3,646.7	4,366.0		976.0	3,389.9	1,878.3	1,202.8	858.1	661.3

Totals may not add because of rounding.

(1) Oil and gas profits levy rates and estimates are provided by Delek Drilling.
(2) Corporate income tax rates and estimates of corporate income taxes are provided by Delek Drilling and are its expected corporate income taxes per year.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

REVENUE, COSTS, AND TAXES
POSSIBLE RESERVES
DELEK DRILLING LIMITED PARTNERSHIP INTEREST
TAMAR AND TAMAR SOUTHWEST FIELDS, TAMAR LEASE I/12, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2020

Period Ending	Working Interest Revenue (MM$)	Royalties: State (MM$)	Royalties: Interested Party (MM$)	Royalties: Third Party (MM$)	Royalties: Total (MM$)	Net Capital Costs (MM$)	Net Abandonment Costs (MM$)	Net Operating Expenses[1] (MM$)	Future Net Revenue Before Levy and Corporate Income Taxes Discounted at 0% (MM$)
12-31-2021	-	-	-	-	-	-	-	-	-
12-31-2022	-	-	-	-	-	-	-	-	-
12-31-2023	-	-	-	-	-	-	-	-	-
12-31-2024	-	-	-	-	-	-	-	-	-
12-31-2025	-	-	-	-	-	-68.6	-	-	68.6
12-31-2026	-	-	-	-	-	26.7	-	-	-26.7
12-31-2027	-	-	-	-	-	41.9	-	-	-41.9
12-31-2028	-	-	-	-	-	-	-	-	-
12-31-2029	-	-	-	-	-	-	-	-	-
12-31-2030	-	-	-	-	-	-	-	-	-
12-31-2031	-	-	-	-	-	-	-	-	-
12-31-2032	-	-	-	-	-	-	-	-	-
12-31-2033	-	-	-	-	-	-	-	-	-
12-31-2034	-	-	-	-	-	-	-	-	-
12-31-2035	-	-	-	-	-	-7.8	-	-	7.8
12-31-2036	-	-	-	-	-	-35.0	-	-	35.0
12-31-2037	-	-	-	-	-	20.5	-	-	-20.5
12-31-2038	-	-	-	-	-	-20.5	-	-	20.5
12-31-2039	-	-	-	-	-	-	-	-	-
12-31-2040	-	-	-	-	-	-	-	-	-
12-31-2041	-	-	-	-	-	-	-	-	-
12-31-2042	18.3	2.1	0.8	0.9	3.8	42.9	-	0.1	-28.4
12-31-2043	77.3	8.9	3.5	3.6	15.9	-	-	0.3	61.0
12-31-2044	130.2	15.0	5.8	6.1	26.9	-	-	0.5	102.9
12-31-2045	175.6	20.2	7.9	8.2	36.2	-	-	0.7	138.7
12-31-2046	214.9	24.7	9.6	10.0	44.3	-	-	0.8	169.8
12-31-2047	249.1	28.6	11.2	11.6	51.4	-	-	1.0	196.7
12-31-2048	278.0	32.0	12.5	12.9	57.4	-	-	1.1	219.6
12-31-2049	255.9	29.4	11.5	11.9	52.8	-	-	1.0	202.1
12-31-2050	250.6	28.8	11.2	11.6	51.7	-	-	1.0	198.0
12-31-2051	227.3	26.1	10.2	10.6	46.9	-	-19.0	0.9	198.5
12-31-2052	190.7	21.9	8.6	8.9	39.3	-	-19.0	0.7	169.6
12-31-2053	249.5	28.7	11.2	11.6	51.5	-	-19.0	1.0	216.1
12-31-2054	213.6	24.6	9.6	9.9	44.1	-	19.0	28.7	121.8
12-31-2055	168.6	19.4	7.6	7.8	34.8	-	19.0	28.6	86.2
12-31-2056	79.3	9.1	3.6	3.7	16.4	-	19.0	28.2	15.7
Total	2,779.0	319.6	124.6	129.1	573.3	-	-	94.4	2,111.3

Totals may not add because of rounding.

[1] Operating costs are limited to direct project-level costs, insurance costs, workover costs, indirect headquarters general and administrative overhead expenses, and Delek Drilling's estimate of the portion of the operator's headquarters general and administrative overhead expenses that can be directly attributed to this project.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

NETHERLAND, SEWELL & ASSOCIATES, INC.

REVENUE, COSTS, AND TAXES
POSSIBLE RESERVES
DELEK DRILLING LIMITED PARTNERSHIP INTEREST
TAMAR AND TAMAR SOUTHWEST FIELDS, TAMAR LEASE I/12, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2020

Period Ending	Levy Rate[(1)] (%)	Levy[(1)] (MM$)	Future Net Revenue After Levy and Before Corporate Income Taxes Discounted at 0% (MM$)	Corporate Income Tax Rate[(2)] (%)	Corporate Income Taxes[(2)] (MM$)	Future Net Revenue After Levy and Corporate Income Taxes				
						Discounted at 0% (MM$)	Discounted at 5% (MM$)	Discounted at 10% (MM$)	Discounted at 15% (MM$)	Discounted at 20% (MM$)
12-31-2021	24.0	-	-	23.0	-0.0	0.0	0.0	0.0	0.0	0.0
12-31-2022	30.5	-	-	23.0	-0.0	0.0	0.0	0.0	0.0	0.0
12-31-2023	36.5	-	-	23.0	-0.0	0.0	0.0	0.0	0.0	0.0
12-31-2024	42.0	-	-	23.0	-	-	-	-	-	-
12-31-2025	46.4	32.4	36.2	23.0	-7.4	43.7	35.1	28.4	23.3	19.2
12-31-2026	46.8	-12.5	-14.2	23.0	4.5	-18.7	-14.3	-11.1	-8.7	-6.9
12-31-2027	46.8	-19.6	-22.3	23.0	4.5	-26.8	-19.5	-14.4	-10.8	-8.2
12-31-2028	46.8	-	-	23.0	-	-	-	-	-	-
12-31-2029	46.8	-	-	23.0	-	-	-	-	-	-
12-31-2030	46.8	-	-	23.0	-	-	-	-	-	-
12-31-2031	46.8	-	-	23.0	0.0	-0.0	-0.0	-0.0	-0.0	-0.0
12-31-2032	46.8	-	-	23.0	0.0	-0.0	-0.0	-0.0	-0.0	-0.0
12-31-2033	46.8	-	-	23.0	0.0	-0.0	-0.0	-0.0	-0.0	-0.0
12-31-2034	46.8	-	-	23.0	-	-	-	-	-	-
12-31-2035	46.8	3.7	4.2	23.0	-0.8	5.0	2.5	1.3	0.7	0.4
12-31-2036	46.8	16.4	18.6	23.0	-5.2	23.8	11.2	5.4	2.7	1.4
12-31-2037	46.8	-9.6	-10.9	23.0	3.2	-14.1	-6.3	-2.9	-1.4	-0.7
12-31-2038	46.8	9.6	10.9	23.0	-1.7	12.6	5.4	2.4	1.1	0.5
12-31-2039	46.8	-	-	23.0	1.0	-1.0	-0.4	-0.2	-0.1	-0.0
12-31-2040	46.8	-	-	23.0	1.0	-1.0	-0.4	-0.2	-0.1	-0.0
12-31-2041	46.8	-	-	23.0	1.0	-1.0	-0.4	-0.1	-0.1	-0.0
12-31-2042	46.8	-13.3	-15.1	23.0	7.4	-22.5	-7.9	-2.9	-1.1	-0.4
12-31-2043	46.8	28.6	32.5	23.0	7.5	25.0	8.3	2.9	1.1	0.4
12-31-2044	46.8	48.1	54.7	23.0	12.6	42.1	13.4	4.5	1.6	0.6
12-31-2045	46.8	64.9	73.8	23.0	17.0	56.8	17.2	5.5	1.9	0.7
12-31-2046	46.8	79.5	90.3	23.0	20.6	69.7	20.1	6.1	2.0	0.7
12-31-2047	46.8	92.1	104.7	23.0	23.1	81.6	22.4	6.5	2.0	0.7
12-31-2048	46.8	102.8	116.8	23.0	26.4	90.5	23.7	6.6	1.9	0.6
12-31-2049	46.8	94.6	107.5	23.0	24.2	83.3	20.7	5.5	1.6	0.5
12-31-2050	46.8	92.6	105.3	23.0	23.7	81.6	19.4	4.9	1.3	0.4
12-31-2051	46.8	92.9	105.6	23.0	19.4	86.2	19.5	4.7	1.2	0.3
12-31-2052	46.8	79.4	90.2	23.0	15.4	74.8	16.1	3.7	0.9	0.2
12-31-2053	46.8	84.7	131.4	23.0	21.7	109.7	22.5	5.0	1.2	0.3
12-31-2054	46.8	57.0	64.8	23.0	18.8	46.0	9.0	1.9	0.4	0.1
12-31-2055	46.8	40.4	45.9	23.0	14.5	31.4	5.8	1.2	0.3	0.1
12-31-2056	46.8	7.4	8.4	23.0	5.9	2.5	0.4	0.1	0.0	0.0
Total		971.9	1,139.4		257.9	881.5	223.4	64.9	22.9	10.7

Totals may not add because of rounding.

(1) Oil and gas profits levy rates and estimates are provided by Delek Drilling.
(2) Corporate income tax rates and estimates of corporate income taxes are provided by Delek Drilling and are its expected corporate income taxes per year.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

NETHERLAND, SEWELL & ASSOCIATES, INC.

REVENUE, COSTS, AND TAXES
PROVED + PROBABLE + POSSIBLE (3P) RESERVES
DELEK DRILLING LIMITED PARTNERSHIP INTEREST
TAMAR AND TAMAR SOUTHWEST FIELDS, TAMAR LEASE I/12, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2020

		Royalties							
Period Ending	Working Interest Revenue (MM$)	State (MM$)	Interested Party (MM$)	Third Party (MM$)	Total (MM$)	Net Capital Costs (MM$)	Net Abandonment Costs (MM$)	Net Operating Expenses[1] (MM$)	Future Net Revenue Before Levy and Corporate Income Taxes Discounted at 0% (MM$)
12-31-2021	299.7	34.5	13.4	13.9	61.8	14.6	-	32.1	191.2
12-31-2022	337.8	38.8	15.1	15.7	69.7	6.2	-	29.1	232.9
12-31-2023	344.6	39.6	15.5	16.0	71.1	5.6	-	28.9	239.0
12-31-2024	357.4	41.1	16.0	16.6	73.7	-	-	28.9	254.8
12-31-2025	392.1	45.1	17.6	18.2	80.9	-	-	29.0	282.2
12-31-2026	412.6	47.4	18.5	19.2	85.1	68.6	-	29.1	229.8
12-31-2027	429.6	49.4	19.3	20.0	88.6	41.9	-	29.1	269.9
12-31-2028	440.9	50.7	19.8	20.5	91.0	-	-	29.6	320.3
12-31-2029	464.6	53.4	20.8	21.6	95.8	-	-	29.7	339.0
12-31-2030	476.5	54.8	21.4	22.1	98.3	-	-	29.7	348.5
12-31-2031	476.8	54.8	21.4	22.2	98.4	-	-	29.7	348.7
12-31-2032	474.9	54.6	21.3	22.1	98.0	-	-	29.7	347.2
12-31-2033	474.9	54.6	21.3	22.1	98.0	-	-	29.7	347.2
12-31-2034	475.1	54.6	21.3	22.1	98.0	-	-	29.7	347.3
12-31-2035	465.2	53.5	20.9	21.6	96.0	-	-	29.7	339.5
12-31-2036	465.3	53.5	20.9	21.6	96.0	-	-	29.7	339.6
12-31-2037	464.0	53.4	20.8	21.6	95.7	42.9	-	29.7	295.7
12-31-2038	464.2	53.4	20.8	21.6	95.8	22.4	-	29.7	316.4
12-31-2039	464.4	53.4	20.8	21.6	95.8	-	-	29.7	338.9
12-31-2040	464.7	53.4	20.8	21.6	95.9	42.9	-	29.7	296.3
12-31-2041	464.5	53.4	20.8	21.6	95.8	-	-	29.7	339.0
12-31-2042	464.4	53.4	20.8	21.6	95.8	42.9	-	29.7	296.0
12-31-2043	464.2	53.4	20.8	21.6	95.8	-	-	29.7	338.7
12-31-2044	464.1	53.4	20.8	21.6	95.7	-	-	29.7	338.6
12-31-2045	463.9	53.3	20.8	21.6	95.7	-	-	29.7	338.5
12-31-2046	463.7	53.3	20.8	21.5	95.7	-	-	29.7	338.4
12-31-2047	463.6	53.3	20.8	21.5	95.6	-	-	29.7	338.3
12-31-2048	463.4	53.3	20.8	21.5	95.6	-	-	29.7	338.1
12-31-2049	415.8	47.8	18.6	19.3	85.8	-	-	29.5	300.5
12-31-2050	388.6	44.7	17.4	18.1	80.2	-	-	29.4	279.0
12-31-2051	346.5	39.8	15.5	16.1	71.5	-	-	29.2	245.8
12-31-2052	293.6	33.8	13.2	13.6	60.6	-	-	29.0	204.0
12-31-2053	264.4	30.4	11.9	12.3	54.6	-	-	28.9	180.9
12-31-2054	213.6	24.6	9.6	9.9	44.1	-	19.0	28.7	121.8
12-31-2055	168.6	19.4	7.6	7.8	34.8	-	19.0	28.6	86.2
12-31-2056	79.3	9.1	3.6	3.7	16.4	-	19.0	28.2	15.7
Total	14,527.5	1,670.7	651.6	674.9	2,997.1	287.8	57.0	1,061.6	10,124.0

Totals may not add because of rounding.

[1] Operating costs are limited to direct project-level costs, insurance costs, workover costs, indirect headquarters general and administrative overhead expenses, and Delek Drilling's estimate of the portion of the operator's headquarters general and administrative overhead expenses that can be directly attributed to this project.

REVENUE, COSTS, AND TAXES
PROVED + PROBABLE + POSSIBLE (3P) RESERVES
DELEK DRILLING LIMITED PARTNERSHIP INTEREST
TAMAR AND TAMAR SOUTHWEST FIELDS, TAMAR LEASE I/12, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2020

Period Ending	Levy Rate[1] (%)	Levy[1] (MM$)	Future Net Revenue After Levy and Before Corporate Income Taxes Discounted at 0% (MM$)	Corporate Income Tax Rate[2] (%)	Corporate Income Taxes[2] (MM$)	Future Net Revenue After Levy and Corporate Income Taxes: Discounted at 0% (MM$)	Discounted at 5% (MM$)	Discounted at 10% (MM$)	Discounted at 15% (MM$)	Discounted at 20% (MM$)
12-31-2021	24.0	45.8	145.4	23.0	29.6	115.8	113.0	110.4	108.0	105.7
12-31-2022	30.5	71.0	161.8	23.0	31.7	130.2	121.0	112.8	105.5	99.0
12-31-2023	36.5	87.2	151.8	23.0	31.5	120.3	106.5	94.8	84.8	76.3
12-31-2024	42.0	107.1	147.7	23.0	29.6	118.1	99.5	84.6	72.4	62.4
12-31-2025	46.4	131.0	151.2	23.0	30.4	120.7	96.9	78.6	64.4	53.1
12-31-2026	46.8	107.5	122.2	23.0	40.5	81.8	62.5	48.4	37.9	30.0
12-31-2027	46.8	126.3	143.6	23.0	37.1	106.5	77.5	57.3	42.9	32.5
12-31-2028	46.8	149.9	170.4	23.0	34.1	136.3	94.5	66.7	47.8	34.7
12-31-2029	46.8	158.7	180.4	23.0	36.8	143.6	94.8	63.9	43.8	30.5
12-31-2030	46.8	163.1	185.4	23.0	38.1	147.3	92.7	59.6	39.0	26.1
12-31-2031	46.8	163.2	185.5	23.0	38.4	147.1	88.2	54.1	33.9	21.7
12-31-2032	46.8	162.5	184.7	23.0	38.3	146.4	83.6	48.9	29.4	18.0
12-31-2033	46.8	162.5	184.7	23.0	38.4	146.3	79.5	44.5	25.5	15.0
12-31-2034	46.8	162.6	184.8	23.0	38.6	146.2	75.6	40.4	22.2	12.5
12-31-2035	46.8	158.9	180.6	23.0	38.0	142.6	70.3	35.8	18.8	10.1
12-31-2036	46.8	158.9	180.7	23.0	38.1	142.6	67.0	32.6	16.3	8.5
12-31-2037	46.8	138.4	157.3	23.0	46.0	111.3	49.7	23.1	11.1	5.5
12-31-2038	46.8	148.1	168.3	23.0	42.8	125.5	53.4	23.7	10.9	5.2
12-31-2039	46.8	158.6	180.3	23.0	39.9	140.4	56.9	24.1	10.6	4.8
12-31-2040	46.8	138.7	157.6	23.0	44.6	113.0	43.7	17.6	7.4	3.2
12-31-2041	46.8	158.7	180.4	23.0	39.0	141.4	52.0	20.0	8.1	3.4
12-31-2042	46.8	138.5	157.5	23.0	43.6	113.9	39.9	14.7	5.6	2.3
12-31-2043	46.8	158.5	180.2	23.0	37.9	142.3	47.5	16.7	6.1	2.4
12-31-2044	46.8	158.5	180.1	23.0	37.9	142.2	45.2	15.1	5.3	2.0
12-31-2045	46.8	158.4	180.1	23.0	37.9	142.2	43.0	13.8	4.6	1.6
12-31-2046	46.8	158.4	180.0	23.0	37.9	142.1	41.0	12.5	4.0	1.4
12-31-2047	46.8	158.3	180.0	23.0	37.9	142.1	39.0	11.4	3.5	1.1
12-31-2048	46.8	158.2	179.9	23.0	38.9	141.0	36.9	10.3	3.0	0.9
12-31-2049	46.8	140.6	159.9	23.0	34.8	125.1	31.1	8.3	2.3	0.7
12-31-2050	46.8	130.6	148.4	23.0	32.2	116.3	27.6	7.0	1.9	0.5
12-31-2051	46.8	115.0	130.8	23.0	29.1	101.7	23.0	5.6	1.4	0.4
12-31-2052	46.8	95.4	108.5	23.0	23.5	85.0	18.3	4.2	1.0	0.3
12-31-2053	46.8	84.7	96.3	23.0	21.7	74.6	15.3	3.4	0.8	0.2
12-31-2054	46.8	57.0	64.8	23.0	18.8	46.0	9.0	1.9	0.4	0.1
12-31-2055	46.8	40.4	45.9	23.0	14.5	31.4	5.8	1.2	0.3	0.1
12-31-2056	46.8	7.4	8.4	23.0	5.9	2.5	0.4	0.1	0.0	0.0
Total		4,618.6	5,505.3		1,233.9	4,271.4	2,101.7	1,267.6	881.0	672.0

Totals may not add because of rounding.

(1) Oil and gas profits levy rates and estimates are provided by Delek Drilling.
(2) Corporate income tax rates and estimates of corporate income taxes are provided by Delek Drilling and are its expected corporate income taxes per year.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

HISTORICAL PRODUCTION AND OPERATING EXPENSE DATA
DELEK DRILLING LIMITED PARTNERSHIP INTEREST
TAMAR AND TAMAR SOUTHWEST FIELDS, TAMAR LEASE I/12, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2020

Year	Delek Drilling Working Interest Production (BCF)	Average Per Production Unit ($/MCF)				Reserves Depletion Rate[1] (%)
		Price Received	Royalties Paid	Production Costs	Net Revenue	
2020	64.6	5.14	1.05	0.38	3.71	2.7
2019	81.7	5.50	1.13	0.46	3.91	3.3
2018[2]	93.4	5.53	1.08	0.39	4.07	3.3

Note: Values in this table have been provided by Delek Drilling; these values are based on historical data since January 2018 and include condensate production, revenue, and costs.

[1] The reserves depletion rate is the percentage of yearly gas produced to the estimated proved plus probable reserves at the beginning of that year.
[2] The 2018 data include the Delek Drilling indirect interest in Tamar Field through Tamar Petroleum Ltd.

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.

VOLUMETRIC INPUT SUMMARY
TAMAR FIELD, TAMAR LEASE I/12, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2020

	Gross Rock Volume (acre-feet)			Area (acres)			Average Gross Thickness[1] (feet)			Net-to-Gross Ratio (decimal)		
Reservoir	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate
A Sand	2,460,861	2,594,825	2,845,871	21,711	21,711	22,935	113	120	124	0.88	0.93	0.93
B Sand	1,590,333	1,693,767	1,782,698	15,027	15,027	15,158	106	113	118	0.72	0.85	0.85
C Sand	1,839,279	1,964,971	2,063,220	9,095	9,095	9,095	202	216	227	0.87	0.90	0.90

	Porosity[2] (decimal)			Gas Saturation (decimal)			Gas Formation Volume Factor (SCF/RCF)[3]			Gas Recovery Factor (decimal)		
Reservoir	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate
A Sand	0.26	0.26	0.25	0.75	0.78	0.83	372	372	372	0.62	0.67	0.72
B Sand	0.25	0.24	0.24	0.76	0.79	0.82	372	372	372	0.62	0.67	0.72
C Sand	0.25	0.24	0.24	0.78	0.81	0.83	372	372	372	0.62	0.67	0.72

Note: For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, seismic data, core data, well test data, production data, historical price and cost information, and property ownership interests.

(1) Average gross thickness is calculated by dividing the gross rock volume by the area.
(2) The increasing net-to-gross ratio between cases includes lower porosity rock which results in a lower porosity in the best and high estimate cases relative to the low estimate case.
(3) The abbreviation SCF/RCF represents standard cubic feet per reservoir cubic foot.

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.

VOLUMETRIC INPUT SUMMARY
TAMAR SOUTHWEST FIELD, TAMAR LEASE I/12, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2020

	Gross Rock Volume (acre-feet)			Area (acres)			Average Gross Thickness[1] (feet)			Net-to-Gross Ratio (decimal)		
Reservoir	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate
A Sand	300,301	318,108	318,108	2,517	2,517	2,517	119	126	126	0.99	1.00	1.00
B Sand	128,228	137,183	137,183	1,065	1,065	1,065	120	129	129	0.82	0.87	0.88

	Porosity (decimal)			Gas Saturation (decimal)			Gas Formation Volume Factor (SCF/RCF)[2]			Gas Recovery Factor (decimal)		
Reservoir	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate
A Sand	0.24	0.24	0.24	0.84	0.87	0.89	372	372	372	0.62	0.67	0.72
B Sand	0.22	0.22	0.22	0.78	0.81	0.85	372	372	372	0.62	0.67	0.72

Note: For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, seismic data, core data, well test data, production data, historical price and cost information, and property ownership interests.

(1) Average gross thickness is calculated by dividing the gross rock volume by the area.
(2) The abbreviation SCF/RCF represents standard cubic feet per reservoir cubic foot.

ESTIMATES

of

UNRISKED CONTINGENT AND PROSPECTIVE RESOURCES

to the

DELEK DRILLING LIMITED PARTNERSHIP WORKING INTEREST

in

DISCOVERIES AND PROSPECTS

located in the

APHRODITE FIELD AREA BLOCK 12, OFFSHORE CYPRUS

as of

DECEMBER 31, 2020

NETHERLAND, SEWELL & ASSOCIATES, INC.

WORLDWIDE PETROLEUM CONSULTANTS

ENGINEERING • GEOLOGY
GEOPHYSICS • PETROPHYSICS

March 14, 2021

Delek Drilling Limited Partnership
19 Abba Eban Boulevard
Herzliya 4612001
Israel

Ladies and Gentlemen:

In accordance with your request, we have estimated the unrisked contingent and prospective resources, as of December 31, 2020, to the Delek Drilling Limited Partnership (Delek Drilling) working interest in discoveries and prospects located in the Aphrodite Field Area, Block 12, offshore Cyprus. Resources that extend beyond Block 12 have not been included in this report. It is our understanding that Delek Drilling owns a direct interest in these properties. We completed our evaluation on or about the date of this letter.

The estimates in this report have been prepared in accordance with the definitions and guidelines set forth in the 2018 Petroleum Resources Management System (PRMS) approved by the Society of Petroleum Engineers (SPE) and in accordance with internationally recognized standards, as stipulated by the Israel Securities Authority (ISA). As presented in the 2018 PRMS, petroleum accumulations can be classified, in decreasing order of likelihood of commerciality, as reserves, contingent resources, or prospective resources. Different classifications of petroleum accumulations have varying degrees of technical and commercial risk that are difficult to quantify; thus reserves, contingent resources, and prospective resources should not be aggregated without extensive consideration of these factors. Definitions are presented immediately following this letter. This report has been prepared for Delek Drilling's use in filing with the ISA; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

CONTINGENT RESOURCES

Contingent resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by the application of development project(s) not currently considered to be commercial owing to one or more contingencies. The contingent resources shown in this report are contingent upon finalization and sanctioning of the development plan, execution of gas purchase and sales agreements, and commitment to develop the resources. If these contingencies are successfully addressed, some portion of the contingent resources estimated in this report may be reclassified as reserves; our estimates have not been risked to account for the possibility that the contingencies are not successfully addressed. This report does not include economic analysis for the discoveries. Based on analogous field developments, it appears that the best estimate contingent resources in this report have a reasonable chance of being economically viable. There is no certainty that it will be commercially viable to produce any portion of the contingent resources. The project maturity subclass for these contingent resources is development pending.

We estimate the unrisked gross (100 percent) contingent resources for the Aphrodite Field Area by reservoir, as of December 31, 2020, to be:

	Unrisked Gross (100%) Contingent Resources					
	Low Estimate (1C)		Best Estimate (2C)		High Estimate (3C)	
Reservoir	Gas (BCF)	Condensate (MMBBL)	Gas (BCF)	Condensate (MMBBL)	Gas (BCF)	Condensate (MMBBL)
A Sand	18.7	0.0	87.3	0.2	117.2	0.3
C Sand	1,539.4	3.1	2,269.1	5.0	2,946.7	7.1
D1 Upper Sand	55.9	0.1	267.6	0.6	365.0	0.9
D1 Middle Sand	12.1	0.0	190.7	0.4	306.1	0.7
D1 Lower Sand	64.9	0.1	196.5	0.4	250.7	0.6
D2 Upper Sand	236.6	0.5	330.0	0.7	367.2	0.9
D2 Middle Sand	61.3	0.1	104.9	0.2	132.1	0.3
D2 Lower Sand	17.9	0.0	30.6	0.1	61.4	0.1

We estimate the unrisked contingent resources to the Delek Drilling working interest in the Aphrodite Field Area by reservoir, as of December 31, 2020, to be:

	Unrisked Working Interest Contingent Resources					
	Low Estimate (1C)		Best Estimate (2C)		High Estimate (3C)	
Reservoir	Gas (BCF)	Condensate (MMBBL)	Gas (BCF)	Condensate (MMBBL)	Gas (BCF)	Condensate (MMBBL)
A Sand	5.6	0.0	26.2	0.1	35.2	0.1
C Sand	461.8	0.9	680.7	1.5	884.0	2.1
D1 Upper Sand	16.8	0.0	80.3	0.2	109.5	0.3
D1 Middle Sand	3.6	0.0	57.2	0.1	91.8	0.2
D1 Lower Sand	19.5	0.0	58.9	0.1	75.2	0.2
D2 Upper Sand	71.0	0.1	99.0	0.2	110.1	0.3
D2 Middle Sand	18.4	0.0	31.5	0.1	39.6	0.1
D2 Lower Sand	5.4	0.0	9.2	0.0	18.4	0.0

Gas volumes are expressed in billions of cubic feet (BCF) at standard temperature and pressure bases. Condensate volumes are expressed in millions of barrels (MMBBL); a barrel is equivalent to 42 United States gallons.

The contingent resources shown in this report have been estimated using deterministic methods. Once all contingencies have been successfully addressed, the approximate probability that the quantities of contingent resources actually recovered will equal or exceed the estimated amounts is generally inferred to be 90 percent for the low estimate, 50 percent for the best estimate, and 10 percent for the high estimate. The estimates of contingent resources included herein have not been adjusted for development risk.

PROSPECTIVE RESOURCES

Prospective resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. The prospective resources included in this report should not be construed as reserves or contingent resources; they represent exploration opportunities and quantify the development potential in the event a petroleum discovery is made. A geologic risk assessment was performed for these prospects, as discussed in subsequent paragraphs. This report does not include economic analysis for these prospects. Based on analogous field developments, it appears that, assuming a discovery is made, a portion of the unrisked best estimate prospective resources in this report have a reasonable chance of being economically viable. There is no certainty that any portion of the prospective resources will be discovered. If they are discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources.

Totals of unrisked prospective resources beyond the prospect level are not reflective of volumes that can be expected to be recovered and are therefore not shown. Because of the geologic risk associated with each prospect, meaningful totals beyond this level can be defined only by summing risked prospective resources. Such risk is often significant.

We estimate the unrisked gross (100 percent) prospective resources for the Aphrodite Field Area by fault block, as of December 31, 2020, to be:

	Unrisked Gross (100%) Prospective Resources					
	Low Estimate (1U)		Best Estimate (2U)		High Estimate (3U)	
Fault Block/Prospect	Gas (BCF)	Condensate (MMBBL)	Gas (BCF)	Condensate (MMBBL)	Gas (BCF)	Condensate (MMBBL)
Central						
D1 Upper Sand	98.1	0.2	163.3	0.4	269.8	0.6
D1 Middle Sand	46.0	0.1	104.6	0.2	246.9	0.6
D1 Lower Sand	125.4	0.3	190.7	0.4	281.4	0.7
D2 Upper Sand	164.5	0.3	348.8	0.8	796.1	1.9
D2 Middle Sand	2.5	0.0	22.6	0.0	246.8	0.6
D2 Lower Sand	0.1	0.0	3.4	0.0	185.2	0.4
Southwest						
A Sand	3.8	0.0	9.8	0.0	18.5	0.0
C Sand	33.0	0.1	52.3	0.1	81.0	0.2
D1 Upper Sand	0.3	0.0	2.8	0.0	26.2	0.1
D1 Middle Sand	0.0	0.0	0.8	0.0	17.0	0.0
D1 Lower Sand	1.7	0.0	4.0	0.0	10.1	0.0
D2 Upper Sand	0.7	0.0	7.4	0.0	86.9	0.2
D2 Middle Sand	0.0	0.0	1.0	0.0	24.3	0.1
D2 Lower Sand	0.1	0.0	1.1	0.0	21.3	0.1

We estimate the Delek Drilling unrisked working interest prospective resources for the Aphrodite Field Area by fault block, as of December 31, 2020, to be:

	Unrisked Working Interest Prospective Resources					
	Low Estimate (1U)		Best Estimate (2U)		High Estimate (3U)	
Fault Block/Prospect	Gas (BCF)	Condensate (MMBBL)	Gas (BCF)	Condensate (MMBBL)	Gas (BCF)	Condensate (MMBBL)
Central						
D1 Upper Sand	29.4	0.1	49.0	0.1	80.9	0.2
D1 Middle Sand	13.8	0.0	31.4	0.1	74.1	0.2
D1 Lower Sand	37.6	0.1	57.2	0.1	84.4	0.2
D2 Upper Sand	49.4	0.1	104.7	0.2	238.8	0.6
D2 Middle Sand	0.8	0.0	6.8	0.0	74.1	0.2
D2 Lower Sand	0.0	0.0	1.0	0.0	55.6	0.1

Fault Block/Prospect	Unrisked Working Interest Prospective Resources					
	Low Estimate (1U)		Best Estimate (2U)		High Estimate (3U)	
	Gas (BCF)	Condensate (MMBBL)	Gas (BCF)	Condensate (MMBBL)	Gas (BCF)	Condensate (MMBBL)
Southwest						
A Sand	1.1	0.0	2.9	0.0	5.6	0.0
C Sand	9.9	0.0	15.7	0.0	24.3	0.1
D1 Upper Sand	0.1	0.0	0.8	0.0	7.9	0.0
D1 Middle Sand	0.0	0.0	0.2	0.0	5.1	0.0
D1 Lower Sand	0.5	0.0	1.2	0.0	3.0	0.0
D2 Upper Sand	0.2	0.0	2.2	0.0	26.1	0.1
D2 Middle Sand	0.0	0.0	0.3	0.0	7.3	0.0
D2 Lower Sand	0.0	0.0	0.3	0.0	6.4	0.0

The prospective resources shown in this report have been estimated using probabilistic methods and are dependent on a petroleum discovery being made. If a discovery is made and development is undertaken, the probability that the recoverable volumes will equal or exceed the unrisked estimated amounts is 90 percent for the low estimate, 50 percent for the best estimate, and 10 percent for the high estimate.

Unrisked prospective resources are estimated ranges of recoverable gas and condensate volumes assuming their discovery and development and are based on estimated ranges of undiscovered in-place volumes. Geologic risking of prospective resources addresses the probability of success for the discovery of a significant quantity of potentially recoverable petroleum; this risk analysis is conducted independent of estimations of petroleum volumes and without regard to the chance of development. Principal geologic risk elements of the petroleum system include (1) trap and seal characteristics; (2) reservoir presence and quality; (3) source rock capacity, quality, and maturity; and (4) timing, migration, and preservation of petroleum in relation to trap and seal formation. Risk assessment is a highly subjective process dependent upon the experience and judgment of the evaluators and is subject to revision with further data acquisition or interpretation. The primary geologic risk element for these prospects is reservoir quality. The geologic risk elements and overall probability of geologic success by fault block for each prospect are shown in the following table:

Fault Block/Prospect	Geologic Risk Element (%)				Probability of Geologic Success (%)
	Trap Integrity	Reservoir Quality	Source Evaluation	Timing/ Migration	
Central					
D1 Upper Sand	100	95	100	100	95
D1 Middle Sand	100	85	100	100	85
D1 Lower Sand	100	95	100	100	95
D2 Upper Sand	100	95	100	100	95
D2 Middle Sand	100	75	100	100	75
D2 Lower Sand	100	85	100	100	85
Southwest					
A Sand	100	70	100	100	70
C Sand	100	95	100	100	95
D1 Upper Sand	100	90	100	100	90
D1 Middle Sand	100	80	100	100	80
D1 Lower Sand	100	90	100	100	90
D2 Upper Sand	100	95	100	100	95
D2 Middle Sand	100	70	100	100	70
D2 Lower Sand	100	80	100	100	80

Each prospect was evaluated to determine ranges of in-place and recoverable petroleum and was risked as an independent entity without dependency between potential prospect drilling outcomes. If petroleum discoveries are made, smaller-volume prospects may not be commercial to independently develop, although they may become candidates for satellite developments and tie-backs to existing infrastructure at some future date. The development infrastructure and data obtained from early discoveries will alter both geologic risk and future economics of subsequent discoveries and developments.

The Aphrodite Field Area is covered by a 3-D seismic data set. The 3-D seismic data were acquired in 2009 and 2013 by Petroleum Geo-Services, then merged and processed in 2014. All seismic interpretation was performed on the prestack depth-migrated data.

It should be understood that the prospective resources discussed and shown herein are those undiscovered, highly speculative resources estimated beyond reserves or contingent resources where geological and geophysical data suggest the potential for discovery of petroleum but where the level of proof is insufficient for classification as reserves or contingent resources. The unrisked prospective resources shown in this report are the range of volumes that could reasonably be expected to be recovered in the event of the discovery and development of these prospects.

GENERAL INFORMATION

For the purposes of this report, we did not perform any field inspection of the discoveries and prospects. We have not investigated possible environmental liability related to the discoveries and prospects; however, we are not currently aware of any possible environmental liability that would have any material effect on the contingent and prospective resources quantities estimated in this report or the commerciality of such estimates.

The contingent and prospective resources shown in this report are estimates only and should not be construed as exact quantities. Estimates may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, seismic data, well test data, and property ownership interests. We were provided with all the necessary data to prepare the estimates for the discoveries and prospects, and we were not limited from access to any material we believe may be relevant. The contingent and prospective resources in this report have been estimated using a combination of deterministic and probabilistic methods; these estimates have been prepared in accordance with generally accepted petroleum engineering and evaluation principles set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the SPE (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including volumetric analysis and analogy, that we considered to be appropriate and necessary to classify, categorize, and estimate volumes in accordance with the 2018 PRMS definitions and guidelines. Certain parameters used in our volumetric analysis are summarized in Tables I and II. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment. The prospective information is not an assessment regarding the reserves and contingent resources, which can be assessed only after exploratory drilling, if at all.

Netherland, Sewell & Associates, Inc. (NSAI) was engaged on December 15, 2020, by Mr. Yossi Abu, Chief Executive Officer of Delek Drilling, to perform this assessment. The data used in our estimates were obtained from Delek Drilling; Noble Energy Mediterranean Ltd., the operator of the properties; public data sources; and the nonconfidential files of NSAI and were accepted as accurate. Supporting work data are on file in our office. We have not examined the contractual rights to the discoveries and prospects or independently confirmed the actual degree or type of interest owned. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these discoveries and prospects nor are we employed on a contingent basis. Furthermore, no limitations or restrictions were placed upon NSAI by officials of Delek Drilling.

QUALIFICATIONS

NSAI performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. We provide a complete range of geological, geophysical, petrophysical, and engineering services, and we have the technical expertise and ability to perform these services in any oil and gas producing area in the world. The staff are familiar with the recognized industry reserves and resources definitions, specifically those promulgated by the U.S. Securities and Exchange Commission, by the Alberta Securities Commission, and by the SPE, Society of Petroleum Evaluation Engineers, World Petroleum Council, and American Association of Petroleum Geologists. The technical persons primarily responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards.

This assessment has been led by Mr. Richard B. Talley, Jr. and Mr. Zachary R. Long. Mr. Talley is a Senior Vice President and Mr. Long is a Vice President in the firm's Houston office at 1301 McKinney Street, Suite 3200, Houston, Texas 77010, USA. Mr. Talley is a Licensed Professional Engineer (Texas Registration No. 102425). He has been practicing consulting petroleum engineering at NSAI since 2004 and has over 5 years of prior industry experience. Mr. Long is a Licensed Professional Geoscientist (Texas Registration No. 11792). He has been practicing consulting petroleum geoscience at NSAI since 2007 and has over 2 years of prior industry experience.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

By:
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

By:
Richard B. Talley, Jr., P.E. 102425
Senior Vice President

Date Signed: March 14, 2021

By:
Zachary R. Long, P.G. 11792
Vice President

Date Signed: March 14, 2021

RBT:MDK

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the Petroleum Resources Management System Approved by
the Society of Petroleum Engineers (SPE) Board of Directors, June 2018

This document contains information excerpted from definitions and guidelines prepared by the Oil and Gas Reserves Committee of the Society of Petroleum Engineers (SPE) and reviewed and jointly sponsored by the SPE, World Petroleum Council, American Association of Petroleum Geologists, Society of Petroleum Evaluation Engineers, Society of Exploration Geophysicists, Society of Petrophysicists and Well Log Analysts, and European Association of Geoscientists & Engineers.

Preamble

Petroleum resources are the quantities of hydrocarbons naturally occurring on or within the Earth's crust. Resources assessments estimate quantities in known and yet-to-be-discovered accumulations. Resources evaluations are focused on those quantities that can potentially be recovered and marketed by commercial projects. A petroleum resources management system provides a consistent approach to estimating petroleum quantities, evaluating projects, and presenting results within a comprehensive classification framework.

This updated PRMS provides fundamental principles for the evaluation and classification of petroleum reserves and resources. If there is any conflict with prior SPE and PRMS guidance, approved training, or the Application Guidelines, the current PRMS shall prevail. It is understood that these definitions and guidelines allow flexibility for entities, governments, and regulatory agencies to tailor application for their particular needs; however, any modifications to the guidance contained herein must be clearly identified. The terms "shall" or "must" indicate that a provision herein is mandatory for PRMS compliance, while "should" indicates a recommended practice and "may" indicates that a course of action is permissible. The definitions and guidelines contained in this document must not be construed as modifying the interpretation or application of any existing regulatory reporting requirements.

1.0 Basic Principles and Definitions

1.0.0.1 A classification system of petroleum resources is a fundamental element that provides a common language for communicating both the confidence of a project's resources maturation status and the range of potential outcomes to the various entities. The PRMS provides transparency by requiring the assessment of various criteria that allow for the classification and categorization of a project's resources. The evaluation elements consider the risk of geologic discovery and the technical uncertainties together with a determination of the chance of achieving the commercial maturation status of a petroleum project.

1.0.0.2 The technical estimation of petroleum resources quantities involves the assessment of quantities and values that have an inherent degree of uncertainty. These quantities are associated with exploration, appraisal, and development projects at various stages of design and implementation. The commercial aspects considered will relate the project's maturity status (e.g., technical, economical, regulatory, and legal) to the chance of project implementation.

1.0.0.3 The use of a consistent classification system enhances comparisons between projects, groups of projects, and total company portfolios. The application of PRMS must consider both technical and commercial factors that impact the project's feasibility, its productive life, and its related cash flows.

1.1 Petroleum Resources Classification Framework

1.1.0.1 Petroleum is defined as a naturally occurring mixture consisting of hydrocarbons in the gaseous, liquid, or solid state. Petroleum may also contain non-hydrocarbons, common examples of which are carbon dioxide, nitrogen, hydrogen sulfide, and sulfur. In rare cases, non-hydrocarbon content can be greater than 50%.

1.1.0.2 The term resources as used herein is intended to encompass all quantities of petroleum naturally occurring within the Earth's crust, both discovered and undiscovered (whether recoverable or unrecoverable), plus those quantities already produced. Further, it includes all types of petroleum whether currently considered as conventional or unconventional resources.

1.1.0.3 Figure 1.1 graphically represents the PRMS resources classification system. The system classifies resources into discovered and undiscovered and defines the recoverable resources classes: Production, Reserves, Contingent Resources, and Prospective Resources, as well as Unrecoverable Petroleum.

1.1.0.4 The horizontal axis reflects the range of uncertainty of estimated quantities potentially recoverable from an accumulation by a project, while the vertical axis represents the chance of commerciality, P_c, which is the chance that a project will be committed for development and reach commercial producing status.

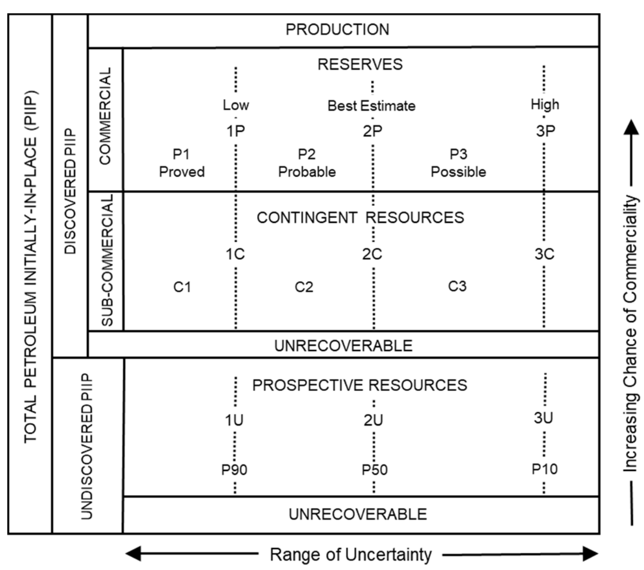

Figure 1.1—Resources classification framework

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1.1.0.5 The following definitions apply to the major subdivisions within the resources classification:

A. **Total Petroleum Initially-In-Place** (PIIP) is all quantities of petroleum that are estimated to exist originally in naturally occurring accumulations, discovered and undiscovered, before production.

B. **Discovered PIIP** is the quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations before production.

C. **Production** is the cumulative quantities of petroleum that have been recovered at a given date. While all recoverable resources are estimated, and production is measured in terms of the sales product specifications, raw production (sales plus non-sales) quantities are also measured and required to support engineering analyses based on reservoir voidage (see Section 3.2, Production Measurement).

1.1.0.6 Multiple development projects may be applied to each known or unknown accumulation, and each project will be forecast to recover an estimated portion of the initially-in-place quantities. The projects shall be subdivided into commercial, sub-commercial, and undiscovered, with the estimated recoverable quantities being classified as Reserves, Contingent Resources, or Prospective Resources respectively, as defined below.

A. 1. **Reserves** are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must satisfy four criteria: discovered, recoverable, commercial, and remaining (as of the evaluation's effective date) based on the development project(s) applied.

2. Reserves are recommended as sales quantities as metered at the reference point. Where the entity also recognizes quantities consumed in operations (CiO) (see Section 3.2.2), as Reserves these quantities must be recorded separately. Non-hydrocarbon quantities are recognized as Reserves only when sold together with hydrocarbons or CiO associated with petroleum production. If the non-hydrocarbon is separated before sales, it is excluded from Reserves.

3. Reserves are further categorized in accordance with the range of uncertainty and should be sub-classified based on project maturity and/or characterized by development and production status.

B. **Contingent Resources** are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, by the application of development project(s) not currently considered to be commercial owing to one or more contingencies. Contingent Resources have an associated chance of development. Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the range of uncertainty associated with the estimates and should be sub-classified based on project maturity and/or economic status.

C. **Undiscovered PIIP** is that quantity of petroleum estimated, as of a given date, to be contained within accumulations yet to be discovered.

D. **Prospective Resources** are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of geologic discovery and a chance of development. Prospective Resources are further categorized in accordance with the range of uncertainty associated with recoverable estimates, assuming discovery and development, and may be sub-classified based on project maturity.

E. **Unrecoverable Resources** are that portion of either discovered or undiscovered PIIP evaluated, as of a given date, to be unrecoverable by the currently defined project(s). A portion of these quantities may become recoverable in the future as commercial circumstances change, technology is developed, or additional data are acquired. The remaining portion may never be recovered because of physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

1.1.0.7 The sum of Reserves, Contingent Resources, and Prospective Resources may be referred to as "remaining recoverable resources." Importantly, these quantities should not be aggregated without due consideration of the technical and commercial risk involved with their classification. When such terms are used, each classification component of the summation must be provided.

1.1.0.8 Other terms used in resource assessments include the following:

A. **Estimated Ultimate Recovery (EUR)** is not a resources category or class, but a term that can be applied to an accumulation or group of accumulations (discovered or undiscovered) to define those quantities of petroleum estimated, as of a given date, to be potentially recoverable plus those quantities already produced from the accumulation or group of accumulations. For clarity, EUR must reference the associated technical and commercial conditions for the resources; for example, proved EUR is Proved Reserves plus prior production.

B. **Technically Recoverable Resources (TRR)** are those quantities of petroleum producible using currently available technology and industry practices, regardless of commercial considerations. TRR may be used for specific Projects or for groups of Projects, or, can be an undifferentiated estimate within an area (often basin-wide) of recovery potential.

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1.2 Project-Based Resources Evaluations

1.2.0.1 The resources evaluation process consists of identifying a recovery project or projects associated with one or more petroleum accumulations, estimating the quantities of PIIP, estimating that portion of those in-place quantities that can be recovered by each project, and classifying the project(s) based on maturity status or chance of commerciality.

1.2.0.2 The concept of a project-based classification system is further clarified by examining the elements contributing to an evaluation of net recoverable resources (see Figure 1.2).

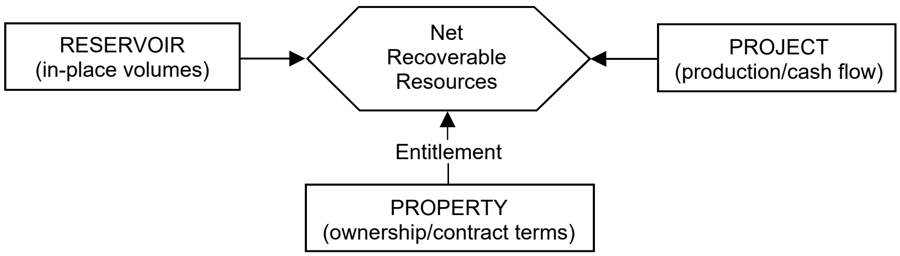

Figure 1.2—Resources evaluation

1.2.0.3 **The reservoir** (contains the petroleum accumulation): Key attributes include the types and quantities of PIIP and the fluid and rock properties that affect petroleum recovery.

1.2.0.4 **The project:** A project may constitute the development of a well, a single reservoir, or a small field; an incremental development in a producing field; or the integrated development of a field or several fields together with the associated processing facilities (e.g., compression). Within a project, a specific reservoir's development generates a unique production and cash-flow schedule at each level of certainty. The integration of these schedules taken to the project's earliest truncation caused by technical, economic, or the contractual limit defines the estimated recoverable resources and associated future net cash flow projections for each project. The ratio of EUR to total PIIP quantities defines the project's recovery efficiency. Each project should have an associated recoverable resources range (low, best, and high estimate).

1.2.0.5 **The property** (lease or license area): Each property may have unique associated contractual rights and obligations, including the fiscal terms. This information allows definition of each participating entity's share of produced quantities (entitlement) and share of investments, expenses, and revenues for each recovery project and the reservoir to which it is applied. One property may encompass many reservoirs, or one reservoir may span several different properties. A property may contain both discovered and undiscovered accumulations that may be spatially unrelated to a potential single field designation.

1.2.0.6 An entity's net recoverable resources are the entitlement share of future production legally accruing under the terms of the development and production contract or license.

1.2.0.7 In the context of this relationship, the project is the primary element considered in the resources classification, and the net recoverable resources are the quantities derived from each project. A project represents a defined activity or set of activities to develop the petroleum accumulation(s) and the decisions taken to mature the resources to reserves. In general, it is recommended that an individual project has assigned to it a specific maturity level sub-class (See Section 2.1.3.5, Project Maturity Sub-Classes) at which a decision is made whether or not to proceed (i.e., spend more money) and there should be an associated range of estimated recoverable quantities for the project (See Section 2.2.1, Range of Uncertainty). For completeness, a developed field is also considered to be a project.

1.2.0.8 An accumulation or potential accumulation of petroleum is often subject to several separate and distinct projects that are at different stages of exploration or development. Thus, an accumulation may have recoverable quantities in several resources classes simultaneously.

1.2.0.10 Not all technically feasible development projects will be commercial. The commercial viability of a development project within a field's development plan is dependent on a forecast of the conditions that will exist during the time period encompassed by the project (see Section 3.1, Assessment of Commerciality). Conditions include technical, economic (e.g., hurdle rates, commodity prices), operating and capital costs, marketing, sales route(s), and legal, environmental, social, and governmental factors forecast to exist and impact the project during the time period being evaluated. While economic factors can be summarized as forecast costs and product prices, the underlying influences include, but are not limited to, market conditions (e.g., inflation, market factors, and contingencies), exchange rates, transportation and processing infrastructure, fiscal terms, and taxes.

1.2.0.11 The resources being estimated are those quantities producible from a project as measured according to delivery specifications at the point of sale or custody transfer (see Section 3.2.1, Reference Point) and may permit forecasts of CiO quantities (see Section 3.2.2., Consumed in Operations). The cumulative production forecast from the effective date forward to cessation of production is the remaining recoverable resources quantity (see Section 3.1.1, Net Cash-Flow Evaluation).

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1.2.0.12 The supporting data, analytical processes, and assumptions describing the technical and commercial basis used in an evaluation must be documented in sufficient detail to allow, as needed, a qualified reserves evaluator or qualified reserves auditor to clearly understand each project's basis for the estimation, categorization, and classification of recoverable resources quantities and, if appropriate, associated commercial assessment.

2.0 Classification and Categorization Guidelines

2.1 Resources Classification

2.1.0.1 The PRMS classification establishes criteria for the classification of the total PIIP. A determination of a discovery differentiates between discovered and undiscovered PIIP. The application of a project further differentiates the recoverable from unrecoverable resources. The project is then evaluated to determine its maturity status to allow the classification distinction between commercial and sub-commercial projects. PRMS requires the project's recoverable resources quantities to be classified as either Reserves, Contingent Resources, or Prospective Resources.

2.1.1 Determination of Discovery Status

2.1.1.1 A discovered petroleum accumulation is determined to exist when one or more exploratory wells have established through testing, sampling, and/or logging the existence of a significant quantity of potentially recoverable hydrocarbons and thus have established a known accumulation. In the absence of a flow test or sampling, the discovery determination requires confidence in the presence of hydrocarbons and evidence of producibility, which may be supported by suitable producing analogs (see Section 4.1.1, Analogs). In this context, "significant" implies that there is evidence of a sufficient quantity of petroleum to justify estimating the in-place quantity demonstrated by the well(s) and for evaluating the potential for commercial recovery.

2.1.1.2 Where a discovery has identified potentially recoverable hydrocarbons, but it is not considered viable to apply a project with established technology or with technology under development, such quantities may be classified as Discovered Unrecoverable with no Contingent Resources. In future evaluations, as appropriate for petroleum resources management purposes, a portion of these unrecoverable quantities may become recoverable resources as either commercial circumstances change or technological developments occur.

2.1.2 Determination of Commerciality

2.1.2.1 Discovered recoverable quantities (Contingent Resources) may be considered commercially mature, and thus attain Reserves classification, if the entity claiming commerciality has demonstrated a firm intention to proceed with development. This means the entity has satisfied the internal decision criteria (typically rate of return at or above the weighted average cost-of-capital or the hurdle rate). Commerciality is achieved with the entity's commitment to the project and all of the following criteria:

A. Evidence of a technically mature, feasible development plan.
B. Evidence of financial appropriations either being in place or having a high likelihood of being secured to implement the project.
C. Evidence to support a reasonable time-frame for development.
D. A reasonable assessment that the development projects will have positive economics and meet defined investment and operating criteria. This assessment is performed on the estimated entitlement forecast quantities and associated cash flow on which the investment decision is made (see Section 3.1.1, Net Cash-Flow Evaluation).
E. A reasonable expectation that there will be a market for forecast sales quantities of the production required to justify development. There should also be similar confidence that all produced streams (e.g., oil, gas, water, $CO2$) can be sold, stored, re-injected, or otherwise appropriately disposed.
F. Evidence that the necessary production and transportation facilities are available or can be made available.
G. Evidence that legal, contractual, environmental, regulatory, and government approvals are in place or will be forthcoming, together with resolving any social and economic concerns.

2.1.2.2 The commerciality test for Reserves determination is applied to the best estimate (P50) forecast quantities, which upon qualifying all commercial and technical maturity criteria and constraints become the 2P Reserves. Stricter cases [e.g., low estimate (P90)] may be used for decision purposes or to investigate the range of commerciality (see Section 3.1.2, Economic Criteria). Typically, the low- and high-case project scenarios may be evaluated for sensitivities when considering project risk and upside opportunity.

2.1.2.3 To be included in the Reserves class, a project must be sufficiently defined to establish both its technical and commercial viability as noted in Section 2.1.2.1. There must be a reasonable expectation that all required internal and external approvals will be forthcoming and evidence of firm intention to proceed with development within a reasonable time-frame. A reasonable time-frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While five years is recommended as a benchmark, a longer time-frame could be applied where justifiable; for example, development of economic projects that take longer than five years to be developed or are deferred to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented.

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2.1.2.4 While PRMS guidelines require financial appropriations evidence, they do not require that project financing be confirmed before classifying projects as Reserves. However, this may be another external reporting requirement. In many cases, financing is conditional upon the same criteria as above. In general, if there is not a reasonable expectation that financing or other forms of commitment (e.g., farm-outs) can be arranged so that the development will be initiated within a reasonable time-frame, then the project should be classified as Contingent Resources. If financing is reasonably expected to be in place at the time of the final investment decision (FID), the project's resources may be classified as Reserves.

2.2 Resources Categorization

2.2.0.1 The horizontal axis in the resources classification in Figure 1.1 defines the range of uncertainty in estimates of the quantities of recoverable, or potentially recoverable, petroleum associated with a project or group of projects. These estimates include the uncertainty components as follows:

A. The total petroleum remaining within the accumulation (in-place resources).
B. The technical uncertainty in the portion of the total petroleum that can be recovered by applying a defined development project or projects (i.e., the technology applied).
C. Known variations in the commercial terms that may impact the quantities recovered and sold (e.g., market availability; contractual changes, such as production rate tiers or product quality specifications) are part of project's scope and are included in the horizontal axis, while the chance of satisfying the commercial terms is reflected in the classification (vertical axis).

2.2.0.2 The uncertainty in a project's recoverable quantities is reflected by the 1P, 2P, 3P, Proved (P1), Probable (P2), Possible (P3), 1C, 2C, 3C, C1, C2, and C3; or 1U, 2U, and 3U resources categories. The commercial chance of success is associated with resources classes or sub-classes and not with the resources categories reflecting the range of recoverable quantities.

2.2.1 Range of Uncertainty

2.2.1.1 Uncertainty is inherent in a project's resources estimation and is communicated in PRMS by reporting a range of category outcomes. The range of uncertainty of the recoverable and/or potentially recoverable quantities may be represented by either deterministic scenarios or by a probability distribution (see Section 4.2, Resources Assessment Methods).

2.2.1.2 When the range of uncertainty is represented by a probability distribution, a low, best, and high estimate shall be provided such that:

A. There should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate.
B. There should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate.
C. There should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

2.2.1.3 In some projects, the range of uncertainty may be limited, and the three scenarios may result in resources estimates that are not significantly different. In these situations, a single value estimate may be appropriate to describe the expected result.

2.2.1.4 When using the deterministic scenario method, typically there should also be low, best, and high estimates, where such estimates are based on qualitative assessments of relative uncertainty using consistent interpretation guidelines. Under the deterministic incremental method, quantities for each confidence segment are estimated discretely (see Section 2.2.2, Category Definitions and Guidelines).

2.2.1.5 Project resources are initially estimated using the above uncertainty range forecasts that incorporate the subsurface elements together with technical constraints related to wells and facilities. The technical forecasts then have additional commercial criteria applied (e.g., economics and license cutoffs are the most common) to estimate the entitlement quantities attributed and the resources classification status: Reserves, Contingent Resources, and Prospective Resources.

2.2.2 Category Definitions and Guidelines

2.2.2.1 Evaluators may assess recoverable quantities and categorize results by uncertainty using the deterministic incremental method, the deterministic scenario (cumulative) method, geostatistical methods, or probabilistic methods (see Section 4.2, Resources Assessment Methods). Also, combinations of these methods may be used.

2.2.2.2 Use of consistent terminology (Figures 1.1 and 2.1) promotes clarity in communication of evaluation results. For Reserves, the general cumulative terms low/best/high forecasts are used to estimate the resulting 1P/2P/3P quantities, respectively. The associated incremental quantities are termed Proved (P1), Probable (P2) and Possible (P3). Reserves are a subset of, and must be viewed within the context of, the complete resources classification system. While the categorization criteria are proposed specifically for Reserves, in most cases, the criteria can be equally applied to Contingent and Prospective Resources. Upon satisfying the commercial maturity criteria for discovery and/or development, the project quantities will then move to the appropriate resources sub-class. Table 3 provides criteria for the Reserves categories determination.

2.2.2.3 For Contingent Resources, the general cumulative terms low/best/high estimates are used to estimate the resulting 1C/2C/3C quantities, respectively. The terms C1, C2, and C3 are defined for incremental quantities of Contingent Resources.

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2.2.2.4 For Prospective Resources, the general cumulative terms low/best/high estimates also apply and are used to estimate the resulting 1U/2U/3U quantities. No specific terms are defined for incremental quantities within Prospective Resources.

2.2.2.5 Quantities in different classes and sub-classes cannot be aggregated without considering the varying degrees of technical uncertainty and commercial likelihood involved with the classification(s) and without considering the degree of dependency between them (see Section 4.2.1, Aggregating Resources Classes).

2.2.2.6 Without new technical information, there should be no change in the distribution of technically recoverable resources and the categorization boundaries when conditions are satisfied to reclassify a project from Contingent Resources to Reserves.

2.2.2.7 All evaluations require application of a consistent set of forecast conditions, including assumed future costs and prices, for both classification of projects and categorization of estimated quantities recovered by each project (see Section 3.1, Assessment of Commerciality).

Table 1—Recoverable Resources Classes and Sub-Classes

Class/Sub-Class	Definition	Guidelines
Reserves	Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.	Reserves must satisfy four criteria: discovered, recoverable, commercial, and remaining based on the development project(s) applied. Reserves are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by the development and production status. To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability (see Section 2.1.2, Determination of Commerciality). This includes the requirement that there is evidence of firm intention to proceed with development within a reasonable time-frame. A reasonable time-frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While five years is recommended as a benchmark, a longer time-frame could be applied where, for example, development of an economic project is deferred at the option of the producer for, among other things, market-related reasons or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented. To be included in the Reserves class, there must be a high confidence in the commercial maturity and economic producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.
On Production	The development project is currently producing or capable of producing and selling petroleum to market.	The key criterion is that the project is receiving income from sales, rather than that the approved development project is necessarily complete. Includes Developed Producing Reserves. The project decision gate is the decision to initiate or continue economic production from the project.
Approved for Development	All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is ready to begin or is under way.	At this point, it must be certain that the development project is going ahead. The project must not be subject to any contingencies, such as outstanding regulatory approvals or sales contracts. Forecast capital expenditures should be included in the reporting entity's current or following year's approved budget. The project decision gate is the decision to start investing capital in the construction of production facilities and/or drilling development wells.

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the Petroleum Resources Management System Approved by
the Society of Petroleum Engineers (SPE) Board of Directors, June 2018

Class/Sub-Class	Definition	Guidelines
Justified for Development	Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals/contracts will be obtained.	To move to this level of project maturity, and hence have Reserves associated with it, the development project must be commercially viable at the time of reporting (see Section 2.1.2, Determination of Commerciality) and the specific circumstances of the project. All participating entities have agreed and there is evidence of a committed project (firm intention to proceed with development within a reasonable time-frame). There must be no known contingencies that could preclude the development from proceeding (see Reserves class). The project decision gate is the decision by the reporting entity and its partners, if any, that the project has reached a level of technical and commercial maturity sufficient to justify proceeding with development at that point in time.
Contingent Resources	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable owing to one or more contingencies.	Contingent Resources may include, for example, projects for which there are currently no viable markets, where commercial recovery is dependent on technology under development, where evaluation of the accumulation is insufficient to clearly assess commerciality, where the development plan is not yet approved, or where regulatory or social acceptance issues may exist. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by the economic status.
Development Pending	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.	The project is seen to have reasonable potential for eventual commercial development, to the extent that further data acquisition (e.g., drilling, seismic data) and/or evaluations are currently ongoing with a view to confirming that the project is commercially viable and providing the basis for selection of an appropriate development plan. The critical contingencies have been identified and are reasonably expected to be resolved within a reasonable time-frame. Note that disappointing appraisal/evaluation results could lead to a reclassification of the project to On Hold or Not Viable status. The project decision gate is the decision to undertake further data acquisition and/or studies designed to move the project to a level of technical and commercial maturity at which a decision can be made to proceed with development and production.
Development on Hold	A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay.	The project is seen to have potential for commercial development. Development may be subject to a significant time delay. Note that a change in circumstances, such that there is no longer a probable chance that a critical contingency can be removed in the foreseeable future, could lead to a reclassification of the project to Not Viable status. The project decision gate is the decision to either proceed with additional evaluation designed to clarify the potential for eventual commercial development or to temporarily suspend or delay further activities pending resolution of external contingencies.
Development Unclarified	A discovered accumulation where project activities are under evaluation and where justification as a commercial development is unknown based on available information.	The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are ongoing to clarify the potential for eventual commercial development. This sub-class requires active appraisal or evaluation and should not be maintained without a plan for future evaluation. The sub-class should reflect the actions required to move a project toward commercial maturity and economic production.

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS
Excerpted from the Petroleum Resources Management System Approved by
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Class/Sub-Class	Definition	Guidelines
Development Not Viable	A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time because of limited production potential.	The project is not seen to have potential for eventual commercial development at the time of reporting, but the theoretically recoverable quantities are recorded so that the potential opportunity will be recognized in the event of a major change in technology or commercial conditions. The project decision gate is the decision not to undertake further data acquisition or studies on the project for the foreseeable future.
Prospective Resources	Those quantities of petroleum that are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.	Potential accumulations are evaluated according to the chance of geologic discovery and, assuming a discovery, the estimated quantities that would be recoverable under defined development projects. It is recognized that the development programs will be of significantly less detail and depend more heavily on analog developments in the earlier phases of exploration.
Prospect	A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.	Project activities are focused on assessing the chance of geologic discovery and, assuming discovery, the range of potential recoverable quantities under a commercial development program.
Lead	A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation to be classified as a Prospect.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to confirm whether or not the Lead can be matured into a Prospect. Such evaluation includes the assessment of the chance of geologic discovery and, assuming discovery, the range of potential recovery under feasible development scenarios.
Play	A project associated with a prospective trend of potential prospects, but that requires more data acquisition and/or evaluation to define specific Leads or Prospects.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to define specific Leads or Prospects for more detailed analysis of their chance of geologic discovery and, assuming discovery, the range of potential recovery under hypothetical development scenarios.

Table 2—Reserves Status Definitions and Guidelines

Status	Definition	Guidelines
Developed Reserves	Expected quantities to be recovered from existing wells and facilities.	Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well. Where required facilities become unavailable, it may be necessary to reclassify Developed Reserves as Undeveloped. Developed Reserves may be further sub-classified as Producing or Non-producing.
Developed Producing Reserves	Expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.	Improved recovery Reserves are considered producing only after the improved recovery project is in operation.
Developed Non-Producing Reserves	Shut-in and behind-pipe Reserves.	Shut-in Reserves are expected to be recovered from (1) completion intervals that are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the Petroleum Resources Management System Approved by
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Status	Definition	Guidelines
Undeveloped Reserves	Quantities expected to be recovered through future significant investments.	Undeveloped Reserves are to be produced (1) from new wells on undrilled acreage in known accumulations, (2) from deepening existing wells to a different (but known) reservoir, (3) from infill wells that will increase recovery, or (4) where a relatively large expenditure (e.g., when compared to the cost of drilling a new well) is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects.

Table 3—Reserves Category Definitions and Guidelines

Category	Definition	Guidelines
Proved Reserves	Those quantities of petroleum that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable from a given date forward from known reservoirs and under defined economic conditions, operating methods, and government regulations.	If deterministic methods are used, the term "reasonable certainty" is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the estimate. The area of the reservoir considered as Proved includes (1) the area delineated by drilling and defined by fluid contacts, if any, and (2) adjacent undrilled portions of the reservoir that can reasonably be judged as continuous with it and commercially productive on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, Proved quantities in a reservoir are limited by the LKH as seen in a well penetration unless otherwise indicated by definitive geoscience, engineering, or performance data. Such definitive information may include pressure gradient analysis and seismic indicators. Seismic data alone may not be sufficient to define fluid contacts for Proved reserves. Reserves in undeveloped locations may be classified as Proved provided that: A. The locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially mature and economically productive. B. Interpretations of available geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with drilled Proved locations. For Proved Reserves, the recovery efficiency applied to these reservoirs should be defined based on a range of possibilities supported by analogs and sound engineering judgment considering the characteristics of the Proved area and the applied development program.
Probable Reserves	Those additional Reserves that analysis of geoscience and engineering data indicates are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves.	It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate. Probable Reserves may be assigned to areas of a reservoir adjacent to Proved where data control or interpretations of available data are less certain. The interpreted reservoir continuity may not meet the reasonable certainty criteria. Probable estimates also include incremental recoveries associated with project recovery efficiencies beyond that assumed for Proved.

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the Petroleum Resources Management System Approved by
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Category	Definition	Guidelines
Possible Reserves	Those additional reserves that analysis of geoscience and engineering data indicates are less likely to be recoverable than Probable Reserves.	The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high-estimate scenario. When probabilistic methods are used, there should be at least a 10% probability (P10) that the actual quantities recovered will equal or exceed the 3P estimate. Possible Reserves may be assigned to areas of a reservoir adjacent to Probable where data control and interpretations of available data are progressively less certain. Frequently, this may be in areas where geoscience and engineering data are unable to clearly define the area and vertical reservoir limits of economic production from the reservoir by a defined, commercially mature project. Possible estimates also include incremental quantities associated with project recovery efficiencies beyond that assumed for Probable.
Probable and Possible Reserves	See above for separate criteria for Probable Reserves and Possible Reserves.	The 2P and 3P estimates may be based on reasonable alternative technical interpretations within the reservoir and/or subject project that are clearly documented, including comparisons to results in successful similar projects. In conventional accumulations, Probable and/or Possible Reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from Proved areas by minor faulting or other geological discontinuities and have not been penetrated by a wellbore but are interpreted to be in communication with the known (Proved) reservoir. Probable or Possible Reserves may be assigned to areas that are structurally higher than the Proved area. Possible (and in some cases, Probable) Reserves may be assigned to areas that are structurally lower than the adjacent Proved or 2P area. Caution should be exercised in assigning Reserves to adjacent reservoirs isolated by major, potentially sealing faults until this reservoir is penetrated and evaluated as commercially mature and economically productive. Justification for assigning Reserves in such cases should be clearly documented. Reserves should not be assigned to areas that are clearly separated from a known accumulation by non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results); such areas may contain Prospective Resources. In conventional accumulations, where drilling has defined a highest known oil elevation and there exists the potential for an associated gas cap, Proved Reserves of oil should only be assigned in the structurally higher portions of the reservoir if there is reasonable certainty that such portions are initially above bubble point pressure based on documented engineering analyses. Reservoir portions that do not meet this certainty may be assigned as Probable and Possible oil and/or gas based on reservoir fluid properties and pressure gradient interpretations.

NETHERLAND, SEWELL & ASSOCIATES, INC.

VOLUMETRIC INPUT SUMMARY
CONTINGENT RESOURCES
APHRODITE FIELD AREA, BLOCK 12, OFFSHORE CYPRUS
AS OF DECEMBER 31, 2020

Fault Block/ Reservoir	Gross Rock Volume (acre-feet) Low Estimate	Gross Rock Volume (acre-feet) Best Estimate	Gross Rock Volume (acre-feet) High Estimate	Area (acres) Low Estimate	Area (acres) Best Estimate	Area (acres) High Estimate	Average Gross Thickness[1] (feet) Low Estimate	Average Gross Thickness[1] (feet) Best Estimate	Average Gross Thickness[1] (feet) High Estimate	Net-to-Gross Ratio (decimal) Low Estimate	Net-to-Gross Ratio (decimal) Best Estimate	Net-to-Gross Ratio (decimal) High Estimate
A-1 ST01												
A Sand	16,232	422,683	422,683	436	8,509	8,509	37	50	50	0.03	0.04	0.07
C Sand	671,471	1,335,571	1,335,571	3,783	5,517	5,517	177	242	242	0.44	0.48	0.61
D1 Upper Sand	75,966	400,595	400,595	1,525	6,074	6,074	50	66	66	0.34	0.39	0.49
D1 Middle Sand	31,022	611,725	611,725	556	5,383	5,383	56	114	114	0.30	0.26[2]	0.40
D1 Lower Sand	53,034	265,674	265,674	1,169	4,248	4,248	45	63	63	0.24	0.29	0.35
D2 Upper Sand	204,975	233,024	233,024	2,705	2,990	2,990	76	78	78	0.74	0.77	0.83
D2 Middle Sand	150,064	184,162	184,162	1,965	2,297	2,297	76	80	80	0.26	0.36	0.43
D2 Lower Sand	35,706	65,121	65,121	770	1,207	1,207	46	54	54	0.42	0.36[2]	0.70
A-2a												
C Sand	131,811	238,660	238,660	1,968	2,166	2,166	67	110	110	0.45	0.33[2]	0.49
D1 Upper Sand	72,693	72,693	72,693	1,420	1,420	1,420	51	51	51	0.26	0.40	0.75
D1 Lower Sand	105,540	137,059	137,059	1,554	1,798	1,798	68	76	76	0.32	0.36	0.50
Central												
A Sand	249,442	319,236	319,236	5,531	8,293	8,293	45	38[3]	38[3]	0.07	0.18	0.21
C Sand	1,331,072	1,372,557	1,372,557	5,912	5,912	5,912	225	232	232	0.54	0.51[2]	0.74

Fault Block/ Reservoir	Porosity (decimal) Low Estimate	Porosity (decimal) Best Estimate[5]	Porosity (decimal) High Estimate[5]	Gas Saturation (decimal) Low Estimate	Gas Saturation (decimal) Best Estimate	Gas Saturation (decimal) High Estimate[6]	Gas Formation Volume Factor (SCF/RCF)[4] Low Estimate	Gas Formation Volume Factor (SCF/RCF)[4] Best Estimate	Gas Formation Volume Factor (SCF/RCF)[4] High Estimate	Gas Recovery Factor (decimal) Low Estimate	Gas Recovery Factor (decimal) Best Estimate	Gas Recovery Factor (decimal) High Estimate
A-1 ST01												
A Sand	0.16	0.19	0.19	0.58	0.63	0.58	375	375	375	0.60	0.65	0.70
C Sand	0.21	0.21	0.20	0.68	0.73	0.70	378	378	378	0.60	0.65	0.70
D1 Upper Sand	0.21	0.20	0.20	0.56	0.67	0.65	378	378	378	0.60	0.65	0.70
D1 Middle Sand	0.25	0.23	0.23	0.53	0.48	0.48	378	378	378	0.60	0.65	0.70
D1 Lower Sand	0.22	0.21	0.20	0.64	0.70	0.69	378	378	378	0.60	0.65	0.70
D2 Upper Sand	0.21	0.21	0.21	0.74	0.81	0.79	378	378	378	0.60	0.65	0.70
D2 Middle Sand	0.23	0.21	0.21	0.68	0.70	0.69	378	378	378	0.60	0.65	0.70
D2 Lower Sand	0.23	0.20	0.19	0.54	0.61	0.60	378	378	378	0.60	0.65	0.70
A-2a												
C Sand	0.22	0.21	0.19	0.66	0.70	0.68	378	378	378	0.60	0.65	0.70
D1 Upper Sand	0.23	0.20	0.18	0.61	0.63	0.63	378	378	378	0.60	0.65	0.70
D1 Lower Sand	0.24	0.22	0.20	0.60	0.63	0.62	378	378	378	0.60	0.65	0.70
Central												
A Sand	0.20	0.18	0.18	0.54	0.60	0.59	375	375	375	0.60	0.65	0.70
C Sand	0.21	0.20	0.18	0.69	0.72	0.69	378	378	378	0.60	0.65	0.70

Note: For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, seismic data, well test data, and property ownership interests.

(1) Average gross thickness is calculated by dividing the gross rock volume by the area.
(2) The best estimate net-to-gross ratio is lower than the low estimate ratio due to the inclusion of additional gross rock volume below the lowest known gas depth.
(3) The structural character of the A Sand results in a lower average gross thickness in the best estimate and high estimate cases relative to the low estimate case.
(4) The abbreviation SCF/RCF represents standard cubic feet per reservoir cubic foot.
(5) The net rock volume in the low estimate case includes only higher quality rock. The best estimate and high estimate cases include more net rock volume with lower porosity.
(6) The high estimate gas saturation is lower than the best estimate case due to the use of more optimistic petrophysical cut-off parameters.

NETHERLAND, SEWELL & ASSOCIATES, INC.

VOLUMETRIC INPUT SUMMARY
PROSPECTIVE RESOURCES
APHRODITE FIELD AREA, BLOCK 12, OFFSHORE CYPRUS
AS OF DECEMBER 31, 2020

	Gross Rock Volume (acre-feet) Lognormal Distribution		Area (acres) Lognormal Distribution		Average Gross Thickness[1] (feet)		Net-to-Gross Ratio (decimal) Normal Distribution	
Fault Block/Prospect	Low Estimate	High Estimate	Low Estimate	High Estimate	Low Estimate	High Estimate	Low Estimate	High Estimate
Central								
D1 Upper Sand	235,317	416,701	3,473	5,878	68	71	0.30	0.50
D1 Middle Sand	135,311	472,365	2,252	5,013	60	94	0.25	0.45
D1 Lower Sand	298,899	396,826	3,889	5,005	77	79	0.30	0.50
D2 Upper Sand	152,116	558,147	2,428	6,222	63	90	0.70	0.90
D2 Middle Sand	5,372	504,043	332	5,152	16	98	0.25	0.45
D2 Lower Sand	100	549,579	25	4,058	4	135	0.40	0.70
Southwest								
A Sand	97,488	146,232	1,930	2,896	51	51	0.03	0.13
C Sand	50,648	75,972	490	736	103	103	0.40	0.70
D1 Upper Sand	770	56,044	52	1,018	15	55	0.30	0.50
D1 Middle Sand	100	61,355	25	732	4	84	0.25	0.45
D1 Lower Sand	3,649	15,383	115	395	32	39	0.30	0.50
D2 Upper Sand	700	85,606	46	1,296	15	66	0.70	0.90
D2 Middle Sand	100	66,966	25	909	4	74	0.25	0.45
D2 Lower Sand	100	40,415	25	487	4	83	0.40	0.70

	Porosity (decimal) Normal Distribution		Gas Saturation (decimal) Normal Distribution		Gas Formation Volume Factor (SCF/RCF)[2] Uniform Distribution		Gas Recovery Factor (decimal) Normal Distribution	
Fault Block/Prospect	Low Estimate	High Estimate	Low Estimate	High Estimate	Low Estimate	High Estimate	Low Estimate	High Estimate
Central								
D1 Upper Sand	0.19	0.23	0.55	0.65	378	378	0.60	0.70
D1 Middle Sand	0.21	0.26	0.45	0.55	378	378	0.60	0.70
D1 Lower Sand	0.20	0.24	0.55	0.65	378	378	0.60	0.70
D2 Upper Sand	0.19	0.23	0.65	0.75	379	379	0.60	0.70
D2 Middle Sand	0.20	0.24	0.65	0.75	379	379	0.60	0.70
D2 Lower Sand	0.19	0.23	0.55	0.65	379	379	0.60	0.70
Southwest								
A Sand	0.16	0.20	0.50	0.60	375	375	0.60	0.70
C Sand	0.19	0.23	0.65	0.75	378	378	0.60	0.70
D1 Upper Sand	0.19	0.23	0.55	0.65	378	378	0.60	0.70
D1 Middle Sand	0.21	0.26	0.45	0.55	378	378	0.60	0.70
D1 Lower Sand	0.20	0.24	0.55	0.65	378	378	0.60	0.70
D2 Upper Sand	0.19	0.23	0.65	0.75	379	379	0.60	0.70
D2 Middle Sand	0.20	0.24	0.65	0.75	379	379	0.60	0.70
D2 Lower Sand	0.19	0.23	0.55	0.65	379	379	0.60	0.70

Note: For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, seismic data, well test data, and property ownership interests.

[1] Average gross thickness is calculated by dividing the gross rock volume by the area.
[2] The abbreviation SCF/RCF represents standard cubic feet per reservoir cubic foot.

Appendix A—Glossary of Terms Used in Resources Evaluations

This Glossary provides high-level definitions of terms used in resources evaluations. Where appropriate, sections within the PRMS document are referenced to best show the use of selected terms in context.

TERM	See PRMS Section	DEFINITION
1C	2.2.2	Denotes low estimate of Contingent Resources.
2C	2.2.2	Denotes best estimate of Contingent Resources.
3C	2.2.2	Denotes high estimate of Contingent Resources.
1P	2.2.2	Denotes low estimate of Reserves (i.e., Proved Reserves). Equal to P1.
2P	2.2.2	Denotes the best estimate of Reserves. The sum of Proved plus Probable Reserves.
3P	2.2.2	Denotes high estimate of reserves. The sum of Proved plus Probable plus Possible Reserves.
1U	2.2.2	Denotes the unrisked low estimate qualifying as Prospective Resources.
2U	2.2.2	Denotes the unrisked best estimate qualifying as Prospective Resources.
3U	2.2.2	Denotes the unrisked high estimate qualifying as Prospective Resources.
Abandonment, Decommissioning, and Restoration (ADR)	3.1.2	The process (and associated costs) of returning part or all of a project to a safe and environmentally compliant condition when operations cease. Examples include, but are not limited to, the removal of surface facilities, wellbore plugging procedures, and environmental remediation. In some instances, there may be salvage value associated with the equipment removed from the project. ADR costs are presumed to be without consideration of any salvage value, unless presented as "ADR net of salvage."
Accumulation	2.4	An individual body of naturally occurring petroleum in a reservoir.
Aggregation	4.2.5	The process of summing well, reservoir, or project-level estimates of resources quantities to higher levels or combinations, such as field, country or company totals. Arithmetic summation of incremental categories may yield different results from probabilistic aggregation of distributions.
Appraisal	1.2	The phase that may follow successful exploratory drilling. Activities to further evaluate the discovery, such as seismic acquisition, geological studies, and drilling additional wells may be conducted to reduce technical uncertainties and commercial contingencies.
Approved for Development	2.1.3.5, Table I	All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is underway. A project maturity sub-class of Reserves.
Analog	4.1.1	Method used in resources estimation in the exploration and early development stages (including improved recovery projects) when direct measurement is limited. Based on evaluator's assessment of similarities of the analogous reservoir(s) together with the development plan.
Analogous Reservoir	4.1.1	Reservoirs that have similar rock properties (e.g., petrophysical, lithological, depositional, diagenetic, and structural), fluid properties (e.g., type, composition, density, and viscosity), reservoir conditions (e.g., depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide insight and comparative data to assist in estimation of recoverable resources.
Assessment	2.1.2	See Evaluation.

Associated Gas	Table 3	A natural gas found in contact with or dissolved in crude oil in the reservoir. It can be further categorized as gas cap gas or solution gas.
Basin-Centered Gas	2.4	An unconventional natural gas accumulation that is regionally pervasive and characterized by low permeability, abnormal pressure, gas-saturated reservoirs, and lack of a down dip water leg.
Barrel of Oil Equivalent (BOE)	3.2.9	The term allows for a single value to represent the sum of all the hydrocarbon products that are forecast as resources. Typically, condensate, oil, bitumen, and synthetic crude barrels are taken to be equal (1 bbl = 1 BOE). Gas and NGL quantities are converted to an oil equivalent based on a conversion factor that is recommended to be based on a nominal heating content or calorific value equivalent to a barrel of oil.
Basis for Estimate	1.2	The methodology (or methodologies) and supporting data on which the estimated quantities are based. (Also referenced as basis for the estimation.)
Behind-Pipe Reserves	2.1.3.6	Reserves that are expected to be recovered from zones in existing wells, which will require additional completion work or future re-completion before the start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling and completing a new well including hook-up to allow production.
Best Estimate	2.2.2	With respect to resources categorization, the most realistic assessment of recoverable quantities if only a single result were reported. If probabilistic methods are used, there should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate.
C1	2.2.2	Denotes low estimate of Contingent Resources. C1 is equal to 1C.
C2	2.2.2	Denotes Contingent Resources of same technical confidence as Probable, but not commercially matured to Reserves.
C3	2.2.2	Denotes Contingent Resources of same technical confidence as Possible, but not commercially matured to Reserves.
Chance	1.1	Chance equals 1-risk. Generally synonymous with likelihood. (See Risk)
Chance of Commerciality	2.1.3	The estimated probability that the project will achieve commercial maturity to be developed. For Prospective Resources, this is the product of the chance of geologic discovery and the chance of development. For Contingent Resources and Reserves, it is equal to the chance of development.
Chance of Development	2.1.3	The estimated probability that a known accumulation, once discovered, will be commercially developed.
Chance of Geologic Discovery	2.1.3	The estimated probability that exploration activities will confirm the existence of a significant accumulation of potentially recoverable petroleum.
Coalbed Methane (CBM)	2.4	Natural gas contained in coal deposits. Coalbed gas, although usually mostly methane, may be produced with variable amounts of inert or even non-inert gases. [Also called coal-seam gas (CSG) or natural gas from coal (NGC).]
Commercial	2.1.2	A project is commercial when there is evidence of a firm intention to proceed with development within a reasonable time-frame. Typically, this requires that the best estimate case meet or exceed the minimum evaluation decision criteria (e.g., rate of return, investment payout time). There must be a reasonable expectation that all required internal and external approvals will be forthcoming. Also, there must be evidence of a technically mature, feasible development plan and the essential social, environmental, economic, political, legal, regulatory, decision criteria, and contractual conditions are met.
Committed Project	2.1.3.1	Project that the entity has a firm intention to develop in a reasonable time-frame. Intent is demonstrated with funding/financial plans, but FID has not yet been declared (See also Final Investment Decision.)

Completion	2.1.3.6	Completion of a well. The process by which a well is brought to its operating status (e.g., producer, injector, or monitor well). A well deemed to be capable of producing petroleum, or used as an injector, is completed by establishing a connection between the reservoir(s) and the surface so that fluids can be produced from, or injected into, the reservoir.
Completion Interval	2.1.3.6	The specific reservoir interval(s) that is (are) open to the borehole and connected to the surface facilities for production or injection, or reservoir intervals open to the wellbore and each other for injection purposes.
Concession	3.3	A grant of access for a defined area and time period that transfers certain entitlements to produced hydrocarbons from the host country to an entity. The entity is generally responsible for exploration, development, production, and sale of hydrocarbons that may be discovered. Typically granted under a legislated fiscal system where the host country collects taxes, fees, and sometimes royalty on profits earned. (Also called a license.)
Condensate	3.2	A mixture of hydrocarbons (mainly pentanes and heavier) that exist in the gaseous phase at original temperature and pressure of the reservoir, but when produced, are in the liquid phase at surface pressure and temperature conditions. Condensate differs from NGLs in two respects: (1) NGL is extracted and recovered in gas plants rather than lease separators or other lease facilities, and (2) NGL includes very light hydrocarbons (ethane, propane, or butanes) as well as the pentanes-plus that are the main constituents of condensate.
Confidence Level	4.2	A measure of the estimated reliability of a result. As used in the deterministic incremental method, the evaluator assigns a relative level of confidence (high/moderate/low) to areas/segments of an accumulation based on the information available (e.g., well control and seismic coverage). Probabilistic and statistical methods use the 90% (P90) for the high confidence (low value case), 50% (P50) for the best estimate (moderate value case), and 10% (P10) for the low (high value case) estimate to represent the chances that the actual value will equal or exceed the estimate.
Constant Case	3.1.2	A descriptor applied to the economic evaluation of resources estimates. Constant-case estimates are based on current economic conditions being those conditions (including costs and product prices) that are fixed at the evaluation date and held constant, with no inflation or deflation made to costs or prices throughout the remainder of the project life other than those permitted contractually.
Consumed in Operations (CiO)	3.2.2	That portion of produced petroleum consumed as fuel in production or lease plant operations before delivery to the market at the reference point. (Also called lease fuel.)
Contingency	1.1	A condition that must be satisfied for a project in Contingent Resources to be reclassified as Reserves. Resolution of contingencies for projects in Development Pending is expected to be achieved within a reasonable time period.
Contingent Project	1.1	A project that is not yet commercial owing to one or more contingencies that have not been resolved.
Contingent Resources	1.1 Table 1	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable owing to one or more contingencies.
Continuous-Type Deposit	2.4	A petroleum accumulation that is pervasive throughout a large area and that generally lacks well-defined OWC or GWC. Such accumulations are included in unconventional resources. Examples of such deposits include “basin-centered” gas, tight gas, tight oil, gas hydrates, natural bitumen, and oil shale (kerogen) accumulations.

Conventional Resources	2.4	Resources that exist in porous and permeable rock with buoyancy pressure equilibrium. The PIIP is trapped in discrete accumulations related to a localized geological structural feature and/or stratigraphic condition, typically with each accumulation bounded by a down dip contact with an aquifer, and is significantly affected by hydrodynamic influences such as buoyancy of petroleum in water.
Cost Recovery	3.3	Under a typical production-sharing agreement, the contractor is responsible for the field development and all exploration and development expenses. In return, the contractor recovers costs (investments and operating expenses) out of the production stream. The contractor normally receives an entitlement interest share in the petroleum production and is exposed to both technical and market risks.
Crude Oil	3.2.9	Crude oil is the portion of petroleum that exists in the liquid phase in natural underground reservoirs and remains liquid at atmospheric conditions of pressure and temperature (excludes retrograde condensate). Crude oil may include small amounts of non-hydrocarbons produced with the liquids but does not include liquids obtained from the processing of natural gas.
Cumulative Production	1.1	The sum of petroleum quantities that have been produced at a given date. (See also Production). Production is measured under defined conditions to allow for the computation of both reservoir voidage and sales quantities and for the purpose of voidage also includes non-petroleum quantities.
Current Economic Conditions	3.1.2	Economic conditions based on relevant historical petroleum prices and associated costs averaged over a specified period. The default period is 12 months. However, in the event that a step change has occurred within the previous 12-month period, the use of a shorter period reflecting the step change must be justified and used as the basis of constant-case resources estimates and associated project cash flows.
Defined Conditions	3.0	Forecast of conditions to exist and impact the project during the time period being evaluated. Forecasts should account for issues that impact the commerciality, such as economics (e.g., hurdle rates and commodity price); operating and capital costs; and technical, marketing, sales route, legal, environmental, social, and governmental factors.
Deposit	2.4	Material laid down by a natural process. In resources evaluations, it identifies an accumulation of hydrocarbons in a reservoir. (See Accumulation.)
Deterministic Incremental Method	4.2	An assessment method based on defining discrete parts or segments of the accumulation that reflect high, moderate, and low confidence regarding the estimates of recoverable quantities under the defined development plan.
Deterministic Method	4.2	An assessment method based on discrete estimate(s) made based on available geoscience, engineering, and economic data and corresponds to a given level of certainty.
Deterministic Scenario Method	4.2	Method where the evaluator provides three deterministic estimates of the quantities to be recovered from the project being applied to the accumulation. Estimates consider the full range of values for each input parameter based on available engineering and geoscience data, but one set is selected that is most appropriate for the corresponding resources confidence category. A single outcome of recoverable quantities is derived for each scenario.
Developed Reserves	2.1.3.5 Table 2	Reserves that are expected to be recovered from existing wells and facilities. Developed Reserves may be further sub-classified as Producing or Non-Producing.
Developed Producing Reserves	2.1.3.5 Table 2	Developed Reserves that are expected to be recovered from completion intervals that are open and producing at the effective date. Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves	2.1.3.5 Table 2	Developed Reserves that are either shut-in or behind-pipe. (See also Shut-In Resources and Behind-Pipe Reserves.)
Development On Hold	2.1.3.5 Table 1	A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay. A project maturity sub-class of Contingent Resources.
Development Not Viable	2.1.3.5 Table 1	A discovered accumulation for which there are contingencies resulting in there being no current plans to develop or to acquire additional data at the time due to limited commercial potential. A project maturity sub-class of Contingent Resources.
Development Pending	2.1.3.5 Table 1	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future. A project maturity sub-class of Contingent Resources.
Development Plan	2.1.3.6	The design specifications, timing, and cost estimates of the appraisal and development project(s) that are planned in a field or group of fields. The plan will include, but is not limited to, well locations, completion techniques, drilling methods, processing facilities, transportation, regulations, and marketing. The plan is often executed in phases when involving large, complex, sequential recovery and/or extensive areas.
Development Unclarified	2.1.3.5 Table 1	A discovered accumulation where project activities are under evaluation and where justification as a commercial development is unknown based on available information. This sub-class requires appraisal or study and should not be maintained without a plan for future evaluation. The sub-class should reflect the actions required to move a project toward commercial maturity. A project maturity sub-class of Contingent Resources.
Discovered	2.1.1	A petroleum accumulation where one or several exploratory wells through testing, sampling, and/or logging have demonstrated the existence of a significant quantity of potentially recoverable hydrocarbons and thus have established a known accumulation. In this context, “significant” implies that there is evidence of a sufficient quantity of petroleum to justify estimating the in-place volume demonstrated by the well(s) and for evaluating the potential for technical recovery. (See also Known Accumulation.)
Discovered Petroleum Initially-In-Place	1.1	Quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations before production. Discovered PIIP may be subdivided into commercial, sub-commercial, and the portion remaining in the reservoir as Unrecoverable.
Discovered Unrecoverable	2.1.1	Discovered petroleum in-place resources that are evaluated, as of a given date, as not able to be recovered by the commercial and sub-commercial projects envisioned.
Dry Gas	3.2.3	Natural gas remaining after hydrocarbon liquids have been removed before the reference point. It should be recognized that this is a resources assessment definition and not a phase behavior definition. (Also called lean gas.)
Economic	3.1.2	A project is economic when it has a positive undiscounted cumulative cash flow from the effective date of the evaluation, the net revenue exceeds the net cost of operation (i.e., positive cumulative net cash flow at discount rate greater than or equal to zero percent).
Economic Interest	3.3	Interest that is possessed when an entity has acquired an interest in the minerals in-place or a license and secures, by any form of legal relationship, revenue derived from the extraction of the mineral to which he must look for a return.
Economic Limit	3.1.2	Defined as the time when the maximum cumulative net cash flow (see Net Entitlement) occurs for a project.

Economically Not Viable Contingent Resources	2.1.3.7	Those quantities for which development projects are not expected to yield positive cash flows under reasonable forecast conditions. May also be subject to additional unsatisfied contingencies.
Economically Viable Contingent Resources	2.1.3.7	Those quantities associated with technically feasible projects where cash flows are positive under reasonable forecast conditions but are not Reserves because it does not meet the other commercial criteria
Economically Producible	3.1.2	Refers to the situation where the net revenue from an ongoing producing project exceeds the net expenses attributable to a certain entity's interest. The ADR costs are excluded from the determination.
Effective Date	1.2	Resource estimates of remaining quantities are "as of the given date" (effective date) of the evaluation. The evaluation must take into account all data related to the period before the "as of date."
Entitlement	3.3	That portion of future production (and thus resources) legally accruing to an entity under the terms of the development and production contract or license.
Entity	3.0	A legal construct capable of bearing legal rights and obligations. In resources evaluations, this typically refers to the lessee or contractor, which is some form of legal corporation (or consortium of corporations). In a broader sense, an entity can be an organization of any form and may include governments or their agencies.
Established Technology	2.3.4	Methods of recovery or processing that have proved to be successful in commercial applications.
Estimated Ultimate Recovery (EUR)	1.1	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable plus those quantities that have been already produced. For clarity, EUR must reference the associated technical and commercial conditions for the resources; for example, proved EUR is Proved Reserves plus prior production.
Evaluation	3.0	The geosciences, engineering, and associated studies, including economic analyses, conducted on a petroleum exploration, development, or producing project resulting in estimates of the quantities that can be recovered and sold and the associated cash flow under defined forward conditions. (Also called assessment.)
Evaluator	1.2	The person or group of persons responsible for performing an evaluation of a project. These may be employees of the entities that have an economic interest in the project or independent consultants contracted for reviews and audits. In all cases, the entity accepting the evaluation takes responsibility for the results, including its resources and attributed value estimates.
Exploration	2.1.3.5	Prospecting for undiscovered petroleum using various techniques, such as seismic surveys, geological studies, and exploratory drilling.
Field	1.2	In conventional reservoirs, a field is typically an area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impermeable rock, laterally by local geologic barriers, or both. The term may be defined differently by individual regulatory authorities. For unconventional reservoirs without hydrodynamic influences, a field is often defined by regulatory or ownership boundaries as necessary.
Final Investment Decision (FID)	2.1.3.1	Project approval stage when the participating companies have firmly agreed to the project and the required capital funding.
Flare Gas	3.2.2	The total quantity of gas vented and/or burned as part of production and processing operations (but not as fuel).

Flow Test	2.1.1	An operation on a well designed to demonstrate the existence of recoverable petroleum in a reservoir by establishing flow to the surface and/or to provide an indication of the potential productivity of that reservoir (such as a wireline formation test). May also demonstrate the potential of certain completion techniques, particularly in unconventional reservoirs.
Fluid Contacts	4.2	The surface or interface in a reservoir separating two regions characterized by predominant differences in fluid saturations. Because of capillary and other phenomena, fluid saturation change is not necessarily abrupt or complete, nor is the surface necessarily horizontal.
Forecast Case	3.1.2	A descriptor applied to a scenario when production and associated cash-flow estimates are based on those conditions (including costs and product price schedules, inflation indexes, and market factors) forecast by the evaluator to reasonably exist throughout the evaluation life (i.e., defined conditions). Inflation or deflation adjustments are made to costs and revenues over the evaluation period.
Gas Balance	3.2.8	In gas production operations involving multiple working interest owners, maintaining a statement of volumes attributed to each, depending on each owner's portion received. Imbalances may occur that must be monitored over time and eventually balanced in accordance with accepted accounting procedures.
Gas Cap Gas	Table 3	Free natural gas that overlies and is in contact with crude oil in the reservoir. It is a subset of associated gas.
Gas Hydrates	2.4	Naturally occurring crystalline substances composed of water and gas, in which a solid water lattice accommodates gas molecules in a cage-like structure or clathrate. At conditions of standard temperature and pressure, one volume of saturated methane hydrate will contain as much as 164 volumes of methane gas. Gas hydrates are included in unconventional resources, but the technology to support commercial maturity has yet to be developed.
Gas/Oil Ratio	4.1.4	Ratio that is calculated using measured natural gas and crude oil volumes at stated conditions. The gas/oil ratio may be the solution gas/oil ratio, R_s; produced gas/oil ratio, R_p; or another suitably defined ratio of gas production to oil production.
Geostatistical Methods	4.2.2	A variety of mathematical techniques and processes dealing with the collection, methods, analysis, interpretation, and presentation of large quantities of geoscience and engineering data to (mathematically) describe the variability and uncertainties within any reservoir unit or pool, specifically related here to resources estimates.
High Estimate	2.2.2	With respect to resources categorization, this is considered to be an optimistic estimate of the quantity that will actually be recovered from an accumulation by a project. If probabilistic methods are used, there should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate.
Hydrates	2.4	See Gas Hydrates.
Hydrocarbons	1.1	Hydrocarbons are chemical compounds consisting wholly of hydrogen and carbon molecules.
Improved Recovery	2.3.4	The extraction of additional petroleum, beyond primary recovery, from naturally occurring reservoirs by supplementing the natural forces in the reservoir. It includes waterflooding and gas injection for pressure maintenance, secondary processes, tertiary processes, and any other means of supplementing natural reservoir recovery processes. Improved recovery also includes thermal and chemical processes to improve the in-situ mobility of viscous forms of petroleum. (Also called enhanced recovery.)
Injection	3.2.5	The forcing, pumping, or natural flow of substances into a porous and permeable subsurface rock formation. Injected substances can include either gases or liquids.

Justified for Development	2.1.3.5 Table 1	A development project that has reasonable forecast commercial conditions at the time of reporting and there are reasonable expectation that all necessary approvals/ contracts will be obtained. A project maturity sub-class of Reserves.
Kerogen	2.4	The naturally occurring, solid, insoluble organic material that occurs in source rocks and can yield oil upon heating. Kerogen is also defined as the fraction of large chemical aggregates in sedimentary organic matter that is insoluble in solvents (in contrast, the fraction that is soluble in organic solvents is called bitumen). (See also Oil Shales.)
Known Accumulation	2.1.1	An accumulation that has been discovered.
Lead	2.1.3.5 Table 1	A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation to be classified as a Prospect. A project maturity sub-class of Prospective Resources.
Learning Curve	2.4	Demonstrated improvements over time in performance of a repetitive task that results in efficiencies in tasks to be realized and/or in reduced time to perform and ultimately in cost reductions.
Likelihood	1.1	Likelihood (the estimated probability or chance) is equal (1- risk). (See Probability and Risk.)
Low/Best/High Estimates	2.2.2	Reflects the range of uncertainty as a reasonable range of estimated potentially recoverable quantities.
Low Estimate	2.2.2	With respect to resources categorization, this is a conservative estimate of the quantity that will actually be recovered from the accumulation by a project. If probabilistic methods are used, there should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate.
Lowest Known Hydrocarbons (LKH)	4.1.2	The deepest documented occurrence of a producible hydrocarbon accumulation as interpreted from well log, flow test, pressure measurement, core data, or other conclusive and reliable evidence.
Market	1.1	A consumer or group of consumers of a product that has been obtained through purchase, barter, or contractual terms.
Marketable Quantities	2.0	Those quantities of hydrocarbons that are estimated to be producible from petroleum accumulations and that will be consumed by the market. (Also referred to as marketable products.)
Mean	4.2.5	The sum of a set of numerical values divided by the number of values in the set.
Measurement	3.2	The process of establishing quantity (volume, mass, or energy content) and quality of petroleum products delivered to a reference point under conditions defined by delivery contract or regulatory authorities.
Mineral Lease	3.3	An agreement in which a mineral owner (lessor) grants an entity (lessee) rights. Such rights can include (1) a fee ownership or lease, concession, or other interest representing the right to extract oil or gas subject to such terms as may be imposed by the conveyance of the lease; (2) royalty interests, production payments payable in oil or gas, and other non-operating interests in properties operated by others; and/or (3) those agreements with foreign governments or authorities under which a reporting entity participates in the operation of the related properties or otherwise serves as producer of the underlying reserves (as opposed to being an independent purchaser, broker, dealer, or importer).
Monte Carlo Simulation	4.2	A type of stochastic mathematical simulation that randomly and repeatedly samples input distributions (e.g., reservoir properties) to generate a resulting distribution (e.g., recoverable petroleum quantities).

Multi-Scenario Method	4.2	An extension of the deterministic scenario method. In this case, a significant number of discrete deterministic scenarios are developed by the evaluator, with each scenario leading to a single deterministic outcome. Probabilities may be assigned to each discrete input assumption from which the probability of the scenario can be obtained; alternatively, each outcome may be assumed to be equally likely.
Natural Bitumen	2.4	The portion of petroleum that exists in the semi-solid or solid phase in natural deposits. In its natural state, it usually contains sulfur, metals, and other non-hydrocarbons. Natural bitumen has a viscosity greater than 10,000 mPa·s (or 10,000 cp) measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural viscous state, it is not normally recoverable at commercial rates through a well and requires the implementation of improved recovery methods such as steam injection. Natural bitumen generally requires upgrading before normal refining.
Natural Gas	3.2.3	Portion of petroleum that exists either in the gaseous phase or is in solution in crude oil in a reservoir, and which is gaseous at atmospheric conditions of pressure and temperataure. Natural gas may include some amount of non-hydrocarbons.
Natural Gas Liquids (NGLs)	3.2.3	A mixture of light hydrocarbons that exist in the gaseous phase in the reservoir and are recovered as liquids in gas processing plants. NGLs differ from condensate in two principal respects: (1) NGLs are extracted and recovered in gas plants rather than lease separators or other lease facilities, and (2) NGLs include very light hydrocarbons (ethane, propane, or butanes) as well as the pentanes-plus that are the main constituents of condensates.
Net Entitlement	1.1 3.3	That portion of future production (and thus resources) legally accruing to an entity under the terms of the development and production contract or license. Under the terms of PSCs, the producers have an entitlement to a portion of the production. This entitlement, often referred to as “net entitlement” or “net economic interest,” is estimated using a formula based on the contract terms incorporating costs and profits.
Net Pay	4.1.1	The portion (after applying cutoffs) of the thickness of a reservoir from which petroleum can be produced or extracted. Value is referenced to a true vertical thickness measured.
Net Revenue Interest	3.3.1	An entity’s revenue share of petroleum sales after deduction of royalties or share of production owing to others under applicable lease and fiscal terms. (See also Entitlement and Net Entitlement)
Netback Calculation	3.2.1	Term used in the hydrocarbon product price determination at reference point to reflect the revenue of one unit of sales after the costs associated with bringing the product to a market (e.g., transportation and processing) are removed.
Non-Hydrocarbon Gas	3.2.4	Associated gases such as nitrogen, carbon dioxide, hydrogen sulfide, and helium that are present in naturally occurring petroleum accumulations.
Non-Sales	1.1	That portion of estimated recoverable or produced quantities that will not be included in sales as contractually defined at the reference point. Non-sales include quantities CiO, flare, and surface losses, and may include non-hydrocarbons.
Oil Sands	2.4	Sand deposits highly saturated with natural bitumen. Also called “tar sands.” Note that in deposits such as the western Canada oil sands, significant quantities of natural bitumen may be hosted in a range of lithologies, including siltstones and carbonates.
Oil Shales	2.4	Shale, siltstone, and marl deposits highly saturated with kerogen. Whether extracted by mining or in-situ processes, the material must be extensively processed to yield a marketable product (synthetic crude oil). (Often called kerogen shale.)

On Production	2.1.3.5 Table 1	A project maturity sub-class of Reserves that reflects the operational execution phase of one or multiple development projects with the Reserves currently producing or capable of producing. Includes Developed Producing and Developed Non-Producing Reserves.
Overlift/Underlift	3.2.8	Production entitlements received that vary from contractual terms resulting in overlift or underlift positions. This can occur in annual records because of the necessity for companies to lift their entitlement in parcel sizes to suit the available shipping schedules as agreed upon by the parties. At any given financial year-end, a company may be in overlift or underlift. Based on the production matching the company's accounts, production should be reported in accord with and equal to the liftings actually made by the company during the year and not on the production entitlement for the year.
P1	1.1	Denotes Proved Reserves. P1 is equal to 1P.
P2	1.1	Denotes Probable Reserves.
P3	1.1	Denotes Possible Reserves.
Penetration	Table 3	The intersection of a wellbore with a reservoir.
Petroleum	1.0	Defined as a naturally occurring mixture consisting of hydrocarbons in the gaseous, liquid, or solid phase. Petroleum may also contain non-hydrocarbon compounds, common examples of which are carbon dioxide, nitrogen, hydrogen sulfide, and sulfur. In rare cases, non-hydrocarbon content of petroleum can be greater than 50%.
Petroleum Initially-in-Place (PIIP)	1.1	The total quantity of petroleum that is estimated to exist originally in naturally occurring reservoirs, as of a given date. Crude oil in-place, natural gas in-place, and natural bitumen in-place are defined in the same manner.
Pilot Project	2.3	A small-scale test or trial operation used to assess technology, including recovery processes, for commercial application in a specific reservoir.
Play	2.1.3.5 Table 1	A project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation to define specific Leads or Prospects. A project maturity sub-class of Prospective Resources.
Pool	4.2.2	An individual and separate accumulation of petroleum in a reservoir within a field.
Possible Reserves	2.2.2	An incremental category of estimated recoverable quantities associated with a defined degree of uncertainty. Possible Reserves are those additional reserves that analysis of geoscience and engineering data suggest are less likely to be recoverable than Probable Reserves. The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high estimate scenario. When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate.
Primary Recovery	2.3.4	The extraction of petroleum from reservoirs using only the natural energy available in the reservoirs to move fluids through the reservoir rock to other points of recovery.
Probability	2.2.1	The extent to which an event is likely to occur, measured by the ratio of the favorable cases to the whole number of cases possible. PRMS convention is to quote cumulative probability of exceeding or equaling a quantity where P90 is the small estimate and P10 is the large estimate. (See also Uncertainty.)
Probabilistic Method	4.2.3	The method of estimation of resources is called probabilistic when the known geoscience, engineering, and economic data are used to generate a continuous range of estimates and their associated probabilities.

Probable Reserves	2.2.2	An incremental category of estimated recoverable quantities associated with a defined degree of uncertainty. Probable Reserves are those additional Reserves that are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves. It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate.
Production	1.1	The cumulative quantities of petroleum that have been recovered at a given date. Production can be reported in terms of the sales product specifications, but project evaluation requires that all production quantities (sales and non-sales), as measured to support engineering analyses requiring reservoir voidage calculations, are recognized.
Production Forecast	2.1.3.7	A forecasted schedule of production over time. For Reserves, the production forecast reflects a specific development scenario under a specific recovery process, a certain number and type of wells and particular facilities and infrastructure. When forecasting Contingent or Prospective Resources, more than one project scope (e.g., wells and facilities) is frequently carried to determine the range of the potential project and its uncertainty together with the associated resources defining the low, best, and high production forecasts. The uncertainty in resources estimates associated with a production forecast is usually quantified by using at least three scenarios or cases of low, best, and high, which lead to the resources classifications of, respectively, 1P, 2P, 3P and 1C, 2C, 3C or 1U,2U and 3U.
Production- Sharing Contract (PSC)	3.3.2	A contract between a contractor and a host government in which the contractor typically bears the risk and costs for exploration, development, and production. In return, if exploration is successful, the contractor is given the opportunity to recover the incurred investment from production, subject to specific limits and terms. Ownership of petroleum in the ground is retained by the host government; however, the contractor normally receives title to the prescribed share of the quantities as they are produced. (Also termed production-sharing agreement (PSA).
Project	1.2	A defined activity or set of activities that provides the link between the petroleum accumulation's resources sub-class and the decision-making process, including budget allocation. A project may, for example, constitute the development of a single reservoir or field, an incremental development in a larger producing field, or the integrated development of a group of several fields and associated facilities (e.g. compression) with a common ownership. In general, an individual project will represent a specific maturity level (sub-class) at which a decision is made on whether or not to proceed (i.e., spend money), suspend, or remove. There should be an associated range of estimated recoverable resources for that project. (See also Development Plan.)
Property	1.2	A defined portion of the Earth's crust wherein an entity has contractual rights to extract, process, and market specified in-place minerals (including petroleum). In general, defined as an area but may have depth and/or stratigraphic constraints. May also be termed a lease, concession, or license.
Prospect	2.1.3.5 Table 1	A project associated with an undrilled potential accumulation that is sufficiently well defined to represent a viable drilling target. A project maturity sub-class of Prospective Resources.
Prospective Resources	1.1 Table 1	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects.

Proved Reserves	2.2.2 Table 3	An incremental category of estimated recoverable quantities associated with a defined degree of uncertainty. Proved Reserves are those quantities of petroleum that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations. If deterministic methods are used, the term “reasonable certainty” is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate.
Pure Service Contract	3.3	Agreement between a contractor and a host government that typically covers a defined technical service to be provided or completed during a specific time period. The service company investment is typically limited to the value of equipment, tools, and expenses for personnel used to perform the service. In most cases, the service contractor’s reimbursement is fixed by the contract’s terms with little exposure to either project performance or market factors. No Reserves or Resources can be attributed to these activities.
Qualified Reserves Auditor	1.2	A reserves evaluator who (1) has a minimum of ten years of practical experience in petroleum engineering or petroleum production geology, with at least five years of such experience being in responsible charge of the estimation and evaluation of Reserves information; and (2) either (a) has obtained from a college or university of recognized stature a bachelor’s or advanced degree in petroleum engineering, geology, or other discipline of engineering or physical science or (b) has received, and is maintaining in good standing, a registered or certified professional engineer’s license or a registered or certified professional geologist’s license, or the equivalent, from an appropriate governmental authority or professional organization. (see SPE 2007 “Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information”)
Qualified Reserves Evaluator	1.2	A reserves evaluator who (1) has a minimum of five years of practical experience in petroleum engineering or petroleum production geology, with at least three years of such experience being in the estimation and evaluation of Reserves information; and (2) either (a) has obtained from a college or university of recognized stature a bachelor’s or advanced degree in petroleum engineering, geology, or other discipline of engineering or physical science or (b) has received, and is maintaining in good standing, a registered or certified professional engineer’s license or a registered or certified professional geologist’s license, or the equivalent, from an appropriate governmental authority or professional organization. (modified from SPE 2007 “Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information”)
Range of Uncertainty	2.2	The range of uncertainty of the in-place, recoverable, and/or potentially recoverable quantities; may be represented by either deterministic estimates or by a probability distribution. (See Resources Categories.)
Raw Production	3.2.1	All components, whether hydrocarbon or other, produced from the well or extracted from the mine (hydrocarbons, water, impurities such as non-hydrocarbon gases, etc.).
Reasonable Certainty	2.2.2	If deterministic methods for estimating recoverable resources quantities are used, then reasonable certainty is intended to express a high degree of confidence that the estimated quantities will be recovered. Typically attributed to Proved Reserves or 1C Resources quantities.
Reasonable Expectation	2.1.2	Indicates a high degree of confidence (low risk of failure) that the project will proceed with commercial development or the referenced event will occur. (Differs from reasonable certainty, which applies to resources quantity technical confidence, while reasonable expectation relates to commercial confidence.).

Recoverable Resources	1.1 Table 1	Those quantities of hydrocarbons that are estimated to be producible by the project from either discovered or undiscovered accumulations.
Recovery Efficiency	1.2	A numeric expression of that portion (expressed as a percentage) of in-place quantities of petroleum estimated to be recoverable by specific processes or projects, most often represented as a percentage. It is estimated using the recoverable resources divided by the hydrocarbons initially in-place. It is also referenced to timing; current and ultimate (or estimated ultimate) are descriptors applied to reference the stage of the recovery. (Also called recovery factor.)
Reference Point	3.2.1	A defined location within a petroleum extraction and processing operation where quantities of produced product are measured under defined conditions before custody transfer (or consumption). Also called point of sale, terminal point, or custody transfer point.
Report	2.0	The presentation of evaluation results within the entity conducting the assessment. Should not be construed as replacing requirements for public disclosures under guidelines established by regulatory and/or other government agencies.
Reserves	1.1 Table 1	Those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of a given date) based on the development project(s) applied.
Reservoir	1.2	A subsurface rock formation that contains an individual and separate natural accumulation of petroleum that is confined by impermeable barriers, pressure systems, or fluid regimes (conventional reservoirs), or is confined by hydraulic fracture barriers or fluid regimes (unconventional reservoirs).
Resources	1.1	Term used to encompass all quantities of petroleum (recoverable and unrecoverable) naturally occurring in an accumulation on or within the Earth's crust, discovered and undiscovered, plus those quantities already produced. Further, it includes all types of petroleum whether currently considered conventional or unconventional. (See Total Petroleum Initially-in-Place.)
Resources Categories	2.2 Table 3	Subdivisions of estimates of resources to be recovered by a project(s) to indicate the associated degrees of uncertainty. Categories reflect uncertainties in the total petroleum remaining within the accumulation (in-place resources), that portion of the in-place petroleum that can be recovered by applying a defined development project or projects, and variations in the conditions that may impact commercial development (e.g., market availability and contractual changes). The resource quantity uncertainty range within a single resources class is reflected by either the 1P, 2P, 3P, Proved, Probable, Possible, or 1C, 2C, 3C or 1U, 2U, 3U resources categories.
Resources Classes	2.1 Table 1	Subdivisions of resources that indicate the relative maturity of the development projects being applied to yield the recoverable quantity estimates. Project maturity may be indicated qualitatively by allocation to classes and sub-classes and/or quantitatively by associating a project's estimated likelihood of commerciality.
Resources Type	2.4	Describes the accumulation and is determined by the combination of the type of hydrocarbon and the rock in which it occurs.
Revenue-Sharing Contract	3.3.2	Contracts that are very similar to the PSCs with the exception of contractor payment in these contracts, the contractor usually receives a defined share of revenue rather than a share of the production.
Risk	2.1.3	The probability of loss or failure. Risk is not synonymous with uncertainty. Risk is generally associated with the negative outcome, the term "chance" is preferred for general usage to describe the probability of a discrete event occurring.

Risk and Reward	3.3	Risk and reward associated with oil and gas production activities are attributed primarily from the variation in revenues cause by technical and economic risks. The exposure to risk in conjunction with entitlement rights is required to support an entity's resources recognition. Technical risk affects an entity's ability to physically extract and recover hydrocarbons and is usually dependent on a number of technical parameters. Economic risk is a function of the success of a project and is critically dependent on cost, price, and political or other economic factors.
Risk Service Contract (RSC)	3.3	Agreements that are very similar to the production-sharing agreements in that the risk is borne by the contractor but the mechanism of contractor payment is different. With a RSC, the contractor usually receives a defined share of revenue rather than a share of the production.
Royalty	3.3.1	A type of entitlement interest in a resource that is free and clear of the costs and expenses of development and production to the royalty interest owner. A royalty is commonly retained by a resources owner (lessor/host) when granting rights to a producer (lessee/contractor) to develop and produce that resource. Depending on the specific terms defining the royalty, the payment obligation may be expressed in monetary terms as a portion of the proceeds of production or as a right to take a portion of production in-kind. The royalty terms may also provide the option to switch between forms of payment at discretion of the royalty owner.
Sales	3.2	The quantity of petroleum and any non-hydrocarbon product delivered at the custody transfer point (reference point) with specifications and measurement conditions as defined in the sales contract and/or by regulatory authorities.
Shale Gas	2.4	Although the terms shale gas and tight gas are often used interchangeably in public discourse, shale formations are only a subset of all low-permeability tight formations, which include sandstones and carbonates, as well as shales, as sources of tight gas production
Shale Oil	2.4	Although the terms shale oil and tight oil are often used interchangeably in public discourse, shale formations are only a subset of all low-permeability tight formations, which include sandstones and carbonates, as well as shales, as sources of tight oil production
Shut-In Resources	2.1.3.6 Table 2	Resources planned to be recovered from (1) completion intervals that are open at the time of the estimate, but which have not started producing; (2) wells that were shut-in for market conditions or pipeline connections; or (3) wells not capable of production for mechanical reasons that can be remediated at a limited cost compared to the cost of the well.
Split Classification	2.2	A single project should be uniquely assigned to a sub-class along with its uncertainty range, For example, a project cannot have quantities categorized as 1C, 2P, and 3P. This is referred to as "split classification." If there are differing commercial conditions, separate sub-classes should be defined.
Split Conditions	2.2	The uncertainty in recoverable quantities is assessed for each project using resources categories. The assumed commercial conditions are associated with resource classes or sub-classes and not with the resources categories. For example, the product price assumptions are those assumed when classifying projects as Reserves, and a different price would not be used for assessing Proved versus Probable reserves. That would be referred to as "split conditions."
Stochastic	4.2.3	Adjective defining a process involving or containing a random variable or variables or involving likelihood or probability, such as a stochastic simulation.

Sub-Commercial	1.1	A project subdivision that is applied to discovered resources that occurs if either the technical or commercial maturity conditions of project have not yet been achieved. A project is sub-commercial if the degree of commitment is such that the accumulation is not expected to be developed and placed on production within a reasonable time-frame. Sub-commercial projects are classified as Contingent Resources.
Sunk Cost	3.1.2	Money spent before the effective date and that cannot be recovered by any future action. Sunk costs are not relevant to future business decisions because the cost will be the same regardless of the outcome of the decision. Sunk costs differ from committed (obligated) costs, where there is a firm and binding agreement to spend specified amounts of money at specific times in the future (i.e., after the effective date).
Synthetic Crude Oil	3.2.9	A mixture of hydrocarbons derived by upgrading (i.e., chemically altering) natural bitumen from oil sands, kerogen from oil shales, or processing of other substances such as natural gas or coal. Synthetic crude oil may contain sulfur or other non-hydrocarbon compounds and has many similarities to crude oil.
Taxes	3.1.1	Obligatory contributions to the public funds, levied on persons, property, or income by governmental authority.
Technical Forecast	2.1.2	The forecast of produced resources quantities that is defined by applying only technical limitations (i.e., well-flow-loading conditions, well life, production facility life, flow-limit constraints, facility uptime, and the facility's operating design parameters). Technical limitations do not take into account the application of either an economic or license cutoff. (See also Technically Recoverable Resources).
Technical Uncertainty	2.2	Indication of the varying degrees of uncertainty in estimates of recoverable quantities influenced by the range of potential in-place hydrocarbon resources within the reservoir and the range of the recovery efficiency of the recovery project being applied.
Technically Recoverable Resources	1.1	Those quantities of petroleum producible using currently available technology and industry practices, regardless of commercial or accessibility considerations.
Technology Under Development	2.1.1	Technology that is currently under active development and that has not been demonstrated to be commercially viable. There should be sufficient direct evidence (e.g., a test project/pilot) to indicate that the technology may reasonably be expected to be available for commercial application.
Tight Gas	2.4	Gas that is trapped in pore space and fractures in very low-permeability rocks and/or by adsorption on kerogen, and possibly on clay particles, and is released when a pressure differential develops. It usually requires extensive hydraulic fracturing to facilitate commercial production. Shale gas is a sub-type of tight gas.
Tight Oil	2.4	Crude oil that is trapped in pore space in very low-permeability rocks and may be liquid under reservoir conditions or become liquid at surface conditions. Extensive hydraulic fracturing is invariably required to facilitate commercial maturity and economic production. Shale oil is a sub-type of tight oil.
Total Petroleum Initially-in-Place	1.1	All estimated quantities of petroleum that are estimated to exist originally in naturally occurring accumulations, discovered and undiscovered, before production.
Uncertainty	2.2	The range of possible outcomes in a series of estimates. For recoverable resources assessments, the range of uncertainty reflects a reasonable range of estimated potentially recoverable quantities for an individual accumulation or a project. (See also Probability.)

Unconventional Resources	2.4	Unconventional resources exist in petroleum accumulations that are pervasive throughout a large area and lack well-defined OWC or GWC (also called “continuous-type deposits”). Such resources cannot be recovered using traditional recovery projects owing to fluid viscosity (e.g., oil sands) and/or reservoir permeability (e.g., tight gas/oil/CBM) that impede natural mobility. Moreover, the extracted petroleum may require significant processing before sale (e.g., bitumen upgraders).
Undeveloped Reserves	2.1.3.5 Table 2	Those quantities expected to be recovered through future investments: (1) from new wells on undrilled acreage in known accumulations, (2) from deepening existing wells to a different (but known) reservoir, (3) from infill wells that will increase recovery, or (4) where a relatively large expenditure (e.g., when compared to the cost of drilling and completing a new well) is required to recomplete an existing well.
Undiscovered Petroleum Initially-in-Place	1.1	That quantity of petroleum estimated, as of a given date, to be contained within accumulations yet to be discovered.
Unrecoverable Resources	1.1	Those quantities of discovered or undiscovered PIIP that are assessed, as of a given date, to be unrecoverable by the currently defined project(s). A portion of these quantities may become recoverable in the future as commercial circumstances change, technology is developed, or additional data are acquired. The remaining portion may never be recovered owing to physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.
Upgrader	2.4	A general term applied to processing plants that convert extra-heavy crude oil and natural bitumen into lighter crude and less viscous synthetic crude oil. While the detailed process varies, the underlying concept is to remove carbon through coking or to increase hydrogen by hydrogenation processes using catalysts.
Wet Gas	3.2.3	Natural gas from which no liquids have been removed before the reference point. The wet gas is accounted for in resources assessments, and there is no separate accounting for contained liquids. It should be recognized that this is a resources assessment definition and not a phase behavior definition.
Working Interest	3.3	An entity’s equity interest in a project before reduction for royalties or production share owed to others under the applicable fiscal terms.

Delek Drilling

Board of Directors Report

2020

Delek Drilling – Limited Partnership

Chapter B

The Board of Directors' Report about the State of the Partnership's Affairs

for the Year Ended December 31, 2020

This report is a translation of Delek Drilling - Limited Partnership's Hebrew-language Board of Directors' Report of the General Partner. It is prepared solely for convenience purposes. Please note that the Hebrew version constitutes the binding version, and in any event of discrepancy, the Hebrew version shall prevail.

March 14, 2021

Delek Drilling - Limited Partnership

Report of the Board of Directors of the General Partner for the Period Ended December 31, 2020

The board of directors of Delek Drilling Management (1993) Ltd. (the "**General Partner"**) hereby respectfully submits the board of directors' report for the year ended December 31, 2020 (the "**Report Year**").

Part One – Explanations of the Board of Directors on the State of the Partnership's Business

1. Main figures from the description of the Partnership's business

For a description of the Partnership's business and the developments that occurred in the Report Year – see Chapter A (Description of the Partnership's Business).

2. Results of operations

A. General

On December 31, 2019, the piping of natural gas from the Leviathan reservoir to the domestic market began, and in January 2020, the piping of natural gas began to Jordan and to Egypt.

As of the date of approval of the financial statements, the Partnership's primary business is exploration, development and production of natural gas, condensate and oil in Israel and Cyprus, as well as the promotion of various natural gas-based projects, with the aim of increasing the volume of natural gas sales from the Partnership's assets. At the same time, the Partnership explores business opportunities in the exploration, development and production of natural gas and oil in the Mediterranean Basin. According to the provisions of the Gas Framework (see Note 12L1 to the attached financial statements), the Partnership is required to transfer, by December 2021, all of its interests in the Tamar I/12 and Dalit I/13 leases (collectively: "**Tamar and Dalit**"). Therefore, as of the date of approval of the financial statements, the Partnership intends to focus its efforts in the near future on finding the best solution for compliance with the requirements of the Gas Framework, in which context it intends to work mainly to advance the possibility of sale of such interests to a third party. At the same time, the Partnership is working to advance a possible split of its assets, under which all of the Partnership's assets, apart from its interests in the Tamar and Dalit leases and the Yam Tethys project, shall be transferred to a new UK corporation (the "**UK Corporation**") against an allotment of shares to be distributed to the holders of the participation units. Further thereto, the UK Corporation will issue shares to foreign investors and have its shares listed on the London Stock Exchange and on the Tel Aviv Stock Exchange (TASE). For details, see Note 1E to the financial statements attached below.

The Partnership's net profit in 2020 amounted to approx. $365 million, compared with approx. $224 million last year. The increase in profit mainly derives from commencement of the production of gas from the Leviathan reservoir for the domestic market and regional markets. Conversely, in the Report Year, credit costs were recorded which were capitalized to the cost of the Leviathan project last year.

The Partnership's net profit in Q4/2020 totaled approx. $142 million, compared with approx. $78 million in the same quarter last year. The increase in net profit chiefly derived from the production of gas from the Leviathan reservoir for the domestic market and regional markets and from increase in revenues from revaluation of royalties receivable from the Karish and Tanin leases. Conversely, in Q4/2020 credit costs were recorded which were capitalized to the cost of the Leviathan project in the same quarter last year.

B. Analysis of statements of comprehensive income

Below are main figures with regards to the Partnership's statements of comprehensive income (dollars in thousands):

	1-3/20	4-6/20	7-9/20	10-12/20	2020	10-12/19	2019
Revenues:							
From natural gas and condensate sales	225,189	167,731	282,179	244,023	919,122	113,408	453,344
Net of royalties	38,510	27,509	47,961	40,284	154,264	26,588	94,318
Revenues, net	**186,679**	**140,222**	**234,218**	**203,739**	**764,858**	**86,820**	**359,026**
Expenses and costs:							
Cost of gas and condensate production	23,858	24,081	30,720	35,298	113,957	8,801	40,731
Depreciation, depletion and amortization expenses	24,574	28,248	30,699	28,286	111,807	17,475	67,581
Other general expenses	1,315	749	928	619	3,611	4,625	14,298
G&A expenses	2,641	3,254	5,154	3,581	14,630	2,964	11,130
Total expenses and costs	**52,388**	**56,332**	**67,501**	**67,784**	**244,005**	**33,865**	**133,740**
Other expenses	-	-	-	-	-	-	(474)
The Partnership's share in the profits (losses) of companies accounted for at equity, net	5	-	(3,778)	(3,934)	(7,707)	(5)	(36,645)
Operating income before oil and gas profit levy	**134,296**	**83,890**	**162,939**	**132,021**	**513,146**	**52,950**	**188,167**
Oil and gas profit levy	-	-	-	(3,837)	(3,837)	5,934	4,620
Operating income	**134,296**	**83,890**	**162,939**	**128,184**	**509,309**	**58,884**	**192,787**
Financial expenses	(52,602)	(57,461)	(70,912)	(51,537)	(232,512)	(11,212)	(47,487)
Financial income	2,573	8,836	11,123	65,791	88,323	30,713	78,390
Financial income (expenses), net	(50,029)	(48,625)	(59,789)	14,254	(144,189)	19,501	30,903
Net profit	**84,267**	**35,265**	**103,150**	**142,438**	**365,120**	**78,385**	**223,690**
Other comprehensive income (loss) in respect of items which may subsequently be reclassified to profit or loss:							
Profit (loss) in respect of cash flow hedging transactions	(6,486)	1,895	(166)	-	(4,757)	1,037	(5,150)
Carried to profit or loss in respect of cash flow hedging transactions	(42)	575	6,827	-	7,360	(559)	(1,830)
	(6,528)	2,470	6,661	-	2,603	478	(6,980)
Amounts which will not be subsequently reclassified to profit or loss:							
Profit (loss) from investment in equity instruments designated for measurement at fair value through other comprehensive income	(35,975)	584	1,545	4,524	(29,322)	(4,840)	(41,256)
Total other comprehensive income (loss) for the period	**(42,503)**	**3,054**	**8,206**	**4,524**	**(26,719)**	**(4,362)**	**(48,236)**
Total comprehensive income	**41,764**	**38,319**	**111,356**	**146,962**	**338,401**	**74,023**	**175,454**
Gas sales in BCM[1]	**3.6**	**2.9**	**4.6**	**4.4**	**15.5**	**2.6**	**10.5**
Condensate sales in Israel in thousands of barrels[2]	**213**	**141**	**320**	**270**	**944**	**123**	**482**

[1] The figures refer to natural gas sales (100%) from the Tamar and Leviathan projects (last year Tamar and Yam Tethys), rounded off to one tenth of the BCM.

[2] The figures refer to condensate sales (100%) from the Tamar and Leviathan projects (last year Tamar only), rounded off to thousands of barrels. Also see Note 12D to the financial statements attached below regarding agreements with respect to the condensate sales from the Leviathan reservoir.

Net revenues in the Report Year amounted to approx. $765 million, compared with approx. $359 million last year, an increase of approx. 113%. The increase chiefly derives from the commencement of production from the Leviathan reservoir as noted above. In the Report Year, approx. 15.5 BCM of natural gas were sold from the Tamar and Leviathan reservoirs (100%), compared with approx. 10.5 BCM last year, approx. 11.2 BCM of which to the domestic market and approx. 4.3 BCM for export (last year, approx. 10.3 BCM to the domestic market and approx. 0.2 BCM for export).

The Partnership's net revenues from the Leviathan reservoir in the Report Year totaled approx. $501 million and reflect a sales volume of approx. 7.3 BCM (the Partnership's share is approx. 3.3 BCM). The Partnership's net revenues from the Tamar reservoir in the Report Year totaled approx. $264 million, and reflect a sales volume of approx. 8.2 BCM (the Partnership's share is approx. 1.8 BCM), compared with net revenues of approx. $356 million from the Tamar reservoir last year, reflecting a sales volume of approx. 10.4 BCM (the Partnership's share is approx. 2.3 BCM). The decrease in revenues from the Tamar reservoir in the period mainly derived from the spread of COVID-19 (see Section 3G) and from the commencement of production from the Leviathan reservoir.

Below is a table with a breakdown of the gas quantities (100%) which were sold in the Report Year by reservoir and by customer location:

		Y2020 (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**

		Y2019 (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**

Net revenues in Q4/2020 amounted to approx. $204 million, compared with approx. $87 million in the same period last year, an increase of approx. 135%. The increase chiefly derives from the commencement of production from the Leviathan reservoir as noted above. InQ4/2020, approx. 4.4 BCM of natural gas were sold from the Tamar and Leviathan reservoirs (100%), compared with approx. 2.6 BCM in the same period last year, approx. 3.1 BCM of which to the domestic market and approx. 1.3 BCM for export (in the same period last year, approx. 2.5 BCM to the domestic market and approx. 0.1 BCM for export).

The Partnership's net revenues from the Leviathan reservoir in Q4/2020 totaled approx. $129 million. The sales volume from the Leviathan reservoir in Q4/2020 amounted to approx. 1.9 BCM (the Partnership's share is approx. 0.9 BCM). The Partnership's net revenues from the Tamar reservoir in Q4/2020 totaled approx. $75 million. The sales volume from the Tamar reservoir in Q4/2020 amounted to approx. 2.5 BCM (the Partnership's share is approx. 0.5 BCM).

The net revenues from the Tamar reservoir in the same period last year amounted to approx. $87 million. The sales volume from the Tamar reservoir in Q4/2020 amounted to approx. 2.6 BCM (the Partnership's share is 0.6 BCM). The decrease in revenues from the Tamar reservoir in the period mainly derived from the reasons specified above.

Cost of gas and condensate production mainly includes management and operating expenses in the Tamar and Leviathan projects which include, *inter alia*, expenses of haulage and transport, salaries, consulting, maintenance, insurance and transport of natural gas to Egypt. The cost of gas and condensate production in the Report Year amounted to approx. $114 million, compared with approx. $41 million last year, an increase of approx. 180%. The increase in the Report Year compared with last year mainly derives from the commencement of production from the Leviathan reservoir which was offset through a decrease of approx. $15 million (the Partnership's share) in the cost of gas production from the Tamar reservoir compared with last year which mainly derived from a decrease in the expenses of upgrading equipment on the Tamar platform that was performed last year.

The cost of gas and condensate production in Q4/2020 amounted to approx. $35 million, compared with approx. $9 million in the same quarter last year. The increase primarily resulted from expenses in the sum of approx. $27 million in respect of the cost of production and transport of gas from the Leviathan reservoir.

Depreciation, depletion and amortization expenses in the Report Year amounted to approx. $112 million, compared with approx. $68 million last year. The depreciation expenses in the Report Year include primarily depletion depreciation in the Tamar and Leviathan projects. The increase derives primarily from recording depletion depreciation in the Leviathan project for the first time, which was offset by a decrease in the depreciation, depletion and amortization expenses in the Tamar and Yam Tethys projects. For details regarding the effect of the change in the estimate of reserves that are being used as a base for depreciation of the oil and gas assets, see Note 2K1E to the financial statements attached below.

Depreciation and amortization expenses in Q4/2020 amounted to approx. $28 million, compared with approx. $17 million in the same quarter last year. Depreciation expenses in the report period include depletion depreciation primarily in the Tamar and Leviathan projects. The increase derives primarily from the above-specified reasons.

Other general expenses include, *inter alia*, expenses of geologists, engineers and consulting, as well as G&A expenses of various projects. Other general expenses totaled approx. $4 million and include, *inter alia*, expenses in the Leviathan project and expenses in the Cyprus project. Last year, other general expenses totaled approx. $14 million and included, *inter alia*, expenses in the Leviathan project in the sum of approx. $11 million and expenses in the Cyprus project in the sum of approx. $1 million. The decrease in the Report Year derives primarily from classification of administrative expenses of the Leviathan project operator under the "Cost of gas and condensate production" item due to the commencement of the production from the Leviathan reservoir.

Other general expenses in Q4/2020 amounted to approx. $1 million, compared with approx. $5 million in the same period last year. The decrease in Q4/2020 compared with the same quarter last year, mainly derives from the above-specified reason.

G&A expenses in the Report Year amounted to approx. $15 million, compared with approx. $11 million last year, and include, *inter alia*, expenses for professional services, payroll expenses and expenses in respect of management fees to the General Partner. In addition, G&A expenses include an amount of approx. $3 million (last year, approx. $2 million) recorded against a capital reserve for transactions between a corporation and the controlling interest holder thereof and mainly deriving from costs that are financed by the General Partner, which – according to the partnership agreement – are not borne by the Partnership. The increase in G&A expenses in the Report Year mainly derived from an increase in expenses for professional services and from an increase in the Partnership's D&O insurance expenses.

G&A expenses in Q4/2020 amounted to approx. $4 million, compared with approx. $3 million in the same quarter last year. The increase in Q4/2020 compared with the same quarter last year, derives from the above-specified reasons.

Other expenses in the same period last year in the sum of approx. $0.5 million derived from the update of other long-term assets.

The Partnership's share in the profits (losses) of a company accounted for at equity, net, amounted in the Report Year to a loss of approx. $8 million, compared with a loss of approx. $37 million in the same period last year. The loss in the period derived from the company accounted for at equity EMED Pipeline B.V. ("**EMED**") which holds 39% of the shares of Eastern Mediterranean Gas Company S.A.E ("**EMG**"). The loss last year mainly derived from adjustment of the value of the investment in the shares of Tamar Petroleum Ltd. to the market value thereof until the last date of treatment of the investment according to the equity method.

In Q4/2020 loss from the company accounted for at equity was recorded in the sum of approx. $4 million.

The Oil profit levy amounted in the Report Year to an expense of approx. $4 million, which derives from a current levy which applies in the Report Year due to the Tamar project, compared with income in the sum of approx. $5 million last year, which derived from the update of the provision for the oil and gas profit levy according to levy reports filed in previous years for the Yam Tethys project.

Financial expenses in the Report Year amounted to approx. $232 million, compared with approx. $47 million last year. Most of the financial expenses derived from interest in respect of bonds and liabilities to banking corporations in the sum of approx. $229 million (last year, approx. $194 million out of which the Partnership capitalized for the Leviathan project a sum of approx. $147 million). The increase in financial expenses in the report period compared with last year derives mainly from the discontinuation of capitalization of the credit costs for the Leviathan project upon completion of the construction stage and the commencement of gas production from the project and from depreciation of the balance of the cost of raising debt that was prepaid, including LIBOR interest hedging expenses.

With respect to the issuance of bonds of Leviathan Bond that was closed in August 2020, see Note 10C to the financial statements attached below and Chapter Four below.

Financial expenses in Q4/2020 amounted to approx. $52 million, compared with approx. $11 million in the same quarter last year. Most of the financial expenses derived from interest in respect of bonds in the sum of approx. $51 million (last year, expenses in respect of bonds and in respect of liabilities to banking corporations totaled approx. $51 million out of which the Partnership capitalized for the Leviathan project a sum of approx. $41 million). The increase in financial expenses in the report period compared with the same period last year derives mainly from the above-specified reasons.

Financial income in the Report Year amounted to approx. $88 million, compared with approx. $78 million last year. The increase mainly derives from the revaluation of royalties receivable from the Karish and Tanin leases and from a loan to Energean in the context of the sale of the Partnership's interests in the Karish and Tanin leases (jointly: "**Receivables**") in the sum of approx. $83 million, compared with approx. $57 million last year. For further details in connection with revaluation of receivables, see Annex C, Note 8B to the financial statements attached below, and the valuation of royalties attached below.

Financial income in Q4/2020 amounted to approx. $66 million and mainly derived from the update of royalties receivable from the Karish and Tanin leases as noted above, compared with income in the amount of approx. $31 million, which mainly derived from the revaluation of royalties receivable from the Karish and Tanin leases last year.

3. Financial position, liquidity and financing sources

A. Financial position

The main changes in the items of the statement of financial position as of December 31, 2020, compared with the statement of financial position as of December 31, 2019, are specified below:

Total assets as of December 31, 2020 amounted to approx. $4,585 million, compared with approx. $4,503 million as of December 31, 2019.

Current assets amounted to approx. $418 million as of December 31, 2020 compared with approx. $368 million as of December 31, 2019. The change primarily derived from the following factors:

(1) Cash and cash equivalents as of December 31, 2020 total approx. $70 million, compared with approx. $171 million as of December 31, 2019. The decrease during the Report Year derived primarily from the Partnership's investments and the operation of the various projects, the distribution of profits to the participation unit holders, interest payments to bondholders and to banking corporations and tax and balancing payments which was mainly offset by the proceeds of the issue of Leviathan bond (see Section C below) and by the Partnership's revenues from the sale of gas in the Leviathan project.

(2) Short-term investments as of December 31, 2020 total approx. $169 million, compared with approx. $63 million as of December 31, 2019, and primarily consist of deposits serving as a safety cushion for the bonds of Tamar Bond in the sum of approx. $35 million (last year, approx. $63 million) and a deposit serving as a safety cushion for the bonds of Leviathan Bond in the sum of approx. $134 million. The aforesaid increase in deposits mainly derived from income in respect of the sale of gas from the Leviathan reservoir.

(3) Trade receivables item as of December 31, 2020 totals approx. $146 million, compared with approx. $47 million as of December 31, 2019. The increase in the trade receivables balance derives from trade receivables balance in the Leviathan project following commencement of production of the gas from the project.

(4) Other receivables item as of December 31, 2020 totals approx. $32.8 million, compared with approx. $86.9 million as of December 31, 2019. The decrease derives primarily from a decrease in the balance of the operator of the joint ventures in the Leviathan project.

Non-current assets as of December 31, 2020 amount to approx. $4,167 million, compared with approx. $4,135 million on December 31, 2019, as specified below:

(1) Investments in oil and gas assets as of December 31, 2020 total approx. $3,440 million, compared with approx. $3,429 million as of December 31, 2019. The change in the Report Year mainly derived from investments in the sum of approx. $95 million in the Leviathan and Tamar projects and in the sum of approx. $8 million in evaluation and exploration assets. Conversely, the Partnership recorded depreciation, depletion and amortization expenses in the Tamar and Leviathan projects in the sum of approx. $91 million. See also Note 2K1E to the financial statements attached below regarding the change in the estimate of the reserves used as a basis for impairment of the oil and gas assets.

(2) Investment in the company accounted for at equity as of December 31, 2020 totaled approx. $67 million compared with a sum of approx. $75 million as of December 31, 2019, and included the investment in shares of EMED. The decrease derived from the recording of a loss for an investment in a company accounted for at equity in the report period that derived mainly from depreciation of the excess purchase cost. See Note 6 to the financial statements as of December 31, 2020.

(3) Long-term bank deposits as of December 31, 2020 amount to approx. $100 million, compared with approx. $103 million as of December 31, 2019. The balance as of December 31, 2019 included a long-term deposit in the sum of approx. $102.5 million, which was used to repay the principal of the Tamar Bond Series 2020 bonds. The balance as of December 31, 2020 consists mainly of a deposit in the sum of approx. $100 million which serves as a safety cushion for the repayment of the bonds of Leviathan Bond issued in August 2020 as set forth in Note 10 to the financial statements attached below and in Section C below.

(4) Other long-term assets as of December 31, 2020 totaled approx. $559 million, compared with approx. $528 million as of December 31, 2019. The increase mainly derived from a rise in the fair value of royalties and revenues receivable from the Karish and Tanin leases in the sum of approx. $69 million. Conversely, there was a decrease in the share price of a financial asset measured at fair value through other comprehensive income in the sum of approx. $29 million and the classification of revenues receivables from the sale of the Karish leases in the sum of approx. $14 as current assets.

Current liabilities as of December 31, 2020 amount to approx. $566 million, compared with approx. $825 million as of December 31, 2019, as specified below:

(1) Bonds – Current maturities of Series A Bonds, which are due December 2021, in the sum of approx. $394 million (net of issue expenses) compared with bonds of Tamar Bond in the sum of approx. $319 million (net of issue expenses) as of December 31, 2019. The Tamar Bond Series 2020 bonds were repaid in 2020, as follows: principal in the sum of $240 million prepaid in July 2020 and the balance of $80 million paid when due in December 2020. See also Section C below.

(2) Liabilities to banking corporations – As of December 31, 2019, amounted to approx. $297 million (net of debt-raising costs), which were due in December 2020. The liabilities were prepaid in August 2020 in the context of the issuance of the bonds of Leviathan Bond as set forth in Section C below and in Note 4 to the financial statements attached below.

(3) Provisions for balancing and tax payments – In December 2020, the Partnership announced tax payments to individual holders and balancing payment to non-individual holders in the sum of approx. ILS 117 million (approx. $36 million), which were made in January 2021 and were based on an estimate of the taxable income in respect of the 2020 tax year. In December 2019 the Partnership announced tax payments to individual holders and balancing payments to non-individual holders in the sum of approx. ILS 116 million (approx. $34 million), which were made in January 2020 and were based on an estimate of the taxable income for the 2019 tax year.

(4) Trade and other payables as of December 31, 2020 amounted to approx. $74 million, compared with approx. $175 million as of December 31, 2019. The decrease derives primarily from a decrease in the payables item in the context of the joint ventures in respect of the Leviathan and Tamar projects.

(5) Other short-term liabilities as of December 31, 2020 amounted to a sum of approx. $62 million and derive from a classification of part of the oil and gas asset retirement obligation in the Yam Tethys project as short term.

Non-current liabilities as of December 31, 2020 amount to approx. $3,021 million, compared with approx. $2,865 million as of December 31, 2019, as specified below:

(1) Bonds as of December 31, 2020 amount to approx. $2,855 million, compared with approx. $1,031 million as of December 31, 2019. The increase derives from the issue of bonds of Leviathan Bond in the amount of $2,250 million, which was offset by the classification of Series A Bonds as short term. The balance as of December 31, 2020 includes the bonds of Leviathan Bond in the sum of approx. $2,219 million (net of issue expenses), which were issued in August 2020 as set forth in Note 10C to the financial statements attached below and in Section C below, and the bonds of Tamar Bond in the sum of approx. $635 million (net of issue expenses) (see Part Five below).

(2) Long-term liabilities to banking corporations as of December 31, 2019, net of current maturities, totaled approx. $1,630 million (net of debt-raising costs) and were repaid in August 2020 in the context of the issue of the bonds of Leviathan Bond as set forth in Note 10C to the financial statements attached below and in Section C below.

(3) Other long-term liabilities as of December 31, 2020 total approx. $166 million, compared with approx. $203 million as of December 31, 2019.

The decrease mainly derives from the classification of a sum of approx. $62 million in respect of the oil and gas asset retirement obligation in the Yam Tethys project as current liabilities, and conversely, oil and gas asset retirement obligations in the Yam Tethys, Tamar and Leviathan projects were updated by a sum of approx. $23 million.

The capital of the limited partnership as of December 31, 2020 totals approx. $998 million, compared with approx. $814 million as of December 31, 2019. The change in capital mainly derives from comprehensive income recorded in the Report Year in the sum of approx. $338 million as well as from an increase in a capital reserve for benefits from a control holder in the sum of approx. $3 million, which was offset by distributed profits and payable tax payments and balancing payments in the sum total of approx. $102 million and income tax advances on account of the tax owed by the holders of participation units of the Partnership, net, in the sum of approx. $55 million.

B. Cash flow

(1) The net cash flow deriving from operating activities amounted in the Report Year to approx. $329 million, compared with a net cash flow deriving from operating activities of approx. $254 million last year. The increase primarily derives following the commencement of the production of gas from the Leviathan project.

(2) The net cash flow which was used for investment activities amounted in the Report Year to approx. $242 million, compared with a net cash flow of approx. $704 million last year. In the Report Year, the Partnership invested approx. $165 million, mainly in the Tamar and Leviathan projects compared with approx. $610 million in last year. Short-term deposits that serve primarily as safety cushions for Tamar Bond and Leviathan Bond increased in 2020 by approx. $106 million, compared with a decrease of approx. $124 million last year. In the report period, the Partnership invested $100 million in a long-term deposit that serves as a safety cushion for the bonds of Leviathan Bond and conversely, it has withdrew approx. $100 million for a long-term deposit that served as a safety cushion for the bonds of Tamar Bond as part of the repayment of the Tamar Bond Series 2020 bonds. Negative balances of the operator of the joint ventures decreased by approx. $29 million, and approx. $15 million was received on account of a loan that was given in the context of the transaction for the sale of the Karish and Tanin leases.

(3) The net cash flow used for financing activities amounted in the Report Year to approx. $188 million, compared with a net cash flow generated from financing activities, in the sum of approx. $477 last year.

Cash flow from the financing activities derived from the completion of raising bonds of Leviathan Bond (net of issue expenses) in the sum of approx. $2,217 million, against loans from banking corporations in the sum of approx. $2,050 million part of which were received last year in the sum of approx. $104 million (last year, approx. $688 million). Conversely, the repayment of the Tamar Bond Series 2020 bonds was made in the sum of approx. $320 million, the distribution of profits and tax and balancing payments in the sum of approx. $134 million (last year, approx. $218 million).

The balance of cash and cash equivalents as of December 31, 2020 amounted to approx. $70 million, compared with approx. $171 million as of December 31, 2019.

C. Financing

(1) August 18, 2020 saw the completion of the process of issuance of bonds offered by Leviathan Bond Ltd. (the "**Issuer**"), a special-purpose company (SPC) wholly held by the Partnership, in which bonds in the sum total of $2.25 billion were issued in accordance with Rule 144A and Regulation S. For further details with respect to the terms and conditions of the bonds, see Note 10C to the financial statements attached below and Part Five below.

(2) On July 15, 2020, Delek & Avner (Tamar Bond) Ltd. (a company wholly owned by the Partnership), made a partial prepayment of the Tamar Bond Series 2020 bonds in the sum of $240 million (the "**Amount of the Principal**"), the original maturity date of which was December 30, 2020. The amount of the prepayment includes the Amount of the Principal, plus accrued interest in the sum total of approx. $0.4 million, plus a prepayment fee in the sum of approx. $4.2 million (the "**Prepayment Fee**"). It is noted that the amount of the Prepayment Fee is lower than the balance of the interest that Delek & Avner (Tamar Bond) Ltd. would have paid if the Amount of the Principal would have been repaid on the original maturity date. The balance of the principal of the Tamar Bond Series 2020 bonds in the sum of $80 million was repaid when due.

Also see Part Five below.

D. Distribution of profit, tax payments and balancing payments

(1) On January 9, 2020, the Partnership made a payment of approx. ILS 116 million (ILS 0.09909 per participation unit), which was approved by the General Partner's board of directors on December 12, 2019. The said payment includes tax payments to entitled individual holders and balancing payments to holders that are not individuals.

(2) On February 12, 2020, the General Partner's board of directors approved a distribution to the limited partner in the sum of ILS 1 million, which distribution will be used for payment of the supervisor's fees and the trustee's fees and expenses, in accordance with the provisions of the trust agreement.

(3) On November 1, 2020, the General Partner's board of directors approved a distribution to the limited partner in the sum of ILS 1 million, which distribution will be used for payment of the supervisor's fees and the trustee’s fees and expenses, in accordance with the provisions of the trust agreement.

(4) On November 17, 2020 the General Partner’s board of directors, after receiving the recommendation of the Financial Statements Review Committee of the Partnership's General Partner, approved a distribution of profits in the sum of approx. $66 million ($0.055375 per participation unit of the Partnership), the record date for which distribution is November 25, 2020. The said profit distribution was completed in December 2020.

(5) On January 20, 2021, the Partnership made a payment of approx. ILS 117 million (ILS 0.0998676 per participation unit), which was approved by the General Partner’s board of directors on December 25, 2020. Such payment includes tax payments for individual eligible holders and balancing payments for non-individual holders.

E. <u>Buyback plan</u>:

1. At its meeting of July 26, 2020, the board of directors of the Partnership’s General Partner adopted a buyback plan for bonds (Series A bonds and Tamar Bond bonds) (the "**Buyback Plan**"), to be executed from time to time at the discretion of the company's management by way of purchase on or off TASE during the period of the plan as specified below, at a total cost of up to U.S. $50 million (Series A bonds and Tamar Bond bonds together). The buyback will be made from the funds in the Partnership’s unpledged accounts. The Buyback Plan is valid starting from July 27, 2020 until December 31, 2021. The board of directors approved the Buyback Plan for the following main reasons:

    a. In the current market situation, a buyback of the Partnership's bonds is a good business and economic opportunity for the Partnership.

    b. At present, the Buyback Plan for the Partnership's bonds will enable the reduction of the Partnership's net debt, and is expected to contribute to the Partnership's debt repayment capacity.

    c. It is noted that the bond Buyback Plan is consistent with the provisions of the Partnership's indentures, and that approval of the plan does not constitute a breach of the Partnership's undertakings to its bondholders.

    d. It is clarified that the bond buyback will be performed subject to completion of the refinancing (which was completed) of loans provided to the Partnership, *inter alia*, for the purpose of financing of the Leviathan project (the “**Refinancing**”), that the said decision does not obligate the Partnership to buy back any or all of the bonds, and that the Partnership's management is entitled to decide not to buy back bonds at all and/or to buy back less bonds than authorized.

It is clarified that the decision of the board of directors to approve the Buyback Plan does not obligate the Partnership to buy back bonds in the full amount of the Buyback Plan or any part thereof, and that the actual buyback is subject to the discretion of the Partnership's management.

Following the aforesaid decision of the board of directors, the Partnership carried out buybacks of ILS 11,413,393 par value of Series A bonds in a total amount of approx. $3 million.

2. At its meeting of November 17, 2020, the board of directors of the Partnership's General Partner adopted a plan to buy back Series A bonds for a total estimated cost of up to $30 million (the "**Plan**"), according to the directive of the Israel Securities Authority of July 26, 2010 (Position 199-8) regarding the "safe harbor" protection in a corporation's buyback of securities (the "**Safe Harbor Directive**"). The purchases will be made from time to time in the period between November 19, 2020 and December 31, 2020, in transactions on or off TASE, by a trustee through a TASE member (the "**TASE Member**"), which has no material business ties with the Partnership, with which the Partnership will engage for implementation of the Plan, including by way of a blind trust, all according to the absolute discretion of the TASE Member and without the Partnership's involvement.

   It is noted that this Plan has replaced the Buyback Plan referred to in Section 1 above.

   The board of directors approved by the purchase Plan for the following main reasons:

   a. In the current market situation, a buyback of the Partnership's bonds is a good business and economic opportunity for the Partnership.

   b. The Plan will enable the reduction of the Partnership's debt, and is expected to contribute to the Partnership's debt repayment capacity.

   c. The Plan meets the provisions of the Partnership's indenture on the basis of which the Partnership's Series A bonds were issued, and approval of the Plan does not constitute a breach of the Partnership's undertakings to the Partnership's Series A bondholders.

   d. The Plan meets the conditions set forth in the buyback procedure adopted by the Partnership, as well as the Safe Harbor Directive.

   e. Approval of the Plan under the Safe Harbor Directive will reduce the risk that decisions and actions taken thereunder will be interpreted as a breach of the law, including the prohibition on the use of inside information.

Following the aforesaid decision of the board of directors, the Partnership carried out buybacks of ILS 7,450,000 par value of Series A bonds in a total amount of approx. $2 million.

F. In accordance with the provisions of Section 10(b)(14) of the Securities Regulations (Periodic and Immediate Reports), 5730-1970 (the "**Securities Regulations**"), a corporation which, on the date of release of the financial statements, has bond certificates in circulation, is required to examine whether warning signs, as defined in the Securities Regulations, exist in respect thereof. Should one or more of the warning signs occur, the corporation will attach a disclosure of projected cash flow.

According to the figures of the Partnership's financial statements as of December 31, 2020, the Partnership has a working capital deficit of approx. $148 million, arising mainly from current maturities of Series A bonds, which mature in December 2021.

The Partnership's management has presented to the board of directors of the General Partner all of the sources that may be used by the Partnership in order to comply with its obligations in the upcoming years, including the Partnership's projected revenues from the Tamar and Leviathan projects, expected cash flow from royalties and the loan repayment from the sale of Tanin I/16 and Karish I/17 leases, the balance of cash and short-term and long-term deposits in the sum of approx. $398 million, which have accrued in the Partnership's coffers (including money accrued in the Partnership's coffers from the beginning of the year until the date of the periodic report), which are designated for the operating activities and for repayment of its obligations, the Partnership's plans to sell its direct and indirect holdings in the Tamar project in accordance with the provisions of the Gas Framework, and the option available to the Partnership to obtain capital by way of a rights offering in a sum of up to $300 million[3].

On March 13, 2021, the board of directors of the Partnership's General Partner, after examining the estimated sources and uses report presented thereto by the Partnership's management, under different scenarios, gained the impression that, based on past experience, the Partnership's proven ability to raise money in recent years, and the Partnership's assets, the underlying assumptions of the report are reasonable and accordingly, the said deficit does not indicate a liquidity problem in the Partnership, and accordingly no warning sign as defined in Section 10(b)(14)(a) of the Securities Regulations (Periodic and Immediate Reports), 5730-1970 is present. See also Section G below regarding the COVID-19 crisis and its possible impact on the Partnership's business.

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[3] On May 17, 2018, the meeting of the holders of participation units of the Partnership approved the performance of an offering of participation units and/or securities convertible into participation units by way of a rights offering to the existing holders of the participation units, during a period from the date of the meeting's approval as aforesaid until May 6, 2021, in such scope and under such conditions as shall be determined according to the decision of the General Partner for the purpose of raising sums that will be required, in the opinion of the General Partner, for the financing of the Partnership's operating activities, including the making of investments in the Partnership's petroleum assets and the repayment of its existing liabilities, and authorized the General Partner to determine the structure, scope and timing of the offering, at its sole and absolute discretion, subject to the sum total of the proceeds of the offering (or offerings) in the said period not exceeding a sum in ILS equivalent to $300 million. The performance of such offerings may be carried out at any time under one or more prospectuses and/or one or more shelf offering reports, as shall be determined by the General Partner.

G. **<u>The spread of COVID-19 and its possible impact on the Partnership's business</u>**:

At the end of 2019 and during Q1/2020, COVID-19 began to spread in China and later on all over the world, and in March 2020 it was defined by the WHO as a global pandemic (the "**COVID-19 Crisis**").

During H1/2020, international markets recorded very sharp declines in oil and natural gas prices, which, in the Partnership's estimation, could be attributed to the COVID-19 Crisis, as well as other causes and factors affecting the demand for and supply of energy products. However, towards the end of 2020 and in the first months of 2021, a recovery is felt in the prices of energy products worldwide, including oil and LNG prices.

In addition, in H1/2020 and mainly in Q2, stagnation in the demand for natural gas was recorded in the domestic market compared with the same period last year, mainly due to the effect of the Covid-19 Crisis on the demand for electricity in these markets as a result of closures and restrictions on economic activity. It is noted that even though the Covid-19 Crisis continues, an increase in the demand for natural gas was recorded in H2/2020 compared with the same period last year.

It is noted that further to the aforesaid trend in January and February 2021, natural gas from the Leviathan reservoir was sold in an amount of approx. 0.9 BCM and approx. 0.8 BCM, respectively, and from the Tamar reservoir approx. 0.7 BCM and approx. 0.6 BCM, respectively.

As of the date of approval of Report, it is impossible to estimate how the Covid-19 Crisis will continue to develop in the coming years and what the extent of its impact on the global economy will be and its effect on the demand and sales from the Leviathan and Tamar reservoirs in the coming years. In these circumstances, the Covid-19 Crisis constitutes a global macroeconomic risk that creates uncertainty as to the future economic activity in the world and the expected effects on financial markets, interest rate margins, currency exchange rates and commodity prices in the energy sector and may impair many sectors including the energy sector in which the Partnership operates.

In addition, following the spread of the COVID-19 Crisis, many countries, including Israel, are taking extreme measures in an attempt to prevent the spread of the virus, such as restrictions on the movement of civilians and gatherings, transportation restrictions on passengers and goods, closing borders between countries, etc. Beyond the negative impact of these measures on domestic and global economic growth, the restrictions and actions taken and to be taken by Israel and other countries to deal with the COVID-19 Crisis may have a material adverse effect on the Partnership's work plans. As a result of these measures, there may be delays in the entry of foreign experts as well as in the supply of designated equipment into the State of Israel, due to restrictions that apply to the movement of citizens between sites and countries and restrictions on production or transportation that apply in the various countries, which may, *inter alia*, disrupt regular production activity, the work plans of the operator and even impose unforeseen additional costs. In this regard, it is noted that Noble, the operator in the Tamar and Leviathan projects, in coordination with the Petroleum Commissioner and the Ministry of Health, has formulated an action plan to deal with the COVID-19 Crisis, *inter alia*, in order to ensure, insofar as possible, that the operator's workforce will be able to reach the project facilities on and off shore and continue to carry out essential operations at the aforesaid facilities. As of the date of approval of the Report, the COVID-19 Crisis did not result in a material damage to the operating system in the Tamar and Leviathan projects. However, since there is uncertainty with respect to how the COVID-19 Crisis will develop, there is a risk that despite the preventive measures taken by the partners in the projects, the operation of the reservoirs will be harmed.

Caution concerning forward-looking information – The Partnership's assessments regarding the possible consequences of COVID-19 constitute forward-looking information, as defined in Section 32A of the Securities Law, 5728-1968. Such information is based, *inter alia*, on the Partnership's assessments and estimates as of the date of this report and on reports published in Israel and around the world on this issue and the directives of the relevant authorities, the materialization of which is uncertain and not in the Partnership's control.

H. Work plan for reducing operating and investment budgets:

As part of the strategy for dealing with the COVID-19 crisis, the Tamar partners, the Leviathan partners and the partners in Block 12 in Cyprus have acted for streamlining and reducing the operating budgets and postponing planned investment budgets to later years and accordingly, the partners in the aforesaid projects approved updated budgets for 2020, that the actual total reduction amounted to approx. $179 million (in 100% terms; the Partnership's share is approx. $56 million), as follows: In the Leviathan project – a reduction of approx. $62 million (100%; the Partnership's share approx. $28 million); in the Tamar project – a reduction of approx. $87 million (100%; the Partnership's share is approx. $19 million); and in the Block 12 project in Cyprus – a reduction of approx. $30 million (100%; the Partnership's share is approx. $9 million).

Part Two – Exposure to and Management of Market Risks

Report on exposure to and management of market risks

1. The person in charge of market risk management in the Partnership

The person in charge of market risk management in the Partnership is the Deputy CEO, Mr. Yossi Gvura.

2. Description of the main market risks to which the Partnership is exposed

a. The exchange rate risk

Changes in the ILS/Dollar exchange rate may affect the Partnership's results in several ways, as follows: (a) The Partnership's functional currency is the U.S. dollar. Since some of the Partnership's expenses are stated in ILS or affected by the ILS/Dollar exchange rate, a decrease in the ILS/Dollar exchange rate (a strengthening of the ILS against the Dollar) increases such expenses in Dollar terms; (b) Since the gas prices in the agreements for the sale of gas from the reservoirs in which the Partnership is a partner, are determined by price formulas that include various linkage components, and, *inter alia*, linkage to the ILS/Dollar exchange rate and linkage to the PUA's tariff, which is partly affected by the ILS/Dollar exchange rate. A weakening of the ILS against the Dollar may have an immaterial negative effect on the Partnership's revenues; (c) Since the Partnership reports its taxable income in ILS and pays the tax advances for the holders of the Partnership's participation units in ILS, then changes in the ILS/Dollar exchange rate affect the amount of the Partnership's taxable income and the amount of the cash flow which is used for payment of such tax advances.

b. The natural gas and condensate price risk

The price of gas in the contracts for natural gas supply, was determined according to price formulas that include various linkage components, including linkage to the electricity production tariff, linkage to the U.S. CPI, linkage to the Brent barrel price and linkage to the ILS/Dollar exchange rate. In the contracts for natural gas supply signed by the Partnership, floor prices were set alongside the price formulas, which to some extent limit the exposure to fluctuations in the linkage components, but there is no certainty that the Partnership will be able to set floor prices as aforesaid also in new contracts to be signed thereby in the future.

A decline in the electricity production tariff (resulting, *inter alia*, from a price adjustment to be sought by the IEC, if any, according to the mechanism that was determined in the IEC-Tamar Agreement and/or decrease in the Brent prices and/or decrease in the U.S. CPI and/or increase in the ILS/Dollar exchange rate (devaluation of the ILS against the Dollar) may adversely affect the Partnership's revenues from the existing and future gas sale agreements.

It is noted that the frequent methodological changes made by the PUA-E to the method of calculation of the electricity production tariff make its predictability difficult, and may lead to disputes between gas suppliers and customers in connection with the method of calculation thereof. In this context, it is noted that in relation to some of the private power plants (including plants which were sold by the IEC), the PUA-E instituted SMP regulation (System-Marginal Price) according to which every half hour the wholesale electricity tariff is determined by the marginal cost for the production of one additional kWh in the sector, based on half-hour tenders that are held by the manager of the electricity system between the various electricity producers, every day. The aforesaid pricing method may have an effect on the prices of the natural gas which is sold by the Partnership to the electricity producers in the domestic market, in the event that the gas prices are linked to the aforesaid pricing in futures contracts.

The demand for natural gas from the Partnership’s customers and its price are affected, *inter alia*, also by significant changes in the prices of oil, natural gas, including LNG, and the prices of other sources of energy, including coal and other alternatives to the natural gas produced from the Tamar and Leviathan reservoirs, both in the domestic market and in the international markets. Thus, for example, low LNG prices in the international markets may lead to an increase in the import of LNG to Israel and/or the regional markets, reduce natural gas demand in markets that are relevant to the Partnership and impair the Partnership’s revenues from the Tamar and Leviathan reservoirs. An increase in supply, a decrease in demand or a decrease in the prices of alternative energy sources for natural gas (including coal and other products) in the domestic market or international markets may reduce demand from existing and potential customers and lead to a decrease 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 operation.

Reforms and decisions relating to the electricity sector, and the energy sector generally, including changes in the environmental laws, may also reduce the demand for the natural gas sold by the Partnership and/or affect its price.

In addition, material events in the global economy such as an economic slowdown, recession, inflation, irregular volatility in foreign exchange rates, trade wars, an impairment of the efficient functioning of the global manufacture and supply chains in general, and 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 eruption of epidemics such as 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 the existing and future agreements for the sale of the gas, as well as the making of decisions on investment in new natural gas projects and/or expansion of existing projects.

3. The Partnership’s policy on exchange rate market risk management

a. The Partnership invests its surplus liquidity in accordance with the provisions of the Partnership Agreement with the aim of obtaining appropriate yield with a suitable yield/risk ratio.

b. The Partnership’s funds are intended, *inter alia*, for exploration activities in its oil and gas assets and for their development. In view of the aforesaid, the General Partner, which manages the Partnership, invested the Partnership’s available funds in Dollar-denominated financial assets, which mainly include (as of the date of the statement of financial position) bank deposits. For the purpose of financing the Partnership’s business, the Partnership liquidated during the Report Year its investments in the ETFs and corporate bonds.

c. When the Partnership is aware of material payments in foreign currency or ILS it aspires to protect the payment and hedge against currency rate changes.

d. No events have been determined regarding which there is an obligation to adopt a special resolution at the board of directors with regard to market risks.

4. Means of supervision and implementation of the policy

The Partnership’s investment policy is set forth in the Partnership Agreement. On November 20, 2018, the board of directors of the Partnership’s General Partner decided to approve the setup of an investment committee, the purpose of which is to hold thorough discussions on the Partnership’s investments and recommend methods of action on such issue to the board of directors of the Partnership’s General Partner. The committee was established in view of the need for professional and thorough discussions by a special forum (designated by the board of directors of the Partnership’s General Partner). The investment committee convenes at least once every six months and when necessary. The committee’s powers are as follows: To discuss the Partnership's investment portfolio, *inter alia*, in order to ascertain that the method of investment of the Partnership's available cash is in keeping with the investment policy set forth in Section 9.4 of the Partnership Agreement of July 1, 1993 (as amended from time to time); to determine the mix and structure of the Partnership's investment portfolio according to the management's recommendation and, insofar as the investment committee believes that there is need to modify the investment policy, recommend such change to the board of directors of the

General Partner. The committee is required to report its recommendations to the board of directors on an ongoing basis and also report the mix and structure of the Partnership's investment portfolio as part of the annual report.

The members of the investment committee, as of this report date are: Mr. Roni Bar-On (Chairman of the Investment Committee, independent director), Efraim Sadka (external director) and Mr. Amos Yaron (external director).

The handling of currency and interest risk exposure, formulation of hedging strategies and supervision of the performance thereof is entrusted to the board of directors of the General Partner.

5. Sensitivity tests

In accordance with Amendment 5767 to the provisions of the Second Schedule to the Securities Regulations (Immediate and Periodic Reports), 5730-1970, the Partnership carried out tests of sensitivity to changes in risk factors affecting the fair value of "sensitive instruments".

Description of parameters, assumptions and models

Parameters:

Parameter	Source/Manner of Treatment
ILS/Dollar exchange rate	Representative rate as of December 31, 2020
Dollar interest	According to the LIBOR curve

a. For details regarding the analysis of the sensitivity of the value of royalties and a loan to Energean from the sale of the Karish and Tanin leases to changes in the cap rate, see Note 22F4 to the financial statements attached below.

b. Regarding the analysis of the sensitivity of the value of royalties receivable from the Karish and Tanin leases to changes in the price of natural gas and condensate, see Note 22F3 to the financial statements attached below.

c. Tests of sensitivity to changes in Dollar/ILS exchange rate ($ in thousands):

Sensitive Instrument	**Profit/(Loss) from Changes**		**Fair Value**	**Profit/(Loss) from Changes**	
	10%	**5%**		**-5%**	**-10%**
	3.537	**3.376**	**3.215**	**3.054**	**2.894**
Cash and cash equivalents	(663)	(331)	6,628	331	663
Bank deposits	(22)	(11)	218	11	22
Trade and other payables	92	46	(917)	(46)	(92)
Total	**(593)**	**(296)**	**5,929**	**296**	**593**

6. Report on linkage bases in Dollars in thousands, as of December 31, 2020:

	Financial Balances				
	In dollars or dollar-linked	In non-linked ILS	Non-linked	Non-financial balances	Total
Assets					
Cash and cash equivalents	63,351	6,628	-	-	69,979
Short-term investments	169,149	218	-	-	169,367
Trade receivables	145,681	-	-	-	145,681
Other receivables	20,212	-	-	12,664	32,876
Investments in oil and gas assets	-	-	-	3,439,902	3,439,902
Investment in company accounted for at equity	-	-	-	67,288	67,288
Long-term deposits	100,529	-	-	-	100,529
Other long-term assets	323,664	-	17,033	218,368	559,065
Total assets	**822,586**	**6,846**	**17,033**	**3,738,222**	**4,584,687**
Liabilities					
Trade and other payables	35,145	917	-	37,505	73,567
Other short-term liabilities	-	-	-	62,212	62,212
Provision for balancing and tax payments	-	-	-	36,462	36,462
Bonds	3,248,505	-	-	-	3,248,505
Other long-term liabilities	-	-	-	166,246	166,246
Total liabilities	**3,283,650**	**917**	**-**	**302,425**	**3,586,992**
Total net balance sheet balance	**(2,461,064)**	**5,929**	**17,033**	**3,435,797**	**997,695**

7. Report on linkage bases in Dollars in thousands, as of December 31, 2019:

	Financial Balances				
	In dollars or dollar-linked	In non-linked ILS	Non-linked	Non-financial balances	Total
Assets					
Cash and cash equivalents	147,806	23,240	-	-	171,046
Short-term investments	63,271	188	-	-	63,459
Trade receivables	46,862	-	-	-	46,862
Other receivables	78,586	-	-	8,295	86,881
Investments in oil and gas assets	-	-	-	3,429,178	3,429,178
Investment in company accounted for at equity	-	-	-	74,995	74,995
Long-term deposits	102,919	-		-	102,919
Other long-term assets	265,874	-	46,354	215,505	527,733
Total assets	**705,318**	**23,428**	**46,354**	**3,727,973**	**4,503,073**
Liabilities					
Trade and other payables	160,440	655	-	13,643	174,738
Provision for tax and balancing payments	-	-	-	33,657	33,657
Bonds	1,350,831	-	-	-	1,350,831
Liabilities to banking corporations	1,927,271	-	-	-	1,927,271
Other long-term liabilities	-	-	-	203,069	203,069
Total liabilities	**3,438,542**	**655**	**-**	**250,369**	**3,689,466**
Total net balance sheet balance	**(2,733,224)**	**22,773**	**46,354**	**3,477,604**	**813,507**

Part Three – Corporate Governance Aspects

1. The Partnership's donation policy

The Partnership has not yet set out a donation policy, and accordingly made no monetary contributions in the Report Year, due to restrictions applicable thereto under the Partnership Agreement.

2. Directors having accounting and financial expertise

The board of directors of the General Partner has determined, pursuant to Section 92(a)(12) of the Companies Law, 5759-1999 (the "**Companies Law**"), that the minimum appropriate number of directors having accounting and financial expertise shall be one. The board of directors of the General Partner believes that considering the type of business of the company, which is the General Partner in a partnership that is primarily engaged in the field of natural gas, condensate and oil exploration, development and production and the vast business experience of the directors (also those who do not fulfill the definition of "having accounting and financial expertise"), the aforesaid minimum number allows the board of directors to fulfill the obligations imposed thereon pursuant to the law and the documents of incorporation of the Partnership, in respect of the examination of the Partnership's financial position and the preparation and approval of the financial statements. The aforesaid reasons are accompanied by the fact that pursuant to the Partnership's work procedure, the auditors of the financial statements are invited to every board meeting at which the financial statements are discussed, and are available to give the members of the board of directors any explanation required in relation to the financial statements and the financial position of the Partnership, both in and outside of the meetings in which they participate. In addition, it is noted that under the law any director who so wishes is entitled, in circumstances that so justify and under the conditions set forth in the law, to receive professional advice, at the expense of the General Partner, in order to perform his work, including accounting and financial advice.

As of the Report Release Date, four directors with accounting and financial expertise serve on the board of directors of the General Partner (Messrs. Efraim Sadka, Tamir Poliker, Jacob Zack and Ronnie Bar-On). For details regarding the education, experience and qualifications of these directors, see Section 26 of Chapter D (Additional Details regarding the Partnership), which is attached below.

3. Independent directors

The Partnership did not adopt a provision in the Trust and Partnership Agreements with regards to the number of independent directors, as they are defined by the Companies Law. Although exceeding the requirements, on January 4, 2016, Mr. Ronnie Bar-On was appointed as an independent director on the board of directors of the General Partner, in addition to three external directors serving on the board of directors of the General Partner as of the date of this report (although it is required that there be at least two serving external directors, according to the Companies Law). For details on directors' independence, see Regulation 26 of Chapter D (Additional Details on the Partnership) which is attached below.

4. Disclosure on the internal auditor at the Partnership

a. Details of the internal auditor

1. Internal auditor's name: CPA Gali Gana.

   Date of commencement of office: February 1, 2016.

2. His qualifications for the position:

   The internal auditor fulfills the terms and conditions set forth in Sections 3(a) and 8 of the Internal Audit Law, 5752-1992 (the "**Internal Audit Law**") and Section 146(b) of the Companies Law, 5759-1999 (the "**Companies Law**").

   A CPA with a degree in Business Administration majoring in accounting, and an M.A. in Public Administration and Internal Audit, Certified Information Systems Auditor (CISA), Certified Internal Auditor (CIA), Certified in Risk Management Assurance (CRMA), Certified in Risk and Information Systems Control (CRISC).

3. The internal auditor is not an employee of the Partnership, but rather provides internal audit services thereto by outsourcing. In addition, the internal auditor provides the Partnership with services for examination of the effectiveness of the controls over processes in connection with the internal control of the Partnership's financial statement (ISOX). The internal auditor is a partner at the accounting firm Rosenblum Holtzman.

4. The internal auditor holds no other office at the Partnership in addition to the internal audit.

5. The internal auditor also serves as the internal auditor of the General Partner of the Partnership and of Delek Group Ltd. His service as the internal auditor of the aforesaid corporations does not create a conflict of interests with his function as the internal auditor at the Partnership.

6. The internal auditor is not an interested party of the Partnership or a relative of an interested party of the Partnership and is also not the auditor or another on his behalf.

7. The internal auditor does not hold securities of the Partnership or of a body affiliated therewith.

b. <u>Appointment procedure</u>

The appointment of Mr. Gana as the internal auditor was approved by the board of directors of the General Partner on January 27, 2016. The board of directors of the General Partner approved the internal auditor's appointment after receipt of the recommendation of the audit committee, and after it found him to have the appropriate qualifications for the position, *inter alia* in view of his specialization and vast experience in the field of internal audit, and after Mr. Gana declared that he meets all of the eligibility requirements needed to fulfill his position as internal auditor pursuant to law, considering, *inter alia*, the Partnership's type, size and the scope and complexity of its operations.

c. <u>Identity of the organizational supervisor of the internal auditor</u>

The chairman of the board of directors of the General Partner.

d. <u>The work plan</u>

The internal auditor of the Partnership operates according to an annual work plan as part of a multi-year plan. The internal auditor recommended an annual and multi-annual audit plan which is based on a risk survey for the determination of the internal audit targets. The annual plan was approved by the audit committee. The multi-annual plan is based on the performance of audits in connection with central processes at the Partnership at an audit frequency that was determined in accordance with the level of prioritization that was weighted based on the exposure to fraud and evaluation of the probability of a failure event and the extent of the damage.

The plan is prepared by the Partnership's internal auditor in coordination with the Chairman of the Board and management of the General Partner, is presented to the audit committee and the board of directors of the General Partner and approved by the audit committee.

The work plan leaves the internal auditor discretion to deviate therefrom, subject to the formal approval of the audit committee.

Transactions as set forth in Sections 65UU-65YY of the Partnerships Ordinance [New Version], 5735-1975 which were performed in the Report Year, including their approval processes, are examined by the internal auditor as part of his annual work plan.

It is noted that, in addition to the internal auditor's work and pursuant to the joint operating agreement (JOA), the Partnership performs, through external companies, a joint audit with its partners in the Tamar, Leviathan and Block 12 projects, over the work of the operator in such projects. The Partnership's control and investment manager participates in the preparation, monitoring and supervision meetings of the aforesaid audit and the internal auditor reports to the audit committee and the board of directors of the General Partner on its findings and results.

In 2020 a periodic audit was conducted by an international outside consultant specializing in audits in the oil and gas industry, in the books of the operator of the joint venture Ratio Yam (Leviathan project) for 2019, with an approved budget of approx. 540 hours. It is noted that the audit was conducted in cooperation with all of the partners in the project other than the operator, in accordance with the audit rules set forth in the joint operation agreement which govern the aforementioned project.

e. **<u>Scope of engagement</u>**

The number of hours is determined according to the needs of the approved annual audit, in the budget determined upon commencement of the internal auditor's term of office. The scope of the internal auditor's engagement at the Partnership and at the General Partner in the reporting year amounted to approx. 600 hours.

The scope of the internal auditor's engagement was determined, *inter alia*, based on the size and complexity of the Partnership's business activity. The General Partner's management, the audit committee and the board of directors of the General Partner have the option to expand the scope of the plan according to the circumstances.

The management, the audit committee and the Chairman of the Board have the option to change the scope of the plan, upon the request of the internal auditor and according to his recommendations or according to the instructions of the audit committee.

f. **<u>Conduct of the audit</u>**

The internal audit is conducted according to the internal audit standards that are accepted in Israel and worldwide, and in accordance with professional directives in the field of internal auditing, as set forth in Section 4(b) of the Internal Audit Law.

The board of directors of the General Partner is satisfied, in accordance with the audit committee's examination, that the auditor has fulfilled all of the requirements and the conditions that were stated above, considering the internal auditor's notice, as delivered to the audit committee and the board of directors of the General Partner.

g. **<u>Access to information</u>**

The internal auditor has full, unlimited, constant and direct access to the Partnership's information systems, including financial figures for the purpose of the audit pursuant to Section 9 of the Internal Audit Law.

h. **<u>The internal auditor's report</u>**

The internal auditor's report was submitted in writing.

After submission of the audit reports to the General Partner's management and receipt of its position, audit reports were submitted to the chairman of the board, to the members of the audit committee and to the members of the General Partner's board of directors, and were discussed at length at the audit committee. Below are dates on which the audit committee discussed reports of the internal auditor: January 7, 2020, March 15, 2020, May 27, 2020, October 12, 2020, December 25, 2020, March 14, 2021.

i. Board of directors' assessment of the internal auditor's activity

The board of directors of the General Partner estimates, in accordance with the audit committee's examination, that the scope, nature and continuousness of the activity and work plan of the internal auditor of the General Partner are reasonable, considering the organizational structure, the nature and scope of the business activities of the Partnership, and achieve the objectives of the internal audit.

j. Compensation

In 2020 the Partnership recorded a total annual amount of ILS 120 thousand in respect of the internal audit services. The General Partner's board of directors has determined, in accordance with the audit committee's examination, that the compensation is reasonable and does not affect the exercise of the internal auditor's independent professional discretion.

5. Auditors' fees

The Partnership has joint auditors: BDO Ziv Haft and EY – Kost Forer Gabbay & Kasierer.

Following is a specification of the amounts of the fees of the auditors at the Partnership, and the Partnership's share of the auditors' fees in joint ventures:

	Y2020				Y2019			
	For audit, audit-related and tax services	Hours	For other services*	Hours	For audit, audit-related and tax services	Hours	For other services*	Hours
	ILS in thousand		ILS in thousand		ILS in thousand		ILS in thousand	
Kost Forer Gabbay & Kasierer and Ziv Haft, co-auditors	2,078	8,812	2,974	5,859	1,790	9,748	1,261	3,218
Somekh Chaikin CPAs**	22	185	-	-	30	227	-	-
Total	2,100	8,997	2,974	5,859	1,820	9,975	1,261	3,218

*** Other services, mainly in connection with offerings.**

**** Co-accountants in the "Michal and Matan" joint venture.**

According to the Companies Law, the auditor's fee for the audit work is determined by the general meeting, which has empowered the General Partner's board of directors for this purpose. The organ that authorizes the auditors' fees for the audit work as well as for other services is the board of directors of the General Partner, after the financial statements review committee examines the scope of the auditors' work and their fees and presents its recommendations to the board of directors of the General Partner.

6. The Partnership's policy on negligible transactions

On March 11, 2009, the board of directors of the General Partner adopted, for the first time, guidelines and rules for the classification of a transaction of the Partnership with an interested party therein as a negligible transaction, as stated in Regulation 41(a3) of the Securities Regulations (Annual Financial Statements), 5710-2010 (the "**Negligibility Procedure**" and "**Reporting Regulations**", respectively). The Negligibility Procedure has been updated over the years and most recently updated by the audit committee and the board of the General Partner on March 14, 2019 and March 17, 2019, respectively.

The audit committee and board of directors of the General Partner (within the approval of the annual report) determined that a transaction shall be considered a negligible transaction if it fulfills all of the following conditions:

a. It is not an irregular transaction (as this term is defined in the Companies Law).

b. In any transaction for which the negligibility threshold is examined, the criterion that is relevant to the contemplated transaction shall be examined before the event as specified below, and insofar as each of the criteria that are relevant to the transaction (as specified below in sub-sections 1-5) is at a rate of no more than 0.8% and the scope of the transaction does not exceed U.S. $1,000,000 (the "**Negligibility Threshold**"), the transaction shall be considered as negligible:

1) In a purchase/sale of a fixed asset – the scope of the asset contemplated in the transaction divided by the total assets of the Partnership according the last reviewed or audited financial statements, as the case may be.

2) A sale of products or services – the sale volume contemplated in the transaction divided by the total annual sales, calculated based on the last four quarters regarding which reviewed or audited financial statements were released.

3) A purchase of products or services – the scope of the expenses contemplated in the transaction divided by the total annual operating expenses that are relevant to the transaction calculated based on the last four quarters regarding which reviewed or audited financial statements were released.

4) An assumption of a financial liability – the undertaking contemplated in the transaction divided by the total liabilities according to the latest reviewed or audited financial statements, as the case may be.

5) Insurance transactions – the premium shall be examined as the transaction amount, as distinguished from the scope of the insurance coverage that is given.

The aforesaid notwithstanding, in transactions in which the Partnership will enter into joint agreements with an interested party therein and/or the control holder for the receipt of consultation and/or management services from employees or third parties in various fields – the transaction shall be considered negligible if it meets all of the rules of the Negligibility Procedure (other than the Negligibility Threshold), provided that the scope of the annual expenses for the services contemplated in the transaction does not exceed ILS 1.5 million and that the terms of the engagement in joint agreements in respect of the Partnership do not differ from the terms with respect to the interested party and/or control holder, considering their relative share.

c. In cases where, according to the discretion of the audit committee, all of the aforesaid criteria are irrelevant to the contemplated transaction, the audit committee shall determine other criteria, provided that the scope of the transaction shall not exceed the rules that have been set forth above.

d. The transaction is negligible also from the qualitative aspect. Thus, one of the criteria for such examination is that the transaction is not classified by the Partnership as an event which is required to be reported according to the provisions of Regulation 36 to the Reporting Regulations.

e. In multi-annual transactions (such as a lease of a property for several years) the negligibility of the transaction shall be examined on an annual basis (by calendar year) (in other words, in the aforesaid example, the annual rent shall be examined).

f. The negligibility of each transaction shall be examined separately, although the negligibility of integrated or contingent transactions shall be examined in the aggregate. Transactions that are performed frequently during the year and in close time proximity to one another shall be deemed as integrated transactions.

g. For the purpose of disclosure in the periodic report the negligibility of each transaction shall be examined on an annual basis while combining all of the same-kind transactions that were performed with the interested party or controlling interest holder, as the case may be, in the Report Year.

h. In cases where questions arise with regard to the implementation of the aforesaid criteria, the Partnership shall exercise discretion and examine the negligibility of the transaction based on the purpose of the Reporting Regulations and the rules and guidelines above.

i. Each year, the Partnership's management shall present to the audit committee transactions with interested parties to which the Partnership is a party and which were classified as negligible transactions under the procedure, and the audit committee will review the implementation of the provisions of the said procedure by the Partnership.

7. Internal enforcement program

The board of directors of the General Partner has determined that the audit committee will be in charge of the adoption of an updated internal enforcement program in respect of securities, for the management of the program and for the ongoing follow-up and supervision on the performance thereof. Accordingly, in August 2018, the audit committee approved an updated internal enforcement program in respect of securities, according to the criteria published by the ISA and based on the results of a compliance survey that was conducted in the Partnership. In this context, among other things, the procedures were updated according to the changes in the law since the adoption of the enforcement program existing in the Partnership until that date and the results of the said survey, and an officer responsible for internal enforcement was appointed.

8. Corporate Responsibility in the Partnership ("ESG")

In view of the importance placed by the Partnership on advancing the values of sustainability and incorporating them into the Partnership's operations, the board of directors of the General Partner of the Partnership has determined that the Audit Committee shall be in charge of ESG at the Partnership. As of the date of approval of the report, the Partnership is working to complete a long-term work plan on corporate responsibility areas, which will incorporate clear goals and transparency in its operations. Among other things, it intends to release a corporate responsibility report that will specify the economic aspects, the direct and indirect effects of the Partnership's operations, environmental, social and corporate governance data and goals according to a global standard of the GRI organization, and its goals in keeping with the UN's SDGs.

Part Four – Disclosure in connection with the Partnership's Financial Reporting

Subsequent events

See Note 23 to the financial statements attached below.

Part Five – Details of bonds issued by Delek & Avner (Tamar Bond) Ltd., Leviathan Bond Ltd. and the issue of bonds by the Partnership (in ILS in thousands)

Tamar Bond Bonds Series[4]	2023	2025
Par value on issue date	400,000	400,000
Issue date	May 19, 2014	May 19, 2014
Par value as of December 31, 2020	320,000	320,000
Linked par value as of December 31, 2020	320,000	320,000
Value in the Partnership's books as of December 31, 2020	318,260	317,099
TASE value as of December 31, 2020[5]	332,480	333,542
Fixed annual interest rate	5.082%	5.412%
Principal payment date[11]	December 30, 2023	December 30, 2025
Interest payment dates	Semiannual interest payable on every June 30th and every December 30th from the issue date in 2014-2023	Semiannual interest payable on every June 30th and every December 30th from the issue date in 2014-2025
Linkage base: base index[6]	None	
Conversion right	None	
Right to prepayment or mandatory conversion[7]	Right to prepayment	
Guarantee for payment of the liability	See Note 10B to the annual financial statements	
Name of the trustee	HSBC BANK USA, NATIONAL ASSOCIATION	
Name of person in charge at the trust company	Susie Moy	
Trustee's address and e-mail	HSBC Bank USA, National Association, as TRUSTEE 452 5th Avenue, 8E6 New York, NY 10018 CTLANYDealManagement@us.hsbc.com	
Rating as of the issue date[8]	Moody's: Baa3 Stable S&P: BBB- Midroog Ltd: Aa2 Stable Standard & Poor's Maalot: ilAA	
Rating as of the report date[9]	Moody's: Baa3 Negative S&P: BBB- Negative Midroog Ltd: Aa2 Negative Standard & Poor's Maalot: ilAA Negative	

4 $80 million was repaid in each one of the series as part of the sale of 9.25% (out of 100%) of the interests in the Tamar lease.
5 The bonds are traded in Israel on "TACT-Institutional" on TASE.
6 The principal and interest of the bonds are in dollars.
7 The Partnership is entitled to prepay the loan, in whole or in part, at any time, subject to a prepayment fee. Prepayment following events determined in the bonds may be performed without a prepayment fee.
8 See the Partnership's immediate reports of May 29, 2014 (Ref. No. 2014-01-077676), June 8, 2014 (Ref. No: 2014-01-084870) and June 17, 2014 (Ref. No. 2014-01-093135, 2014-01-093132), the information included in which is incorporated herein by reference.
9 See the Partnership's immediate reports of April 7, 2020 (Ref. No.: 2020-01-033091), of April 17, 2020 (Ref. No.: 2020-01-038931), of May 4, 2020 (Ref. No.: 2020-01-039325), and of October 9, 2020 (Ref. No. 2020-01-110016 and 2020-01-110058), the information included in which is incorporated herein by reference.

Has the company fulfilled, by December 31, 2020 and during the Report Year, all of the conditions and obligations under the indenture	Yes
Is the bond series material[10]	Yes
Have any conditions establishing cause for acceleration of the bonds been fulfilled	No
Pledges to secure the bonds	See Note 10B to the annual financial statements.

[10] The series of bond certificates will be deemed material if the total liabilities of the corporation thereunder at the end of the Report Year, as presented in the financial statements, constitute five percent or more of the total liabilities of the corporation.

Bond series of Leviathan Bond	2023	2025	2027	2030
Par value on the issue date	500,000	600,000	600,000	550,000
Issue date	August 18, 2020	August 18, 2020	August 18, 2020	August 18, 2020
Par value as of December 31, 2020	500,000	600,000	600,000	550,000
Linked par value as of December 31, 2020	500,000	600,000	600,000	550,000
Value in the Partnership's books as of December 31, 2020	496,621	593,153	590,770	538,797
TASE value as of December 31, 2020[11]	535,310	659,958	676,758	628,210
Fixed annual interest rate	5.750%	6.125%	6.500%	6.750%
Principal payment date[11]	June 30, 2023	June 30, 2025	June 30, 2027	June 30, 2030
Interest payment dates	Semiannual interest payable on every June 30th and every December 30th from the issue date in 2020-2023	Semiannual interest payable on every June 30th and every December 30th from the issue date in 2020-2025	Semiannual interest payable on every June 30th and every December 30th from the issue date in 2020-2027	Semiannual interest payable on every June 30th and every December 30th from the issue date in 2020-2030
Linkage base: base index[12]	None			
Conversion right	None			
Right to prepayment or mandatory conversion[13]	Right to prepayment			
Guarantee for payment of the liability	See Note 10C to the financial statements attached below.			
Name of the trustee	HSBC Bank USA, National Association			
Name of person in charge at the trust company	Asma Alghofailey			
Trustee's address and e-mail	HSBC Bank USA, National Association, as TRUSTEE 452 5th Avenue, 8E6 New York, NY 10018 asma.x.alghofailey@us.hsbc.com			
Rating as of the issue date[14]	Fitch Rating: BB stable Moody's: Ba3 Stable S&P: BB- Stable Standard & Poor's Maalot: ilA+ stable			
Rating as of the report date[15]	Fitch Rating: BB stable Moody's: Ba3 Stable			

[11] The bonds are traded in Israel on the "TACT-institutional" system on TASE

[12] The bonds' principal and interest are depicted in dollars.

[13] The financing documents prescribe provisions regarding the prepayment of the bonds, including (1) prepayment initiated by the issuer, subject to a prepayment fee (make whole premium), and (2) mandatory prepayment in certain cases that were defined, including by way of a bond buyback and/or an issuance of a purchase offer to all of the bond holders, including upon the sale of all or part of the rights in the Leviathan project.

[14] See the Partnership's immediate reports of August 19, 2020 (Ref. No. 2020-01-090852 and 2020-01-091134), and of August 23, 2020 (Ref. No. 2020-01-092247), the information included in which is incorporated herein by reference.

	S&P: BB- Stable Standard & Poor's Maalot: ilA+ stable
Has the Partnership fulfilled, by December 31, 2020 and during the Report Year, all of the conditions and obligations under the indenture	Yes
Is the bond series material[16]	Yes
Have any conditions establishing cause for acceleration of the bonds been fulfilled	No
Pledges to secure the bonds	See Note 10C to the financial statements attached below.

The Bond Series	**Series A[17]**
Par value on the issue date in ILS in thousands	1,528,533
Issue date	December 26, 2016
Par value as of December 31, 2020 in ILS	1,509,670
Linked par value as of December 31, 2020 in ILS in thousands	1,270,905
Value in the Partnership's books as of December 31, 2020 in ILS in thousands	1,267,544
TASE value as of December 31, 2020 in ILS in thousands	1,259,366
Fixed annual interest rate	4.5%
Principal payment date	December 31, 2021
Interest payment dates	Semiannual interest payable on every June 30th and every December 31st from the issue date in 2017-2021
Linkage base: base index	The bond is stated in ILS. The principal and interest are linked to a dollar rate of 3.819
Conversion right	None
Right to prepayment or mandatory conversion[18]	Right to prepayment
Guarantee for payment of the liability	See Note 10E to the financial statements attached below.
Name of the trustee	Reznik Paz Nevo Trusts Ltd.
Name of person in charge at the trust company	Adv. Michal Avtalion-Rishony
Trustee's address and e-mail	14 Yad Harutzim St., Tel Aviv
Rating as of the issue date[19]	Midroog Ltd.: A1 stable

[15] See Footnote 14.
[16] A series of bond certificates will be deemed material if the total liabilities of the corporation thereunder at the end of the Report Year, as presented in the financial statements, constitute five percent or more of the total liabilities of the corporation.
[17] On July 26, 2020, the board of directors of the General Partner approved a buyback plan in respect of Series A Bonds and bonds of Delek & Avner (Tamar Bond) in the sum total of up to $50 million. As of the report date the Partnership purchased ILS 11,403 thousand par value of the bonds in the context of the plan.
[18] The Partnership has the right to perform early redemption of the bonds at any time, in whole or in part, all in accordance with the indenture.
[19] See the Partnership's immediate report of December 22, 2016 (Ref. No. 2016-01-090873), the information included in which is incorporated herein by reference.

Rating as of the report date[20]	Midroog Ltd.: A2 stable
Has the Partnership fulfilled, by December 31, 2020 and during the Report Year, all of the conditions and obligations under the indenture	Yes
Have any conditions establishing cause for acceleration of the bonds been fulfilled	No
Pledges to secure the bonds	See Note 10E to the financial statements attached below.
The Partnership's financial equity as of December 31, 2020, as defined in the indenture[21]	Approx. $3,438 thousand
The financial equity to debt ratio as of December 31, 2020, as defined in the indenture[21]	Approx. 9
Is it material[22]	Yes

Additional information

The board of directors of the General Partner expresses its appreciation of the management of the General Partner of the Partnership, the officers and the entire team of employees for their dedicated work and their significant contribution to the promotion of the Partnership's business.

Sincerely,

Gabi Last	**Yossi Abu**
Chairman of the Board	CEO

Delek Drilling Management (1993) Ltd.
On behalf of: Delek Drilling – Limited Partnership

[20] For an updated rating report, see the Partnership's immediate reports of June 5, 2020 (Ref. No.: 2020-01-057768) and of October 15, 2020 (Ref. No. 2020-01-103519), the information included in which is incorporated herein by reference.
[21] Included in accordance with the Partnership's undertaking on the date of the issue of the bonds – for further details, see Note 10E to the financial statements attached below. The ratio was calculated, *inter alia*, based on the discounted cash flows of the Tamar project which were included in Section 7.3.11 to the above Description of the Corporation's Business chapter and of the Leviathan project (as released in the immediate report of March 10, 2021, Ref. No. 2021-01-030942) as of December 31, 2020.
[22] The series of bond certificates will be deemed material if the total liabilities of the corporation thereunder at the end of the Report Year, as presented in the financial statements, constitute five percent or more of the total liabilities of the corporation.

Annex A to the Board of Directors' Report

Figures regarding Delek & Avner (Tamar Bond) Ltd.

Further to Note 10B to the financial statements attached below and to Part Five of the Board of Directors' Report, and following a tax ruling received by the Partnership immediately prior to the bond issuance, below are financial figures which will be disclosed to the holders of bonds of Delek & Avner (Tamar Bond) Ltd.

Statements of Financial Position (Expressed in US$ Thousands)

	31.12.2020	**31.12.2019**
	Audited	**Audited**
Assets:		
Current Assets:		
Short term deposits	89	*67
Related parties	99,911	-
Loans to Shareholders	-	319,614
	100,000	319,681
Noncurrent Assets:		
Loans to shareholders	639,491	639,227
Long term bank deposits	-	102,419
	639,491	741,646
	739,491	1,061,327
Liabilities and Equity:		
Current Liabilities:		
Related parties	-	*2,485
Bonds	-	320,000
	-	322,485
Noncurrent Liabilities:		
Bonds	640,000	640,000
Loans from shareholders	100,000	100,000
	740,000	740,000
Equity	(509)	(1,158)
	739,491	1,061,327

***reclassified**

Statements of Comprehensive Income (Expressed in US$ Thousands)

	For the Year Ended 31.12.2020	**For the Year Ended 31.12.2019**
	Audited	**Audited**
Financial expenses	48,119	51,005
Financial income	(48,768)	(51,025)
Total comprehensive income	(649)	(20)

SPONSOR FINANCIAL DATA REPORT[23]
Cash flow for the period from January 1, 2020 – December 31, 2020

	Item	Quantity/Actual Amount (In thousands)
A.	Total Offtake (BCM) (100%)[24]	8.25
B.	Tamar Revenues (100%)[24]	1,510,385
C.	Loss Proceeds, if any, paid to Revenue Accounts	-
D.	Sponsor Deposits, if any, into Revenue Accounts	-
E.	Gross Revenues (before Royalties)[25]	350,195
F.	Overriding Royalties	
	(a) Statutory Royalties	(40,019)
	(b) Third Party Royalties	(34,861)
G.	Net Revenues	275,315
H.	Costs and Expenses:	
	(a) Fees Under the Financing Documents (Interest Income)	458
	(b) Taxes	(2,200)
	(c) Operation and Maintenance Expenses	(22,664)
	(d) Capital Expenditures	(11,951)
	(e) Payments under the Tamar FUA	-
	(f) Insurance	(3,328)
I.	Total Costs and Expenses (sum of Items H(a), (b), (c), (d), (e) and (f)	(39,685)
J.	Total Cash Flows Available for Debt Service (Item G minus Item H)	235,630
K.	Total Debt Service	(367,054)

[23] The aforesaid report is delivered to the trustee for the bonds on a quarterly and annual basis and represents the cash flow deriving for the Partnership from the Tamar project relative to the amounts required for the debt service in such period.
[24] Sections A and B are based on 100% of Tamar partners on an accrual basis.
[25] Sections C-K are based on Delek Drilling Share in Tamar (22%) and on actual cash flow of the Sponsor Accounts as part of the Tamar Bond indenture.

Annex B to the Board of Directors' Report

Figures regarding Leviathan Bond Ltd.

Further to Note 10C to the financial statements attached below and Part Five of the Board of Directors' Report and following a tax ruling received by the Partnership immediately prior to the issue of the bonds, below are financial figures which will be provided to the holders of the bonds of Leviathan Bond Ltd.

Statements of Financial Position (Expressed in US$ Thousands)

	31.12.2020	*15.7.2020
	Audited	**Audited**
Assets:		
Current Assets:		
Short term Bank deposits	15	-
Related parties	**	**
	15	**
Noncurrent Assets:		
Loans to shareholders	2,247,611	-
Long term bank deposits	100,000	-
	2,347,611	-
	2,347,626	**
Liabilities and Equity:		
Current Liabilities:		
Related parties	15	-
	15	-
Noncurrent Liabilities:		
Bonds	2,250,000	-
Loans from shareholders	100,000	-
	2,350,000	-
Equity (Deficit)	(2,389)	**
	2,347,626	**

*** Date of incorporation**
**** Less than $1,000**

Statements of Comprehensive Income (Expressed in US$ Thousands)

	For the Period Ended 31.12.2020
	Audited
Financial expenses	54,427
Financial income	(52,038)
Total comprehensive expenses (income)	2,389

SPONSOR FINANCIAL DATA REPORT[26]

		Year Ended
		31.12.2020
	Item	Quantity/Actual Amount (in USD$,000)
A.	Total Offtake (BCM)	7.25[27]
B.	Leviathan Revenues (100%)	1,295,808[28]
C.	Loss Proceeds, if any, paid to Revenue Account	-
D.	Sponsor Deposits, if any, into Revenue Account	-
E.	Gross Revenues (before Royalties)	228,763
F.	Overriding Royalties	
	(a) Statutory Royalties	(31,000)
	(b) Third Party Royalties	(11,675)
G.	Net Revenues	186,088[29]
H.	Costs and Expenses:	
	(a) Fees Under the Financing Documents (Interest Income)	32
	(b) Taxes	-
	(c) Operation and Maintenance Expenses	-[30]
	(d) Capital Expenditures	-[31]
	(e) Insurance (income)	172
I.	Total Costs and Expenses (sum of Items H(a), (b), (c), (d) and (e))	204
J.	Total Cash Flows Available for Debt Service (Item G *minus* Item H)	186,292
K.	Total Cash Flow from operation (Item G minus Items H(c) and H(e)	186,292
L.	Total Debt Service	(51,994)
M.	Total Distribution to the Sponsor	-

[26] The aforesaid report is delivered to the trustee for the bonds on a quarterly and annual basis and represents the cash flow deriving for the Partnership from the Leviathan project relative to the amounts required for the debt service in such period.
[27] Gas sales from January 1, 2020 until December 31, 2020 for 100% of the Leviathan partners on an accrual basis.
[28] Gas sales from January 1, 2020 until December 31, 2020 for 100% of the Leviathan partners on an accrual basis.
[29] Sections C-M are based on Delek Drilling Share in Leviathan (45.34%) and on actual cash flow of the Sponsor Accounts as part of the Leviathan Bond indenture from the Issuance Date (August 18, 2020) until December 31, 2020.
[30] As of the Issuance Date (August 18, 2020) until December 31, 2020 a sum of US $31,984 Thousands was paid by the Sponsor from its own sources.
[31] As of the Issuance Date (August 18, 2020) until December 31, 2020 a sum of US $21,248 Thousands was paid by the Sponsor from its own sources.

Annex C to the Board of Directors' Report

Summary of Data of a Valuation of Royalties from the Karish and Tanin Leases

Following are details of a highly material valuation with respect to the profit from the revaluation of royalties from the sale of the Partnership's interests in the Karish and Tanin leases (for further details, see Note 8B to the annual financial statements and the valuation attached below):

Identification of the object of the valuation:	Royalties in respect of the sale of all of the interests in the Karish and Tanin leases.
Timing of the valuation:	December 31, 2020
Value of the object of the valuation shortly before the date of the valuation, if GAAP, including depreciation and amortization, did not warrant a change in its value according to the valuation:	Not applicable.
Value of the object of the valuation determined according to the valuation:	A sum of approx. U.S. $242.2 million, which is included under other long-term assets of the Partnership.
Identification of the valuator and his/its characteristics, including education, experience in the preparation of valuations for accounting purposes in reporting corporations and in scopes similar to or exceeding those of the reported valuation, and dependence on the party commissioning the valuation, including reference to indemnification agreements with the valuator:	GSE Financial Advisory Ltd. is a subsidiary of Giza Singer Even Ltd. (jointly: the "**Valuator**"), which is a leading financial consulting and investment banking firm in Israel. The firm has vast experience in supporting the largest companies, the most prominent privatizations and the most important transactions in the Israeli market, which experience was gained thereby over the course of its thirty years of activity. Giza Singer Even is active in three segments, through autonomous and independent business divisions: economic consulting; investment banking; analytical research and corporate governance. The work was performed by a team headed by CPA Eitan Cohen, partner and Head of the Economic Department at Giza Singer Even, who has more than ten years of experience in economic and business consulting, company valuations and financial instruments. Eitan is an accountant holding a B.A. in Economics and Business Administration from the Ben Gurion University and an M.A. in Financial Mathematics from the Bar Ilan University. The Valuator has no personal interest in and/or dependence on the Partnership and/or the General Partner of the Partnership, other than the fact that it received a fee for the

	valuation. Furthermore, the Valuator has confirmed that its fee is not contingent on the results of the valuation. In addition, insofar as the Valuator shall be bound by a peremptory judgment to pay any sum to a third party in connection with the work, the Partnership shall pay the Valuator the sum charged to the Valuator in excess of the fee paid for the work multiplied by 3. It is noted that this indemnification undertaking shall not apply should it be ruled that the Valuator acted with negligence or intentional misconduct in connection with the performance of the work.
The valuation model applied by the Valuator:	Discounting expected cash flows while adjusting the discount rates to the risks entailed by the cash flow forecasts.
The assumptions based on which the Valuator prepared the valuation according to the valuation model:	The key assumptions underlying the valuation are as follows: 1. Dates of production of gas from the Karish lease: April 1, 2022 to December 31, 2040; 2. Average annual production rate from the Karish lease: approx. 3.91 BCM of natural gas; condensate annual average production rate from the Karish lease of approx. 5.0 million condensate barrels; 3. Dates of production of gas from the Tanin reservoir: January 1, 2027 to December 31, 2036; 4. Average annual production rate from the Tanin lease: approx. 2.51 BCM of natural gas; average annual condensate production rate from the Tanin lease of approx. 0.44 million condensate barrels; 5. Royalty component cap rate: 12.0%; 6. Effective royalty rate to be paid to the State for the gas and the condensate: 11.5%; 7. Gas price formula: The basic price in the contracts according to which the valuation was prepared was estimated based on the formula

	specified in the price mechanism between Energean and ICL and ORL and between Energean and OPC and weighting the price of the gas in the Ramat Hovav contract; 8. Condensate price: The condensate price forecast was estimated based on a long-term oil price forecast average of the World Bank[32] and the EIA[33] and the forward prices of Brent according to Bloomberg data and based on the assumption that the condensate price will derive from the Brent price with adjustments to oil quality differences; 9. On February 11, 2021, Energean released an updated resource report of D&M, a certified reserves and resources valuator, which pertains to the Karish and Tanin leases. According to this report, the gas quantity in Karish Center is approx. 40.2 BCM and the quantity of the hydrocarbon liquids is approx. 65.1 MMBBL, the gas quantity in Karish North is approx. 33.1 BCM and the quantity of the hydrocarbon liquids is approx. 30.6 MMBBL and the gas quantity in Tanin is approx. 25.1 BCM and the quantity of the hydrocarbon liquids is approx. 3.9 MMBBL. 10. Petroleum profit levy: According to the Petroleum Profit Taxation Law, 5771-2011; 11. Corporate tax rate: 23%, according to the statutory tax rate throughout the years of the forecast.

[32] A world Bank Quarterly Report: Commodity Markets Outlook, October 2020.
[33] U.S Energy Information Administration: Analysis & Projections, February 2021.

Delek Drilling

Financial Statements

2020

March 14, 2021

To

The Board of Directors of the General Partner of Delek Drilling – Limited Partnership (the "Partnership")

<u>19 Abba Eban, Herzliya</u>

Dear Sir/Madam,

Re: <u>Consent given simultaneously with the release of a periodic report in connection with the shelf prospectus of the Partnership (the "Offering Document")</u>

We hereby notify you that we agree to the inclusion (including by way of reference) in the above referenced Offering Document of our reports as specified below:

1. Auditors' report of March 14, 2021 on the Partnership's financial statements as of December 31, 2020 and 2019 and for each of the three years in the period ended December 31, 2020.

2. The Auditors' report of March 14, 2021 on the audit of components of internal control over financial reporting of the Partnership as of December 31, 2020.

Kost Forer Gabbay & Kasierer
Certified Public Accountants

Ziv Haft
Certified Public Accountants

<u>Delek Drilling – Limited Partnership</u>

<u>Financial Statements as of December 31, 2020</u>

<u>in U.S. Dollars in Thousands</u>

This report is a translation of Delek Drilling - Limited Partnership's Hebrew-language financial statements, prepared solely for convenience purposes. Please note that the Hebrew version is the binding version, and in any event of discrepancy, the Hebrew version shall prevail.

Delek Drilling – Limited Partnership

Financial Statements as of December 31, 2020

in U.S. Dollars in Thousands

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Independent Auditors' Report to the Partners of Delek Drilling – Limited Partnership regarding Audit of Components of Internal Control over Financial Reporting pursuant to Section 9B(c) of the Securities Regulations (Periodic and Immediate Reports), 5730-1970

We have audited components of internal control over financial reporting of Delek Drilling – Limited Partnership **(**the "**Partnership**") as of December 31, 2020. These components of control were determined as explained in the following paragraph. The Board of Directors and Management of the Partnership's general partner are responsible for maintaining effective internal control over financial reporting and for their assessment of the effectiveness of the components of internal control over financial reporting, attached to the periodic report as of the above date. Our responsibility is to express an opinion on the components of internal control over financial reporting of the Partnership, based on our audit.

The components of the internal control over financial reporting that were audited were determined pursuant to Audit Standard (Israel) 911 of the Institute of Certified Public Accountants in Israel "Audit of Components of Internal Control over Financial Reporting" ("**Audit Standard (Israel) 911**"). These Components are: 1) Entity-level controls, including controls over the financial reporting and closing process and ITGCs; 2) Controls over the calculating process versus the operators of the joint ventures; 3) Controls over the process of cash management including investments and process of raising and management of bonds and loans (all hereinafter jointly referred to as: the "**Audited Components of Control**").

We conducted our audit pursuant to Audit Standard (Israel) 911. This Standard requires that we plan and perform the audit with the purpose of identifying the Audited Components of Control, and to obtain reasonable assurance about whether these components of control were effectively maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, identifying the Audited Components of Control, assessing the risk that a material weakness exists in the Audited Components of Control, and testing and evaluating the design and operating effectiveness of such components of control, based on the assessed risk. Our audit of such components of control also included performing such other procedures as we considered necessary in the circumstances. Our audit only referred to the Audited Components of Control, as opposed to internal control over all of the material processes in connection with the financial reporting, and therefore our opinion refers only to the Audited Components of Control. In addition, our audit did not address mutual effects between the Audited Components of Control and non-audited controls, and therefore, our opinion does not take into consideration such possible effects. We believe that our audit provides a reasonable basis for our opinion in the context described above.

Because of its inherent limitations, internal control over financial reporting in general and components thereof in particular, may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Partnership effectively maintained, in all material respects, the Audited Components of Control as of December 31, 2020.

We have also audited, based on Generally Accepted Auditing Standards in Israel, the financial statements of the Partnership as of December 31, 2020 and 2019, and for each of the three years in the period ended December 31, 2020, and our report of March 14, 2021 included an unqualified opinion on the aforesaid financial statements.

Tel Aviv, March 14, 2021

Kost Forer Gabbay & Kasierer **Certified Public Accountants**	**Ziv Haft** **Certified Public Accountants**

Independent Auditors' Report to the Partners of Delek Drilling – Limited Partnership

We have audited the accompanying statements of financial position of Delek Drilling – Limited Partnership (the "**Partnership**") as of December 31, 2020 and 2019 and the statements of comprehensive income, the statements of changes in equity, and the statements of cash flows for each of the years in the three-year period ended December 31, 2020. The board and management of the Partnership's general partner are responsible for these financial statements. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Generally Accepted Auditing Standards in Israel, including standards set in the Accountants Regulations (Mode of Operation of Accountants) 5733-1973. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by the board and management of the Partnership's general partner, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the Partnership as of December 31, 2020 and 2019 and the results of its operations, the changes in its capital and cash flows for each of the years in the three-year period ended December 31, 2020 in accordance with International Financial Reporting Standards (IFRS) and the provisions of the Securities Regulations (Annual Financial Statements), 5770-2010.

We have also audited, pursuant to Audit Standard (Israel) 911 of the Institute of Certified Public Accountants in Israel "Audit of Components of Internal Control over Financial Reporting", components of the Partnership's internal control over financial reporting as of December 31, 2020 and our report as of March 14, 2021 included an unqualified opinion on the effective maintenance of such components.

Tel Aviv, March 14, 2021

Kost Forer Gabbay & Kasierer	**Ziv Haft**
Certified Public Accountants	**Certified Public Accountants**

Delek Drilling – Limited Partnership

Statements of Financial Position (Dollars in thousands)

	Note	31.12.2020	31.12.2019
Assets:			
Current assets:			
Cash and cash equivalents	3	69,979	171,046
Short-term investments	4	169,367	63,459
Trade receivables	22G	145,681	46,862
Trade and other receivables	5	32,876	86,881
		417,903	368,248
Non-current assets:			
Investments in oil and gas assets	7	3,439,902	3,429,178
Investments in a company accounted for at equity	6	67,288	74,995
Long-term deposits	4	100,529	102,919
Other long-term assets	8	559,065	527,733
		4,166,784	4,134,825
		4,584,687	4,503,073
Liabilities and equity:			
Current liabilities:			
Bonds	10E	393,806	319,421
Liabilities to banking corporations	10D	-	296,867
Provision for balancing payments and tax	13D	36,462	33,657
Trade and other payables	9	73,567	174,738
Other short-term liabilities	11	62,212	-
		566,047	824,683
Non-current liabilities:			
Bonds	10	2,854,699	1,031,410
Long-term liabilities to banking corporations	10D	-	1,630,404
Other long-term liabilities	11	166,246	203,069
		3,020,945	2,864,883
Equity:	13		
Partners' equity		154,791	154,791
Capital reserves		(48,616)	(25,851)
Retained earnings		891,520	683,567
		997,695	813,507
		4,584,687	4,503,073

The attached notes constitute an integral part of the financial statements.

March 14, 2021			
Date of approval of the Financial Statements	Gabi Last Chairman of the Board Delek Drilling Management (1993) Ltd. General Partner	Yossi Abu CEO Delek Drilling Management (1993) Ltd. General Partner	Yossi Gvura Deputy CEO Delek Drilling Management (1993) Ltd. General Partner

Delek Drilling – Limited Partnership

Statements of Comprehensive Income (Dollars in thousands)

	Note	For the year ended 31.12.2020	31.12.2019	31.12.2018
Revenues:				
From natural gas and condensate sales	14	919,122	453,344	457,982
Net of royalties	15	154,264	94,318	91,333
Revenues, net		**764,858**	**359,026**	**366,649**
Expenses and costs:				
Cost of production of natural gas and condensate	16	113,957	40,731	32,720
Depreciation, depletion and amortization expenses	7	111,807	67,581	45,058
Other general expenses	17	3,611	14,298	9,720
G&A	18	14,630	11,130	9,811
Total expenses and costs		**244,005**	133,740	**97,309**
Other expenses, net		-	(474)	(561)
The Partnership's share in the profits (losses) of companies accounted for at equity, net	6	(7,707)	(36,645)	10,542
Operating profit before oil and gas profit levy		**513,146**	**188,167**	**279,321**
Oil and gas profit levy	20	(3,837)	4,620	(4,205)
Operating profit		**509,309**	**192,787**	**275,116**
Financial expenses	19	(232,512)	(47,487)	(57,432)
Financial income	19	88,323	78,390	59,149
Financial income (expenses), net		(144,189)	30,903	1,717
Net income		**365,120**	**223,690**	**276,833**
Other comprehensive loss:				
Amounts which may subsequently be reclassified to profit or loss:				
Loss in respect of cash flow hedging transactions	22B	(4,757)	(5,150)	-
Carried to profit or loss in respect of cash flow hedging transactions		7,360	(1,830)	(2,721)
		2,603	(6,980)	(2,721)
Amounts which shall not subsequently be reclassified to profit or loss:				
Loss from investment in equity instruments designated for measurement at fair value through other comprehensive income	8A	(29,322)	(41,256)	-
Total other comprehensive loss		**(26,719)**	**(48,236)**	**(2,721)**
Total comprehensive income		**338,401**	**175,454**	**274,112**
Basic and diluted profit per participation unit (in Dollars)		0.311	0.191	0.236
Weighted number of participation units for the purpose of the said calculation (in thousands)		1,173,815	1,173,815	1,173,815

The attached notes constitute an integral part of the financial statements.

Delek Drilling – Limited Partnership

Statements of Changes in the Partnership's Equity (Dollars in thousands)

	The Partnership's equity	Capital reserve for redemption of participati on units	Capital reserve for transactions between the corporation and a control holder thereof	Capital reserve for financial assets available for sale, for equity instruments and cash flow hedging transactions	Retained earnings	Total
Balance as of December 31, 2017	**154,791**	**1,631**	**13,166**	**9,198**	**439,692**	**618,478**
Effect of initial application of IFRS9	-	-	-	(2,100)	2,114	14
Balance as of January 1, 2018	**154,791**	**1,631**	**13,166**	**7,098**	**441,806**	**618,492**
Changes in the year ended December 31, 2018:						
Net income	-	-	-	-	276,833	276,833
Other comprehensive loss	-	-	-	(2,721)	-	(2,721)
Total comprehensive income (loss)				(2,721)	276,833	274,112
Profits distributed (Note 13C)	-	-	-	-	(274)	(274)
Declared profits for distribution[1] (Note 13C)	-	-	-	-	(34,446)	(34,446)
Tax advances on account of the tax owed by the participation unit holders (Note 13D)	-	-	-	-	(4,616)	(4,616)
Capital reserve for benefits from a control holder (Note 13G)	-	-	1,836	-	-	1,836
Balance as of December 31, 2018	**154,791**	**1,631**	**15,002**	**4,377**	**679,303**	**855,104**
Balance as of January 1, 2019						
Changes in the year ended December 31, 2019:						
Net profit	-	-	-	-	223,690	223,690
Other comprehensive loss	-	-	-	(48,236)	-	(48,236)
Total comprehensive income (loss)	-	-	-	(48,236)	223,690	175,454
Profits distributed (Note 13C)	-	-	-	-	(150,354)	(150,354)
Declared tax and balancing payments (Note 13D)	-	-	-	-	(33,502)	(33,502)
Provision made for balancing payments due to previous years (see Note 20A7)	-	-	-	-	(12,300)	(12,300)
Tax advances on account of the tax owed by the participation unit holders (Note 13D)	-	-	-	-	(23,270)	(23,270)
Capital reserve for benefits from a control holder (Note 13G)			2,375		-	2,375
Balance as of December 31, 2019	**154,791**	**1,631**	**17,377**	**(43,859)**	**683,567**	**813,507**
Changes in the year ended December 31, 2020:						
Net profit	-	-	-	-	365,120	365,120
Other comprehensive loss	-	-	-	(26,719)	-	(26,719)
Total comprehensive income (loss)	-	-	-	(26,719)	365,120	338,401
Profits distributed (Note 13C)	-	-	-	-	(65,593)	(65,593)
Declared tax and balancing payments (Note 13D)	-	-	-	-	(36,428)	(36,428)
Tax advances on account of the tax owed by the participation unit holders (Note 13D)	-	-	-	-	(55,146)	(55,146)
Capital reserve for benefits from a control holder (Note 13G)	-	-	2,954	-	-	2,954
Balance as of December 31, 2020	**154,791**	**1,631**	**20,331**	**(70,578)**	**891,520**	**997,695**

The attached notes constitute an integral part of the financial statements.

[1] Including mostly tax and balancing payments to entitled holders, as specified in footnote 47.

Delek Drilling – Limited Partnership

Statements of Cash Flows (Dollars in thousands)

	For the year ended		
	31.12.2020	31.12.2019	31.12.2018
Cash Flows - Current Operations:			
Income for the year	365,120	223,690	276,833
Adjustments for:			
Depreciation, depletion and amortization	140,295	69,719	47,518
Change in fair value of financial derivatives, net	(2,920)	373	-
Update of asset retirement obligation	(631)	4,637	5,070
Revaluation of short-term and long-term investments and deposits	2,390	(2,666)	2,603
Revaluation of liability due to participation unit-based payment	(13)	(154)	(221)
Benefit from a control holder included in expenses against a capital reserve	2,954	2,375	1,836
Revaluation of other long-term assets	(84,836)	(57,458)	(48,804)
The Partnership's share in the losses (profits) of companies accounted for at equity, net	7,707	36,645	(10,542)
Changes in assets and liabilities items:			
Decrease (increase) in trade receivables	(98,819)	(1,381)	1,025
Decrease in trade and other receivables (including operator of joint ventures)	23,319	337	446
Increase in other long-term assets	(5,697)	(4,552)	(2,114)
Decrease in trade and other payables (including operator of joint ventures)	(21,060)	(14,943)	(15,503)
Decrease in oil and gas profit levy liability	(1,333)	-	-
Increase (decrease) in another long-term liability	2,199	(2,604)	(1)
	(36,445)	30,328	(18,687)
Net cash deriving from current operations	**328,675**	**254,018**	**258,146**
Cash Flows - Investment Activity:			
Investment in oil and gas assets	(165,085)	(609,926)	(744,186)
Increase in other long-term assets	(14,596)	(140,523)	(15,930)
Investment in a company accounted for at equity	-	(75,000)	
Repayment of loans given	14,843	15,342	10,850
Decrease (increase) in short-term investment, net	(105,908)	124,150	91,159
Long-term deposit in bank deposits	(100,000)	(41,428)	(60,000)
Repayment of long-term bank deposits	100,000	-	100,000
Dividend received from a company accounted for at equity	-	-	16,125
Decrease (increase) in other receivables – operator of the joint ventures	28,921	23,843	(52,590)
Net cash deriving from (used for) investment activity	**(241,825)**	**(703,542)**	**(654,572)**
Cash Flows - Financing Activity:			
Issuance of bonds (net of issuance costs)	2,217,332	-	-
Receipt of long-term loans from banking corporations (net of debt-raising costs)	103,831	688,136	775,384
Repayment of long-term loans from banking corporations	(2,050,000)	-	-
Distributed profits, balancing payments and tax	(99,120)	(185,902)	(61,359)
Payments on account of the tax liable by participation unit holders	(35,021)	(31,919)	(33,310)
Reimbursement received from income tax for previous years, net	-	6,370	24,761
Repurchase of issued bonds	(4,939)	-	(10,103)
Repayment of bonds	(320,000)	-	(309,897)
Net cash generated by (used in) financing activity	**(187,917)**	**476,685**	**385,476**
Increase (decrease) in cash and cash equivalents	(101,067)	27,161	(10,950)
Cash and cash equivalents balance at the beginning of the year	171,046	143,885	154,835
Cash and cash equivalents balance at the end of the year	69,979	171,046	143,885
Annex A - Finance and investment activity not involving cash flows:			
Investments in oil and gas assets against liabilities	42,259	150,156	127,110
Declared distributable profits, balancing payments and tax	36,428	33,502	34,446
Provision for balancing payments for previous years	-	12,300	
Annex B - Additional information on cash flows:			
Interest paid (including capitalized interest)	256,977	166,291	129,117
Interest received	1,666	8,857	10,205
Dividend received	-	9,040	16,125

The attached notes constitute an integral part of the financial statements.

Note 1 – General:

A. Delek Drilling – Limited Partnership (the "**Partnership**") was founded according to a limited partnership agreement of July 1, 1993 between Delek Drilling Management (1993) Ltd. as general partner (the "**General Partner**") of the first part, and Delek Drilling Trusts Ltd. as a limited partner (the "**Trustee**") of the second part.

The Trustee serves as trustee for the holders of the participation units, under the supervision of the supervisor, CPA Micha Blumenthal on behalf of Fahn Kanne & Co., CPAs and Adv. Uri Keidar on behalf of Keidar Supervision and Management (jointly, the "**Supervisor**").

The parent company of the General Partner is Delek Energy Systems Ltd. (the "**Parent Company**" and/or "**Delek Energy**") and the Partnership's ultimate parent company is Delek Group Ltd. ("**Delek Group**").

The participation units of the Partnership are listed on the Tel Aviv Stock Exchange ("**TASE**") and trading therein commenced in 1993.

The address of the Partnership's registered office is 19 Abba Eban Boulevard, Herzliya.

B. As of the date of approval of the financial statements, the Partnership's primary business is exploration, development and production of natural gas, condensate and oil in Israel and in Cyprus, as well as the promotion of various natural gas-based projects, aiming to increase the sales volume of natural gas. Concurrently, the Partnership is examining various business opportunities with characteristics similar to the ones in which the Partnership operates in the field of exploration, the development and production of natural gas and oil. According to the provisions of the Gas Framework (see Note 12L1 below), the Partnership is required to transfer by December 17, 2021 all of its interests in the Tamar I/12 and Dalit I/13 leases (jointly: "**Tamar and Dalit Leases**") and its holdings in Tamar Petroleum Ltd. For details regarding a possible restructuring for a split of the Partnership's assets, which is being examined by the Partnership and the manner of transfer of the interests in Tamar and Dalit, see Section E below.

C. On December 31, 2019, the piping of natural gas from the Leviathan reservoir to the domestic market began, and in January 2020, the piping of natural gas began to Jordan and to Egypt (collectively: the "**Regional Market**"), respectively. In July 2020, the piping of natural gas from the Tamar reservoir to Egypt began. The Partnership's revenues in the report period from the sale of natural gas are affected mainly by the volume of natural gas consumption in the domestic market by the Israel Electric Corp. Ltd. ("**IEC**") and in the Regional Market by Blue Ocean Energy ("**Dolphinus**") and the National Electric Power Company ("**NEPCO**") (see Notes 12C1, 12C2 and 14 below).

D. The financial figures of the joint ventures that are used by the Partnership in the preparation of its financial statements are based, *inter alia*, on documents and accounting data provided by the operator of the joint ventures in Israel, Noble Energy Mediterranean Ltd. ("**Noble**" or the "**Operator**") and the operator of the joint venture in Cyprus, Noble Energy International Ltd. ("**Noble Cyprus**").

On October 5, 2020 Chevron Corporation ("**Chevron**") announced the closing of a merger between itself and Noble Energy Inc. ("**Noble Inc.**"), the parent company of Noble, the operator of the petroleum assets Tamar and Leviathan, and of Noble Cyprus.

Note 1 – General (Cont.):

E. On March 17, 2019, the General Partner's board of directors decided to instruct the Partnership's management to examine and promote a plan for the splitting of the Partnership's assets. Therefore, the Partnership acted, during the last year, for promotion of a possible outline for the splitting of its assets, according to which all of the Partnership's assets, with the exception of its interests in the Tamar and Dalit Leases and in the Yam Tethys project, will be transferred to a new English corporation (the "**English Corporation**") against the allotment of shares which shall be distributed to the holders of the participation units, and further thereto the English Corporation shall perform a share offering to foreign investors and will list its shares on the London Stock Exchange and on TASE (the "**London Transaction**"). In the context of promotion of the London Transaction, the Partnership prepared a draft offering prospectus that was recently filed for the approval of the British regulator (the FCA) on behalf of the English Corporation. As of the date of approval of the Financial Statements, the Partnership is continuing to act for the promotion of the London Transaction and is working, with the help of its advisors, to put together the details of the transaction.

It is emphasized that, as of the date of approval of the Financial Statements, the General Partner's board of directors has not yet adopted a resolution to approve the London Transaction, and that the London Transaction requires, *inter alia*, receipt of regulatory approvals in Israel and overseas, and is subject, *inter alia*, to the approval of the unitholders' meeting, the obtaining of various approvals and completion of additional actions whose feasibility is uncertain, and therefore there is no certainty that the transaction will be consummated.

Considering the provisions of the Gas Framework which require the Partnership to transfer all of its interests in the Tamar and Dalit Leases to a third party by December 2021, the Partnership intends, in the upcoming period, to focus its efforts on finding an optimal solution for fulfilling the requirements of the Gas Framework, in which context it intends to act mainly for promotion of the possibility of selling the said interests to a third party.

F. The spread of Covid-19 and its possible impact on the Partnership's business:

At the end of 2019 and during Q1/2020, the Coronavirus (Covid-19) began to spread in China and thereafter all over the world, when in March 2020 it was defined by the World Health Organization as a global pandemic (the "**Covid-19 Crisis**").

During the H1/2020, extremely sharp declines were recorded in the international markets in oil and natural gas prices, which may, in the Partnership's estimation, be attributed to the Covid-19 Crisis, as well as to other causes and reasons which affect the supply and demand of energy products. However, towards the end of 2020 and in the first months of 2021, a recovery is felt in the prices of energy products worldwide, including oil and LNG prices.

In addition, in H1/2020, mainly in Q2, the domestic market saw a stagnation in the demand for natural gas compared with the same period last year, mainly due to the effect of the Covid-19 Crisis on the demand for electricity in these markets, as a result of closures and restrictions on economic activity. It is noted that even though the Covid-19 Crisis continued, an increase in demand for natural gas was recorded in H2/2020 compared with the same period last year.

Note 1 – General (Cont.):

F. The spread of Covid-19 and its possible impact on the Partnership's business (Cont.):

As of the date of approval of the financial statements, it is difficult to estimate how the Covid-19 Crisis will continue to develop in the coming years, what the extent of its impact on the global economy will be and what its impact will be on the demand and sales from the Leviathan and Tamar reservoirs in the coming years. Under these circumstances, the Covid-19 Crisis constitutes a global macroeconomic risk inducing uncertainty as to future economic activity in the world and the expected effects on the financial markets, interest margins, currency rates and commodity prices in the energy field, and may adversely affect many industries, including the energy sector in which the Partnership operates.

As part of their Covid-19 strategy, the Tamar partners, the Leviathan partners and the partners in Block 12 in Cyprus, worked to streamline and reduce operating budgets for 2020 and postpone planned investment budgets to later years. Accordingly, the partners in the said projects approved updated budgets for 2020. The Partnership is continuing to work with its other partners in the said projects to expand the streamlining plans into the coming years as well.

In addition, as a result of the spread of the Covid-19 Crisis, many countries, including Israel, are taking extreme steps to try and prevent the spread of the virus, such as restrictions of civilian movements and gatherings, transit restrictions on passengers and goods, closures between borders, and the like. Beyond the negative impact of these measures on local and global economic growth, the restrictions and actions that are and will be taken by Israel and other countries for coping with the Covid-19 Crisis can have a material adverse effect on the Partnership's work plans. As a result of these measures, delays may be caused in the entry of foreign experts and in the supply of designated equipment to Israel, due to restrictions that apply to civilian movement between sites and countries and restrictions on production or shipment that apply in the various countries which may, *inter alia*, disrupt the regular production activity, the work plans of the operator, and even impose additional unexpected costs. In this context, it should be noted that Noble, the Operator of the Tamar and Leviathan projects, in coordination with the Petroleum Commissioner and the Ministry of Health, formulated an action plan to deal with the Covid-19 Crisis, among other things, to ensure, as much as possible, that the Operator's workforce will be able to reach the projects' offshore and onshore facilities and continue to perform essential operations in said facilities. As of the date of approval of the financial statements, the Covid-19 Crisis has not had a material adverse effect on the operation system in the Tamar and Leviathan projects. However, since there is uncertainty as to the manner in which the Covid-19 Crisis will develop, there is a risk that despite the prevention measures being taken by the partners in the projects, the operation of the reservoirs will be adversely impacted.

G. As of December 31, 2020, the Partnership has a working capital deficit in the sum of approx. \$148 million for a period of twelve months, which mainly derives from Series A bonds which are maturing in December 2021. On March 14, 2021, the General Partner's board of directors determined that the said deficit does not indicate a liquidity problem at the Partnership and that it will have sufficient resources in the coming year to finance its operations and/or to meet its existing and expected liabilities.

Note 2 - Significant Accounting Policies:

The accounting policy specified below was consistently applied in the financial statements of the Partnership, throughout the presented periods, unless stated otherwise.

A. Declaration regarding compliance with the International Financial Reporting Standards (IFRS):

The financial statements comply with the provisions of the International Financial Reporting Standards.

B. Principles of preparation of the financial statements:

The annual financial statements include the additional disclosure required pursuant to the Securities Regulations (Annual Financial Statements), 5770-2010.

The financial statements were prepared applying the cost principle, except in relation to financial assets and liabilities which are measured at fair value.

The Partnership has elected to present the profit or loss items using the function of expense method.

C. Functional currency and presentation currency:

1) Functional currency: The functional currency which best and most faithfully represents the economic effects of transactions, events and circumstances on the Partnership's business is the U.S. Dollar. Any transaction that is not in the Partnership's functional currency is a foreign currency transaction. See Section D below.

2) Presentation currency: The Partnership's financial statements are presented in the U.S. Dollar.

D. Transactions in foreign currency:

A transaction denoted in foreign currency is recorded, upon initial recognition, in the functional currency, using the immediate exchange rate between the functional currency and the foreign currency on the date of the transaction.

At the end of each report period:

- Financial items in foreign currency are translated using the exchange rate as of the end of the report period;
- Non-financial items measured at historic cost in foreign currency are translated using the exchange rate on the date of the transaction;
- Rate differentials, excluding those which are capitalized to qualifying assets or carried to equity in hedging transactions, carried to profit or loss;
- Rate differentials deriving from the settlement of financial items or deriving from the translation of financial items according to different exchange rates to those used for translation upon initial recognition during the period, or to those used for translation in previous financial statements, shall be recognized at profit or loss in the period in which they derived.

E. The operating cycle period:

The Partnership's operating cycle period is one year.

Note 2 - Significant Accounting Policies (Cont.):

F. Joint ventures and SPCs:

1. A joint venture constitutes a contractual arrangement, according to which two or more parties assume economic activity of oil and gas exploration in a jointly owned asset. Certain joint ventures often involve joint ownership of one or more assets.

Ventures in which there is no formal requirement for unanimous consent of the parties who are partners to the venture, do not meet the definition of joint control according to IFRS 11.

Nevertheless, examination of such ventures indicates that the ventures themselves have no rights in the assets and do not commit to engagements on behalf of the participants. Engagements are made directly between the participants and a third party (which is not a partner in the joint venture). However, there are engagements in which the Operator engages directly with a third party.

Each participant may pledge its rights in the assets and each participant is entitled to the economic benefits deriving from the joint venture. Consequently, the participants have a relative share of the assets and liabilities attributed to the joint venture.

In respect of the Partnership's rights in activity in the jointly owned assets, the Partnership recognized in its financial statements:

a. Its share in the jointly owned assets.

b. Any liabilities it incurred.

c. Its share in any liabilities it jointly incurred in connection with activity in the jointly owned assets.

d. Any income from the sale or use of its share in the period of the jointly owned assets, together with its share in any expenses it incurred for activity in the jointly owned assets.

e. Any expenses it incurred due to its right in the jointly owned assets.

2. The Partnership presents its share in payments transferred to the Operator of the joint ventures and not yet used under the trade and other receivables item, since such amounts do not meet the definition of cash and cash equivalents.

3. The Partnership presents its share in the liabilities of the joint ventures to third parties under the item trade and other payables.

4. The Partnership's financial statements include the assets and liabilities created following financing rounds performed through special purpose companies (SPCs) and which were established for the purpose of the financing.

G. Cash equivalents:

Highly liquid short-term investments, which include, *inter alia*, short-term deposits deposited in bank which are unlimited in use and unpledged, are deemed as cash equivalents. Such investments may easily be converted into known amounts of cash and are exposed to an insignificant risk of changes in value, with the period until repayment being up to three months from the date of the investment.

Note 2 - Significant Accounting Policies (Cont.):

H. Short-term deposits:

Short-term deposits in banking corporations whose original term exceeds three months but is shorter than one year on the date of the investment. The deposits are presented in accordance with the terms of their deposit.

I. Financial instruments:

1) Financial assets:

Financial assets are measured upon initial recognition at their fair value, together with transaction costs which may be directly attributed to the purchase of the financial asset, except in respect of financial assets that are measured at fair value through profit or loss, in respect of which transaction costs are carried to profit or loss.

The Partnership classifies and measures the debt instruments in its financial statements based on the following criteria:

(a) The Partnership's business model for management of the financial assets, and

(b) The characteristics of the contractual cash flow of the financial asset.

The Partnership measures debt instruments at amortized cost, when:

The Partnership's business model is holding the financial assets in order to collect contractual cash flows; and the contractual terms and conditions of the financial asset provide entitlement on set dates to cash flows that are only interest and principal payments for the outstanding principal amount.

Subsequently to the initial recognition, instruments in this group will be presented according to their terms according to cost plus direct transaction costs, using the amortized cost method.

In addition, on the date of the initial recognition the Partnership may designate, irrevocably, a debt instrument as measured at fair value through profit or loss if such designation significantly reduces or cancels inconsistent measurement or recognition, for example in the event that the relevant financial liabilities are also measured at fair value through profit or loss.

The Partnership measures debt instruments at fair value through other comprehensive income, when:

The Partnership's business model is both holding the financial assets in order to collect contractual cash flows and sale of the financial assets; and the contractual terms and conditions of the financial asset provide entitlement on set dates to cash flows that are only interest and principal payments for the outstanding principal amount. Subsequently to the initial recognition, instruments in this group are measured according to fair value. Profit or loss as a result of fair value adjustments, other than interest, rate differentials and impairment, are recognized in other comprehensive income.

The Partnership measures debt instruments at fair value through profit or loss where:

A financial asset which constitutes a debt instrument does not meet the criteria for measurement thereof at amortized cost or at fair value through other comprehensive income. After the initial recognition, the financial asset is measured at fair value where profits or losses as a result of fair value adjustments are carried to profit or loss.

Note 2 - Significant Accounting Policies (Cont.):

I. Financial instruments (Cont.):

1) Financial assets (Cont.):

Equity instruments:

Financial instruments that constitute investments in equity instruments do not meet the aforesaid criteria and are therefore measured at fair value through profit or loss.

In relation to equity instruments that are not held for trade, on the date of first-time recognition, the Partnership may make an irrevocable choice, to present in other comprehensive income subsequent changes to the fair value that would have otherwise been recognized through profit or loss. Such fair value changes will not be carried to profit or loss in the future even upon write-off of the investment.

Dividend income from investments in equity instruments designated for measurement at fair value through other comprehensive profit is recognized on the record date for entitlement to the dividend in the income statement.

2) Impairment of financial assets:

On each report date the Partnership examines the provision for loss due to financial debt instruments that are not measured at fair value through profit or loss.

The Partnership distinguishes between two situations of recognition of a provision for loss;

Debt instruments whose credit quality did not significantly deteriorate since the date of first-time recognition, or cases in which the credit risk is low – the provision to loss that will be recognized with respect to such debt instrument will take into account anticipated credit loss in the 12-month period after the report date, or debt instruments whose credit quality did significantly deteriorate since the date of first-time recognition and with respect to which the credit risk is not low, the provision to loss that will be recognized will take into account anticipated credit loss – for the remainder of the instrument's life. The Partnership applies the relief set forth in IFRS 9 according to which it assumes that the credit risk of a debt instrument did not significantly increase since the date of first-time recognition if it was determined on the report date that the instrument has low credit risk, for example when the instrument has an external "investment grade" rating.

The decrease in value with respect to debt instruments measured according to a depreciated cost shall be carried to profit or loss against a provision while the decrease in value with respect to debt instruments measured at fair value through other comprehensive income will be attributed to profit or loss against other comprehensive income and will not reduce the book value of the financial asset in the statement of financial position.

Note 2 - Significant Accounting Policies (Cont.):

I. Financial instruments (Cont.):

3) Write-off of financial assets:

The Partnership writes-off a financial asset when, and only when:

(a) The contractual rights to the cash flows from the financial asset expired, or

(b) The Partnership materially transfers all of the risks and benefits that derive from the contractual rights to receive the cash flows from the financial asset or when part of the risks and benefits upon transfer of the financial asset remain in the hands of the Partnership but it can be said that it transferred control over the asset, or

(c) The Partnership retains the contractual rights to receive the cash flows that derive from the financial asset, but assumes a contractual obligation to pay such cash flows in full to a third party, without substantial delay.

4) Financial liabilities:

On the date of initial recognition, the Partnership measures the financial liabilities at fair value, less transaction costs that can be directly attributed to the issuance of the financial liability.

Subsequently to the date of initial recognition, the Partnership measures all of the financial liabilities at amortized cost method.

5) Write-off of financial liabilities:

The Partnership writes-off a financial liability when, and only when it is retired – i.e., when the liability that was defined in the contract is paid or cancelled or expires.

A financial liability is retired when the debtor pays the liability by payment in cash, with other financial assets or is legally released from the liability.

In the event of a change of conditions with respect to an existing financial liability, the Partnership examines whether the terms and conditions of the liability are materially different than the existing conditions.

When a material change is made in the conditions of an existing financial liability or the substitution of a financial liability for another liability with materially different conditions, the change is treated as a write-off of the original financial liability and recognition of a new financial liability. The difference between the balance of the two aforesaid liabilities in the financial statements is carried to profit or loss.

If the change is immaterial, or the financial liability is substituted for another financial liability which conditions are not materially different, the Partnership is required to update the financial liability amount, i.e., capitalize the new cash flows at the original effective interest rate, with the differences carried to profit or loss.

Upon examining whether the change to the conditions of an existing liability is material, the Partnership takes qualitative and quantitative considerations into account.

Note 2 - Significant Accounting Policies (Cont.):

I. Financial instruments (Cont.):

6) Setoff of financial instruments:

Financial assets and financial liabilities are offset and the net amount presented in the statement of financial position if there is a legally enforceable right to offset the amounts recognized, and there is an intention to retire the asset and the liability on a net basis or to dispose of the asset and settle the liability simultaneously. The setoff right must be legally enforceable, not only in the ordinary course of business of the parties to the contract but also in the event of bankruptcy or insolvency of one of the parties. For the setoff right to be available immediately, it cannot be contingent on a future event or, occasionally inapplicable or, expire pursuant to certain events.

7) Embedded derivatives:

Pursuant to the provisions of IFRS 9, derivatives embedded in financial assets shall not be separated from a host contract. Such hybrid contracts shall be measured in their entirety at a depreciated cost or at fair value, according to the criteria of the business model and contractual cash flows.

When a host contract does not fulfill the definition of a financial asset, an embedded derivative is separated from the host contract and treated as a derivative when the economic risks and characteristics of the embedded derivative are not tightly connected to the economic risks and characteristics of the host contract, the embedded derivative fulfills the definition of a derivative and the hybrid instrument is not measured at fair value when the differences are carried to profit or loss.

The need to separate an embedded derivative is reassessed only when there is a change in the engagement which significantly affects the cash flows from the engagement.

8) Derivative financial instruments for hedging (protection) purposes:

The Partnership occasionally performs engagements in derivative financial instruments such as foreign currency forward contracts and interest rate swap (IRS) transactions in order to protect itself against the risks entailed by interest rate and foreign currency exchange rate fluctuations.

Profits or losses deriving from changes in the fair value of derivatives that are not used for hedging purposes are immediately carried to profit or loss.

Hedging transactions qualify for hedging accounting, *inter alia*, when on the hedging creation date there is formal documentation and designation of the hedging relations and of the purpose of the risk management and the Partnership's strategy to perform hedging.

The hedging is examined on an ongoing basis and it is determined in practice to be highly effective in the financial reporting period for which the hedging is designated.

Hedging (protection) transactions are treated as follows:

Cash flow hedging:

The effective part of the changes in the fair value of the hedging instrument is recognized in other comprehensive profit while the ineffective part is immediately carried to profit or loss.

Note 2 - Significant Accounting Policies (Cont.):

I. Financial instruments (Cont.):

8) Derivative financial instruments for hedging (protection) purposes (Cont.):

Other comprehensive profit is carried to profit or loss when the defined [Translator's note: probable typographical error; intended meaning probably 'hedged] item results are carried to profit or loss. For example, in periods when interest revenues or expenses are recognized or when an anticipated sale occurs.

When the hedged item is a non-financial asset or liability, their cost also includes the amount of profit (loss) with respect to the hedging instrument which was previously recognized in other comprehensive income.

The Partnership ceases to apply hedge accounting henceforth only when all or part of the hedge ratios cease to fulfill the entitling criteria (after taking into account a rebalance of the hedge ratios, if applicable), including cases where the hedging instrument expires, is sold, cancelled or settled. When the Partnership discontinues the application of hedge accounting, the amount that accrued in the hedge fund remains in the hedge fund until the cash flow materializes or is carried to profit or loss if the hedged future cash flows are no longer expected to materialize.

J. Provisions:

A provision according to IAS 37 is recognized when the Partnership has a liability in the present (legal or implicit) as a result of an event that occurred in the past, use of economic resources is expected to be required in order to settle the liability, and it may be reliably estimated. When the Partnership expects to recover the expenditure, in whole or in part, the recovery will be recognized as a separate asset, only on the date on which receipt of the asset is in fact certain.

Below are the types of provisions included in the financial statements:

Legal claims:

A provision for claims is recognized when the Partnership has a present legal liability or an implicit liability as a result of an event that occurred in the past, where it is more likely than not that the Partnership will require its economic resources to settle the liability, and it may be reliably estimated.

Levies:

Levies imposed on the Partnership by government institutions through legislation are treated in accordance with the IFRIC 21 interpretation, according to which the levy payment liability is only recognized upon the occurrence of the event that creates the payment liability (see Section V below).

Asset retirement obligation:

An asset retirement obligation was recorded on the Partnership's books, see Section K2 below regarding costs in respect of asset retirement obligations.

Note 2 - Significant Accounting Policies (Cont.):

K. Expenses of oil and gas exploration, development of proved reservoirs and investment in oil and gas assets:

1. The Partnership's accounting policy in respect of the treatment of investments in oil and gas exploration is the "successful efforts" method, whereby:

a) The expenses of participation in the performance of geological and seismic surveys and tests which occur at the preliminary stages of the exploration are carried to profit or loss upon the forming thereof, until the date on which, following the performance of these surveys and tests, a specific drilling plan is formulated.

b) Investments in reservoirs before they are proven uncommercial, were classified as "exploration and appraisal assets", and are presented at cost (see Note 7 below).

c) Investments in reservoirs that have been proven dry and were abandoned or determined to be uncommercial, are fully amortized from the "exploration and appraisal assets" item to expenses in the statement of comprehensive income.

d) Investments in reservoirs with regards to which it has been determined that there is technical feasibility and commercial viability of gas or oil production, which are examined in a gamut of events and circumstances, are classified, subject to the performance of an examination of impairment, from the "exploration and appraisal assets" item to the "oil and gas assets" item, and are presented in the statement of financial position at cost (see Note 7 below). Such oil and gas assets, which include, *inter alia*, reservoir development planning costs, development wells, purchase and construction of production facilities, gas transmission pipelines, drilling equipment, construction of a terminal and asset retirement costs (see also Paragraph 2 below), are amortized to the statement of comprehensive income as specified in Paragraph E below.

e) Investments in oil and gas assets, which commenced commercial production, were amortized until December 31, 2019 in the depletion method (i.e., based on the production amount) as follows: the drilling cost was amortized according to the quantity of the proved and developed reserves, and the cost of the additional components (such as: platform, pipeline and terminals) was amortized according to the quantity of the proved reserves (developed and to be developed).

In Q1/2020, the Partnership made a change in the evaluation of the reserves that are used as a basis for the depreciation of the oil and gas assets, *inter alia*, in view of the experience accumulated by the Partnership over the years of operation of the Tamar reservoir, and the accepted practice in the world with respect to the depreciation of oil and gas assets, the Partnership examined the basis of the depreciated reserves and reached the conclusion that the depreciation of assets according to the production unit method and based on proved + probable reserves ("**2P**") in lieu of proved reserves only, will more fairly reflect the pattern of projected use of the asset.

In the Partnership's estimation, depreciation of the oil and gas assets based on proved and probable reserves (2P) enhances the comparativeness between the Partnership's results and the results of similar companies in Israel and the world (*inter alia*, the Partnership's benchmark companies), fairly presents the management's assessments in relation to the use of the asset, is consistent with the information the Partnership provides to the various investors and is also consistent with the accounting treatment in other transactions that are related to oil and gas assets, such as valuations, value impairment examinations and directives designated for the oil and gas industry.

Note 2 - Significant Accounting Policies (Cont.):

K. Expenses of oil and gas exploration, development of proved reservoirs and investment in oil and gas assets (Cont.):

1. (Cont.):

e) (Cont.):

In accordance with the depreciation based on proved and probable reserves, the estimate of future investments (in non-discounted values) required to produce such reserves is added to the book value (only for the purpose of calculating the depreciation costs). These sums are multiplied by the amount of gas produced during the period proportionately to the 2P reserves estimate.

The estimate change was made for all of the Partnership's oil and gas assets and implemented henceforth. The effect of the estimate change on the financial statements for 2020 led to a decrease in depreciation expenses of approx. $8.4 million, of which approx. $6.3 million are attributed to the Leviathan reservoir, which commenced commercial production in Q1/2020.

f) Impairment of exploration and appraisal assets and oil and gas assets is examined when facts and circumstances indicate that the value on the books of an exploration and appraisal asset and oil and gas assets may exceed its recoverable amount in accordance with IAS 36 and IFRS 6 (see Paragraph N below).

g) If, at the time of farm-in agreements, at the exploration and appraisal stages, a holder of a petroleum and/or gas right transfers part of the right, in consideration for the transferee's consent to bear future investments which the transferor would otherwise have had to bear, these agreements will be treated as follows:

In agreements in which the Partnership is the transferee: at the stage of creation of the costs, the Partnership shall recognize an expense in respect of the costs which it bore and which are attributed to the rights retained by the transferor.

In agreements in which the Partnership is the transferor: The Partnership shall not record any expense that was incurred by the transferee and shall recognize in the statement of comprehensive income from the farm-in agreement the amount of the difference between the consideration received or which it is entitled to receive and the value on the books of the rights that were written off.

2. Asset retirement obligation costs:

The Partnership recognizes a liability in respect of its share in the asset retirement obligation at the end of the period of use thereof. The liability is initially recorded at its present value against an asset, and the expenses deriving from the revaluation of its present value, as a result of the lapse of time, are carried to profit or loss. The asset is initially measured at the present value of the liability and is amortized to profit or loss as stated in Paragraph 1 above.

Changes deriving from timing, cap rates and the amount of the financial resources required to retire the obligation, are added to or subtracted from the asset (if not fully amortized) in the current period concurrently with the change in the liability. The items of the statement of financial position record the balance of the liability (under the "**other short-term liabilities**" and "**other long-term liabilities**" items) Note 11B below, and the asset balance after amortization (under "**investments in oil and gas assets**" item). Note 7A below.

Note 2 - Significant Accounting Policies (Cont.):

L. Credit costs:

The Partnership capitalizes credit costs related to the purchase, construction or production of qualified assets, the preparation, designated use or sale of which require a significant period of time. Capitalization of the credit costs begins on the date on which costs in respect of the asset itself are incurred, the actions for preparation of the asset begin and credit costs are caused, and it ends when all of the actions for preparation of the qualified asset for the designated use or for sale thereof have been substantially completed.

M. Recognition of income:

On January 1, 2018, the Partnership performed initial application of International Financial Reporting Standard No. 15 – Revenue from Contracts with Customers ("**IFRS 15**"), the Partnership chose to retroactively apply the provisions of IFRS 15 with reliefs and without restatement of comparison figures.

Revenues from contracts with customers are recognized in profit or loss when control of the asset or service are transferred to the customer. Revenue is measured and recognized according to fair value of the consideration which the entity expects to be entitled to pursuant to the terms and conditions of the contract, net of the royalties collected in favor of the State, related parties, and third parties. Revenue is recognized in profit or loss up to the extent the Partnership expects to receive the economic benefits, and the revenue and costs, if applicable, may be reliably measured.

N. Impairment of non-financial assets:

The Partnership examines, in accordance with the rules set forth in IAS 36 and IFRS 6, the need to recognize the impairment of non-financial assets when there are indications, as a result of events or changes in circumstances, that the balance in the financial statements is not recoverable.

In cases in which the balance in the financial statements of the non-financial assets exceeds their recoverable amount, the assets are amortized to their recoverable amount. The recoverable amount is the higher of the fair value net of sale costs and usage value.

In the assessment of the usage value, the expected cash flows are discounted according to a discount rate before tax which reflects the risks specific to each asset. In respect of an asset that does not generate independent cash flows, the recoverable amount is determined for the cash-producing unit to which the asset belongs.

For the purpose of examination of impairment, a cash-producing unit is comprised of all of the Partnership's investments in the single reservoir, except in cases in which two or more reservoirs are grouped into a single cash-producing unit, inter alia in view of the existence of dependency on the positive cash flows deriving from the reservoirs and the joint use of infrastructures. Losses from impairment are carried to profit or loss.

A loss from impairment of an asset is cancelled only when changes occur in the estimates used to determine the recoverable amount of the asset from the date on which the loss from the impairment was last recognized. Cancelation of the loss as aforesaid is limited to the lower of the amount of the impairment of the asset that was recognized in the past (net of depreciation or amortization) and the total appreciation.

The recoverable value of oil and gas assets, in accordance with economic valuations which include use of appraisal techniques and assumptions in respect of estimates of future cash flows expected from the asset and an estimate of an appropriate cap rate for these cash flows.

Note 2 - Significant Accounting Policies (Cont.):

N. Impairment of non-financial assets (Cont.):

In the measurement of the recoverable value of oil and gas assets, the management of the Partnership's General Partner is required to use certain assumptions with respect to expected investments and costs, the likelihood of the existence of development plans, quantities of the resources in the reservoir, the expected sale prices, repercussions of the Petroleum Profits Levy Law, determination of the cap rates etc., in order to estimate the future cash flows from the assets. If possible, the fair value is determined in relation to transactions made recently in assets with a similar character and location to the subject of the assessment.

At the end of every report period, the Partnership examines whether there are signs indicating impairment of assets.

O. Critical accounting estimates and judgements:

Preparation of the Partnership's financial statements in accordance with IFRS requires the management of the Partnership's General Partner to make estimates and assumptions that affect the amounts presented in the financial statements. These estimates occasionally require judgment in an environment of uncertainty and have a material effect on the presentation of the data in the financial statements.

Below is a description of the critical judgements and key sources of estimation uncertainty used in the preparation of the Partnership's financial statements, in the preparation of which the management of the Partnership's General Partner was required to make assumptions as to circumstances and events that involve significant uncertainty.

In exercising its judgment when making the estimates, the management of the Partnership's General Partner relies on past experience, various facts, external factors and reasonable assumptions according to the circumstances relevant to each estimate. Actual results differ from the estimates of the management of the Partnership's General Partner.

Estimate of gas and condensate reserves (jointly: the "**Gas Reserves**") – the estimate of the Gas Reserves is used, *inter alia*, in determining the rate of amortization of the producing assets serving the operations during the reported period, as well as in the examination of potential impairments. Investments related to the discovery and production of proved Gas Reserves are amortized according to the depletion method as stated in Section K1E above.

The estimated gas quantity in the proven reservoirs in the reported period is determined on an annual basis, according to the opinions of independent external experts on the evaluation of reserves in oil and gas reservoirs.

Evaluation of the proved gas reserves according to the above principles is a subjective process and the evaluations of different experts may occasionally be materially different. In light of the materiality of the amortization expenses, the abovementioned changes may have a material effect on the results of the operations and the financial condition of the Partnership.

Asset retirement obligation – the Partnership recognizes the asset concurrently with a liability in respect of its oil and gas asset retirement obligation at the end of the period of use thereof.

The timing and amount of the economic resources required to discharge the obligation are based on estimation by the management of the General Partner of the Partnership, which relies, *inter alia*, on evaluations of professional consultants, and are examined periodically to ensure the fairness of such estimations.

Note 2 - Significant Accounting Policies (Cont.):

O. Critical accounting estimates and judgements (Cont.):

The investment recovery date for the payment of overriding royalty in the Tamar project – in the preparation of a report for the determination of the date of recovery of the investment in the Tamar project, the Partnership relied, *inter alia*, on the ruling of an expert from 2002, who was appointed by agreement between the Partnership and the royalty interest owners and who provided his opinion on the method of calculation of the investment recovery date as well as on the various components which must be taken into account for the purpose of determining the investment recovery date. (See also Notes 15B and 12K6 below).

Claims – In the assessment of the chances of the results of the legal claims filed against the Partnership, the Partnership relied on opinions of its legal counsel. This assessment of the legal counsel is based on their best professional judgment, considering the stage of the proceedings, and on the legal experience accrued on the various issues. Since the outcome of the claims shall be determined in court, this outcome may be different to this assessment.

Determination of the fair value of a non-negotiable financial asset – The fair value of a non-negotiable financial asset classified at level 3 of the fair value scale is determined according to valuation methods, generally according to the evaluation of the discounted future cash flow according to current cap rates for items with similar conditions and risk characteristics. Changes in the estimate of future cash flow, in the estimate of cash flow due to resource valuation and the estimate of cap rates, considering the assessment of risks such as the liquidity risk, credit risk and volatility, may affect the fair value of these assets.

Petroleum profit levy – In the report period, the Partnership recognized an expense in respect of a petroleum profit levy for the Tamar project. As of the date of approval of the Financial Statements, there are several interpretation disputes vis-à-vis the Tax Authority. In accordance with the estimates made by the Partnership, as of December 31, 2020, the liability for payment of the levy in the Tamar project was established, and the Partnership recorded a provision on its books for payment of a levy in 2020. The Partnership’s estimates were made to the best of its understanding and based, *inter alia*, on an opinion of its legal counsel with respect to the issues in dispute, in respect of most of which it is estimated that the prospects of the Partnership’s claims being accepted exceed the prospects of their being rejected.

Estimated impairment of oil and gas assets – Examination of impairment of oil and gas assets involves estimates. The examination requires the Partnership to make an estimate of the future cash flows expected to derive from ongoing use of the Partnership’s cash-generating unit from proved + probable (2P) reserves. For examination of the impairment of oil and gas assets, see Note 7C10.

P. Fair value:

1. **Measurement of fair value:**

The Partnership measures fair value as the price that would have been received in the sale of an asset or the price that would have been paid for the transfer of a liability in a regular transaction between market participants on the measurement date.

When the price of an identical asset or identical liability is not observable (i.e. there is no price that is quoted in an active market), the Partnership measures fair value using a different appraisal technique that is suited to the circumstances and for which there are sufficient obtainable data to measure fair value, while making maximum use of relevant observable data and minimum use of non-observable data.

Note 2 - Significant Accounting Policies (Cont.):

P. Fair value (Cont.):

1. (Cont.):

   The Partnership measures fair value under the assumption that the transaction for the sale of the asset or for the transfer of the liability occurs in the main market of the asset or the liability to which the Partnership has access; or in the absence of a main market, in the best market for the asset or the liability to which the Partnership has access.

   In the measurement of fair value of a non-financial asset, the Partnership takes into account the ability of a market participant to generate economic benefits through the asset in its optimal use or through the sale thereof to another market participant that will make optimal use of the asset.

   The fair value of a financial liability with an on-call feature (for example an on-call deposit) is no lower than the amount payable on call, discounted from the first date on which the amount may be called.

2. **Fair value hierarchy:**

   For disclosure purposes, the Partnership classifies fair value measurements under one of the levels in the fair value hierarchy that reflects the significance of the data used when making the measurements. The fair value hierarchy is:

   Level 1 - Quoted prices (unadjusted) in active markets for identical assets or identical liabilities.

   Level 2 - Inputs other than quoted prices included within Level 1, which are observable with regard to the asset or liability, directly or indirectly.

   Level 3 - Inputs that are not observable for the asset or liability.

   When the data used to measure fair value are classified at different levels in the fair value hierarchy, the Partnership classifies the fair value measurement in its entirety at the lowest level of the datum that is significant to the measurement on the whole. The Partnership exercises discretion in assessing the significance of a particular datum to the measurement on the whole, while taking into account factors that are specific to the asset or the liability.

Q. Profit per participation unit:

Profit per participation unit is calculated in accordance with the provisions of IAS 33, which prescribes, *inter alia*, that the Partnership shall calculate the amounts of the basic profit per participation unit in respect of profit or loss, which is attributed to the Participation Unit Holders in the Partnership, and shall calculate the amounts of the basic profit per participation unit in respect of profit or loss from continued operations, which is attributed to the Participation Unit Holders in the Partnership, in the event that such profit is presented.

Note 2 - Significant Accounting Policies (Cont.):

R. Employee benefits:

1. **Short-term employee benefits:**

   Short-term employee benefits, which include salaries, recuperation pay, vacation days, sick days and national insurance employer deposits, are recognized as expenses upon provision of the services. When the Partnership has an established legal or implied reliably estimable liability for the granting of bonuses to employees, the Partnership recognizes this liability on the date of establishment of the liability.

   The Partnership classifies a benefit as a short-term employee benefit when the benefit is expected to be fully settled within 12 months from the end of the annual report period in which the employees provide the relevant service.

2. **Post-employment employee benefits:**

   In accordance with employment law and employment agreements in Israel and in accordance with the Partnership's custom, the Partnership is liable for the payment of severance pay to employees who are terminated and under certain conditions to employees who resign or retire.

The Partnership's liabilities for the payment of severance pay to the Partnership's employees pursuant to Section 14 of the Severance Pay Law (the Partnership pays fixed payments without having any legal or implicit liability to make additional payments, even if sufficient amounts have not accrued in the plan to pay all of the benefits to employees relating to the employee's employment in the current period and in the previous periods) are treated as a defined deposit plan. The Partnership recognizes as an expense, apart from exceptions, the amount that is required to be deposited concurrently with receipt of the work services from the employee.

S. Participation unit-based payment:

1) The Partnership recognizes participation unit-based payment transactions in accordance with the provisions of IFRS 2. These transactions include transactions with employees which are settled in cash.

2) Loans provided to employees for the purchase of participation units of the Partnership, with the participation units themselves serving as sole security for the repayment thereof, are treated as the granting of options to employees. With respect to participation unit-based payment transactions that are settled in cash, the cost of the transaction is measured at fair value on the granting date, using a customary option pricing model. The fair value is recognized as an expense over the vesting period, in parallel to recognition of a liability. The liability is remeasured each reporting period at fair value, until it is settled, and changes to the fair value are carried to profit or loss. When the Partnership receives services in consideration for a payment based on its equity instruments which is granted by the General Partner, it is a participation unit-based payment transaction such that the expense is recognized in profit or loss over the period of the employees' entitlement to the equity instruments against the entry of a corresponding amount in the capital in respect of a capital injection received from the Parent Company or from the General Partner.

T. Benefit from control holders:

The Partnership records expenses in the statements of comprehensive income against a capital reserve for benefits it received from the control holder.

Note 2 - Significant Accounting Policies (Cont.):

U. Taxes on income:

The financial statements do not include taxes on income, since the tax liability on the Partnership's profits applies to the partners in the Partnership. Payments paid by the Partnership to income tax are on account of the tax for which the holders of the units in the Partnership are liable and they are amortized from the retained earnings item in the Partnership's equity See also Note 20A4 regarding the draft income tax regulations published in October 2020.

V. Oil and gas profit levy:

1. The Partnership includes, in the financial statements, expenses in respect of its levy payment liability under the Taxation of Profits and Natural Resources Law, 5771-2011 (the "**Levy**"). The Levy is calculated for each project separately.
2. During 2017, the Partnership's management, together with the Israeli partners (which are reporting corporations) in the Tamar project (the "**Reporting Entities**"), revisited the matter, including reconsideration of whether the Levy is indeed governed by IAS 12 or possibly governed by IFRIC No. 21 by the International Financial Reporting Interpretations Committee – "Levies" ("**IFRIC 21**"), as well as the timing at which recognition of the Levy within the financial statements would be required. In the beginning of August 2017, the Reporting Entities expressed their position on the matter before the Israel Securities Authority (ISA) Staff. After the Reporting Entities had examined the treatment of the Levy and particularly the question of whether, in this case, in view of the unique characteristics of a Levy as aforesaid, the provisions of IFRIC 21 or the provisions of IAS 12 ought to be implemented, the Reporting Entities reached the conclusion that in the case at bar it would be more reliable and relevant to implement the provisions of IFRIC 21 with regard to such Levy, and the ISA Staff decided not to intervene in their position.

   Therefore, *de facto*, the Reporting Entities shall recognize the expense due to the Levy according to the "obligating event" approach, i.e., only on the date on which the obligation of payment thereof arises (i.e., only as of the date of commencement of actual payment thereof). In accordance with the Partnership's estimations, the liability for the Levy due to the Tamar Project was established in the report year (for additional details see Note 20B).

W. Leases:

On January 1, 2019 the Partnership performed initial application of International Financial Reporting Standard No. 16 – Leases, the Partnership chose to apply the provisions of IFRS 16 using the modified retrospective method (without restatement of comparative figures).

The Partnership accounts for a contract as a lease contract when the terms of the contract transfer the right to control the identified asset for a period of time in exchange for consideration.

The Partnership as a lessee:

For transactions in which the Partnership is a lessee, it recognizes on the commencement date of the lease of the asset a right-of-use against a lease liability, excluding lease transactions for a term of up to 12 months and lease transactions in which the underlying asset is of low value, in respect of which the Partnership chose to recognize the lease payments as an expense in profit or loss on a straight-line basis over the term of the lease.

Note 2 - Significant Accounting Policies (Cont.):

W. Leases (Cont.):

The Partnership as a Lessee (Cont.):

In measuring the lease liability, the Partnership chose to apply the practical expedient provided in the Standard and did not separate the lease components from the non-lease components, such as: management services, maintenance services, etc., which are included in the same transaction.

On the commencement date, the lease liability includes all unpaid lease payments discounted at the interest rate inherent in the lease, if that rate can be readily determined, or otherwise using the Partnership's incremental borrowing rate. After the commencement date, the Partnership measures the lease liability using the effective interest rate method.

On the commencement date, the right-of-use asset is recognized in an amount equal to the lease liability plus lease payments already made on or before the commencement date plus initial direct costs incurred. The right-of-use asset is measured applying the cost model and depreciated over the shorter of its useful life or the term of the lease.

Whenever there are indications of impairment, the Partnership tests for impairment of the right-of-use asset pursuant to the provisions of IAS 36.

The Partnership as a lessor:

The criteria for classification of a lease as a finance or operating lease are based on the nature of the agreement, and they are examined on the date of the engagement pursuant to the rules set forth in the Standard:

1) **Finance lease**:

   A lease transaction in which all of the risks and benefits related to the ownership of the asset were substantially transferred to the lessee, is classified as a finance lease.

   On the commencement date, the leased asset is written off and a “finance lease receivable” asset is recognized, which is equal to the present value of the lease payments, discounted at the interest rate implicit in the lease. Any difference between the balance of the leased asset before the write off and the finance lease receivable, is recognized in profit or loss.

2) **Operating lease**:

   A lease transaction in which all of the risks and benefits related to ownership of the leased asset are not substantially transferred, is classified as an operating lease. Lease payments are recognized as income in profit or loss on a straight-line basis over the term of the lease. Initial direct costs incurred in respect of the lease agreement are added to the cost of the leased asset and recognized as an expense over the term of the lease on the same basis.

X. Loss of control:

When the Partnership loses control over a subsidiary, it writes off the assets and liabilities of such subsidiary, according to the book value as of the date of loss of control. The consideration received and any remaining investment in such subsidiary are recognized according to the fair value thereof as of the date of loss of control. Any difference created is recognized as a profit or loss in the statement of comprehensive income.

Note 2 - Significant Accounting Policies (Cont.):

Y. An investment treated according to the equity method:

The Partnership's investment in a company accounted for at equity is treated according to the equity method.

According to the equity method, the investment in a company accounted for at equity is presented according to cost plus changes that occurred subsequent to the purchase in the Partnership's share of the assets, net, including other comprehensive income of the company accounted for at equity. Profits and losses deriving from transactions between the Partnership and the company accounted for at equity are cancelled in accordance with the holding rate.

The financial statements of the Partnership and the company accounted for at equity are prepared as of identical dates and periods. The accounting policy in the financial statements of the company accounted for at equity was implemented uniformly and consistently with that which was implemented in the Partnership's financial statements.

The equity method is implemented until the date of loss of the significant influence in the company accounted for at equity or the classification thereof as an investment held for sale.

The Partnership is examining an amount recoverable from a company accounted for at equity, together with other assets of the Partnership, the cash flows from which are dependent on the same factors on which the cash flows from the company accounted for at equity are dependent.

On the date of loss of significant influence over the company accounted for at equity, the Partnership recognizes a profit or loss, according to the difference between the balance of the investment in the company accounted for at equity on the Partnership's books, and its fair value.

Z. Changes in the accounting policy – Initial application of a new financial reporting standard and amendments to existing accounting standards:

The initial application of financial reporting standards or amendments thereto, did not have a material effect on the financial statements of the Partnership.

AA. Disclosure on new IFRS in the period preceding their application:

1. Amendment to IAS 1 Presentation of Financial Statements

   In January 2020, the IASB released an amendment to IAS 1 regarding the requirements for classification of liabilities as current or non-current (the "**Amendment**").

   The Amendment clarifies the following matters: What is meant by an unconditional right to defer settlement; a right to defer must exist at the end of the reporting period; classification is unaffected by the likelihood that an entity will exercise its deferral right; 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 shall be applied for annual reporting periods beginning on or after January 1, 2023. The Amendment shall be applied by retroactive application. The Partnership is examining the effect of the Amendment on its current loan agreements.

Notes to the Financial Statements as of December 31, 2020 (Dollars in thousands)

Note 2 - Significant Accounting Policies (Cont.):

AA. Disclosure on new IFRS in the period preceding their application (Cont.):

2. Amendments to IFRS 9, IFRS 7, IFRS 16, IFRS 4 and IAS 39 regarding the IBOR reform.

   In August 2020, the IASB published amendments to IFRS 9 Financial Instruments, IFRS 7 Financial Instruments: Disclosures, IAS 39 Financial Instruments: Recognition and Measurement, IFRS 4 Insurance Contracts, and IFRS 16 Leases (the "**Amendments**"). The Amendments provide practical reliefs to handle the effect of the accounting treatment in the financial statements where IBORs (Interbank Offered Rates) shall be replaced with RFRs (Risk Free Interest Rates). In accordance with one of the practical reliefs, the Partnership shall treat contractual amendments or amendments to the cash flows that are required as a direct consequence of implementation of the reform similarly to the accounting treatment of changes in variable interest. In other words, a company is required to recognize the changes in the interest rates through adjustment of the effective interest rate without changing the book value of the financial instrument. Use of this practical relief is dependent on the transition from IBOR to RFR occurring on the basis of economically equivalent conditions. In addition, the Amendments allow the changes required by the IBOR reform to be made to the designation of the hedging and the documentation without causing the hedging ratios to stop when certain conditions are fulfilled. In the context of the Amendments, temporary practical relief was also given in connection with the application of hedge accounting pertaining to identification of the hedged risk as 'separately identifiable'. The Amendments added disclosure requirements in connection with the effect of the expected reform on the Partnership's financial statements, including reference to the manner in which the company manages implementation of the interest rate reform, the risks to which it is exposed as a result of the expected reform, and quantitative disclosures with respect to financial instruments at IBORs that are expected to change. The Amendments shall be applied from the annual periods commencing on or after January 1, 2021. The Amendments will be applied retroactively, but restatement of comparison figures is not required. Early application is possible. In the Partnership's estimation, the above Amendments are not expected to have a material effect on the Partnership's financial statements.

Note 3 – Cash and Cash Equivalents:

Composition:

	Interest rate as of 31.12.2020	**31.12.2020**	**31.12.2019**
In Dollars:	%		
Cash in banks		35,349	62,167
Deposits in banks	0.02-0.23	28,002	85,639
		63,351	147,806
In ILS:			
Cash in banks		2,619	10,841
Deposits in banks	0.01-0.07	4,009	12,399
		6,628	23,240
Total		69,979	171,046

Notes to the Financial Statements as of December 31, 2020 (Dollars in thousands)

Note 4 – Short-Term and Long-Term Investments[2]:

Composition:

	Interest rate as of 31.12.2020	31.12.2020	31.12.2019
	%		
Under current assets:			
Deposits in banks:			
in dollars	0.15	169,149	63,271
in ILS		218	188
		169,367	63,459
Under non-current assets:			
Deposits in banks:			
in dollars	0.18	100,529	102,919

Note 5 – Trade and Other Receivables:

Composition:

	31.12.2020	31.12.2019
Trade and other receivables within joint ventures	4,603	62,448
Related parties (See Note 21 below)	941	31
Receivables in connection with a loan granted (see Note 8B below)	14,344	14,800
Prepaid expenses and other receivables	12,988	9,602
Total	32,876	86,881

[2] With respect to pledges and guarantees, see Note 12J.

Notes to the Financial Statements as of December 31, 2020 (Dollars in thousands)

Note 6 – Investment in a Company Accounted for at Equity EMED Pipeline B.V. ("**EMED**" or the "**Company Accounted for at Equity**"):

Composition:

	31.12.2020	**31.12.2019**
Investment in EMED	67,288	74,995

A. EMED was established in July 2018, and its operations began in September 2019. See Note 7C3 regarding the engagement in agreements for the purchase of EMG shares and for the purchase of rights in the EMG Pipeline, through the Company Accounted for at Equity.

B. As of December 31, 2020, the Partnership holds 25% (December 31, 2019: identical) of the issued and paid-up capital of EMED.

C. Following is condensed financial information regarding the investment of the Partnership in the Company Accounted for at Equity, that is treated according to the book value method:

	31.12.2020	**31.12.2019**
Cost of investment	75,000	75,000
Accrued losses	(7,712)	(5)
Total	67,288	74,995

D. Following are condensed figures from the financial statements of the Company Accounted for at Equity (100%) including excess of fair value over the book value:

	31.12.2020	**31.12.2019**
Assets	581,867	610,650
Liabilities	312,715	310,671
Loss before tax	(30,738)	(20)
Comprehensive Loss	(30,827)	(20)

Notes to the Financial Statements as of December 31, 2020 (Dollars in thousands)

Note 7 – Investments in Oil and Gas Assets:

A. Composition:

1. Composition by oil and gas assets and exploration and appraisal assets:

	Exploration and appraisal assets	Oil and gas assets[3]	Total
Cost[4]			
Balance as of January 1, 2019	114,952	3,193,058	3,308,010
Changes during 2019:			
Investments	2,667	666,531	669,198
Balance as of December 31, 2019	117,619	3,859,589	3,977,208
Changes during 2020:			
Investments	7,810	94,243	102,053
Balance as of December 31, 2020	125,429	3,953,832	4,079,261
Accumulated Depreciation[5]			
Balance as of January 1, 2019	-	502,658	502,658
Changes during 2019:			
Depreciation and amortization[6]	-	45,372	45,372
Balance as of December 31, 2019	-	548,030	548,030
Changes during 2020:			
Depreciation and amortization	-	91,329	91,329
Balance as of December 31, 2020	-	639,359	639,359
Amortized cost as of December 31, 2019	117,619	3,311,559	3,429,178
Amortized cost as of December 31, 2020	125,429	3,314,473	3,439,902

[3] Including the balance of asset retirement amortized cost as of the date of the statement of financial position in the sum of approx. $81 million (December 31, 2019: approx. $66 million).
[4] For details regarding capitalized credit costs, see Note 19B below. In the report period, oil and gas asset credit costs were not capitalized.
[5] The amortization rate of the Tamar project is approx. 2.7% (2019: approx. 7.5%) and of the Leviathan project, approx. 1.9% With regard to the change in the amortization rate, see Note 2K1E.
[6] In 2020, the balance excludes an update in connection with an oil and gas asset retirement obligation in the Yam Tethys project in the amount of approx. $7.4 million (2019: approx. $22.2 million) recorded directly in the statement of comprehensive income.

Notes to the Financial Statements as of December 31, 2020 (Dollars in thousands)

Note 7 – Investments in Oil and Gas Assets (Cont.):

A. Composition (Cont.):

2. Composition by joint ventures:

	31.12.2020	31.12.2019
Oil and gas assets:		
Michal-Matan joint venture (Section C1)	831,208	849,733
Ratio-Yam joint venture (Section C2)	2,483,265	2,461,826
	3,314,473	3,311,559
Exploration and appraisal assets:		
Block 12 Cyprus (Section C4)	119,051	116,435
New Ofek (Section C7)	5,865	671
New Yahel (Section C7)	513	513
	125,429	117,619
Total	3,439,902	3,429,178

B. Details on the Partnership's rights in oil and gas assets and in exploration and appraisal assets (as of December 31, 2020):

The validity of the petroleum rights is extended from time to time and is contingent upon the fulfillment of certain undertakings on the dates set forth in the terms and conditions of the petroleum assets. In the event of non-fulfillment of the conditions, the petroleum right may be invalidated. For information regarding a benefit in respect of the right to receive royalties from the sale of the rights in the Karish and Tanin leases, see Note 8B below. For further information, see Section C9 below and as to pledges registered on part of the oil and gas assets see Note 10.

	Type of right	Name of right	Right valid through	Partnership's share
Yam Tethys	Lease	I/10 Ashkelon	10.6.2032	48.5%
Yam Tethys	Lease	I/7 Noa	31.1.2030	48.5%
Michal-Matan	Lease	I/12 Tamar	1.12.2038	[7] 22%
Michal-Matan	Lease	I/13 Dalit	1.12.2038	[8] 22%
Ratio-Yam	Lease	I/15 Leviathan North	13.2.2044	45.34%
Ratio-Yam	Lease	I/14 Leviathan South	13.2.2044	45.34%
Block 12 in Cyprus	Concession	Block 12	7.11.2044	30%
Alon D	License	367/Alon D	21.6.2020	52.941%[9]
New Ofek	License	405/New Ofek	20.6.2021	25%
New Yahel	License	406/New Yahel	20.6.2021	25%

[7] With regard to the provisions of the Gas Framework see Note 12L1 above. Note that in 2017, the Partnership sold 9.25 of the rights in the Tamar and Dalit Leases to Tamar Petroleum Ltd.
[8] See Footnote 8 above.
[9] See Section C6 below.

Note 7 – Investments in Oil and Gas Assets (Cont.):

C. The Partnership's oil and gas exploration business:

1. The Michal-Matan joint venture (the Tamar and Dalit Leases):

a) The Michal-Matan joint venture is a venture for exploration, development and production of oil and gas in the area of the Tamar and Dalit Leases.

b) Further details with respect to the Michal-Matan joint venture operations:

1) The Tamar Project:

The production system of the Tamar project includes six subsea production wells, that are connected to the production platform (the "**Tamar Platform**"), through the subsea production system. Tamar Platform is connected to an onshore terminal through a system of pipes and from there to the national transmission system of Israel Natural Gas Lines Ltd. ("**INGL**"). The maximum capacity of gas supply from the Tamar project to the INGL transmission system is approx. 1.1 BCF per day.

2) Possibilities for expansion of the Tamar Project's supply capacity:

From time to time the Tamar partners are exploring options for expanding the supply capacity from the Tamar Project, insofar as will be necessary, according to the scope of demand expected in the domestic market and for export.

Expansion of the supply capacity may include, *inter alia*, completion of the development of the Tamar SW reservoir and/or the drilling and/or completion of additional production wells, which will be connected to the existing subsea production system, as well as the laying of an additional third supply pipe from the Tamar field to the Tamar and/or Mari B platforms. In addition, the need for and manner of the upgrade required for the Tamar platform and the terminal are being examined.

Note 7 – Investments in Oil and Gas Assets (Cont.):

C. The Partnership's oil and gas exploration business (Cont.):

1. The Michal-Matan joint venture (the Tamar and Dalit Leases) (Cont.):

c) The Tamar South West reservoir ("Tamar SW"):

According to the development plan of the Tamar SW reservoir, which was approved by the Petroleum Commissioner, the Tamar SW reservoir is planned to be developed by converting the discovery well into a production well and connecting it to the subsea facilities of the Tamar Project. The cost of development of the Tamar SW reservoir was partially approved by the Tamar partners and accordingly equipment was purchased and various acts were performed in relation to the development of the reservoir, including the placement of subsea pipeline between the Tamar SW reservoir and the subsea manifold of Tamar Project. See Section C9B below with regard to the overflow of part of the reserves in the Tamar SW reservoir to the area of the 353/Eran license.

d) Appraisal of the condensate and natural gas reserves in the Tamar gas field:

According to a report prepared in March 2021 by Netherland Sewell & Associates Inc. ("**NSAI**"), which is a qualified, expert an independent reserve and resource appraiser, according to the SPE-PRMS, as of December 31, 2020 the natural gas reserves in the Tamar project (consisting of the Tamar SW and Tamar reservoirs), classified as proved reserves are approx. 218.81 BCM (of which approx. 10.3% attributed to Tamar SW), and the amount of reserves classified as proved + probable reserves is approx. 296.8 BCM (of which approx. 9.1% attributed to Tamar SW).

According to the said report, the condensate reserves in the Tamar and Tamar SW reservoirs, which are classified as proved reserves, are approx. 10 million barrels (of which approx. 10% attributed to Tamar SW), and the amount of reserves classified as proved + probable reserves is approx. 13.6 million barrels (of which approx. 8.8% attributed to Tamar SW). Such reserves do not include the reserves that overflow into the Eran license. See Section 8 below regarding uncertainty in the evaluation of reserves.

e) Dalit 1 well:

In 2009, the Dalit 1 offshore well was drilled, at a distance of around 50 km off the shores of Israel, following which a finding was announced.

According to a report prepared in March 2018 by NSAI according to PRE-PRMS, the amount of the contingent resources at the Dalit lease, classified at the Development Pending stage, as of December 31, 2017, ranges between approx. 6.1 BCM (low estimate) and approx. 9.5 BCM (high estimate). In the resource report, it is indicated that the contingent resources are contingent upon the approval of a project which includes an approved development plan and a reasonable projection for sales of natural gas. As of December 31, 2020, no change occurred in the details provided in such report. See Section 8 below regarding uncertainty in the evaluation of reserves.

The Partnership, jointly with its partners in the Dalit and Tamar project, submitted to the Commissioner in 2010 a development plan of the Tamar reservoir, which includes, *inter alia*, reference to the development of the Dalit lease.

Note 7 – Investments in Oil and Gas Assets (Cont.):

C. The Partnership's oil and gas exploration business (Cont.):

2. The Ratio-Yam joint venture:

a) The "Ratio-Yam" joint venture is a venture for exploration, development and production of oil and gas in the area of the I/15 Leviathan North and I/14 Leviathan South leases (the "**Leases**" and/or "**Leviathan Leases**").

b) The development plan for the Leviathan reservoir:

In June 2016, the Development plan was approved by the Commissioner, as submitted by Noble. On February 23, 2017, the Leviathan partners adopted a final investment decision (FID) for the development of Phase 1A of the Development plan for the Leviathan reservoir, at a capacity of approx. 12 BCM per year. The total cost of development of Phase 1A amounted, as of the date of the financial statements, to a sum of approx. $3.6 billion (100%, the Partnership's share being approx. $1.6 billion). On December 31, 2019, the piping of natural gas from the Leviathan reservoir began.

The plan for the full development of the Leviathan reservoir includes the supply of natural gas and condensate to the domestic market and for export and the supply of condensate to the domestic market (in this section: the "**Development Plan**" or the "**Plan**"), the main provisions of which are as follows:

1. Eight production wells at the first stage (four of which have been drilled and completed for production in Phase 1A) will be connected by a subsea pipeline to a permanent platform (in this section: the "**Platform**"), which is located offshore within the territorial waters of Israel, on which all gas and condensate processing systems were installed. The gas is piped from the Platform to the northern onshore entry point of the national transmission system of INGL (the "**INGL Connection Point**").

   The condensate is also piped to the shore via a separate pipeline parallel to the gas pipeline, and is connected to an existing fuel pipeline of Europe Asia Pipeline Co. ("**EAPC**") that leads to the tank farm of Petroleum & Energy Infrastructures Ltd. ("**PEI**") and from there to the Oil Refineries Ltd. ("**ORL**").

   Furthermore, a pipeline to the Hagit site has been laid and facilities have been set up therein for storage and unloading of the condensate, for the purpose of providing backup in the event that piping condensate to ORL is impossible. Setup of the condensate storage system at the Hagit site has been completed and all of the permits required for the operation thereof have been received.

2. The production system is designed to supply approx. 21 BCM per year after the completion of Phase 1A and Phase 1B of the Development Plan, as specified below.

Note 7 – Investments in Oil and Gas Assets (Cont.):

C. The Partnership's oil and gas exploration business (Cont.):

2. The Ratio-Yam joint venture (Cont.):

b) Development plan for the Leviathan reservoir (Cont.):

3. The Development Plan is implemented in two phases, according to the maturity of the relevant markets, as specified below:

   Phase 1A – includes, at the first stage, four subsea production wells, a subsea production system that connects between the production wells and the Platform, a system for transmission to the shore and related onshore facilities. At this point, the reservoir's gas production capacity is at approx. 12 BCM per year.

   Phase 1B – expected to include four additional production wells, related subsea systems and expansion of the Platform's processing facilities to increase the system's total gas production capacity by approx. 9 additional BCM per year, with an estimated budget of approx. $1.5-2 billion (100%, the Partnership's share is estimated at approx. $0.7-0.9 million). As of the date of release of the financial statements, a final investment decision for the development of Phase 1B has not yet been adopted.

4. It is noted that additional production wells will be required during the life of the project to enable production of the required volume.

5. Upon completion of the running-in of all of the systems on the Platform, and mainly the running-in of the turbo expander system, the ability to increase the maximum daily supply capacity, in certain conditions, beyond 1.2 BCF, will be explored.

c) Consideration of different alternatives for increase of the production capacity from the Leviathan reservoir:

As of the date of approval of the financial statements, the Leviathan partners are considering various alternatives for increasing the volume of the production from the Leviathan reservoir (beyond Phase 1A and concurrently with the examination of Phase 1B), based on the existing facilities, and are acting to update the development plan, so as to allow for an increase of the production capacity up to approx. 24 BCM per year, and all according to the estimates that are updated from time to time with regard to the current and projected demand in the local market and regional and global target markets, and *inter alia* the following alternatives are being considered:

1. Increase of the production capacity of Phase 1A from 12 BCM per year to 16 BCM per year by means of adding two production wells and related subsea infrastructures, and immaterial changes in the Platform. This alternative will allow for maximum utilization of the processing infrastructures installed on the Leviathan platform as part of Phase 1A, and the estimated cost in respect thereof is approx. $875 million (100%, the Partnership's share approx. $397 million).

Note 7 – Investments in Oil and Gas Assets (Cont.):

C. The Partnership's oil and gas exploration business (Cont.):

2. The Ratio-Yam joint venture (Cont.):

c) Consideration of different alternatives for increase of the production capacity from the Leviathan reservoir (Cont.):

2. Increase of the production capacity from 16 BCM per year to 24 BCM per year (subject to implementation of the first alternative as described above), *inter alia*, by means of adding four production wells and related subsea infrastructures, over and above those of the first alternative which is described above, adding a fourth pipe from the field to the platform, and expansion of the processing facilities on the Platform, with an estimated budget of approx. $1.5-2 billion (100%, the Partnership's share approx. $0.7-0.9 million). This alternative will allow for the supply of additional quantities of gas for export, insofar as required, including to the liquefaction facilities situated in Egypt and/or for the supply of gas to a floating liquefaction plant (FLNG).

d) Evaluation of reserves and contingent resources in the Leviathan Leases[10]:

In March 2021, a report on evaluation of reserves and contingent resources in the Leases was received from NSAI, updated as of December 31, 2020. According to the report, the overall quantity of resources is estimated at approx. 641.9 BCM and is divided into categories of reserves and contingent resources.

The quantity of the Proved Developed Producing reserves is approx. 319.1 BCM and the quantity of the Proved + Probable Reserves is approx. 370.6 BCM.

Additionally, the Proved Developed Producing condensate reserves are approx. 24.8 million barrels, and the quantity of Proved + Probable Reserves is approx. 28.8 million barrels.

In the contingent resource report, the contingent resources were divided into two categories, which relate to each of the development stages of the reservoir, as follows:

1. Contingent resources which are classified at the Development Pending stage: these resources are contingent upon the decisions to perform additional drillings, upon the construction of related infrastructures and upon the execution of additional agreements for the sale of natural gas as part of Phase 1A.
2. Future Development: resources contingent upon the adoption of another investment decision, in accordance with Phase 1B of the development plan and with an additional stage (insofar as the development plan is updated) and upon the execution of additional agreements for the sale of natural gas range between approx. 379 BCM (the high estimate) and approx. 154.5 BCM (the low estimate) and condensate contingent resources range between approx. 29.4 million barrels (the high estimate) and approx. 12 million barrels (the low estimate). See Section 8 below regarding uncertainty in the evaluation of reserves.

[10] In the opinion of the Commissioner, according to an opinion provided to his office by an international firm, the estimated amount of natural gas to be produced from the Leviathan reservoir is 17.6 TCF, according to the production plan submitted in the context of the application for approval of the development plan.

Note 7 – Investments in Oil and Gas Assets (Cont.):
C. The Partnership's oil and gas exploration business (Cont.):
2. The Ratio-Yam joint venture (Cont.):

e) Deep Targets:

In 2019, an analysis was performed of reprocessing of seismic surveys, *inter alia* in connection with exploration drilling to the deep targets in the Leviathan Leases (the "**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 analysis of the Data Reprocessing revealed that it is necessary to reclassify and redefine the two deep targets which were previously defined in the area of the lease as a single 'submarine clastic channel' target (collectively: the "**New Targets**").

In January 2020, a report on evaluation of prospective resources in the Leases was received from NSAI, updated as of December 31, 2019. According to the report, the best estimate in the carbonate buildup for gas and oil is estimated at approx. 4.5 BCM and approx. 155.3 million barrels, respectively. and the best estimate in the clastic channel for gas and oil is estimated at approx. 6.5 BCM and approx. 223.9 million barrels, respectively. As of December 31, 2020, the details presented in the aforesaid report remain unchanged. See Section 8 below with regard to uncertainty in the evaluation of reserves.

As of the date of approval of the financial statements, the partners are examining, *inter alia*, the performance of another seismic survey, in view of the development of the technology in the field of seismic surveys, for the purpose of improving the existing data, in order to substantiate the making of a decision on exploration drilling to the New Targets. In addition, the Israeli partners are exploring the possibility of adding a strategic partner with relevant knowledge and experience in the specification, drilling and development of an exploration target (and specifically a carbonate buildup target).

3. Engagement in agreements for the purchase of EMG shares and for the purchase of rights in the EMG Pipeline:

With the purpose of realizing 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 stated in Notes 12C1C and 12C2D below), EMED[11] purchased 39% of the share capital of Eastern Mediterranean Gas Company S.A.E ("**EMG**"). On January 15, 2020, the piping of natural gas began from Israel to Egypt from the Leviathan reservoir, and on June 30, 2020, the piping of gas began 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 contingent, *inter alia*, on the signing of a Capacity, Lease & Operatorship Agreement – CLOA, between EMED and EMG, in which EMG shall grant EMED the exclusive right to lease and operate the EMG Pipeline for the flow of natural gas from Israel to Egypt (the "**CLOA**"), which was signed on June 30, 2019, and all as specified below:

[11] EMED is an SPV which was established for the purpose of the transaction and is registered in the Netherlands, whose shares are held as follows: a wholly-owned subsidiary of the Partnership registered in Cyprus – 25%, Noble Energy EMed Midstream Limited, a company which to the best of the Partnership's knowledge is owned by Noble Energy Inc. – 25% and Sphinx EG BV, a company which to the best of the Partnership's knowledge is wholly owned by East Gas Company which holds, *inter alia*, a gas pipeline and infrastructures in Egypt (the "**Egyptian Partner**") – 50%.

Note 7 – Investments in Oil and Gas Assets (Cont.):

C. The Partnership's oil and gas exploration business (Cont.):

3. Engagement in agreements for the purchase of EMG shares and for the purchase of rights in the EMG pipeline (Cont.):

EMG is a private company registered in Egypt which owns a 26-inch submarine pipeline which is approx. 90 km long, and which connects the Israeli transmission system in the Ashkelon area and the Egyptian transmission system in the el Arīsh area and related facilities (jointly: the "**EMG Pipeline**"). The EMG Pipeline was planned for a capacity of approx. 7 BCM per year, with an option to increase the capacity to approx. 9 BCM per year through the installation of additional systems. The flow of gas in the EMG Pipeline from Egypt to Israel was stopped in 2012, and to the best of the Partnership's knowledge, as of the date of signing of the agreement, EMG had no commercial activity, and it remained exposed to lawsuits (see Note 12K14) and debts on the part of authorities, finance providers, suppliers and customers in significant amounts. It is noted that in the framework of the Transaction, the Partnership is not required to provide collateral or guarantees in relation to the existing debts of EMG.

The shareholders of EMG, as of the date of signing of the agreement, are:

(1) EGI-EMG LP - 12%;

(2) Merhav MNF Ltd. - 8.2%;

(3) Merhav Ampal Energy Holdings, Limited Partnership - 8.6%;

(4) Merhav Ampal Group Ltd. - 8.2% (the "**Merhav Ampal Group**");

(5) PTT Energy Resources Company Limited ("**PTT**")[12] - 25%;

(6) Mediterranean Gas Pipeline Ltd. ("**MGPC**)[13] - 28%;

(7) Egyptian General Petroleum Corporation ("**EGPC**")[14] - 10%;

(Shareholders (1)-(4) above shall be referred to hereinafter collectively as: the "**Sellers**").

1) <u>Agreements for the purchase of 39% of EMG's share capital</u>

On September 26, 2018, EMED signed four separate, mainly 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 (collectively: the "**Share Purchase Agreements**"), as well as another agreement for the purchase of shares at a rate of 2% from MGPC (the "**MGPC Agreement**").

a) <u>The principles of the Share Purchase Agreements</u>

1) Upon the fulfillment of the conditions precedent in November 2019, the main ones of which are mentioned in Paragraph 4 below, and the closing conditions, the Sellers sold and transferred to EMED the EMG shares held thereby, at a total rate of 37% of EMG's share capital (the "**Purchased Shares**"), including all of the rights attached to the Purchased Shares.

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[12] A public energy company partially owned by the Thai Government.
[13] A private company which, to the best of the Partnership's knowledge, is controlled by the Evsen Group, a company headed by Dr. Ali Evsen.
[14] An Egyptian government-owned corporation.

Note 7 – Investments in Oil and Gas Assets (Cont.):

C. The Partnership's oil and gas exploration business (Cont.):

3. Engagement in agreements for the purchase of EMG shares and for the purchase of rights in the EMG Pipeline (Cont.):

1) **Agreements for the purchase of 39% of EMG's share capital (Cont.):**

a) (Cont.):

2) The Sellers, the shareholders of the Sellers and the companies affiliated with the Sellers shall waive any claim, lawsuit, award, decision, order or remedy that are available to them against the Egyptian Government and companies owned thereby in the framework of the Arbitration Proceedings[15].

3) In consideration for the Purchased Shares, for waiver of their rights in the framework of the Arbitration Proceedings, and other rights in accordance with the Share Purchase Agreements, as aforesaid, EMED paid the Sellers, on the date of the closing of the transaction, the sum total of approx. U.S. $527 million (the "**Consideration**"), out of which each one of the Partnership and Noble paid a sum of approx. U.S. $188.5 million, and the balance was paid by the Egyptian Partner.

4) On July 31, 2019, the decision of the Competition Commissioner was issued in accordance with Section 20(b) of the Economic Competition Law, 5748-1988, permitting the merger between EMED and EMG for the purchase of the EMG Pipeline, in the context of which the Partnership and Noble undertook to fulfill the conditions set forth in the aforesaid decision.

Regarding the petition that was filed with the Competition Court at the District Court in Jerusalem in connection with the approval of the Competition Commissioner as aforesaid, see Note 12K7.

Regarding the signing of an agreement between Noble and INGL in connection with the transmission of natural gas to the EMG Pipeline through the INGL system, see Note 12M.

[15] It is noted that some of the Sellers, shareholders of the Sellers and companies affiliated with the Sellers are conducting several arbitration proceedings in international arbitration institutions against the Egyptian Government and companies owned thereby in respect of the cessation of the flow of gas from Egypt to Israel (jointly, the "**Arbitration Proceedings**). Furthermore, EMG is a party to arbitrations against companies owned by the Egyptian Government. See also Notes 12K14 and 12K15.

Note 7 – Investments in Oil and Gas Assets (Cont.):

C. The Partnership's oil and gas exploration business (Cont.):

3. Engagement in agreements for the purchase of EMG shares and for the purchase of rights in the EMG Pipeline (Cont.):

1) **Agreements for the purchase of 39% of EMG's share capital (Cont.)**

b) The principles of the MGPC Agreement

Concurrently with the signing of the Share Purchase Agreements, an agreement was signed between EMED and MGPC whereby MGPC transferred to EMED, without monetary consideration, subject to and concurrently with the closing of the Share Purchase Agreements, 2% of EMG's shares which are held thereby, against the conclusion of disputes between some of the Sellers and MGPC.

After the closing of the EMG Transaction, and as of the date of approval of the financial statements, EMG's shareholders are as follows:

(1) EMED – 39%;

(2) PTT – 25%;

(3) MGPC – 17;

(4) The Egyptian Partner – 9%[16];

(5) EGPC – 10%.

2) The Capacity Lease & Operatorship Agreement

As aforesaid, the closing of the EMG Transaction was contingent, *inter alia*, on 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 Notes 12C1C and 12C2D below), with an option to extend the agreement. According to this agreement, the costs required for refurbishment of the EMG Pipeline, up to the sum of $30 million (which reflects an initial estimate of these costs), and the current operation costs of the pipeline, shall be borne by EMED (collectively: the "**Operation Costs**"), while EMG will be entitled to receive the current transmission fees which Dolphinus shall pay for use of the pipeline (the "**Transmission Fees**"), net of the Operation Costs. As of the date of the Statement of Financial Position, Noble and the Partnership invested, together with the Tamar and Leviathan partners, in accordance with the arrangements set forth in the agreement, in the refurbishment of the EMG Pipeline, due diligence tests and increase of the capacity of the pipeline, though EMED, a sum of approx. $124 million (the Partnership's share being approx. $53.9 million) which shall mostly be repaid from EMG's available cash flow that derives from the revenues from transmission of gas in the EMG Pipeline to Dolphinus.

[16] To the best of the Partnership's knowledge, MGPC transferred the said shares to the Egyptian Partner.

Note 7 – Investments in Oil and Gas Assets (Cont.):

C. The Partnership's oil and gas exploration business (Cont.):

3. Engagement in agreements for the purchase of EMG shares and for the purchase of rights in the EMG Pipeline (Cont.):

2) **The Capacity Lease & Operatorship Agreement (Cont.):**

Concurrently with the signing of the export to Egypt agreements, an agreement was signed between the Partnership and Noble and between the Tamar partners and the Leviathan partners in connection with allocation of the capacity (in this section: the "**Capacity Allocation Agreement**") in the transmission system from Israel to Egypt. The capacity division 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 above the first layer, up to 150,000 MMbtu per day until 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 above the second layer will be allocated to the Leviathan partners.

On the date of the closing of the EMG Transaction, the Leviathan partners paid the sum of $200 million ("**Access/Participation Fees for the Leviathan Dolphinus Agreement**") and the Tamar partners paid the sum of $50 million ("**Access/Participation Fees for the Tamar Dolphinus Agreement**"), in consideration for an undertaking to allow the piping of natural gas to Egypt from the Leviathan and Tamar reservoirs and guaranteed capacity in the EMG Pipeline, all for the purpose of consummation of the export to Egypt agreements.

It is noted that the final amounts of the Access/Participation Fees for the Leviathan Dolphinus Agreement and the Access/Participation Fees for the Tamar Dolphinus Agreement (jointly: the "**Leviathan and Tamar Access Fees**") 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 via the EMG Pipeline until such date (including gas quantities not yet supplied and paid for by virtue of a take-or-pay undertaking).

In addition to the costs invested in the refurbishment of the pipeline as aforesaid, the Capacity Allocation Agreement determined arrangements for participation in the costs of the EMG Transaction, additional costs in connection with the piping of the gas, and investments which will be required for maximum utilization of the capacity of the EMG Pipeline, payment of which shall be divided between the Leviathan partners and the Tamar partners, which were partly included in the Leviathan and Tamar Access Fees.

In view of the aforesaid, the Partnership's share of the Leviathan and Tamar Access Fees amounts to approx. $119.4 million and the Partnership's share of the receivables from a company accounted for at equity amounts to approx. $22.5 million and they were included in the "other long-term assets" item.

Note 7 – Investments in Oil and Gas Assets (Cont.):

C. The Partnership's oil and gas exploration business (Cont.):

3. Engagement in agreements for the purchase of EMG shares and for the purchase of rights in the EMG Pipeline (Cont.):

2) **The Capacity Lease & Operatorship Agreement (Cont.):**

The Capacity Allocation Agreement further determines principles for a "backup" arrangement between the Tamar partners and the Leviathan partners, according to which starting from June 30, 2020 until the Capacity Increase Date, insofar as the Tamar partners shall be unable to supply the quantities which they undertook to supply to Dolphinus, the Leviathan partners shall supply the Tamar partners with the required quantities.

The term of the Capacity Allocation Agreement is until the conclusion of the export to Egypt agreements, unless it shall have ended prior thereto in the following cases: a breach of a payment undertaking which was not remedied by the party in breach; in a case where the Competition Authority shall not have approved extension of the Capacity Lease & Operatorship Agreement according to the decision of the Competition Commissioner, as specified in Section 5A above. In addition, each party shall be entitled to end its part in the Capacity Allocation Agreement insofar as its export agreement shall have been terminated.

3) EMED's shareholders' agreement

In proximity to the date of the signing of the Share Purchase Agreements, EMED's shareholders signed a shareholders' agreement which regulates the relationship between them as shareholders of EMED, including provisions regarding material resolutions that shall be adopted unanimously. In addition, arrangements were put in place for a right of first refusal for transfers of shares of EMED.

4) Term sheet for use of additional infrastructures

Concurrently with the signing of the Share Purchase Agreements, as described above, a term sheet was signed between the Partnership and Noble and the Egyptian Partner (which holds the Arab Gas Pipeline) in the segment from el Arīsh to Aqaba, and an affiliate of Dolphinus, whereby 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 flow of gas in additional quantities over and above the gas quantities that would flow via the EMG Pipeline (the "**Additional Infrastructure**"), for the purpose of implementation of the Dolphinus agreement and other agreements for the sale of natural gas to Egypt. In addition, the parties agreed to look into other projects for the transmission of natural gas from Israel to potential customers and facilities in Egypt.

Note 7 – Investments in Oil and Gas Assets (Cont.):
C. The Partnership's oil and gas exploration business (Cont.):

4. **Block 12 in Cyprus:**

a) The Partnership has a production sharing contract (PSC), whereby the Partnership holds 30% of the rights in the Aphrodite reservoir in Block 12, which is situated in the exclusive economic zone of Cyprus. The operator of the joint venture is Noble Cyprus.

b) In June 2015, the Partnership, together with its partners in the Aphrodite reservoir, notified the Government of Cyprus of a commerciality announcement and a proposed framework for the development of the Aphrodite reservoir.

c) On November 7, 2019, the right holders in the PSC (the "**Partners**") and the Government of Cyprus signed an amendment to the PSC, which modified, *inter alia*, the mechanism for the 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 "**Exploitation License**"), and a development and production plan was approved for the reservoir (the "**Development Plan**").

d) In the amendment to the PSC (the "**Amendment**"), the Partners undertook, *inter alia*, to meet the main milestones for promotion of development of the Reservoir, as follows:

1. Drilling of an appraisal/development well in the area of Block 12 in accordance with the Development Plan, and completion thereof within 24 months from the date of receipt of the Exploitation License; or on a later date upon fulfillment of specific conditions upon whose fulfillment the partners will be entitled to an extension;
2. Completion of the Front-End Engineering Design ("**FEED**"), delivery of the products in accordance with the Development Plan, and adoption of a final investment decision (FID) for development of the Reservoir within 48 months from the date of receipt of the Exploitation License (i.e., until 2023).

The PSC determines specific conditions upon the fulfillment of which the Partners will be entitled to receive an extension for purposes of meeting the said milestones, with the deadline for adoption of a FID being 6 years after the date of receipt of the Exploitation License. It is noted that failure to meet the milestones defined in the PSC will constitute grounds for termination of the PSC, unless this derived from "*force majeure*" (as defined in the PSC).

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

Note 7 – Investments in Oil and Gas Assets (Cont.):

C. The Partnership's oil and gas exploration business (Cont.):

4. Block 12 in Cyprus (Cont.):

f) The Republic of Cyprus is entitled to receive one-time bonuses from the holders of the rights in Block 12 upon fulfillment of milestones regarding the average daily production rate for a consecutive period of 30 days. The PSC specifies mechanisms for the distribution of natural gas and oil output, as specified below. It is noted that the Republic of Cyprus is entitled to receive its share of the produced natural gas or oil, in whole or in part, in kind.

g) On the date of signing of the Amendment, the Cypriot government approved the Development Plan and granted an Exploitation License for a period of 25 years with an option for extension by up to 10 additional 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 processing and production facility in the area of the license, with an estimated maximum production capacity of approx. 800 MMCF per day, through 5 production wells at the preliminary stage, and a subsea transmission system to the Egyptian market. In accordance with the current appraisal of the operator, which was delivered to the Partnership and to the Cypriot government before completion of the technical-economic feasibility tests, including performance of the FEED, the estimated cost of the Development Plan, excluding the cost of construction of the pipelines to the target markets, is estimated at approx. $2.5-3 billion (in 100% terms). The estimated budget for the work plan until the date of adoption of a FID is approx. $150-200 million (in respect of 100%). Formulation of the Development Plan and reaching the stage of adoption of a FID for development of the Aphrodite reservoir are subject, *inter alia*, to the drilling of another appraisal/development well and to the FEED, commercial arrangements for the development of the pipelines for export, the signing of agreements for the supply of natural gas, and fulfillment of the closing conditions in such agreements, regulatory approvals and performance of financing arrangements. It is noted that said estimated costs do not include costs for development and construction of a pipeline for the export of natural gas from the Aphrodite reservoir.

h) According to a report prepared in March 2021 by NSAI according to the rules of SPE-PRMS, the amount of contingent resources of natural gas classified under the "Development Pending" stage at the Aphrodite reservoir, as of December 31, 2020, ranges between approx. 128.8 BCM (the high estimate) and approx. 56.8 BCM (the low estimate).

According to the aforesaid report, the condensate reserves in the Aphrodite reservoir, which are classified as "Development Pending" as of December 31, 2020, range between approx. 10.9 million barrels (the high estimate) and approx. 4 million barrels (the low estimate). See section 8 below with respect to uncertainty in the evaluation of reserves.

Note 7 – Investments in Oil and Gas Assets (Cont.):

C. The Partnership's oil and gas exploration business (Cont.):

4. Block 12 in Cyprus (Cont.):

i) The vast majority of the Aphrodite reservoir is located in the EEZ of Cyprus, and a few percent in the area of the Yishai/370 license, which is located in Israel's EEZ. It is noted that the partners in the Aphrodite reservoir have received letters both from the partners in the Yishai license and from the Ministry of Energy with respect to the need for regulation of such parties' interests prior to the adoption of a decision regarding development of the Aphrodite reservoir. The position of the partners in the Aphrodite reservoir is that the matter is subject to the authority of the governments, and that they will act in accordance with such mechanism for regulation of the parties' interests as shall be determined by the governments, and in accordance with international law. It is further noted that further to discussions that were held between the Israeli and Cypriot governments for regulation of the parties' interests in the Aphrodite reservoir, on March 9, 2021, such governments signed an MOU which instructs the partners in the Aphrodite reservoir and the holders of the rights in the Yishai license to conduct direct negotiations for settlement of the issue of the overflow of the Aphrodite reservoir, which includes principles and timetables for the conduct of the negotiations.

5. The Yam Tethys joint venture:

The Yam Tethys joint venture is located in the areas of the Ashkelon and Noa leases. Production from the Yam Tethys reservoir commenced in 2004 and was discontinued in May 2019, due to the exhaustion of the reservoirs. As of the date of approval of the financial statements, the principal use of the project assets is the provision of infrastructure services to the Tamar reservoir. Note that the holders of the interests in the Tamar Lease are entitled to use the Yam Tethys platform for the entire term of the Tamar Lease, for the purpose of export or supply of natural gas to the domestic market from the Tamar reservoir, subject to the conditions stipulated in the Gas Framework.

a) Commercial arrangement of the operation and production from the Yam Tethys project and the Tamar project ("Commercial Arrangement"):

Commencing from May 2013 through September 2017, and since May 2019, the Tamar reservoir[17] supplies natural gas (*in lieu* of the Yam Tethys reservoir) by virtue of agreements for gas supply between the Yam Tethys partners and their customers (the "**End Customers**" and the "**Early Agreements**", respectively).

[17] As of December 31, 2020, the balance for supply to a Yam Tethys customer is approx. 0.22 BCM. The gas supply agreement is scheduled to expire during 2022.

Note 7 – Investments in Oil and Gas Assets (Cont.):

C. The Partnership's oil and gas exploration business (Cont.):

5. The Yam Tethys Joint Venture (Cont.):

a) (Cont.):

The consideration which was obtained from the End Customers, together with the consideration reflecting the share of the Delek Group, which is a right holder Yam Tethys and is not a holder of direct rights in Tamar, was divided such that the partners in the Tamar project which are not partners in the Yam Tethys project, received a natural gas price equal to the monthly average price of natural gas supplied during that month by virtue of agreements executed between the Tamar partners and their customers, and the remaining monetary 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 allowed for the maintaining of a balance of the gas quantities in the Tamar Project among the partners therein pro rata.

For details with respect to a claim filed by the Partnership and Noble as to the royalties to which the State is entitled in respect of revenues deriving from the supply of natural gas within the framework of the sale as aforesaid, see Note 12K1 below.

In May 2018, the Yam Tethys partners engaged with the Tamar partners in an agreement on an interruptible basis (which was updated in September 2018), for the sale of (immaterial) surplus of production from the Yam Tethys reservoir to the Tamar partners, for the sale thereof to the Tamar project customers, for a period of 24 months from October 1, 2017. This agreement ended with the cessation of the production of natural gas from the Yam Tethys reservoir during May 2019.

b) On May 3, 2020, an agreement was signed (in this section: the "**Agreement**") between the Partnership, Noble, Delek Group Ltd. and Ratio Oil Exploration (1992), Limited Partnership ("**Ratio**"), for the supply of natural gas, under which the supply of gas to customers that had signed earlier agreements with each of the Yam Tethys partners will be carried out from the Leviathan reservoir. Accordingly, the Yam Tethys partners that are Leviathan partners (i.e., the Partnership and Noble) will take from the gas available to them (according to the rate of their holdings in Yam Tethys) whereas the remainder of the gas required to be supplied by Delek Group will be purchased from Ratio according to the consideration determined in such Agreement, which is the average monthly price determined in the agreements signed between the Leviathan partners and their customers in the domestic market.

c) Agreement for the grant of usage rights in the facilities of the Yam Tethys Project:

In July 2012, the Partnership announced that an engagement agreement was signed (the "**Usage Agreement**") between the partners in the Yam Tethys Project and the partners in the Tamar project, whereby the Yam Tethys partners would grant the Tamar partners usage rights in the existing facilities of the Yam Tethys project, including the wells, the Yam Tethys platform, the compression system, the pipeline and the terminal, and the Tamar partners were also granted the right to upgrade and/or construct facilities for the purpose of transmission and storage of natural gas from the Tamar project (the "**Yam Tethys Facilities**"). The usage rights will be granted subject to the reservation of capacity for natural gas produced from the Yam Tethys project in the pipeline and in the terminal.

Note 7 – Investments in Oil and Gas Assets (Cont.):

C. The Partnership's oil and gas exploration business (Cont.):

5. The Yam Tethys Joint Venture (Cont.):

c) (Cont.):

The term of the Usage Agreement will end upon the earlier of: (1) the expiration or termination of the Tamar lease, and in the event that the Dalit field is developed, in a manner that makes use of the Yam Tethys Facilities, then the expiration or termination of the Dalit lease; (2) the giving of a notice by the Tamar partners of the permanent cessation of commercial gas production from the Tamar project; (3) the abandonment of the Tamar project.

The Agreement includes, *inter alia*, provisions that regulate the relationship between the Tamar partners and the Yam Tethys partners throughout the entire term of use of the Yam Tethys Facilities, including with respect to the management of the Yam Tethys Facilities, the mechanism for the distribution of the operating expenses of the Yam Tethys Facilities and the distribution of the capital expenses of the Yam Tethys Facilities in connection with the preparation and upgrade of the Yam Tethys Facilities for the receipt of natural gas from the Tamar project based on the gas capacity scope ratios between the Yam Tethys project and the Tamar project, restrictions on the transfer and/or pledge of the rights of the parties of the Usage Agreement, and an arbitration mechanism for the resolution of disputes between the parties.

It is noted that ownership of the Yam Tethys Facilities and the cost of abandonment of the facilities will remain with the Yam Tethys partners and the Usage Agreement will provide a settlement of accounts mechanism relating to the value of such facilities at the end of the term of production from the Tamar project.

d) Abandonment of wells and subsea equipment:

Pursuant to the approvals and directives received in January 2021 (after the date of the Statement of Financial Position) from the Petroleum Commissioner, the Operator is preparing for decommissioning and abandonment of the project facilities, other than the platform, and including the production wells and the subsea equipment, in accordance with an approved decommissioning plan that is expected to be carried out in 2021-2022. At the same time, the aforesaid parties are discussing the Operator's request to approve "cold stacking" of the Yam Tethys platform, which will enable, *inter alia*, to unman it. A discussion is also being held with respect to possible future uses and/or decommissioning and abandonment of the Yam Tethys platform, considering the link that exists between the facilities of the Yam Tethys project and the production from the Tamar project. The Partnership's share of the abandonment costs (other than the platform abandonment costs) total approx. $76.2 million, of which approx. $62.2 million are presented in the "other short-term liabilities" item.

Note 7 – Investments in Oil and Gas Assets (Cont.):

C. The Partnership's oil and gas exploration business (Cont.):

6. The Alon D License (in this section: the "License"):

a) On June 18, 2020 the partners in the Alon D license filed a petition with the Supreme Court, seated 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 not be granted a substitute license in its stead, and why the license holders should not be allowed to realize their economic rights that arise from the natural gas from the Karish North reservoir, part of which lies within the license area.

A motion was also made for an interim order preventing the expiration of the License, and alternatively prohibiting the launch of a competitive process for a new license for the License area (or part thereof) or the grant of such license to a third party pending a decision on the petition, and a preliminary order pending a decision on the motion for the interim order. On the same day, a decision was issued ordering the Minister of Energy and the Petroleum Commissioner to file their response to the motion for interim order by June 28, 2020. In this decision, the court denied the motion for a preliminary order, and the License thus expired on June 21, 2020.

On June 23, 2020, the Ministry of Energy announced a competitive process for a license for natural gas and oil exploration in Block 72, the area of which was covered by the license. On June 24, 2020, the partners in the license filed a notice with the court in which they updated that the Ministry of Energy had initiated a competitive 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 answer to the motion for an interim order, claiming that the motion for an interim order 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 proximity to the date of commencement of the competitive process). The Minister and the Commissioner further claimed that the chances of the petition being granted are not high since, as they argue, the petition is aimed, in practice, against a decision of the Minister from 2017, such that its filing at the present time constitutes *laches*. On July 6, 2020, the partners in the license filed a response to the answer of the Minister and the Commissioner to the motion for an interim order, in which they specified the reasons why the claims of the Minister and the Commissioner should be denied. On July 7, 2020, the motion for an interim order was denied. The hearing of the petition, was scheduled for May 19, 2021.

Note 7 – Investments in Oil and Gas Assets (Cont.):

C. The Partnership's oil and gas exploration business (Cont.):

6. The Alon D License (in this section: the "License") (Cont.):

b) In this context it is noted that the partners in the Alon D license, submitted an offer in the competitive process announced by the Ministry of Energy on June 23, 2020 for the granting of a license for natural gas and oil exploration in Block 72, on the area of which the License had extended ("**Block 72**"), and that on October 21, 2020, a request from the Competition Authority was received at the Partnership's offices for the provision of information and documents in connection with Block 72. It is noted that the winner of the said competitive process has not yet been announced by the Ministry of Energy. On September 30, 2020, the Petroleum Commissioner approached the Concentration Committee to hold a consultation on the decision on the winners of the said competitive process. On January 10, 2021 (after the date of the Statement of Financial Position) the Concentration Committee announced its recommendation not to allow the Partnership to win the competitive process, irrespective of its meeting the terms and conditions of the process. On January 14, 2021 the Partnership delivered a letter to the Petroleum Commissioner, whereby he should disregard the recommendation of the Concentration Committee as it is lacking, disregards material facts and is inaccurate. It is noted that, to the best of the Partnership's understanding, on the same day the Petroleum Commissioner delivered a request to the Concentration Committee to hold another consultation on the matter. The Partnership believes that insofar as its offer (together with Noble) is superior to other offers submitted in the process, considering the conditions that were determined therein in advance, then it has the full right to win the License and intends to take any and all legal measures available thereto to defend its rights.

Note 7 – Investments in Oil and Gas Assets (Cont.):

C. The Partnership's oil and gas exploration business (Cont.):

7. **New Ofek/405 ("Ofek") and New Yahel/406 ("Yahel") Licenses:**

   On March 19, 2019, the Partnership entered into an agreement with S.O.A Energy Israel Ltd. (the "**Seller**" or "**SOA**") for the purchase of interests at the rate of 25% (out of 100%) in each of the Ofek and Yahel licenses, which are onshore licenses (the "**Petroleum Assets**", the "**Licenses**", the "**Purchased Interests**", the "**Purchase Agreement**" and the "**Transaction**"). Upon fulfillment of the closing conditions in the agreement, on October 10, 2019, the Transaction for the purchase of the interests as aforesaid was closed, and on November 5, 2019, the Petroleum Commissioner announced that the said transfer of interests was registered in the Petroleum Register. SOA acts as operator in the Petroleum Assets.

   Following are key details from the Purchase Agreement:

   On the Transaction closing date, the Seller transferred to the Partnership the Purchased Interests, them being free and clear of any pledge, royalty (it is clarified that the Purchased Interests shall be subject to the Partnership's obligation to pay overriding royalties to interested parties in the Partnership and to third parties, see Note 12B below), liability, claim and third-party rights.

   In addition, the Partnership paid the Seller $1 million as reimbursement for past expenses incurred in relation to the activity in the Petroleum Assets. The Partnership undertook to bear the costs of production tests in the Ofek license up to a sum total that shall not exceed $6.5 million.

   To the extent that the cost of the production tests exceeds the said amount, each of the partners in the Ofek license, including the Partnership, shall pay its proportionate share in such additional cost, in accordance with the provisions of the Joint Operating Agreement (JOA) in the Licenses.

   The main activity planned for the Ofek license is re-entry into the well that exists in the License, and performance of production tests therein.

   In September 2020, the partners in the license made a decision regarding participation in the performance of the production tests to be performed in 2021 with a budget of between approx. $10 million and approx. $13 million (100%). The Partnership's share in the budget is between approx. $7.5 million and approx. $8.5 million.

8. **Appraisals of reserves of natural gas, condensate, contingent and prospective resources:**

   The above appraisals regarding the reserves of natural gas, condensate, and contingent and prospective resources of natural gas and oil in the rights of the Partnership in the leases, licenses and franchise for oil and gas exploration are based, *inter alia*, on geological, geophysical, engineering and other information received from the wells and from the Operator in the said rights. The above appraisals constitute professional hypotheses and appraisals of NSAI, which are uncertain. The quantities of natural gas and/or condensate that will actually be produced may be different to the said appraisals and hypotheses, *inter alia* as a result of operating and technical conditions and/or regulatory changes and/or supply and demand conditions in the natural gas and/or condensate market and/or commercial terms and/or the actual performance of the reservoirs. The above appraisals and hypotheses may be updated insofar as additional information accrues and/or as a result of a gamut of factors relating to the oil and natural gas exploration and production projects.

Note 7 – Investments in Oil and Gas Assets (Cont.):

C. The Partnership's oil and gas exploration business (Cont.):

9. **Additional information**:

   a) The lease deeds were granted subject to the Petroleum Law and grant the partners in the Leases an exclusive right to produce oil and natural gas in the areas of the Leases for a 30-year period, with the right of extension thereof by 20 additional years, in accordance with and subject to the provisions of the Petroleum Law.

   b) In June 2013, the 353/Eran license expired. In November 2014, the Partnership, jointly with its partners in the aforesaid license, filed a petition with the High Court of Justice with respect to the decision of the Minister of Energy to deny the appeal filed by the partners in the license from the decision of the Commissioner not to extend the term of the license. On June 2, 2016, the High Court of Justice sanctioned as a decision the parties' agreement to seek a mediation proceeding.

   Upon conclusion of the mediation proceeding, the parties reached understandings that were established in a mediation settlement.

   On April 11, 2019, the mediation settlement was sanctioned as a judgment which was agreed by all parties, whereby the Tamar SW reservoir will be divided between the area of the Tamar lease (78%) and the area of the Eran license (22%). It was further agreed that the right in the area of the Eran license would be divided at a ratio of 76% to the State and 24% to the holders of the rights in the Eran license prior to the expiration thereof. As of the date of approval of the financial statements, the parties continue to act towards the formulation of the understandings that are required for the implementation of the mediation settlement, as specified above, however, there is no certainty that they will be able to reach such understandings as will enable to begin the work for the development of the Tamar SW reservoir in the near future.

10. Further to Note 1F above regarding the spread of COVID-19 and its possible impact on the Partnership's business, the Partnership assessed the recoverable amount of its oil and gas assets (either separately or as a group of assets constituting a single cash-generating unit). The assessment of the recoverable amount was conducted by means of current value estimation and analyses of sensitivity to projected cash flows from the Partnership's oil and gas assets (the "**Assessment**"). The Assessment was conducted by an independent outside appraiser, who assessed the recoverable amount as of March 31, 2020 by means of discounting the cash flow, based on the forecasts of cash flows from 2P reserves (proved reserves + probable reserves) from the Tamar reservoir as of December 31, 2019 and based on the forecasts of cash flows from 2P + 2C reserves (best estimate contingent resources including 2P reserves) from the Leviathan reservoir as of December 31, 2019, which the Partnership published on January 10, 2020 and January 13, 2020, respectively (the "**Cash Flow Forecasts**"), while applying adjustments with respect to the figures and assumptions taken in the Cash Flow Forecasts.

Note 7 – Investments in Oil and Gas Assets (Cont.):

C. The Partnership's oil and gas exploration business (Cont.):

10. (Cont.):

The principal adjustments included, *inter alia*:

a) An update of the condensate and gas price forecast, *inter alia*, in view of: (i) an update of the Brent barrel price forecast according to an average of the Brent price forecasts of third parties, including the World Bank, the U.S. Department of Energy, and the consulting company Global Insight IHS, which were published in proximity to the date of the Assessment, for the years 2020-2030, and increase thereof by 2% per year starting from 2030; (ii) an update of the Electricity Production Tariff based, *inter alia*, on the ILS-$ exchange rate and on the fuel cost forecast which is based on the price of gas to Israel Electric Corp.; (iii) up-to-date domestic market natural gas demand forecasts, based on a third party's domestic market natural gas demand forecast.

b) Reduction of the annual sale quantities, as described below, based on:
   - An up-to-date domestic market demand forecast in proximity to the date of the aforesaid Assessment;
   - A reduction of the sale quantities under the Dolphinus agreements (see Note 12C1C and Note 12C2D below) to 50% of the annual contract quantity in years in which the updated forecast of the average daily price of a Brent barrel is lower than $50;

c) Adjustment of depreciation expenses for tax purposes to be used by a prospective buyer;

d) Use of a weighted cap rate (WACC) (after tax) of approx. 10.2% in the Tamar reservoir and 11.2% in the Leviathan reservoir.

In accordance with such Assessment, the recoverable amount of the Partnership's petroleum assets is significantly higher (more than 25%) than the balance of the investment therein in the Partnership's books as of March 31, 2020, and accordingly, no provision for impairment was required. As of December 31, 2020, there were no indications of a need to reassess the recoverable amount of the Partnership's oil and gas assets compared to the assessment made as of March 31, 2020.

Notes to the Financial Statements as of December 31, 2020 (Dollars in thousands)

Note 8 – Other Long-Term Assets:

A. Composition:

	31.12.2020	31.12.2019
Royalties receivable (see Paragraph B Below)	242,200	161,900
Loan granted (see Paragraph B Below)	57,956	69,900
Prepaid expenses for raising financing from banking corporations (see Note 10D)	-	3,576
Ministry of Energy for royalties (see Notes 12B, 12K1 and 15)	28,697	25,914
Interested parties for overriding royalties (see Notes 12B and 15)	2,870	3,508
Third party for overriding royalties (see Notes 12B and 15)	4,896	2,093
Access fees for the Dolphinus agreement (see Note 7C3)[18]	119,373	102,851
Receivables from a company accounted for at equity (see Notes 7C3 and 22G4 below)	22,478	31,808
Financial asset at fair value through other comprehensive income	17,033	46,354
Institutions	3,217	9,406
Long-term receivables in joint ventures[19]	60,345	70,423
Total	559,065	527,733

B. Agreement for the sale of rights in the Karish I/17 and Tanin I/16 leases (in this section "Leases"):

On August 16, 2016[20], an agreement was signed between the Partnership and Ocean Energean Oil and Gas Ltd. (the "**Buyer**" or "**Energean**"), for the sale of all of the rights of the Partnership and Noble[21] in the Leases (the "**Agreement**" and the "**Sold Rights**", respectively), according to the terms and conditions specified in the Agreement, the principles of which are as follows:

1) As part of the closing of the transaction, the Buyer paid the Partnership a sum total of $40 million;

2) The balance of the consideration, in the sum total of $108.5 million, will be paid to the Partnership in ten annual equal installments (in the financial statements: the "**Annual Installments**" or the "**Loan**"), plus interest, in the mechanism and at the rate determined in the Agreement, commencing on March 2018;

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[18]The access fees are amortized in accordance with the length of the period of the Dolphinus agreement.

[19] The balance mainly includes the cost for construction of the natural gas transmission systems from Israel to Jordan in the Leviathan and Tamar projects in the sum total of approx. $58.4 million (2019: approx. $68.5 million). With respect to the construction of a transmission system from the Leviathan project to Jordan, see Note 12C2C below. It is noted that the cost of construction of systems for transmission of natural gas from Israel to Jordan in the Leviathan project is amortized over the period of the agreement with NEPCO.

[20] According to the Gas Framework, the Partnership and Noble were required to sell their entire interests in the Leases.

[21] In November 2015, the Partnership entered into a right conferral agreement with Noble, whereby Noble conferred upon the Partnership the right to sell its interests in the Leases.

Note 8 – Other Long-Term Assets (Cont.):

B. Agreement for the sale of rights in the Karish I/17 and Tanin I/16 leases (in this section "Leases") (Cont.):

3) The Sold Rights were transferred to the Buyer together with the obligation to pay overriding royalties existing in the Leases, which the Partnership had undertaken with respect to its share (the "**Existing Royalties**");

4) The Buyer shall pay royalties to the Partnership in connection with natural gas and condensate to be produced from the Leases at the rate of 7.5% – prior to the payment of the petroleum profit levy under the Taxation of Profits from Natural Resources Law, 5771-2011 (the "**Levy**") in connection with the Leases, and at the rate of 8.25%% - from the date of commencement of payment of the Levy, net of the amount of the Existing Royalties.

5) In accordance with the provisions of the Gas Framework, the Agreement determines that the Buyer shall transfer the export quota from the Leases to the Seller and to the other Leviathan partners.

The Partnership engaged with an external independent appraiser in order to assess the fair value of the royalties and Annual Installments.

The financial income item in the report period includes a sum of approx. $82.7 million (2019: approx. $57.3 million; 2018: approx. $48.4 million) deriving from revaluation of the value of the Royalty from the Leases and from revaluation of the Annual Installments. Such update derives mainly from an increase in Energean's estimations regarding the contingent resources in the Leases, a change in the cap rates, a change in the production rate forecast, the condensate price and the lapse of time (see also Note 22F below).

On February 11, 2021 Energean released, inter alia, a resources report that was prepared by a third party, from which it arises that the third party estimates that gas is expected to begin to flow from the Karish reservoir in the beginning of 2022.

On April 15, 2019, Energean announced a natural gas discovery at the Karish North well. According to Enerean's reports, the plan for the development of the Karish North reservoir that was submitted thereby was approved by the Ministry of Energy in August 2020, and a final investment decision for the development of the Karish North reservoir was adopted on January 14, 2021. The production from this well is expected the begin in H2/2023.

To the best of the Partnership's knowledge, the current data on the resources attributed to the Karish, Tanin and Karish North reservoirs (in this section: the "**Reservoirs**"), were last reported by Energean on February 11, 2021 (after the date of the Statement of Financial Position). According to this report, as of December 31, 2020, the Reservoirs contain natural gas reserves (2P) of approx. 98.4 BCM and hydrocarbon liquids (condensate and natural gas liquids, see below) of approx. 99.6 million barrels (compared with natural gas resources (2P + 2C) of approx. 98.6 BCM and hydrocarbon liquids (condensate and natural gas liquids, see below) of approx. 82 million barrels, according to a previous report by Energean of April 2020). Energean further noted that the production and processing capacity of its facilities will reach approx. 8 BCM per year in 2023.

Note 8 – Other Long-Term Assets (Cont.):

b. Agreement for the sale of rights in the Karish I/17 and Tanin I/16 leases (in this section "Leases") (Cont.):

5) (Cont.):

Below are main parameters out of the valuations that were used to measure the royalties and the Annual Installments: cap rate for the Annual Installments is estimated at 7.25% (2019: 6.5%); the cap rate estimated for the royalties component is estimated at 12% (2019: 11%); dates of gas production from Karish lease: April 1, 2022 – December 31, 2040; forecast average annual production rate from Karish lease: approx. 3.91 BCM natural gas; average annual rate of condensate production from Karish lease of approx. 5.0 million; dates of gas production from Tanin lease: January 1, 2027 – December 31, 2036; forecast average annual production rate from Tanin lease: approx. 2.51 BCM natural gas; average annual rate of condensate production from Tanin lease of approx. 0.44 million barrels of condensate; the sum total of the contingent resources of natural gas and hydrocarbon liquids (condensate and natural gas liquids, see below) that were used for the valuation to measure the royalties were estimated at approx. 98.4 BCM (2019: approx. 92 BCM) and approx. 99.6 MMBBL (2019: approx. 49 MMBBL), respectively.

It is noted that in April 2020, Energean and the Partnership exchanged letters in connection with the Partnership's right to receive royalties from the leases. Energean claimed, *inter alia*, that its undertaking to pay royalties does not apply to hydrocarbons from the Karish North reservoir and, additionally, that not all hydrocarbon liquids to be produced from the Karish lease, meet the definition of Condensate under the agreement for the sale of the Partnership's rights in the leases. It is the Partnership's position, based on its counsel, that according to the agreement for the sale of the Partnership's rights in the leases, the royalty documents and the records in the Petroleum Register, Energean's duty to pay royalties applies with respect to natural gas and condensate to be produced from the leases, including from the Karish North reservoir, and that any and all hydrocarbon liquids to be produced from the leases constitute Condensate, as defined in the Agreement.

Notes to the Financial Statements as of December 31, 2020 (Dollars in thousands)

Note 9 – Trade and Other Payables:

Composition:

	31.12.2020	31.12.2019
Related parties for overriding royalties and others (see Note 21)	4,485	4,591
Interest payable for liability to banking corporations	-	24,213
Income Tax (see Note 20A)	19,110	-
Oil and gas profit levy (see Note 20B)	2,012	3,345
Ministry of Energy in respect of royalties	8,694	4,647
Payables in joint ventures[22]	33,479	124,171
Financial derivative (see Note 22F2)	-	5,523
Participation unit-based payment (see Note 13H)	10	7
Other payables and expenses due	5,777	8,241
Total	73,567	174,738

Note 10 – Bonds and Liabilities to Banking Corporations:

A. Composition and maturities by years after the date of the statement of financial position:

1) Composition of bonds and liabilities to banking corporations:

	31.12.2020	31.12.2019
Tamar Bond (see Section B below)	635,358	953,619
Leviathan Bond (see Section C below)	2,219,341	-
Liability to banking corporations (See Section D below)	-	1,927,271
Series A Bonds (See Section E below)	393,806	397,212
	3,248,505	3,278,102
Net of Current Maturities liability to banking corporations (See Section D below)	-	296,867
Net of Current Maturities of bonds	393,806	319,421
Total Current Maturities	393,806	616,288
Total (net of Current Maturities)	2,854,699	2,661,814

[22] Expenses incurred by the Operator of the joint ventures and not yet paid.

Note 10 – Bonds and Liabilities to Banking Corporations (Cont.):

A. Composition and maturities by years after the date of the statement of financial position (Cont.):

2) Maturities by years after the date of statement of financial position:

	Amount ($ in millions)	Amortized Cost ($ in millions)	Interest	Stated Maturity
Series A Bonds	395.3	393.8	4.5%	Dec. 2021
Leviathan Bond-2023	500	496.6	5.750%	June 2023
Tamar Bond-2023	320	318.3	5.082%	Dec. 2023
Leviathan Bond-2025	600	593.2	6.125%	June 2025
Tamar Bond-2025	320	317.1	5.412%	Dec. 2025
Leviathan Bond-2027	600	590.8	6.500%	June 2027
Leviathan Bond-2030	550	538.7	6.750%	June 2030
Total		3,248.5		

B. Bonds of Tamar Bond

In May 2014, the process of issuing bonds offered by Delek & Avner (Tamar Bond) Ltd. (the "**Issuer**"), a special purpose company (SPC) fully owned by the Partnership, was completed, whereby 5 series of bonds in the total sum of $2 billion were issued. The interest on the bonds of each of the series will be paid twice per year, on June 30 and December 30. The bonds were listed on TACT-Institutional on Tel Aviv Stock Exchange Ltd.

In the framework of the transaction, the Issuer and the Partnership undertook, *inter alia*, that if a duty to withhold tax is imposed on the payments they are required to make under the terms and conditions of the bonds to foreign residents, then subject to certain defined exceptions, the Issuer and/or the Partnership, as applicable, will pay additional amounts as required in order for the net amounts received by the foreign resident to be equal to the amounts such foreign resident would receive if no tax withholding were required. In this context, it is noted that on March 27, 2014, the Partnership received confirmation from the Tax Authority that the bonds to be traded on TACT-Institutional on TASE are bonds listed on a stock exchange in Israel for the purpose of Section 9(15D) of the Income Tax Ordinance (concerning an exemption from tax on interest paid to foreign residents on bonds listed on a stock exchange) and Section 97(B2) of the Ordinance (concerning an exemption from tax for foreign residents on capital gains in the sale of bonds listed on a stock exchange), all subject to the conditions specified in the Tax Authority's confirmation and the provisions of the Income Tax Ordinance and the regulations promulgated thereunder.

Note 10 – Bonds and Liabilities to Banking Corporations (Cont.):

B. Bonds of Tamar Bond (Cont.):

To secure the repayment of the bonds, the Partnership pledged its rights in the Tamar project, and mainly its rights in the Tamar lease, in agreements for the sale of gas and condensate, in the joint operating agreement between all of the partners in the Tamar project and the parties' rights in the joint equipment thereunder (including the platform, wells, production system facilities and additional equipment), in the agreement for the grant of usage rights in the Yam Tethys Facilities, in bank accounts, including, *inter alia*, the accounts into which the Partnership's revenues from the sale of gas and condensate from the Tamar project are deposited), in insurance policies (with the exception of D&O liability insurance) for insurance of the assets of the Tamar project, in the Issuer's shares etc. (collectively: the "**Collateral**" or the "**Pledged Assets**").The Collateral for repayment of the bonds is from the Tamar project, without there being any guarantees or collateral external to the Tamar project. However, for as long as certain conditions are not fulfilled and at least until the expiration of 4 years from the date of the issue of the bonds, the bondholders shall have a right of recourse to other assets of the Partnership in respect of 50% of the monies the Partnership has withdrawn and will withdraw from the pledged accounts until such time. The bondholders' right of recourse is limited in amount and also solely limited to assets that have not been pledged by the Partnership by means of a security interest (limited recourse), and without the bondholders being entitled to initiate bankruptcy proceedings against the Partnership.

It is noted that the foregoing 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 interested parties), and that pledges are registered in favor of such royalty holders on the Partnership's rights in the Tamar lease to secure the royalty payment obligation, which will be valid until the repayment of the Bonds. In the framework of the transaction, the Issuer and the Partnership assumed several covenants vis-à-vis the bondholders, including, *inter alia*, the following covenants: restrictions on the creation of additional pledges on the Pledged Assets and the sale thereof; restrictions on the performance of a merger or restructuring as specified in the issue documents, restrictions on amendment or modification of the joint operating agreement, the agreement for use of the facilities or the gas sale agreements, as specified in the issue documents; limitations on expansion of the bond series or the taking of additional debt secured by the Pledged Assets, subject to compliance with several conditions; undertaking to monitor the bonds' rating by the international rating agencies that rated the debt. In addition, restrictions on and conditions were defined for a withdrawal of the surplus cash flow from the Tamar project. The Issuer and the Partnership undertook to indemnify, in certain cases, the representatives that committed to purchase the bonds following the pricing process, if it transpires that representations given by the Issuer and/or the Partnership were breached.

Note 10 – Bonds and Liabilities to Banking Corporations (Cont.):

B. Bonds of Tamar Bond (Cont.):

In addition, events of default were defined, upon the occurrence of which the trustee for the bonds will be entitled (and in the case of a demand of 25% of the bondholders - will be obligated) to accelerate the unpaid balance of the bonds, the principal events of which are: (1) principal or interest payment failure; (2) breach of representations; (3) breach of covenants; (4) events of insolvency of the IEC or of the operator of the Tamar project or of the Partnership, if constituting a significant adverse change (as defined) and subject to certain conditions and qualifications; (5) early termination of the gas supply agreement with the IEC, the joint operating agreement or the agreement for usage of the facilities of the Yam Tethys project with the Partnership, if constituting a significant adverse change, subject to certain conditions and qualifications; (6) an event of default by the IEC under the gas supply agreement with the IEC which constitutes a significant adverse change, subject to certain conditions and qualifications; (7) abandonment or discontinuation of the operation of the Tamar project for a consecutive period of 15 days, which is expected to constitute a significant adverse change; (8) damage to the Tamar project (including physical damage, revocation of a license or transfer of the Partnership's rights therein by the State of Israel) which constitutes a significant adverse change and which is not remedied, in certain cases; (9) revocation of an approval related to the Tamar project by the State of Israel which is expected to constitute a significant adverse change and subject to a remedy period of 30 days; (10) discontinuance of the bonds' rating for a certain period; (11) cross default of another financial liability in an amount exceeding $50 million; (12) if any of the issue documents ceases to be valid, or collateral whose aggregate value exceeds $50 million cease to be valid; and (13) a non-appealable judgment for payment of an amount exceeding $50 million, which is not discharged at the elapse of 90 days. In the case of an event of insolvency (as defined in the indenture), the bonds shall automatically be accelerated (in certain cases, only if not removed within 90 days).

The Partnership has the right to prepay the Loan, in whole or in part, at any time, subject to a prepayment fee. Prepayment resulting from various events specified in the bonds (and *inter alia*, as aforesaid, the sale of rights in Tamar) may be made without a prepayment fee. It is further noted that a certain period before any payment due date of the principal of a bond series, the Issuer is required to accrue money in the pledged account in preparation for the upcoming principal payment date. As of the date of the financial statements, the Partnership complied with the conditions and undertakings under the indenture.

In the report year, the Partnership paid Series 2020 which was partly prepaid in July 2020.

C. Issuance of Bonds of Leviathan Bond:

On August 18, 2020, the issuance of bonds that were offered by Delek Leviathan Bond Ltd. (the "**Issuer**"), an SPC that is wholly held by the Partnership, pursuant to which bonds were issued in the total amount of $2.25 billion, was completed.

The bonds were issued in four series. The bond principal and interest are in dollars. The interest on each one of the bond Series will be paid twice a year, on June 30 and on December 30.

On August 3, 2020, the Issuer received the approval of the Tel Aviv Stock Exchange Ltd. ("**TASE**") for the listing of the bonds on the TACT-Institutional system of TASE ("**TACT-Institutional**").

Note 10 – Bonds and Liabilities to Banking Corporations (Cont.):

C. Issuance of Bonds of Leviathan Bond (Cont.):

The full Issue proceeds were provided by the Issuer as a loan to the Partnership on terms and conditions identical to those of the bonds (back-to-back), and according to a loan agreement that was signed between the Issuer and the Partnership (the "**Loan**").

The Loan money was used by the Partnership for repayment of loans from banking corporations in the sum of approx. $2 billion, for the deposit of a safety cushion in the sum of $100 million in accordance with the terms and conditions of the bonds, for the payment of the Issue costs in the estimated sum of approx. $30 million, and the balance of the proceeds will be used for other uses according to the terms and conditions of the Commissioner's approval as described below (the "**Commissioner's Approval**").

To secure the bonds and the Loan, in the context of the indenture for the bonds and the other documents according to which the bonds will be issued (collectively: the "**Financing Documents**"), the Partnership pledged in favor of the trustee for the bonds (the "**Trustee**"), in a first-ranking fixed charge, its interests in the Leviathan project (45.34%), including its interests in the I/14 Leviathan South and I/15 Leviathan North leases (in this section: the "**Leases**"), the operating approvals of the production system and the export approvals (collectively: the "**Pledge of the Leases**"), the Partnership's rights and the revenues from agreements for the sale of gas and condensate from the Leviathan project (the "**Gas Agreements**"), the Partnership's rights in the joint operating agreement (JOA) for the Leases, the Partnership's share in the project's assets (including the platform, wells, facilities, and systems for production and transmission to 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 thereby in the Issuer, in NBL Jordan Marketing Limited and in Leviathan Transportation System Ltd.

In addition, the Issuer pledged in favor of the Trustee, in a first-ranking floating charge, its rights in all of its existing and future assets and pledged in favor of the Trustee its rights in the loan agreement and in its bank accounts (collectively: 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 bondholders are limited to the Pledged Assets, with no guarantee or additional collateral.

It is noted that the Pledges that the Partnership created in favor of the Trustee are subject, *inter alia*, to the State's royalties according to the Petroleum Law and to the rights of the parties entitled to royalties in respect of the Partnership's revenues from the Leviathan project, including the holder of the controlling interest in the Partnership.

As is standard in financing transactions of this type, in the Financing Documents the Partnership assumed stipulations, restrictions, covenants and there are grounds for acceleration of the bonds and enforcement of the Pledges that include, *inter alia*, the following undertakings:

Note 10 – Bonds and Liabilities to Banking Corporations (Cont.):

C. Issuance of Bonds of Leviathan Bond (Cont.):

The Partnership and the Issuer, as the case may be, undertook, *inter alia*, to fulfill undertakings and conditions that were determined in government licenses and approvals, including in relation to the operator of the project, and including the conditions of the Commissioner's Approval; to fulfill the terms and conditions of the Leases and the JOA (jointly: the "**Leviathan Agreements**"); to protect their rights in the Pledged Assets and to ensure the validity of the Pledges and the rights of the Trustee and the holders according thereto; not to change or discontinue the Issuer's activity, and not to change the incorporation documents of the Issuer; not to create additional pledges on the Pledged Assets (aside from certain exceptions); to fulfill the provisions of the law that apply to their activity; to pay the taxes that apply thereto; to give the Trustee and the holders certain reports, notices and information that were specified; to act to maintain the listing of the bonds on TACT-Institutional; to act for the continued proper operation of the Leviathan project in accordance with the Leviathan Agreements; to take any action possible under the JOA so as to ensure that the operator fulfills its undertakings according to the JOA; to make all of the payments that apply thereto and to bear all of the Trustee's expenses that apply thereto according to the Financing Documents; to purchase and maintain certain insurance policies; to refrain from modifying or amending the Leviathan Agreements or material Gas Agreements, as defined in the Financing Documents ("**Material Gas Agreements**"), or the royalty agreements or engage in a new royalty agreement; to refrain from approval of certain acts in the context of the JOA; etc.

The Issuer undertook not to take additional financial debt, with the exception of the issue of additional bonds or other secured debt *pari passu*, subject to conditions that were specified, including (I) the sum of the secured debt of the Issuer (including the bonds) does not exceed, at any time, $2.5 billion; (ii) certain financial ratios that were specified in the Financing Documents in relation to the issuance of additional debt as aforesaid are maintained.

In addition, the Partnership undertook not to take any additional financial debt which is secured by the Pledged Assets, with the exception of an additional loan that it shall receive from the Issuer on terms and conditions back-to-back to additional debt that the Issuer shall raise subject to the restrictions set forth therefor in the Financing Documents.

The Partnership undertook not to make any merger transaction or change its business in a manner which would likely cause an MAE, or enter dissolution proceedings or other defined restructurings, and not to sell, transfer, pledge or make any other disposition of all or substantially all of its assets, other than permitted transactions, as defined in the Financing Documents, including sale of interests in the Leviathan project subject to mandatory early redemption or a tender offer to the bondholders in certain cases, or permitted restructurings, as defined, including a transfer of the Partnership's interests 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 holders' rights are not prejudiced by such actions and additional terms and conditions as defined.

In addition, provisions were determined regarding early redemption of the bonds, including (1) early redemption at the Issuer's initiative, subject to payment of a Make Whole premium, and (2) mandatory early redemption in certain cases that were defined, including by way of a buyback of the bonds and/or performance of a tender offer to all the bondholders, including upon a sale of all or some of the interests in the Leviathan project.

Note 10 – Bonds and Liabilities to Banking Corporations (Cont.):

C. Issuance of Bonds of Leviathan Bond (Cont.):

The Issuer and the Partnership undertook that if a tax withholding duty shall apply to the payments due under the terms and conditions of the bonds to a foreign resident then, subject to certain exceptions as defined, the Issuer and/or the Partnership, as the case may be, shall pay additional amounts as required for the net amounts to be received by the foreign resident to be equal to the amounts such foreign resident would have received, but for the withholding tax duty. In this context, it is noted that on July 27, 2020 the Partnership received a ruling from the Tax Authority stating, *inter alia*, that the bonds to be traded on the TACT-Institutional system of the TASE are bonds traded on a stock exchange in Israel for purposes of Section 9(15D) of the Income Tax Ordinance (for purposes of exemption from tax on interest paid to a foreign resident on bonds traded on the stock exchange), and Section 97(B2) of the Ordinance (for purposes of exemption from tax for a foreign resident on capital gains in the sale of the bonds traded on the stock exchange), all subject to the terms and conditions specified in the Tax Authority's ruling and the provisions of the Income Tax Ordinance and the regulations promulgated thereunder.

The Financing Documents include a payment waterfall mechanism, whereby the Partnership's entire revenues from the Leviathan project is transferred to an account that is pledged in favor of the Trustee (the "**Revenues Account**"), which is used to make various payments in connection with the project and the bonds, including payment of royalties to the State and to the royalty interests owners; payments to the Trustee; taxes and the levy under the Taxation of Profits from Natural Resources Law, 5771-2011 (in this section: the "**Law**"); capital expenses and operating expenses in connection with the Leviathan project; principal and interest payments; deposits into safety cushions; and balancing payments in connection with tax payments under Section 19 of the Law. The transfer of the amounts remaining in the Revenues Account after the making of the said payments to a non-pledged account of the Partnership is subject to conditions determined, including fulfillment of an NPV Coverage Ratio of at least 1.5[23].

The Financing Documents define Events of Default, upon occurrence of which, subject to certain determined curing periods, exceptions and conditions, the Trustee for the bonds shall be entitled (or required – upon the demand of one quarter of the bondholders) to accelerate the outstanding balance of the bonds and shall be entitled to act to enforce the Pledges.

[23] The NPV Coverage Ratio was defined as the ratio between the net current value of the discounted cash flow expected from proved and probable (2P) reserves, at a cap rate of 10%, from the Partnership's interests in the Leviathan project (the "**Discounted Cash Flow**"), and the debt balance net of cash accrued in the accounts on the measurement date. According to the Financing Documents, the Discounted Cash Flow shall be calculated according to the same assumptions to be used by the Partnership in the resource reports to be released thereby under the provisions of the Securities Law, other than assumptions on the Brent barrel price, which shall be based on the prices of futures traded on ICE, as defined in the Financing Documents.

Note 10 – Bonds and Liabilities to Banking Corporations (Cont.):

C. Issuance of Bonds of Leviathan Bond (Cont.):

The main events are as follows: (1) Default on payment of principal, interest or other payments mandated by the Financing Documents; (2) Breach of representations; (3) Breach of the Covenants or Negative Covenants determined in the Financing Documents; (4) An event or entry into proceedings for insolvency 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 likely to cause an MAE (as defined in the agreement), subject to certain conditions and qualifications; (5) premature termination of any of the Leviathan Agreements or Material Gas Agreements, if likely to cause an MAE, subject to certain conditions and qualifications; (6) If a party to a Material Gas Agreement breaches the agreement with a likely MAE, subject to certain conditions and qualifications; (7) In the event of abandonment or cessation of the Leviathan project operations for more than 15 consecutive days, if likely to cause an MAE; (8) If damage is caused to the Leviathan project (including physical damage, revocation of license or transfer of the Partnership's rights therein by a government authority), with a likely MAE, which was not cured; (9) In the event of denial or revocation of a government approval granted in connection with the Leviathan project, with a likely MAE; (10) If any of the Financing Documents to which the Issuer or the Partnership are a party, or pledges provided under the Financing Documents, with an aggregate value of more than $35 million, cease to be in effect; (11) If a non-appealable judgment is issued against the Issuer for payment of an amount in excess of $35 million which was not paid; (12) If there is a breach of an undertaking in an agreement for the provision of other *pari passu* secured debt of the Issuer worth over $35 million; (13) If an undertaking to perform mandatory early redemption is breached; (14) If the provisions regarding expenditures from the Revenues Account are breached; etc.

The bonds were rated by international rating agencies and an Israeli rating agency.

On August 3, 2020, the Commissioner's Approval was received for the Pledge of the Leases in favor of the Trustee, for the bondholders. The Commissioner's Approval provides that, *inter alia,* the pledge is given to secure payment of the bonds whose proceeds are intended for the granting of credit to the Partnership in the sum of up to $2.5 billion in total, for payment of loans in the sum of approx. $2 billion (which were mainly used for investments in the development of the Leviathan project), the deposit of a safety cushion in the sum of $100 million, investments in the Leviathan project only and the financing of the construction of a pipeline for the export of gas from the Leviathan and Tamar reservoirs. As of the date of the financial statements, the Partnership fulfilled its undertakings as aforesaid.

D. Liabilities to banking corporations paid in the context of the Leviathan Bond issue:

Short-term liabilities to banking corporations as of December 31, 2019 in the sum of approx. $296.9 million and long-term liabilities to banking corporations as of the same date in the sum of approx. $1,630.4 million (on the date of payment in the sum total of approx. $1.7 billion), mainly in connection with the financing of the Leviathan project were paid in full out of the proceeds of the Leviathan Bond bonds, issued in August 2020 as described in Paragraph C above.

Note 10 – Bonds and Liabilities to Banking Corporations (Cont.):

E. Series A Bonds:

In December 2016, the Partnership issued to the public ILS 1,528,533,000 par value of Series A Bonds, which were listed on the TASE (in this section: the "**Bonds**"). The Bonds were issued in consideration for their par value, and they bear fixed annual interest of 4.50%. The Bonds and the Partnership's undertakings under the indenture for the Bonds (the "**Indenture**") are not secured by any collateral.

The consideration received net of issue costs totaled approx. $392.6 million. With regard to Bond repurchase plans, see Section F below.

The principal of the Bonds will be paid in a single payment on December 31, 2021, together with the last interest payment therefor. The interest on the unpaid balance of the principal of the Bonds will be paid in semi-annual payments, on June 30 and December 31 of each of the years 2017 to 2021. The principal and the interest of the Bonds are linked to the US dollar rate. The basic dollar rate is ILS 3.819.

The Partnership has a right to perform at any time, at its own initiative, full or partial pre-payment of the Bonds, in accordance with the conditions determined in the Indenture. The Indenture includes provisions with respect to the acceleration of the Bonds, in the event of a decrease in the full indirect holding rate of the Partnership in the Tamar lease, to under 10% (out of 100% of the holdings of all of the partners in the Tamar project) and/or a decrease in the full indirect holding rate of the Partnership in the Leviathan leases to under 18% (out of 100% of the holdings of all of the partners in the Leviathan project), in accordance with the conditions and the definitions specified in the Indenture. It is noted that on the date of sale of the Partnership's rights in the Tamar Project, the Partnership will be required to pay 50% of the Bond principal.

The Indenture includes the Partnership's undertaking for the payment of the Bonds, according to the conditions thereof, and additional standard undertakings in indentures, including an undertaking to act for the rating of the Bonds until full repayment thereof, by at least one rating agency and an undertaking not to create a floating charge on all of its assets in favor of any third party, to secure any debt or undertaking, without receipt of advance approval from the holders of the Bonds. The aforesaid does not limit corporations controlled by the Partnership from creating such a floating charge on all of their assets, and the Partnership may pledge any and/or all of its assets in various fixed charges including the creation of floating charges on one or more specific assets of the Partnership, and it may further take non-recourse or limited recourse loans without any limitation and without the need to obtain any consent from the Series A Bond holders and/or the trustee, as the case may be.

The Indenture specifies grounds for the acceleration of the Bonds in specific cases, as is standard in indentures, which mainly include (a) in the event that the financial equity of the Partnership (as defined in the Indenture) drops below $400 million (the "**Minimum Financial Equity**") during two consecutive quarters; (b) in the event the Partnership's financial equity to debt ratio on a standalone basis (as defined in the Indenture) drops below 300% (times 3) during two consecutive quarters; and (c) in the event that the Partnership performed a distribution as defined in the Indenture or announced an intention of performing a distribution, following which the Partnership's financial equity to debt ratio on a standalone basis will drop below 450% (times 4.5); and (d) in case the opinion or review report of the accountant for the quarterly or annual financial statements of the Partnership draw attention to significant doubts as to the Partnership's continued activity as a going concern.

Note 10 – Bonds and Liabilities to Banking Corporations (Cont.):

E. Series A Bonds (Cont.):

In addition, the Indenture includes a mechanism for adjusting the annual interest rate to be borne by the unpaid balance of the Bond principal (the "**Interest Rate of the Bonds**"), whereby:

In the event that the rating of the Bonds is updated to be lower than their basic rating which is A1 (on the rating scale of Midroog), the Interest Rate of the Bonds will increase by 0.25% for every notch downgrade, up to a maximum interest equal to the basic interest rate of the Bonds plus 1.25% (the "**Maximum Interest**"). Notwithstanding the aforesaid, the Interest Rate of the Bonds shall not increase due to a single notch downgrade below the basic rating (it is clarified that upon a two-notch downgrade below the basic rating, the Interest Rate of the Bonds will rise by 0.50%), as of the date of the financial statements, the rating of the Bonds was downgraded by one notch and therefore the Interest Rate of the Bonds has not changed.

In the event that the Partnership's financial equity drops below the Minimum Financial Equity, or in the event that the Partnership's financial equity to debt ratio on a standalone basis drops below 350% (times 3.5), the Interest Rate of the Bonds will increase by a rate of 0.5% above the interest rate prior to the change, but in no event higher than the Maximum Interest.

As of the date of the financial statements, the Partnership is in compliance with the financial covenants set forth in the Indenture.

F. Plans for buyback of Series A Bonds and Bonds of Tamar Bond

1. On July 26, 2020, the board of directors of the General Partner approved a buyback plan for series A bonds and bonds of Delek and Avner Tamar Bond is the sum total of up to $50 million. It is noted that the bond buyback plan is consistent with the provisions of the Partnership's indenture, and approval of the plan does not constitute a breach of the Partnership's undertakings to the bondholders. It is clarified that the board of directors has determined that the said bond buyback plan will be performed subject to completion of the refinancing of loans provided to the Partnership, *inter alia* for the purpose of financing of the Leviathan project (completed on August 18, 2020), and that the said decision does not obligate the Partnership to buy back any or all of the bonds, and that the Partnership's management is entitled to decide not to buy back bonds at all and/or to buy less bonds than authorized. The Partnership performed buybacks in accordance with said buyback plan in the amount of ILS 11,413,393 par value of series A bonds in consideration for approx. $3 million.
2. On November 17, 2020, the Board of Directors of the Partnership's General Partner approved a buyback plan for Series A bonds at a total estimated cost of up to $30 million. The purchases will be made from time to time in the period between November 19, 2020 and December 31, 2020, in transactions on or off TASE. It is noted that this plan replaced the buyback plan stated in Section 1. Pursuant to the said buyback plan, the Partnership performed buybacks in the amount of ILS 7,450,000 par value of Series A bonds in consideration for approx. $2 million.

The total profit that derived from the buyback of the two plans as aforesaid totaled approx. $66 thousand and was carried to profit and loss in the financing item.

Notes to the Financial Statements as of December 31, 2020 (Dollars in thousands)

Note 11 - Other Short-Term and Long-Term Liabilities:

A. Other Long-Term Liabilities:

	31.12.2020	31.12.2019
Oil and gas asset retirement obligation (see Note 2K2 and Section B)	133,283	172,289
Taxes payable on deferred capital gain from sale of rights in Tamar and Dalit Leases	19,848	18,463
Provision for balancing payments for previous years (see Note 20A7)	13,115	12,300
Participation unit-based payment (see Note 13H)	-	17
Total	166,246	203,069

B. Transactions in oil and gas asset retirement obligation:

	31.12.2020	31.12.2019
Balance as of January 1	172,289	112,195
Additions	6,433	27,519
Effect of the passing of time	2,189	4,637
Effect of update of the cap rate	14,584	27,938
	195,495	172,289
Net of other short-term liabilities (See Note 7C5D)	(62,212)	-
Total	133,283	172,289

The cap rates used for the measurement of the oil and gas asset retirement obligation as of December 31, 2020 are 1.1%-3.3% (December 31, 2019: 2.8%-4.08%).

Note 12 – Contingent Liabilities, Engagements and Pledges:

A. Under the Partnership agreement, the General Partner will be entitled to 0.01% of the revenues and shall bear 0.01% of the expenses and losses of the Partnership.

The General Partner will be entitled to management fees as specified below:

1. Ongoing management fees in an amount in ILS equal to U.S. $40,000 per month; and in addition,
2. Management fees at a rate of 7.5% of half of the expenses of the limited partnership for oil exploration activity on a quarterly basis and no less than a comprehensive amount of U.S. $120,000 per quarter.

   The General Partner will be entitled to reimbursement of certain direct expenses involved in the management of the Partnership, as specified in the agreement. According to the Partnership agreement, the limited partner (the Trustee) will be entitled to 99.99% of the revenues and will bear 99.99% of the expenses and losses of the Partnership.

B. Engagements for the payment of royalties:

1. Following the closing of the merger between the Partnership and Avner Oil Exploration Limited Partnership of May 2017, all of the liabilities related to royalties apply with respect to all of the (current and future) gas and petroleum assets of the Partnership, however, the rate of royalties in respect thereof, was reduced by 50% compared with the rate of royalties prior to the Merger (since the Partnership and Avner Partnership held equal parts in those petroleum assets, excluding the Ashkelon and Noa leases, in which the Partnership held 25.5% and Avner Partnership 23%, and in their respect the rate of royalties was reduced by 47.42% with respect to the royalties paid by the Partnership to Delek Group and Delek Energy, as defined below, and by 52.58% with respect to the royalties paid by Avner Partnership before the Merger, as specified below).
2. In the context of a right transfer agreement signed in 1993, the Partnership undertook to pay Delek Energy and Delek Group (the "**Royalty Interest Owners**") royalties at the rates specified below from the entire share of the Partnership in petroleum and/or gas and/or other valuable substances that shall be produced and utilized from the petroleum assets, in which the Partnership has or shall have any interest (prior to deduction of any kind of royalties, but after deduction of the petroleum used for the production itself).

   The royalty rates are as follows: until the date of the Partnership's investment recovery, royalties shall be paid at a rate of 2.5% of onshore petroleum assets and 1.5% of offshore petroleum assets, and after the investment recovery date – 7.5% of onshore petroleum assets and 6.5% of offshore petroleum assets.

   According to the agreement between the Partnership and the Royalty Interest Owners, an expert deciding arbitrator was appointed in 2002 in order to determine the right meaning of certain definitions and terms concerning the royalties that the Partnership is liable to pay as aforesaid, mainly with respect to the definition of "investment recovery date". In the appointed arbitrator's decision, he expressed his opinion and determined, *inter alia*, the manner of calculating and various elements that should and shouldn't be taken into account for determining the "investment recovery date". With respect to the dispute regarding the investment recovery date in the Tamar Project between the Partnership and the Royalty Interest Owners, see Notes 15B and 12K6 below.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

B. Engagements for the payment of royalties (Cont.):

2. (Cont.):

In June 2018, the rights to receive royalties in respect of the Tamar and Dalit Leases were transferred from Delek Energy to Delek Royalties (2012) Ltd. ("**Delek Royalties**").

During December 2019, the rights to receive royalties in respect of the Tamar and Dalit Leases were transferred from Delek Group to Study Funds for Teachers and Kindergarten Teachers Managing Company Ltd. and to Study Funds for High School Teachers, Seminary Teachers and Supervisors Managing Company Ltd.

In October 2020, the rights to receive royalties in respect of the Leviathan South and Leviathan North leases were transferred from Delek Group and Delek Energy to Delek Leviathan Overriding Royalty Ltd. which is held by Delek Energy.

3. In addition, the Partnership will pay, by virtue of the Avner Partnership Agreement, royalties at a rate of 3% of all of the share of the limited partnership in petroleum and/or gas and/or other valuable substances which will be produced and utilized out of the petroleum assets in which the limited partnership has a present or will have a future interest (before deduction of royalties of any type, but after the reduction of the oil to be used for the purpose of the production itself).

   In an agreement signed on September 2, 1991, it was determined that the said right of the royalties is held by the General Partner in trust, and it is paid to those entitled to royalties under the Limited Partnership Agreement. Out of the total royalties as aforesaid, Cohen Oil and Gas Development Ltd. (an affiliate until the date it was sold by Delek Group to a third party) will receive 1.375% in the Noa and Ashkelon lease and 1.4375% of any future petroleum right of the Partnership. The remaining entitlement to royalties is paid to third parties.

4. On January 21, 2007, the Partnership and Avner Partnership entered an agreement with Dor Chemicals for the purchase of 2.5% (out of 100%) of rights in the Tamar and Dalit Leases (the "**Sold Rights**"). In consideration for the Sold Rights, Dor Chemicals is entitled to an overriding royalty at a rate of 6% of the quantity of gas and/or other valuable substances that will be produced from the Sold Rights, on the basis of a calculation formula that was determined.

5. It is noted that in view of the transaction of the sale of part of the rights in Tamar and Dalit Leases to Tamar Petroleum, a proportional share of the overriding royalties (9.25% out of 31.25%) is paid by Tamar Petroleum.

6. Royalty to the State:

   The Petroleum Law, 5712-1952 (the "**Petroleum Law**") and the Petroleum Regulations, 5713-1953, prescribe that a lease holder, within the meaning of such term in the Petroleum Law, owes the State Treasury royalty at the rate of one-eighth of the petroleum quantity produced and utilized from the area of the lease, according to the market value at the wellhead, excluding the quantity of petroleum used by the lease holder for operating the area of the lease, but royalties will in no event fall below the minimum royalties prescribed by the law (see Note 15 below).

   In accordance with the Petroleum Law, the State is entitled to royalties from the produced quantity of gas. The Commissioner notified the operator of the joint ventures that the State decided not to receive the royalties, to which it is entitled from the gas discoveries, in kind, but to receive the market value of the royalties at the wellhead, in dollars.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

B. Engagements for the payment of royalties (Cont.):

6. (Cont.):

   In May 2020, the Ministry of Energy released directives for the manner of calculation of the royalty value at the wellhead in connection with offshore petroleum rights, pursuant to Section 32 of the Petroleum Law and specific directives for the Tamar Lease. For details regarding the directives, see Section L4 below.

Notes to the Financial Statements for December 31, 2019 (Dollars in thousands)

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

C. Engagements for the supply of natural gas to the domestic market and for export:

1. **Following is a table presenting the summary of agreements for the sale of natural gas of the Tamar partners (the data described refers to 100% of the rights in the petroleum asset):**

	Supply commencement year	Base period of the agreement[24]	Is it possible to extend[25]	Balance of total maximum contract quantity for supply (100%) (BCM)[26]	Quantity supplied until December 31, 2020 (100%) (BCM)	Main basis of linkage to the gas price
IEC[27]	2013	15 years	The IEC has the option to extend the agreement period by two more years, insofar as the full total contract gas quantity was not supplied in the base period.	Approx. 54.4	Approx. 32.6	The linkage basis determined in the supply agreement is the U.S. Consumer Price Index (U.S. CPI).
Dalia Energies	2015	17 years	Each of the parties may extend the agreement period by two more years, insofar as the total contract gas quantity was not supplied in the base period.	Approx. 17	Approx. 6.3	The Electricity Production Tariff which includes a floor price.[28]

[24] In most of the agreements, the gas supply period, which commences from the date of the piping with respect to the relevant agreement, will be according to the table presented above, or until the purchaser will consume the maximum contract quantity set forth in the agreement, whichever is earlier.
[25] In part of the supply agreements in which the customers have options to extend the agreement, the agreement defines specific conditions to the exercise thereof.
[26] This quantity is the balance of the maximum quantity for supply of gas determined in the agreements throughout the term of the agreements. The minimum quantity which the customers undertook to purchase is the balance of the maximum quantity for supply of gas determined in the agreements throughout the term of the agreements. The minimum quantity which the customers undertook to purchase is lower than such quantity. The aforesaid quantity includes quantities that were actually amortized according to the reduction option.
[27] For details on various terms and conditions determined in the context of a settlement agreement signed with the IEC on January 30, 2021, see Paragraph D below.
[28] The linkage to the Electricity Production Tariff in the supply contracts for the electricity producers is according to the terms and conditions of the alternative set forth in the Gas Framework which includes a floor price. For details see Section 12K1 below.

Notes to the Financial Statements for December 31, 2019 (Dollars in thousands)

	Supply commencement year	Base period of the agreement[24]	Is it possible to extend[25]	Balance of total maximum contract quantity for supply (100%) (BCM) [26]	Quantity supplied until December 31, 2020 (100%) (BCM)	Main basis of linkage to the gas price
Other independent power producers	2013-2020	15-18 years other than one agreement for a period of eight years and two agreements for short periods.	In most of the agreements, both parties are afforded the possibility to extend them, for a period of between one to three more years, insofar as the total contract gas quantity was not consumed in the base period.	Approx. 20.2	Approx. 19.2	Most of the agreements include a formula of linkage to the Electricity Production Tariff, which includes a floor price.
Industrial customers and natural gas marketing companies	2013-2020	3-7 years	In part of the agreements both parties are afforded the possibility to extend by an additional period, insofar as the total contract gas quantity was not consumed in the base period.	Approx. 1.6	Approx. 6.9	Most of the agreements determine a fixed price without linkage.
APC - JBC export agreements	2017-2018	13-15 years	Both parties are afforded the possibility to extend by two more years, insofar as the contract gas quantity was not consumed in the base period.	Approx. 2.3	Approx. 0.65	A linkage formula which is based on the Brent prices and includes a “floor price”.
Dolphinus export agreement	2020	Approx. 15 years	In the event that the purchaser does not purchase the total contract quantity in the base period, the supply period will be extended by two more years.	Approx. 25	Approx. 0.25	A linkage formula which is based on the Brent prices and includes a “floor price”.
Total				**Approx. 120.5**	**Approx. 65.9**	

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

C. Engagements for the supply of natural gas (Cont.):

1. Tamar Project (Cont.):

a. Further details with respect to all of the agreements for natural gas sale in the Tamar Project:

1) Most of the gas supply agreements determine, *inter alia*, an undertaking of the buyers, insofar as the gas supply under the agreement is on a firm basis, to “Take-or-Pay” for a minimal annual quantity of natural gas at a scope and according to the mechanism specified in the supply agreement (the "**Minimum Quantity**"). If such buyers do not purchase the Minimum Quantity in any year, they shall be liable to pay the sellers for the difference between the Minimum Quantity defined and the quantity actually bought by the buyers. It is noted that in most of the agreements which include an obligation for such Minimum Quantity, provisions and mechanisms are determined which allow the buyers, after paying for unused gas pursuant to the activation of the mechanism of Minimum Quantity billable, to receive gas for no additional payment up to the balance of the gas quantity not used in previous years and for which they paid the sellers under their Minimum Quantity billable commitment as aforesaid (Make Up).

The Supply agreements further specify a balance accumulation mechanism for surplus quantities used by the buyers in a given year and the utilization thereof to reduce the buyers' obligation to buy the Minimum Quantity as aforesaid for several years thereafter ("**Carry Forward**").

2) Following the decisions of the Competition Commissioner regarding the grant of restrictive trade practice exemption in respect of agreements wherein the basic supply period is longer than 7 years, except for the agreement with the IEC (the “**Long-Term Agreements**”), in some of the agreements signed with customers, each of the buyers was granted the option to reduce the Minimum Quantity to approx. 50% of the average annual amount consumed thereby in the three years preceding the notice of exercise of the option, subject to adjustments as specified in the supply agreement (in this section: the "**Option**"). Upon the reduction of the Minimum Quantity, the other amounts specified in the supply agreement will be reduced accordingly.

In this context it is noted that during 2019-2020, the Tamar partners signed amendments to agreements with several independent power producers (IPPs), including Dalia Energies, in which such IPPs undertook to purchase from the Tamar Project, the natural gas quantities that shall be consumed in their facilities in the period commencing from the date of gas piping from the Leviathan reservoir until such time as such IPPs exercise the reduction Option (in this section: the “**Period**”), if exercised. In addition, in the context of such amendments, the parties agreed that for the purpose of calculation of the average quantity consumed by such IPPs under the said agreements in the three years preceding the notice of exercise of the Option in relation to the Period, the calculation shall be made based on the Minimum Quantity (in accordance with the mechanism set forth in the amendments to the agreements as aforesaid), and not based on the quantity actually consumed thereby. All of the amendments to the agreements have taken effect, including the amendment to the agreement with Dalia Energies.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

C. Engagements for the supply of natural gas (Cont.):

1. Tamar Project (Cont.):

a. Further details with respect to all of the agreements for natural gas sale in the Tamar Project (Cont.):

3) It is noted that in 2020, several customers gave notices of exercise of said reduction Option, including various IPPs. The aforesaid notices are expected to take effect on various dates in 2021-2022.

4) In accordance with the terms and conditions of the Gas Framework, in the agreements for the supply of natural gas signed commencing from August 16, 2015 for a period exceeding 8 years, the consumer received a unilateral right to shorten the term of the agreement. Such right was also granted in agreements signed up to December 13, 2020 for a period exceeding 8 years. It is noted that in 2020, two customers gave a notice of exercise of the early termination option and they expired on March 1, 2021.

5) The supply agreements stipulate further provisions, *inter alia*, on the following issues: the right to terminate the agreement in the event of a breach of a material undertaking, the right of the Tamar partners to supply gas to the said buyers from other natural gas sources, compensation mechanisms in the case of a delay in the supply of gas from the Tamar Project or in the event of failure to supply the quantities specified 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 the parties' liability upon the occurrence of a *force majeure* event (as defined in the agreements), mechanisms for resolving disputes and disagreements between the parties, and with respect to the relations among the sellers themselves in matters related to the supply of gas to such buyers.

6) Engagement in a condensate supply agreement with Paz Ashdod Oil Refineries Ltd. ("Paz Refineries"):

The Tamar partners supply condensate to Paz Refineries, Ashdod since 2013, in a designated pipeline, in a quantity which is immaterial pursuant to an agreement (as amended), which is expected to expire in December 2030. The condensate price is determined according to the Brent prices net of a margin, as set forth in the supply agreement. All of the sales of condensate by the Tamar partners is in the context of the aforesaid engagement.

7) Agreement for natural gas supply to Delek, the Israel Fuel Corporation Ltd. ("Delek Israel"):

In December 2013, an agreement for the supply of natural gas was signed with Delek Israel, a company wholly controlled by Delek Group, the controlling shareholder of the General Partner.
According to the supply agreement, the sellers undertook to supply natural gas to the buyer in a total quantity of up to approx. 0.46 BCM (the "**TCQ**") according to the terms specified in the supply agreement.

The term of the supply agreement began in H1/2015 and will expire at the end of approx. 7 years or on the date on which the buyer will consume the TCQ, whichever is earlier. As of the date of approval of the financial statements, Delek Group holds 30% of Delek Israel.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

C. Engagements for the supply of natural gas (Cont.):

1. Tamar Project (Cont.):

a. Further details with respect to all of the agreements for natural gas sale in the Tamar Project (Cont.):

8) Agreement for natural gas supply to I.P.P. Delek Sorek Ltd. ("Delek Sorek"):

May 2015 saw the amendment of the natural gas supply agreement signed in March 2014 with Delek Sorek, a company (indirectly) controlled by Delek Group, the controlling shareholder of the General Partner.

The sellers undertook to supply the buyer with natural gas in a total quantity of up to approx. 3.3 BCM (the "**TCQ**") according to the terms specified in the supply agreement.

The term of the supply agreement is approx. 15 years, with an option to extend by two additional years, or on the date on which the buyer will consume the TCQ, whichever is earlier. On November 11, 2019 Delek Sorek gave notice to the Tamar partners regarding the termination of the agreement, beginning from February 9, 2020. As of the date of approval of the financial statements, the transaction of the sale of the holdings of Delek Israel in Delek Sorek was closed. Therefore, Delek Sorek is not a related party.

b. Further details regarding the gas supply agreement between the Tamar partners and the IEC:

1) The gas supply agreement between the Tamar partners and the IEC was signed in March 2012 and amended in July 2012, May 2015 and September 2016 (in this section: the "**Agreement**"), *inter alia*, with respect to the exercise of options for increase of the gas quantities to be consumed by the IEC.

2) The total contract quantity determined in the IEC-Tamar agreement (as amended) is approx. 87 BCM, and the Minimum Quantity billable, from January 1, 2019 until the expiration of the term of the Agreement, will be approx. 3 BCM per year. The Agreement contains provisions regarding the calculation and adjustment of the Minimum Quantity billable including under circumstances of *force majeure* or failure to supply by the sellers. The Agreement further specifies a balance accumulation mechanism for surplus quantities used by the buyers in a given year and the utilization thereof to reduce the buyers' obligation to buy such Minimum Quantity as for several years thereafter ("**Carry Forward**"). Accordingly, the IEC may reduce the purchased quantity while using such mechanism up to 1.75 BCM a year (such that the maximum usable quantity in a calendar year is 1.25 BCM).

The quantity accumulated to the credit of the IEC in the context of the Carry Forward mechanism as of December 31, 2020 is approx. 1.85 BCM (for 100% of the reservoir).

3) The gas price is determined according to a formula which includes a base price and a linkage mechanism which is based on the U.S. CPI in respect of part of the quantities, and subject to specific adjustments.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

C. Engagements for the supply of natural gas (Cont.):

1. Tamar Project (Cont.):

b. Further details regarding the gas supply agreement between the Tamar partners and the IEC (Cont.):

4) The Agreement stipulates two dates on which each party may request the adjustment of the price (according to a mechanism stipulated in the Agreement), if such party believes that the contract price is no longer suitable for a long-term contract with an anchor buyer for the consumption of natural gas for use in the Israeli market: upon the lapse of 8 years and 11 years from the commercial operation date (as defined in the Agreement commencing on July 1, 2013) of the Tamar Project (i.e.: July 1, 2021 and July 1, 2024), whichever is earlier. On the first adjustment date (July 1, 2021) (the "**First Adjustment Date**") the adjustment applied to the price will be at a range of up to 25% (addition or reduction), and on the second adjustment date (July 1, 2024), the adjustment applied to the price will be at a range of up to 10% (addition or reduction) of the price at that time. If the Tamar partners and the IEC fail to agree on the rate of the price adjustment, each one of the parties may refer the matter to an arbitration proceeding. In the context of the discounted cash flow which is included in the Tamar resource report the Partnership assumed that on the First Adjustment Date the price of the gas will be reduced by 25%, and that on the second adjustment date the price of the gas will be reduced by 10%. If the Tamar partners and the IEC fail to agree on the rate of the price adjustment, each one of the parties may refer the matter to an arbitration proceeding.

5) In the event that one of the parties to the Agreement fails to timely make a payment that is required thereof according to the Agreement, the delinquent amount shall accrue interest at an annual rate equal to LIBOR interest plus 5%, from the payment due date according to the Agreement until the date of actual payment. If the delinquency lasts 7 days or more, the party entitled to the payment may, by giving prior written notice of 14 days, suspend provision or receipt of the gas, as the case may be. If the delinquency lasts 120 days from the relevant payment due date, the party entitled to the payment may, by giving prior written notice of 14 days, terminate the Agreement. Exercising the right to terminate the Agreement shall not constitute a waiver of other remedies that are available to such party.

6) The IEC-Tamar agreement stipulates, *inter alia*, provisions whereby the IEC or the Tamar partners will be entitled to terminate the Agreement, in the event that the other party performs an insolvency act (as defined in the Agreement) which is likely to have a material adverse effect on the performance of its undertakings under the Agreement, by providing an advance written notice of at least 120 days. If, due to an event of *force majeure*, the Tamar partners or the IEC are unable to perform any material undertaking that is required according to the Agreement, and their inability to perform such undertaking lasts for a period of three consecutive years, the other party may terminate the Agreement by giving prior written notice of at least 90 days.

The IEC and the Tamar partners agreed not to exercise any right to terminate the Agreement which they may have according to any law, other than with respect to significant or continuous breaches of material provisions of the Agreement and only after provision of a 120-day period to the breaching party (unless a shorter period is stipulated in the Agreement) to remedy the breach.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

C. Engagements for the supply of natural gas (Cont.):

1. Tamar Project (Cont.):

b. Further details regarding the gas supply agreement between the Tamar partners and the IEC (Cont.):

7) According to the Agreement, if the Tamar partners fail to supply the gas quantities nominated by the IEC according to the provisions of the Agreement, and the quantity not supplied exceeds the deviation rates permitted by the Agreement, the Tamar partners shall compensate the IEC by way of supplying gas in the subsequent month in the quantity not supplied, for a reduced price. Furthermore, the Agreement specifies special breaches for which compensation at higher rates will be paid. The Agreement stipulates limits to the liability of each of the parties for a breach of some of the provisions of the Agreement at the rates specified in the Agreement both on an annual basis and throughout the term of the Agreement. The IEC is not liable vis-à-vis the Tamar partners and the Tamar partners are not liable vis-à-vis the IEC for indirect, consequential or punitive losses or damage. The Tamar partners will be liable, severally and not jointly, for such breaches of the Agreement.

8) The assignment of the obligations and rights of the IEC under the Agreement, is contingent upon the transferee being technically and financially able to meet its obligations under the Agreement and that the transferee will also be transferred the same proportional share of the power stations of the IEC (i.e., if a proportional part of the rights and obligations are transferred to any transferee, it will also get a proportional part of the power stations of the IEC).

For details on a settlement agreement between the Tamar partners and the IEC see Section D below.

c. Engagements for the export of natural gas:

On February 19, 2018, an agreement was signed between the Partnership and Noble and Dolphinus for the export of natural gas from the Tamar Project to Egypt (in this section: the "**Original Tamar-Dolphinus Agreement**" and the "**Buyer**", respectively), which superseded a previous agreement that was signed between the said parties on March 17, 2015.

On September 26, 2019, the signing of an 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 in connection with the allocation of the available capacity in the transmission system from Israel to Egypt between the Leviathan partners and the Tamar partners.

It is noted that concurrently with the signing of the Amendment to the Tamar-Dolphinus Agreement, an amendment was signed to the agreement between the Leviathan partners and Dolphinus ("**Amendment to the Leviathan-Dolphinus Agreement**"). For details, see Section C2D. Upon fulfillment of all the conditions precedent to the Amendment to the Tamar-Dolphinus Agreement, on December 24, 2019 the Partnership updated that the Amendment to the Tamar-Dolphinus Agreement had taken effect.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

C. Engagements for the supply of natural gas (Cont.):

1. Tamar Project (Cont.):

c. Engagements for the export of natural gas (Cont.):

In July 2020, after a marine discharge permit was received from the Natural Gas Authority and the running-in of the compressor installed at the EMG station in Ashkelon was completed, the gas flow from the Tamar reservoir to Egypt began.

In July 2020, Dolphinus endorsed the export to Egypt agreements to Blue Ocean Energy, an affiliate of Dolphinus.

It is noted that in a tax decision in connection with the Amendment to the Tamar-Dolphinus Agreement that was issued to the Tamar partners by the Tax Authority on December 9, 2019, and according to the terms and conditions of the Gas Framework, the Tamar partners undertook to offer new customers (as defined in the Gas Framework) with which they engaged or will engage from February 19, 2018 until 3 full years after the date of the signing of the tax decision, i.e. December 9, 2022, to enter into agreements for the sale of natural gas at a price that will be 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 specified 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 and conditions of the Amendment to the Tamar-Dolphinus Agreement:

1) The supply of the gas to the Buyer according to the Amendment to the Tamar-Dolphinus Agreement is on a firm basis (compared with supply according to the Original Tamar-Dolphinus Agreement which was on an interruptible basis with an option for the Tamar partners to transition to a firm basis).

2) The total contract gas quantity which the Tamar partners undertook to supply to the Buyer according to the Amendment to the Tamar-Dolphinus Agreement is approx. 25.3 BCM (the "**TCQ (on a Firm Basis) in the Tamar Agreement**") (compared with approx. 32 BCM according to the Original Tamar-Dolphinus Agreement which was, as aforesaid, on an interruptible basis).

3) The supply according to the Amendment to the Tamar-Dolphinus Agreement will begin on June 30, 2020, and will be until December 31, 2034 or until the supply of the full total contract quantity, whichever is earlier (the "**Date of Conclusion of the Tamar-Dolphinus Agreement**"). In a case where the Buyer does not purchase the total contract quantity by December 31, 2034, each party will be entitled to extend the supply period by up to two additional years.

4) According to the Amendment to the Tamar-Dolphinus Agreement, the Tamar partners undertook to supply the Buyer with annual gas quantities, as follows: (i) in the period commencing June 30, 2020 and ending June 30, 2022, approx. 1 BCM per year; and (ii) in the period commencing July 1, 2022 and ending on the date of conclusion of the Amendment to the Tamar-Dolphinus Agreement, approx. 2 BCM per year, by upgrading the systems in the EMG station in Ashkelon, including installing an additional compressor and increasing the transmission capacity in the INGL system, as specified in Section M.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

C. Engagements for the supply of natural gas (Cont.):

1. Tamar Project (Cont.):

c. Engagements for the export of natural gas (Cont.):

5) The Buyer undertook to take or pay for quarterly and annual quantities, in accordance with the mechanisms set forth in the Amendment to the Tamar-Dolphinus Agreement, which, *inter alia*, allow the Buyer to reduce the TOP quantity in a year in which the average daily Brent price (as defined in the agreement) shall have fallen below $50 per barrel, such that it will be 50% of the annual contract quantity. It is noted that insofar as the contract quantity is reduced in a case of non-consent to update the gas price, as stated in Paragraph 6 below, Dolphinus's right to reduce the Take-or-Pay quantity as aforesaid will be null and void. In the report year, Dolphinus consumed approx. 0.3 BCM (100%) from the Tamar-Dolphinus Agreement. It is noted that further to the sharp decline in energy prices in H1/2020, the average daily Brent price as defined in the agreement dropped below $50 per barrel. (see Note 12K8 regarding a claim and a motion for class certification thereof which was filed against the Partnership in relation to the aforesaid clause).

6) The price of the gas that shall be supplied to the Buyer will be determined according to a formula that is based on the Brent oil barrel price, and includes a "floor price". The Amendment to the Tamar-Dolphinus Agreement includes a mechanism for updating the price by up to 10% (up or down) after the fifth year and after the tenth year of the Amendment to the Tamar-Dolphinus Agreement (in this section: the "**First Adjustment Date**" and the "**Second Adjustment Date**", respectively), upon fulfillment of certain conditions set forth in the agreement. In the event that the parties fail to reach an agreement on the price update as described above, the Buyer will have the right to reduce the contract quantity by up to 50% on the First Adjustment Date and by up to 30% on the Second Adjustment Date. It is noted that the agreement includes an incentive mechanism that is quantity-contingent and subject to the oil barrel price.

7) The Amendment to the Tamar-Dolphinus Agreement includes accepted provisions relating to conclusion of the agreement, as well as a provision for conclusion of the agreement in the case of conclusion of the Amendment to the Leviathan-Dolphinus Agreement as a result of a breach thereof, and the Tamar partners' not agreeing to supply also the quantities stated in the Amendment to the Leviathan-Dolphinus Agreement, as specified in the agreement, and also includes compensation mechanisms in such a case. The Amendment to the Leviathan-Dolphinus Agreement also includes similar provisions.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

C. Engagements for the supply of natural gas (Cont.):

1. Tamar Project (Cont.):

d. Settlement agreement between the Tamar partners and the Leviathan partners:

On October 4, 2020, some of the Tamar partners notified the Partnership and Noble that they had signed an agreement constituting, so they claimed, a supplement to the IEC-Tamar agreement (the "**Agreement in Dispute**"). On January 30, 2021 (after the date of the Statement of Financial Position), the Tamar partners and the IEC signed a settlement agreement with regards to the disagreements which had arisen with respect to the Agreement in Dispute (in this section: the "**Tamar Settlement Agreement**"). The Tamar Settlement Agreement provides, *inter alia*, that: (1) the Agreement in Dispute shall be terminated, and shall be null and void; (2) until June 30, 2021, the IEC will be able to buy from the Tamar reservoir a quantity of 1.25 BCM, for a price lower than the IEC-Tamar agreement price, varying according to the purchased quantity, out of which approx. 0.81 BCM which was supplied in 2020, and, under certain conditions, additional quantities insofar as such quantities are not supplied by the Leviathan partners under the IEC-Leviathan agreement. The gas quantities that were and shall be supplied at such reduced price, shall not be taken into account for calculation of the Take-or-Pay and the Carry Forward in 2020 and 2021 from the IEC-Tamar agreement as specified above.

The Tamar Settlement Agreement further determines that the maximum daily contract quantity which the Tamar partners will be required to supply to the IEC under the IEC-Tamar agreement in H1/2021 shall be limited to 500,000 MMBTU (compared with 655,000 MMBTU).

In the settlement agreement, the parties waived their claims in connection with the disputes.

The Tamar Settlement Agreement is subject to the fulfillment of conditions precedent and regulatory approvals, including the approval of the Competition Authority and the approval of the Competition Court for an agreed order under Section 50B of the Economic Competition Law, 5748-1988, whereby the Competition Commissioner shall not continue her processing and shall take no enforcement measures against Noble for the complaints filed against it in connection with the supplement. Insofar as the conditions precedent are not fulfilled within 30 days of the date of signing of the settlement agreement, and with respect to the approval of the Competition Court – 60 days, each party shall have the right to terminate the agreement. In view of the settlement agreement as aforesaid, the Partnership recorded expenses in the amount of approx. $14.7 million that were deducted from the "revenues from sale of natural gas" item. As of the date of approval of the financial statements, not all the aforesaid conditions precedent have been fulfilled.

Notes to the Financial Statements for December 31, 2020 (Dollars in thousands)

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

C. Engagements for the supply of natural gas (Cont.):

2. Leviathan project:

a) Agreements for the sale of natural gas from the Leviathan project:

During the years 2016-2020, the Partnership signed, together with the other Leviathan partners, several agreements for the supply of natural gas from the Leviathan project, the main provisions of which are presented below:

	Supply commencement year	Agreement period[29]	Total maximum contract quantity for supply (100%) (BCM)[30]	Total quantity supplied until December 31, 2020 (100%) (BCM)[31]	Main linkage basis of the gas price
IEC[32]	2020	Until June 30, 2021.	Approx. 3.6[33]	Approx. 2.4	Fixed non-linked gas price.
Independent power producers	2020, or the date of commencement of the commercial operation of the purchasers' power plant (whichever is later).	Part of the agreements are for a short period of up to approximately two and a half years, and the rest are for a longer term of 14 to 20 years. About half of the agreements do not grant the parties an option for extension. In most of the remaining agreements each party is granted an option to extend the agreement in the event that the total quantity is not purchased.	Approx. 38.3	Approx. 0.7	In most of the agreements the linkage formula of the gas price is based on the Electricity Production Tariff and includes a "floor price". In several short-term agreements the price is fixed and non-linked.
Industrial customers	2020	Part of the agreements are for a period of 5 to 15 years, and the rest are for a shorter period of up to approximately two years. In most of the agreements the parties are not granted an option to extend the agreement period.	Approx. 3.8	Approx. 0.4	The linkage formula in most of the agreements is based in part on linkage to the Brent prices and in part to the Electricity Production Tariff, and includes a "floor price". There is partial linkage also to the refining margin index and to the general TAOZ index published by the Electricity Authority.

[29] In most of the agreements, the gas supply period may end on the date when the maximum contract quantity set forth in the agreement was supplied to the customers.

[30] This quantity is the maximum quantity which the Leviathan partners have undertaken to supply to the customers throughout the term of the agreements. The quantity which the customers undertook to purchase is lower than this quantity. It is noted that there are agreements in which a mechanism is determined whereby the purchaser will be entitled to increase/reduce the purchased quantities (including the total maximum quantity) until the date set forth in the agreement, according to its needs and the provisions determined in the agreement. It is noted that several agreements do not state a maximum supply quantity.

[31] Due to the fact that this is the first year of operation of the Leviathan project, the quantities in 2020 include an accounting due to the date of commencement of commercial supply.

[32] For details on the IEC agreement, see Paragraph B below.

[33] The original supply agreement that was signed with the IEC did not stipulate the total maximum contract quantity for supply. The figure stated above is equal to the quantity of gas supplied according to the contract until December 31, 2020 (approx. 2.4 BCM) plus an additional quantity of 1.2 BCM which the IEC undertook to nominate from the Leviathan partners during H1/2021 (subject to certain adjustments) according to the Leviathan Settlement Agreement described in Paragraph B.

Notes to the Financial Statements for December 31, 2020 (Dollars in thousands)

	Supply commencement year	Agreement period[29]	Total maximum contract quantity for supply (100%) (BCM)[30]	Total quantity supplied until December 31, 2020 (100%) (BCM)[31]	Main linkage basis of the gas price
NEPCO export agreement	2020	15 years. The agreement stipulates that in the event that the purchaser does not buy the total contract quantity during the base period, the basic supply period will be extended by another two years.	Approx. 45	Approx. 1.9	The linkage formula is based on linkage to the Brent prices and includes a "floor price".
Dolphinus export agreement	2020	15 years. The agreement stipulates that in the event that the purchaser does not buy the total contract quantity, the period of the supply will be extended by another two years.	Approx. 60	Approx. 1.9	The linkage formula is based on linkage to the Brent prices, and includes a "floor price". The agreement includes a mechanism for updating the price by up to 10% (up or down) after the fifth year and after the tenth year of the agreement, upon fulfillment of certain conditions determined in the agreement.
Total			**Approx. 151**	**Approx. 7.25**	

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

C. Engagements for the supply of natural gas (Cont.):

2. Leviathan project (Cont.):

a) Agreements for the sale of natural gas from the Leviathan project (Cont.):

Further details with respect to natural gas sale agreements signed by the Leviathan partners:

1) In most of the agreements for the sale of natural gas to independent power producers and to industrial customers (in this section: the "**Agreements**"), the customers undertook to purchase or pay ("Take-or-Pay") for a minimum annual quantity of natural gas at a scope and according to the mechanism specified in the supply agreement (the "**Minimum Quantity**"). Note that in the context of the said Agreements, provisions and mechanisms are provided, which allow each of the said buyers, after paying for gas not consumed under the agreement due to the application of the Take-or-Pay mechanism as aforesaid, to receive gas with no additional payment up to the amount it had paid for gas it had not consumed. The supply agreements further determine a mechanism for accrual of a balance in respect of surplus quantities consumed by the buyers in any given year and application thereof to reduce the buyers' obligation to purchase the Minimum Quantity as aforesaid, in several subsequent years - Carry Forward.

2) In accordance with the Gas Framework, each of the buyers, in agreements executed by June 13, 2017 and for a period to exceed 8 years, was given an option to reduce the minimum quantity to an amount equal to 50% of the average annual quantity it actually consumed in the three years preceding the date of the notice of exercise of the option, subject to adjustments as determined in the supply agreement (in this section: the "**Option**"). Upon the reduction of the minimum quantity, the other quantities determined in the supply agreement will be reduced accordingly. Each one of the said buyers may exercise the above Option with a notice, to be given to the sellers during a period of 3 years which shall commence 5 years after the date of commencement of the gas flow from the Leviathan project to the buyer or 4 years from the date on which the Petroleum Commissioner approved the transfer of the rights in the Karish and Tanin leases in accordance with the Gas Framework (i.e. December 13, 2020) (whichever is later). If the buyer gave notice of the exercise of the said Option, the quantity will be decreased 12 months after the date the notice was given.

3) Most of the supply agreements determined conditions precedent, including, *inter alia*, receipt of the required approvals on the part of the buyers with respect to the agreement. As of the date of approval of the financial statements, the conditions precedent stated in most of the agreements have been fulfilled.

4) In the supply agreements additional provisions were determined, *inter alia*, on the following subjects: a right to terminate the agreement in the event of the breach of a material undertaking, a right of the Leviathan partners to supply gas to the said buyers from other natural gas sources, compensation mechanisms in the event of a failure to supply the contract quantities, limits to the liability of the parties to the agreement, and with respect to the internal relationship among the sellers with respect to the supply of gas to the said buyers.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

C. Engagements for the supply of natural gas (Cont.):

2. Leviathan project (Cont.):

b) Further details regarding a gas supply agreement between the Leviathan partners and the IEC:

Following the competitive process conducted by the IEC, on June 12, 2019, as aforesaid, the IEC-Leviathan agreement was signed, which regulates the supply of natural gas from the Leviathan reservoir to the IEC on an available capacity basis (in this section: the "**Agreement**").

On October 29, 2019, all of the supply agreement's closing conditions were fulfilled.

The supply of the gas to the IEC pursuant to the Agreement began on December 31, 2019 and will end, according to the provisions of the Agreement, on June 30, 2021, or on the date of commencement of the production of gas from the Karish reservoir, whichever is earlier, unless it ends earlier according to the terms of the Agreement. A non-linked fixed gas price was determined in the supply agreement.

On January 30, 2021 (after the date of the Statement of Financial Position), 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 parties' undertakings under the IEC-Leviathan agreement, the IEC undertook to nominate from the Leviathan partners, during the first half of 2021, approx. 1.2 BCM of natural gas, from which certain gas quantities will be deducted, as agreed, and primarily gas quantities that shall be nominated from Leviathan by the IEC and shall not be supplied thereby, and gas quantities that are not 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 nominate the Base Quantity in the said period, it will be charged with payment to the Leviathan partners for the difference between the Base Quantity and the quantity actually nominated thereby. The IEC will be entitled to consume the balance of the Base Quantity that it did not consume but for which it paid, in accordance with the mechanism determined in the Leviathan Settlement Agreement.

In addition, the Leviathan partners shall give the IEC a discount on the price for nomination of gas quantities exceeding approx. 0.5 BCM that shall be nominated from January 1, 2021.

Upon the signing of the Agreement, the Partnership estimated that during the term of the Agreement, the IEC will be supplied with a quantity of approx. 4 BCM. During 2020, a quantity of approx. 2.4 BCM was supplied from the Leviathan reservoir to the IEC. In the Partnership's estimation, in accordance with the Leviathan Settlement Agreement, in H1/2021, an additional quantity of approx. 1.2 BCM will be supplied to the IEC.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

C. Engagements for the supply of natural gas (Cont.):

2. Leviathan project (Cont.):

b) Further details regarding a gas supply agreement between the Leviathan partners and the IEC (Cont.):

Similarly to the Tamar Settlement Agreement, the Leviathan Settlement Agreement is also subject to the fulfillment of conditions precedent and regulatory approvals, including the approval of the Competition Authority and the approval of the Competition Court for the agreed order. As of the date of approval of the financial statements, not all the aforesaid conditions precedent have been fulfilled.

c) Agreement for the Export of Natural Gas from the Leviathan Project to the Jordanian National Electric Power Company:

In September 2016, a detailed agreement was signed for the supply of natural gas between NBL Jordan Marketing Limited (the "**Marketing Company**") and the Jordanian National Electric Power Company (the "**NEPCO Agreement**" and "**NEPCO**", respectively). The Marketing Company is a subsidiary wholly owned by the partners in the Leviathan project, who hold it relative to their holding rates in the Leviathan project.

According to the NEPCO Agreement, the Marketing Company undertook to supply natural gas to NEPCO for a period of approx. 15 years from the date of commencement of the commercial supply or until the total supply volume will be approx. 45 BCM. The supply of gas to NEPCO began on January 1, 2020.

The gas delivery point according to the NEPCO Agreement, is at the exit from the Israeli transmission system on the border between Israel and Jordan. The cost of completion of the Israeli transmission system up to the border between Israel and Jordan is estimated at approx. $120 million (100%, the Partnership's share being approx. $54 million).

NEPCO has undertaken to take or pay for a minimum annual quantity of gas, in such amount and in accordance with the mechanism as determined in the NEPCO Agreement.

d) Agreement for the Export of Natural Gas from the Leviathan Project to Dolphinus:

On February 19, 2018, an agreement was signed between the Partnership and Noble and Dolphinus, which, as aforesaid, in July 2020 endorsed its rights to Blue Ocean Energy (in this section: the "**Buyer**") 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 (the "**Amendment to the Leviathan-Dolphinus Agreement**"), and an agreement was signed in connection with the allocation of the available capacity in the transmission system from Israel to Egypt between the Leviathan partners and the Tamar partners (for details see Note 7C3 above).

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

C. Engagements for the supply of natural gas (Cont.):

2. Leviathan project (Cont.):

d) Agreement for the Export of Natural Gas from the Leviathan Project to Dolphinus (Cont.):

On January 15, 2020, the flow of natural gas to Egypt from the Leviathan reservoir began in accordance with the Amendment to the Leviathan-Dolphinus Agreement. In July 2020, after receipt of a marine discharge permit from the Natural Gas Authority, the running-in of the compressor that was installed at the EMG terminal in Ashkelon was completed. The installation of the compressor enabled the quantity of gas piped to Egypt to be increased.

It is noted that in a tax decision in connection with the Amendment to the Leviathan-Dolphinus Agreement that was issued to the Leviathan partners by the Tax Authority on December 9, 2019, and according to the terms and conditions of the Gas Framework, the Leviathan partners undertook to offer new customers (as defined in the Gas Framework) with which they engaged or shall engage from February 19, 2018 until 3 full years after the date of the signing of the tax decision, i.e. December 9, 2022, to enter into agreements for the sale of natural gas at a price that shall be calculated according to the formula in the Amendment to the Leviathan-Dolphinus Agreement, which is based on the Brent price, while making several adjustments as specified 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 and conditions of the Amendment to the Leviathan-Dolphinus Agreement</u>:

1) The total contract gas quantity which the Leviathan partners undertook to supply to the Buyer according to the amendment to the Leviathan agreement is on a firm basis and increased considerably to approx. 60 BCM (compared with 32 BCM according to the Original Leviathan-Dolphinus Agreement) (the "**TCQ in the Leviathan Agreement**").

2) The supply according to the Amendment to the Leviathan-Dolphinus Agreement began on January 15, 2020, and will be until December 31, 2034 or until the supply of the full total contract quantity, whichever is earlier (the "**Date of Conclusion of the Amendment to the Leviathan Agreement**"). The agreement prescribes that in the event that the Buyer does not purchase the total contract quantity, each party will be entitled to extend the supply period by two additional years.

3) According to the Amendment to the Leviathan-Dolphinus Agreement, the Leviathan partners undertook to supply the Buyer with annual gas quantities as follows: (i) in the period commencing January 15, 2020 and ending June 30, 2020, approx. 2.1 BCM per year; (ii) in the period commencing July 1, 2020 and ending June 30, 2022, approx. 3.6 BCM per year; and (iii) in the period commencing July 1, 2022 and ending on the date of conclusion of the Leviathan agreement, approx. 4.7 BCM per year, by upgrading the systems at the EMG terminal in Ashkelon, including the installation of another compressor, and increasing the transmission capacity in INGL's system, as specified in Section M.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

C. Engagements for the supply of natural gas (Cont.):

2. Leviathan project (Cont.):

d) Agreement for the Export of Natural Gas from the Leviathan Project to Dolphinus (Cont.):

4) The Buyer has undertaken to take or pay for quarterly and annual quantities according to mechanisms set forth in the Amendment to the Leviathan-Dolphinus Agreement which, *inter alia*, enable the Buyer to reduce the TOP quantity in a year in which the average daily Brent price (as defined in the agreement) is lower than $50 per barrel, such that it shall be 50% of the annual contract quantity. It is noted that, if the contract quantity is reduced in the case of a disagreement about the gas price update, as stated in Paragraph 5 below, Dolphinus's right to reduce the take-or-pay quantity as aforesaid will be revoked. In the report year, Dolphinus consumed from the Leviathan-Dolphinus agreement approx. 1.9 BCM (100%). It is noted that as a result of the sharp decline in the energy prices during H1/2020, the average daily Brent price, as defined in the Agreement, dropped below $50 per barrel (see Note 12K8 regarding a claim and a motion for class certification thereof which was filed against the Partnership in connection with the said clause).

5) The price of the gas to be supplied to the Buyer will be determined according to a formula which is based on the Brent oil barrel price, and includes a "floor price". The Amendment to the Leviathan-Dolphinus Agreement includes a mechanism for updating the price by up to 10% (up or down) after the fifth year and after the tenth year of the Amendment to the Leviathan-Dolphinus Agreement (in this section: the "**First Adjustment Date**" and the "**Second Adjustment Date**", respectively), upon fulfillment of certain conditions as set forth in the agreement. In the event that the parties fail to reach an agreement on the price update as described above, the Buyer will have the right to reduce the contract quantity by up to 50% on the First Adjustment Date and by up to 30% on the Second Adjustment Date. It is noted that the agreement includes an incentive mechanism that is quantity-contingent and subject to the oil barrel price.

6) The Amendment to the Leviathan-Dolphinus Agreement includes accepted provisions relating to conclusion of the agreement, as well as provisions in the case of conclusion of the Amendment to the Tamar-Dolphinus Agreement between the Buyer and all of the partners in the Tamar reservoir as a result of a breach thereof, and the Leviathan partners' not agreeing to supply also the quantities according to the Amendment to the Tamar-Dolphinus Agreement, and also includes compensation mechanisms in such a case. The Amendment to the Tamar-Dolphinus Agreement also includes similar provisions.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):
C. Engagements for the supply of natural gas (Cont.):

3. "*Force majeure*" events under natural gas sale agreements:

In most of the Partnership's natural gas sale agreements (the "**Agreements**"), the customers are obligated to take-or-pay for a minimal annual quantity of natural gas, in accordance with the mechanisms set forth in the Agreements. However, the customers may be exempt from this obligation upon the occurrence of "*force majeure*" events, which prevent them from fulfilling their undertakings, 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 in the circumstances. The Agreements specify a list of cases that shall not be deemed as a "*force majeure*" event, also where they are beyond the customer's control. It is noted that the Partnership may also be exempt from its obligations according to the natural gas sale agreements upon the occurrence of a "*force majeure*" event which prevents it from fulfilling its undertakings according to the Agreements.

If a "*force majeure*" event lasts for a prolonged period as determined in a natural gas sale agreement (usually between one and three years), and it has a material effect on the ability of a party to the agreement to fulfill its undertakings as aforesaid, this may constitute grounds for termination of the agreement. Therefore, the occurrence of a "force majeure" event for a long 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.

D. Agreement for the supply of condensate to ORL:

On December 15, 2019, an agreement was signed whereby condensate produced from the Leviathan reservoir will be piped via the existing fuel pipeline of EAPC to PEI's container site in Kiryat Haim, and from there to ORL's facilities, according, *inter alia*, to regulatory directives (the "**ORL Agreement**").

The ORL Agreement is on an interruptible basis, for a period of 15 years from the date of commencement of the piping of condensate in commercial quantities, with each party having the right to terminate the ORL Agreement by giving prior notice of at least 360 days, to the other party. In addition, each party may terminate the ORL Agreement on shorter notice upon the occurrence of various events, including in the case of a breach by the other party, and upon the occurrence of regulatory and other changes which will not allow the piping of the condensate according to the provisions of the ORL Agreement.

The condensate will be piped to ORL according to the ORL Agreement on an interruptible basis up to a maximum quantity that was agreed between the parties (the "**Maximum Quantity**"). The parties may update the Maximum Quantity from time to time, subject to compliance with the conditions that were determined by the authorities in this respect, including the Ministry of Energy and the Ministry of Environmental Protection.

The ORL Agreement stipulates that the delivery of the condensate to ORL will be without consideration, while the Leviathan partners shall bear any and all expenses, including tax exposures, relating to the piping of the condensate.

The ORL Agreement determines several closing conditions, and primarily receipt of the regulatory approvals for the piping of the condensate to ORL, including approvals with respect to the sale of the condensate without consideration. The ORL Agreement took effect on January 29, 2020.

The loss of revenues caused to the Leviathan project due to the terms of the agreement is not material to the Partnership.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

E. Agreement for the supply of natural gas to Delek Sorek:

On September 19, 2019, an agreement was signed for the supply of natural gas between the Leviathan partners (in this section: the "**Leviathan Partners**") and Delek Sorek (the "**Agreement from Leviathan**"). In the Agreement from Leviathan, the Leviathan Partners undertook to supply Delek Sorek with natural gas in a total quantity of up to approx. 0.24 BCM per year, in accordance with the terms and conditions set forth in the Agreement from Leviathan. The supply period according to the Agreement from Leviathan began in proximity to the date of commencement of the gas flow from the Leviathan project and shall end 9 years after the date of the commercial operation of the Leviathan project (the "**Term of the Supply Agreement**"), while Delek Sorek has the right to extend the Agreement from Leviathan by another five years, by dispatching a notice to the Leviathan Partners that it wishes to do so, no later than the end of the seventh year from the date of commercial operation of the Leviathan project. Delek Sorek undertook to take-or-pay for a minimum annual quantity of gas in the volume and according to the mechanism set forth in the Agreement from Leviathan (the "**Take-Or-Pay Quantity**"). The gas price stipulated in the Agreement from Leviathan will be linked to the Electricity Production Tariff, as shall be determined from time to time by the PUA-E, and includes a "floor price".

F. Estimates regarding gas quantities and supply dates:

The estimates regarding the natural gas quantities which will be purchased by the aforesaid buyers in the Leviathan and Tamar projects, and the supply commencement dates according to the supply agreements, constitute information the materialization of which, in whole or in part, is uncertain, and which may materialize in a materially different manner, due to various factors including non-fulfillment of the conditions precedent in each one of the supply agreements (insofar as not yet fulfilled), non-receipt of regulatory approvals, changes in the scope, pace and timing of consumption of the natural gas by each one of the aforesaid buyers, the gas prices to be determined according to the formulas specified in the supply agreements, the electricity production tariff, the Dollar-ILS exchange rate (insofar as relevant to the supply agreement), the Brent prices (insofar as relevant to the supply agreement), the U.S. CPI (insofar as relevant to the supply agreement), construction and operation of the power plants and/or other plants of the buyers (insofar as relevant to the supply agreement), exercise of the options granted in each one of the supply agreements and the date of exercise thereof, etc.

G. Reimbursement of indirect expenses to the project operators:

The Partnership's operations in the joint ventures Michal-Matan, Ratio-Yam, and Yam Tethys is carried out by Noble, in the Ofek and Yahel licenses it is carried out by SOA, and the Partnership's operation in the Block 12 joint venture in Cyprus is carried out by Noble Cyprus.

According to the joint operation agreements in such joint ventures and licenses, it was agreed that Noble, SOA or Noble Cyprus, according to the aforesaid, would serve as the operator and would be exclusively responsible for the management of the joint operations.

According to the rules of settlement of accounts specified in the agreements, Noble, SOA and Noble Cyprus are entitled to reimbursement of indirect expenses calculated as a percentage of the direct expenses, as specified below:

Michal-Matan joint venture:

Noble is entitled to reimbursement of all of the direct expenses it incurs in connection with the fulfillment of its duties as operator and to reimbursement of the indirect expenses deriving from a percentage of the expenses of the joint venture, at a rate equal to 1% of all of the direct expenses as of January 1, 2016, as defined in the agreement, subject to certain exceptions.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):
G. Reimbursement of indirect expenses to the project operators (Cont.):

Ratio-Yam joint venture:

Noble is entitled to reimbursement of all the direct expenses it incurs in connection with the fulfillment of its duties as operator as well as reimbursement of the indirect expenses deriving from a percentage of the expenses of the joint venture at the exploration stage, at a rate of 1% of all the direct development expenses, as defined in the agreement, subject to certain exceptions.

Yam Tethys joint venture:

Noble is entitled to reimbursement of all of the direct expenses it incurs in connection with the fulfillment of its duties as operator as well as reimbursement of the indirect expenses deriving from a percentage of the expenses of the joint venture, at a rate of 1% of the expenses up to an expense amount of $20 million per year, and 0.85% of the expenses beyond such amount.

Ofek and Yahel licenses:

SOA is entitled to reimbursement of all of the expenses it incurs in connection with the fulfillment of its duties as operator and to reimbursement at a rate of 1% of all of the exploration expenses. As of the date of approval of the financial statements, the rate of reimbursement of development expenses is yet to be determined.

Block 12 Cyprus:

Noble Cyprus is entitled to reimbursement of all of the direct expenses it incurs in connection with the fulfillment of its duties as operator as well as reimbursement of the indirect expenses deriving from a percentage of the expenses of the joint venture at a rate of 1% of the expenses up to an expense amount of $20 million per year, and over and above such amount – at a rate of 0.85% of the expenses. Operator fees for the development period at the rate of 1.5% were approved in the 2020 budget. It is noted that as of the date of approval of the financial statements, the partners in Block 12 are holding discussions on the payment of operator fees in respect of indirect production expenses.

H. Dependence on a customer:

The IEC, NEPCO and Dolphinus are the Partnership's largest customers and therefore, termination of the agreements signed between them and the Tamar partners and the Leviathan partners, or the non-fulfillment thereof, will materially affect the Partnership's business and future revenues.

For details regarding sales volumes and trade receivables balance as of December 31, 2020 and December 31, 2019, see Note 14B and Note 22G below.

I. Permits and licenses for the projects' facilities:

1. In the context of the development of the Yam Tethys project, the Yam Tethys partners received approval for construction of a permanent platform for production of natural gas and oil, and approval for operation of a natural gas production system under the Petroleum Law and the Minister of Energy also gave Yam Tethys Ltd. (a company owned by the Yam Tethys partners) a license for construction and operation of a transmission system, that will be used for transfer of natural gas of Yam Tethys partners, or other natural gas suppliers upon fulfillment of certain conditions, all subject to the terms and conditions of the license and the Natural Gas Sector Law from the production platform to the terminal.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

I. Permits and licenses for the projects' facilities (Cont.):

2. In the context of the Tamar Project development plan, the Tamar partners received approval for the construction of a permanent platform for natural gas and oil production, as well as approval for the operation of a system for the production of natural gas and condensate from the Tamar Project. In this context, the Partnership provided a guarantee in favor of the Ministry of Energy.

3. In Phase 1A of the development plan for the Leviathan project, the Leviathan partners received approval for the construction of a permanent platform for the production of natural gas and oil, as well as approval for the operation of a system for production of natural gas and condensate from the Leviathan project pursuant to which the Leviathan partners were obligated, *inter alia*, to submit guarantees.

   In February 2017, the Minister of Energy granted the SPC owned by the Leviathan partners, Leviathan Transmission System Ltd., a license for the construction and operation of the transmission system, which will serve for the transfer of natural gas of the Leviathan partners originating from the Leviathan Leases, or other natural gas suppliers upon the fulfillment of certain conditions, all subject to the terms of the license. In December 2019, the Commissioner's approval was received for the operation of the system for production of natural gas and oil from the Leviathan Leases.

   In addition, other permits were received including a sea discharge permit, an air emission permit, toxic materials permits and business permits.

4. The Ministry of Environmental Protection published the air emission permit for the Tamar platform on August 31, 2020, and it has taken effect. It is noted that Noble is in discussions with the Ministry of Environmental Protection in connection with certain conditions determined in such permit. On December 30, 2020, the operator filed an application for modification of the permit, pursuant to the provisions of the Clean Air Law and another filing which stated the operator's position whereby it is reserving its rights on the issue.

5. On October 30, 2020, the Ministry of Environmental Protection published, for public comment, a draft update to the existing emission permit of the Ashdod Onshore Terminal, which is used by the Tamar reservoir, which is valid until December 31, 2021, and whose purpose it is to regulate all of the activity carried out at the facility. It is noted that concurrently, a process is being carried out in which an application was submitted for the issuance of a new emission permit for the facility.

   On December 16, 2020, an updated emission permit for the facility was released. It is noted that based on information provided to the Partnership by the operator, the demand to update the emission permit for the facility was made incidentally to a hearing held for the operator by the Ministry of Environmental Protection for ostensible non-compliance with the provisions of the facility's emission permit which, according to the Ministry of Environmental Protection, constitute a breach of the Clean Air Law. To the best of the Partnership's knowledge, as of the date of the financial statements, after the operator presented arguments in this regard to the Ministry of Environmental Protection, no further enforcement measures were taken. At the same time, the operator filed an application to renew the facility's emission permit, which is expected to expire in December 2021.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

J. Pledges and guarantees:

1. Short-term bank deposits as of December 31, 2020 in the sum of approx. $169.1 million used for debt service and current payments in the context of the issue of the Tamar Bond bonds (see Note 10B above) and Leviathan Bond bonds (see Note 10C above).
2. A long-term bank deposit as of December 31, 2020 in the sum of approx. $100 million used as a safety cushion in the context of the issue of Leviathan Bond bonds (see Note 10C above) and a deposit in the sum of $0.5 million used to secure a guarantee in the sum of $1 million, provided by the Partnership and Noble (in equal parts) in favor of the Director of the Natural Gas Authority in relation to the license for gas transmission to Egypt.
3. See Note 10 regarding pledges provided by the Partnership on its assets in the context of the bonds.
4. According to the demand of the Republic of Cyprus in the framework of the PSC as stated in Note 7C4 above, in 2013, Delek Group provided a performance guarantee in favor of the Republic of Cyprus. In consideration for provision of the guarantee, the Partnership pays Delek Group a guarantee fee in the amount of approx. $368 thousand per year until 25 years after the date of provision of the guarantee.
5. In the context of the Partnership's activity in the Leviathan and Tamar projects, the Partnership provided a personal guarantee in favor of the Israeli Tax Authority (Customs) in connection with equipment imported by the venture operator in the sum of approx. ILS 82.7 million. It is noted that in the context of the abandonment actions planned in the Yam Tethys project, the Partnership is expected to provide a personal guarantee in the sum of approx. ILS 57.7 million in favor of Customs.
6. During July 2018, the partners in the Leviathan project provided a guarantee in favor of the Israel Land Authority regarding the construction of development infrastructure for the Leviathan project. The share of the Partnership in the said guarantee is approx. ILS 2.3 million.
7. In order to secure payments for rights of use of areas, facilities and infrastructures in connection with the EMG Transaction, the Partnership provided a bank guarantee in the amount of $2 million in favor of EAPC. In the context of the agreement with EAPC, EMED BV provided a company guarantee in the amount of $4 million to EAPC.
8. To secure a transmission agreement for the export of gas to Egypt (see Section M) in the context of the Partnership’s activity in the Leviathan and Tamar projects, in February 2021 (after the date of the Statement of Financial Position) the Partnership provided bank guarantees in favor of INGL in the sum of approx. ILS 172.9 million, against which the Partnership pledged a deposit in the sum of approx. $13.3 million.
9. With regard to guarantees in the sum of approx. $64 million provided by the Partnership to the Petroleum Commissioner in connection with its rights in the oil and gas assets, see Section L3 below.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

K. Legal proceedings:

1. 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 (in this section: the "**Defendant**"), which mainly includes the restitution of royalties overpaid by the Plaintiffs, under protest, to the Defendant, for revenues that derive from gas supply agreements which were signed between third party customers (below in this section, the "**End Customers**") and the Yam Tethys partners, some of the gas contemplated in which agreements was supplied from the Tamar Project, according to an accounting mechanism, according to which the consideration that was received from the End Customers, together with the consideration reflecting the share of Delek Group, which is a rights holder in Yam Tethys and does not hold direct rights in Tamar, was divided such that the Tamar partners, which are not Yam Tethys partners too (i.e. Isramco, Dor Gas, Tamar Petroleum and Everest), received a natural gas price equal to the monthly average price of natural gas supplied during that month by virtue of agreements signed between the Tamar partners and their customers, and the remaining monetary balance was divided between the Yam Tethys partners that also hold rights in the Tamar Project (i.e. the Plaintiffs), according to their share in the Tamar Project. This accounting mechanism allowed maintaining a balance of the gas quantities in the Tamar Project between the partners therein according to their share. *[sic]* sought by the Plaintiffs, as of the date of the filing of the claim, was approx. $15.3 million, and reflects the royalties which the Plaintiffs overpaid from May 2013 until the date of filing of the claim (in this section: the "**Restitution Amount**"). Underlying the claim is the Plaintiffs' argument whereby, as distinguished from the Defendant's argument, the Plaintiffs, as the holders of the rights in both the Yam Tethys project and the Tamar Project are taking from the gas in their possession such that no sale was made between the "Tamar Project" and the "Yam Tethys project", and 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. Consequently, the Defendant is overcollecting royalties from the Plaintiffs, in respect of amounts that exceed the amounts received from the End Customers, which reflect the market value of the gas, in view of the End Customers' being an unaffiliated party. As of December 31, 2020, the restitution remedy due to the Plaintiffs' primary argument as aforesaid, is approx. $28 million (the overpaid royalties restitution principal amount for the period between May 2013 and September 2017, and for the period between May 2019 and December 2020, according to the Plaintiffs) (in this section: the "**Current Restitution Amount**"), with the Partnership's share in the principal being approx. $13 million. Updating the Current Restitution Amount is subject to payment of additional fees by the Plaintiffs.

   Alternatively, the Plaintiffs' claim that even if there had been any kind of a sale, the sale that was performed was with respect to the share of the holders of the rights in the Tamar Project that are not the holders of the rights in the Yam Tethys project (Isramco and Dor – 32.75% and in part of the period also Tamar Petroleum and Everest – 45.5%) and the holders of the rights in the Yam Tethys project, with the balance of the gas that is being supplied to the End Customers by the Plaintiffs (67.25% and in part of the period in which Tamar Petroleum and Everest hold rights – 54.5%) being gas that is in the Plaintiffs' possession, which they are entitled to use for the purpose of supplying gas to the End Customers as aforesaid (in this section: the "**Partial Sale Approach**").

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

K. Legal proceedings (Cont.):

1. (Cont.)

   As of December 31, 2020, the restitution remedy with respect to the Partial Sale Approach as aforesaid is approx. \$19.3 million (the overpaid royalties restitution principal amount 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 approx. \$9 million.

   Trial hearings were held on June 21, 2020. On February 23, 2021 the Plaintiffs filed chief closing statements on behalf thereof. Accordingly, the Defendant will be entitled to file closing statements on its behalf until May 31, 2021 while the Plaintiffs will be entitled to file responding summations on behalf thereof, contemplating the Defendant's closing statements, until June 30, 2021.

   In the Partnership's estimation, based on the opinion of the legal counsel, there is a possible chance that the main argument of the Plaintiffs will be accepted, such that they will be entitled to the Current Restitution Amount, and the chances of the Partial Sale Approach being accepted are higher than the chances of it being dismissed.

2. On June 18, 2014, a motion for class certification was filed with the Tel Aviv District Court by a consumer of the IEC against the Tamar partners (in this section: the "**Petitioner**" and the "**Certification Motion**", respectively). Such motion concerns the price at which the Tamar partners sell natural gas to the IEC.

   The Certification Motion claims that the gas price for the IEC is an unfair price which constitutes abuse of the Tamar partners' position as holders of a monopoly in the Israeli natural gas supply sector in violation of Section 29A of the Economic Competition Law.

   The remedies sought in the Certification Motion are: compensation for all of the electricity consumers in the sum of the difference between the price paid by the IEC for natural gas supplied by the Tamar partners and the fair price thereof, which was estimated on the date of filing of the Certification Motion at a total sum of approx. ILS 2.456 billion (in 100% terms), as well as declaratory orders whereby the Tamar partners are required to refrain from selling the natural gas from the Tamar Project for a sum exceeding the sum specified in the Certification Motion and sale thereof at a higher price constitutes abuse of their monopoly power.

   On July 7, 2016, a court hearing was held on the motion for summary dismissal, which was filed by the Tamar partners on April 20, 2016, after the Attorney General had filed a position on his behalf whereby the Certification Motion should be summarily dismissed. In his position, the Attorney General argued that there was no room to hear the class action, since the price regulation (which is one component of the Gas Framework) cannot be challenged separately from the Gas Framework as a whole, and the place for judicial review of the Gas Framework is at the High Court of Justice and not in a class action. The Attorney General further argued that hearing the class action may impede realization of the Gas Framework.

   On November 23, 2016, a decision was issued denying the motion for summary dismissal of the Certification Motion, and on December 15, 2016, the Tamar partners filed a motion for leave to appeal this decision.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):
K. Legal proceedings (Cont.):

2. (Cont.)

   On September 28, 2017, the Supreme Court's judgment was issued on the motion for leave to appeal. The Supreme Court heard this motion as if leave had been granted and an appeal filed, and on the merits ruled that there was no room to intervene in the decision of the District Court and that the appeal should be denied. However, it ruled that it was necessary to carry out an additional factual investigation, and therefore ordered that the hearing be remanded to the District Court for it to hear the Certification Motion on the 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 granted the motion of the Tamar partners to file the position of the Attorney General regarding his interpretation of Section 29A(b)(1) of the Economic Competition Law, 5748-1988, which had 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.

   In the Partnership's estimation, based on the opinion of its legal counsel, the chances of the motion for class certification being accepted are lower than 50%.

3. On December 25, 2016, a motion for class certification (in this section: the "**Certification Motion**") was filed claiming that the Merger transaction between the Partnership and Avner had been approved by an unfair procedure and the consideration paid to the holders of the minority units in Avner, as determined in the Merger agreement, was unfair. The motion was filed against Avner, the general partner in Avner and the board members thereof, Delek Group as the (indirect) control holder of Avner, and against Price Waterhouse Coopers Consulting Ltd. (PWC), as the economic advisors of an independent board committee set up by Avner (in this section: the "**Respondents**"). Among other claims, the motion argues that the committee members, the board of directors of Avner and the general partner had breached the duty of care to Avner, and that Avner had conducted itself in a manner that oppressed the minority. The petitioners estimate the total damage at ILS 320 million. On February 13, 2017, the court approved a stipulation whereby the motion for class certification would be amended by adding a claim for minority oppression by Delek Group. On July 6, 2017, the court ordered the joining of the Partnership as a respondent, pursuant to its motion. Trial hearings were held on March 9, 2021 and March 10, 2021 and upon conclusion thereof it was ruled that, by March 17, 2021, the parties shall file a stipulation regarding the manner of conduct of the stage of the closing statements.

   In the Partnership's estimation, based on the opinion of the legal counsel, the chances of the certification motion being granted are lower than 50%.

4. On February 4, 2019, a class action and a motion for class certification thereof (in this section: the "**Certification Motion**") was filed with the Tel Aviv District Court (Economic Department) by a shareholder of Tamar Petroleum and the Public Representatives Association (in this section jointly: the "**Petitioners**"), against Tamar Petroleum, the Partnership, the CEO of the Partnership's General Partner and the Chairman of the Board of Tamar Petroleum at the time of the IPO, the CEO of Tamar Petroleum, the CFO of Tamar Petroleum and Leader Underwriters (1993) Ltd. (in this section jointly: the "**Respondents**"), in connection with the issue of the Tamar Petroleum shares in July 2017 (in this section: the "**IPO**").

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):
K. Legal proceedings (Cont.):

4. (Cont.)

   According to the Petitioners, in essence, the Respondents misled the investing public at the time of the IPO with respect to the ability of Tamar Petroleum to distribute a dividend to its shareholders, for the period commencing on the IPO date and ending at the end of 2021 (in this section: the "**Period**"), and breached duties under various laws, *inter alia* a breach of the duty of care of the said officers and breach of the Partnership's duties as a shareholder and controlling shareholder of Tamar Petroleum before the IPO.

   The remedies sought in the said class action mainly include a financial remedy in the minimum sum of $53 million, which is, according to the Petitioners, the difference between the total dividend which Tamar Petroleum is expected to distribute for the Period, as stated in the offering to institutional investors document of July 12, 2017, and the total dividend which, according to an expert opinion attached to the Certification Motion, Tamar Petroleum is expected to distribute for the Period.

   On August 13, 2019, the court ordered the Petitioners to deliver the pleadings in the file to the Attorney General, in order that he give notice, by September 15, 2019, of whether he wishes to join the proceeding. On February 6, 2020, the Attorney General announced that at this stage he did not deem fit to join the proceeding. On November 1, 2020, the Petitioners filed a motion to amend the Certification Motion (in this section: the "**Amendment Motion**"), in which they sought to join to the Certification Motion another petitioner who had participated in the IPO, unlike the current Petitioners who did not take part therein. In addition, the Amendment Motion sought to increase the amount of the alleged damage to $153 million.

   The parties' responses have been filed with the court and as of the date of approval of the financial statements, no decision has yet been received on the Amendment Motion.

   The Partnership estimates, based on the opinion of its legal counsel, that the chances of the Certification Motion being granted are lower than 50%.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

K. Legal proceedings (Cont.):

5. On February 27, 2020, the Partnership learned of the filing of a class action and a motion for class certification (in this section: the "**Certification Motion**"), which was filed with the Tel Aviv District Court by an electricity consumer (in this section: the "**Petitioner**") against the Partnership and Noble and against the other holders of the Tamar Project and the Leviathan project (as parties 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, as agreed by Isramco, Tamar Petroleum, Dor and Everest (collectively in this section: the "**Other Holders in the Tamar Project**"), with no involvement on the part of the Partnership and Noble (in this section: the "**Amendment to the Tamar Agreement**").

   The Petitioner's principal arguments are, in brief, that the bids made by the Other Holders in the Tamar Project and the holders in the Leviathan project in the competitive process amount to abuse of monopoly power and to a restrictive arrangement, as defined in the Economic Competition Law; the Partnership's and Noble's not signing the Amendment to the Tamar Agreement also amounts to abuse of monopoly power; the price determined 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 made and which shall be made by the Partnership and Noble under this agreement, while harming competition, amount to unjust enrichment. The Petitioner asserts that such actions of the Partnership and Noble have caused and are expected to cause damage to the classes he seeks to represent in the sum of approx. ILS 1.16 billion, which he moves to adjudicate in favor of the classes he seeks to represent and according to which the court is moved to award compensation and fees. The main remedy that is sought in the said 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.

   A pretrial hearing on the Certification Motion is scheduled for November 17, 2021.

   The other holders of Tamar and Ratio, the other holder of Leviathan, were also joined as respondents to the Certification Motion, without a remedy being sought against them. On December 22, 2020, the other holders of Tamar filed a motion for summary omission thereof (in this section: the "**Omission Motion**"), the Petitioner filed an objection and the Partnership, Noble and Ratio did not object thereto.

   On January 31, 2021, the court ruled that a hearing will be held on the Omission Motion on May 5, 2021. A date has not yet been set for filing of answers to the Certification Motion.

   In the Partnership's estimation, based on the opinion of its legal counsel, the chances of the Certification Motion being granted are lower than 50%.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):
K. Legal proceedings (Cont.):

6. On January 6, 2019, the Supervisor on behalf of the participation unit holders in the Partnership filed a complaint and an urgent motion for a provisional order with the Tel Aviv District Court (Economic Department) (in this section: the "**Complaint**" or the "**Supervisors' Claim**" and the "**Motion for a Provisional Order**", respectively), according to Section 65W(b) of the Partnerships Ordinance, against the Partnership, the Partnership's general partner, Delek Group, Delek Energy and Delek Royalties (Delek Group, Delek Energy and Delek Royalties, jointly in this section: the "**Royalty Interest Owners**").

   In the Complaint, the Supervisor moves the Court to declare that the calculation of the "investment recovery date" in the Tamar Project must include the payments which the Partnership is required to pay the State under the Taxation of Profits from Natural Resources Law; to declare that the investment recovery date in the Tamar Project has not yet arrived; to determine the date from which the Royalty Interest Owners are entitled to receive the overriding royalty at the increased rate (6.5% in lieu of 1.5%); and to declare that the Royalty Interest Owners are required to return to the Partnership the payments they received in excess, plus linkage differentials and interest. Furthermore, in the Motion for a Provisional Order the Supervisor moves the Court to issue an order preventing an act that may deprive the rights of the participation unit holders, so as to order the Partnership and the General Partner of the Partnership to avoid transferring the overriding royalty at the increased rate to the Royalty Interest Owners, and to transfer the same to an escrow account held by the Partnership, and to order Delek Group and Delek Royalties to return the increased overriding royalty they received to date from the Partnership and deposit the same in the escrow account.

   On February 6, 2019, the Partnership and the General Partner filed a motion for a stay of proceedings in the claim, due to the existence of a binding arbitration clause in the rights transfer agreement between the Partnership and the Royalty Interest Owners of August 2, 1993 (in this section: the "**Motion for a Stay of Proceedings**"). On May 20, 2020, the preliminary proceedings in the above claims were concluded.

   Regarding the Motion for a Provisional Order, it is noted that on May 12, 2020, the Supervisors filed an urgent motion for provisional remedies (in this section: the "**Motion**"), moving the Tel Aviv-Jaffa District Court (Economic Department) to order the Partnership and the General Partner of the Partnership to cease and desist from transferring the increased overriding royalty to the Royalty Interest Owners or, alternatively, to order them to transfer the increased overriding royalty to an escrow account owned by the Partnership at least pending decision of the Supervisors' Claim. According to the Supervisors, the Motion is filed in view of an extreme and dramatic change in circumstances that has resulted in the Royalty Interest Owners being on the verge of insolvency. The Supervisors moved the court to schedule an urgent hearing of the Motion in order to prevent and save the need for a preliminary order until a hearing is held *inter partes*. The court did not grant the Motion, and ruled on that date that the Partnership, the General Partner of the Partnership and the Royalty Interest Owners shall file their responses to the Motion within 7 days.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

K. Legal proceedings (Cont.):

6. (Cont.)

On May 19, 2020, responses to the Motion were filed by the Partnership, the General Partner of the Partnership and the Royalty Interest Owners. The response of the Partnership and the General Partner of the Partnership argued that the Motion should be denied, *inter alia*, because in a situation where any of the Royalty Interest Owners falls into a state of insolvency, the Partnership has a right of setoff according to insolvency law, which guarantees any amount that will be ruled in its favor in the Supervisors' Claim. On June 23, 2020, the Supervisors filed with the court a motion and notice which was agreed with the Royalty Interest Owners, according to which an agreement had been reached between the Supervisors and the Royalty Interest Owners, which obviates, at this time, the need to decide the matters in dispute between the parties to the Motion. On the same date, the court approved the aforesaid agreement, canceled the scheduled hearing, and ordered the parties to give notice within 10 days of whether they had reached a comprehensive agreement and the manner in which they wish to advance the hearing in the Supervisors' Claim. On July 9, 2020, an agreed notice was filed on behalf of the parties, whereby the Supervisors and the Partnership had completed the preliminary proceedings between them, while the Supervisors and the Royalty Interest Owners moved to extend the timeframe for completion of the preliminary proceedings between them until July 23, 2020. On July 12, 2020, the court granted this motion. On September 2, 2020, the Royalty Interest Owners filed an agreed stipulation whereby the evidence of the Supervisors in the claim and the evidence of the Royalty Interest Owners in the counterclaim would be filed by November 24, 2020, and the defendants' evidence in the Supervisors' Claim and in the counterclaim would be filed by January 10, 2021. On September 2, 2020, the court approved the said stipulation, and postponed the pretrial session to January 26, 2021. On November 19, 2020 the court granted the motion of the plaintiffs and the counter-plaintiffs and postponed the date for their evidence filing to December 6, 2020, and the date for filing of the defendants' evidence to January 19, 2021. According to the court's decision, the plaintiffs' and defendants' evidence was filed on December 6, 2020.

On January 12, 2021, the court granted the Partnership's motion and postponed the date of the pretrial session to March 25, 2021, and extended the timeframe for the filing of the defendants' evidence in the Supervisors' Claim and in the counterclaim until 14 days before the date of the hearing, in other words, until March 11, 2021. On March 10, 2021 the court granted another motion for a short extension for filing of evidence on behalf of the Partnership, such that on March 14, 2021 an expert's opinion was filed with respect to the standard practice in the field of oil and gas with regard to determination of an investment recovery date that supports the Partnership's position, and on March 17, 2021, an affidavit in lieu of direct testimony will be filed on behalf of the Partnership as well as a supplemental economic opinion on behalf thereof.

On February 26, 2019, a hearing was held at the court on the motion for a provisional remedy, at which the court clarified that no provisional remedy would be granted with respect to a date earlier than the date of the hearing of the motion. The court requested that the parties hold talks in an attempt to reach agreements regarding the provisional remedy. On April 2, 2019, the court entered a decision on an arrangement between the Royalty Interest Owners and the Supervisors, whereby Delek Energy shall give the Supervisor a letter of undertaking to make payment, insofar as it is ruled that the Royalty Interest Owners were overpaid royalties. This decision obviated the supervisors' motion for a provisional order.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

K. Legal proceedings (Cont.):

6. (Cont.)

On April 4, 2019, the Royalty Interest Owners filed an answer and a counterclaim against the Partnership, the General Partner of the Partnership and the Supervisor (in this section: the "**Counterclaim**"). In the Counterclaim, the Royalty Interest Owners argue, *inter alia*, that the Partnership's calculation of the Investment Recovery Date in the Tamar Project included expenses that were "loaded" onto the calculation, and *inter alia*, the financial expenses of the Partnership itself, future expenses, whose amount is uncertain, of the retirement and removal of facilities, headquarter expenses of the Partnership and any expense intended for stages of the project that are subsequent to the "wellhead". The Royalty Interest Owners argue that, discounting such expenses, the Investment Recovery Date in the Tamar Project already occurred in August 2015, or alternatively in 2016, or alternatively in 2017.

Accordingly, the Royalty Interest Owners are moving the court to declare which expenses should be taken into account in the calculation of the Investment Recovery Date, and to order that the Partnership is required to recalculate the Investment Recovery Date based on the aforesaid, as well as the royalties that the Royalty Interest Owners are entitled to receive, and to deliver the calculation to the Royalty Interest Owners. The Royalty Interest Owners further argue that, according to their position, the issue of the Investment Recovery Date ought to be heard in arbitration proceedings, and not in court, and that insofar as the Supervisors' Claim is referred to arbitration proceedings, the hearing of the Counterclaim ought to also be referred to arbitration. On June 23, 2019, a hearing was held on the Motion for a Stay of Proceedings, and on June 24, 2019, this motion was denied, and therefore the claim will continue to be heard before the court and not an arbitrator.

With the parties' consent, the date for completion of the preliminary proceedings was postponed to March 25, 2020 (in view of the spread of the Covid-19 pandemic and according to notices of the Minister of Justice regarding the application of the Courts and Execution Offices Regulations (Procedures in Special Emergencies), 5751-1991, from March 15, 2020 until April 16, 2020, the period of the application of the said regulations is not counted in the counting of the days for completion of the preliminary proceedings, and hence they will be completed only after the period of the application of the regulations).

In view of the disputes described above and insofar as the Royalty Interest Owners' argument regarding the earlier occurrence of the investment recovery date in August 2015 is fully accepted, in a claim that shall be filed thereby, the Partnership will then be required to pay the Royalty Interest Owners a sum of approx. $56 million (excluding interest and linkage, if any). Conversely, according to the estimation of the Supervisor's economic consultant, in a report submitted by him to the Partnership in June 2018, inclusion of the oil and gas profit levy in the investment recovery date report would postpone the investment recovery date by 1 to 1.5 years. Insofar as the Supervisor's argument concerning the postponement of the investment recovery date is fully accepted, the Royalty Interest Owners will be required to pay the Partnership a sum of approx. $35 million (excluding interest and linkage, if any).

In the Partnership's estimation, following an examination of all of the arguments of both the Royalty Interest Owners and the Supervisor, and based on the opinion of its legal advisors, the exposure to additional costs of the Partnership from the Counterclaim and the provision included in the financial statements as of December 31, 2020 is sufficient.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

K. Legal proceedings (Cont.):

7. Further to Note 7C3 above, following the decision of the Competition Commissioner (in this section, the "**Commissioner**"), according to Section 20(b) of the Economic Competition Law, to conditionally approve the merger between EMG and EMED, in the context of which a set of agreements was signed to enable the export of gas to Egypt from the Tamar and Leviathan gas reservoirs (in this section: the "**Merger**"), on September 8, 2019, Lobby 99 Ltd. (CIC) and Hatzlaha - for Promotion of a Fair Society (R.A.) filed an administrative appeal with the Competition Court at the Jerusalem District Court. The administrative appeal was filed against the Commissioner (as a respondent) and against EMED and EMG. In essence, it was argued in the administrative appeal that the Merger will enable the Partnership and Noble to block any and all possibilities of importing natural gas from Egypt that will compete with the gas produced from the Tamar and Leviathan reservoirs that they own, and that the conditions imposed in the context of the Merger's approval are impracticable and do not remedy the competition damage that may be caused according to them by approval of the Merger. In the administrative appeal, the court was moved to cancel or modify the Commissioner's decision. On December 15, 2020, a preliminary hearing was held on the administrative appeal. As of the date of approval of the financial statements, no dates have yet been scheduled for trial hearings. In the Partnership's estimation, based on the opinion of its legal counsel, the chances of the administrative appeal being granted are lower than 50%.

8. On April 23, 2020, a holder of participation units of the Partnership (in this section: the "**Petitioner**") filed a class action and motion for class certification against the Partnership, the General Partner of the Partnership, Delek Group Ltd., Yitzhak Sharon (Tshuva), the directors of the General Partner of the Partnership (including the former chairman of the board) and the CEO of the General Partner of the Partnership (in this section: the "**Certification Motion**" and the "**Respondents**", respectively), with the Economic Department of the Tel Aviv District Court.

   The Certification Motion alleges that the Respondents refrained from disclosing, in the Partnership's reports, the existence of a clause in the agreements for the sale of natural gas from the Leviathan and Tamar reservoirs to Dolphinus Holdings Limited (in this section: 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) is lower than $50 per barrel, the Buyer is entitled to reduce the minimum annual quantity purchased under the Sale Agreements, to 50% of the annual contract quantity. According to the Petitioner, the alleged non-disclosure in the Partnership's reports establishes causes of action by virtue of various sections of the Securities Law, by virtue of the tort of breach of statutory duty, and by virtue of the tort of negligence.

   The main remedy sought in the Certification Motion is compensation of the class which the Petitioner intends to represent, for the alleged damage incurred thereby, which is estimated, according to the opinion attached to the Certification Motion, at approx. ILS 55.5 million. The Petitioner also moved to issue any and all other remedies in favor of the class, as the court will deem fit under the circumstances.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

K. Legal proceedings (Cont.):

8. (Cont.)

   On January 17, 2021, the Respondents filed their response to the Certification Motion, accompanied by an expert opinion. In summary, according to the response, during the period relevant to the Certification Motion, the reduction clause was never material, and therefore was not required to be disclosed to the public. It was further argued in this context, *inter alia*, that the probability of a drop in Brent barrel prices below the annual average of $50 was very low at least until March 2020 with the outbreak of the Covid-19 crisis 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. It was further argued in the response, *inter alia*, 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 quantities that Dolphinus actually consumes, and warned that this was forward-looking information, that there is evidence that there is no proximate cause between the disclosure of the reduction clause and the decrease observed 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. According to the court's decision, the Petitioner is required to file an answer to the response by March 31, 2021.

   In the Partnership's estimation, based on an opinion of its legal counsel, the chances of the motion being granted are lower than 50%.

9. With regard to the possibility given to the Buyer under the agreements for export to Egypt, to reduce the Take-or-Pay amount as described in Sections 12C1C and 12C2D above, the Partnership received a request from the ISA to provide information and documents as part of an administrative inquiry vis-à-vis the Partnership. On November 10, 2020, the Partnership filed a response to the said request.

10. On August 28, 2019, the Homeland Guards Association (in this section: the "**Petitioner**") petitioned to the Jerusalem District Court against the Ministry of Environmental Protection and position holders therein and against Noble and the Ministry of Energy, in which it sought to instruct the Ministry of Environment Protection and position holders therein to require Noble or the Ministry of Energy to furnish various items of information which are necessary, as claimed by the Petitioner, to make a decision on the application for Leviathan's Emission Permit; to release all of the information to the public and to allocate a 45-day period for the submission of comments; to avoid granting an Emission Permit to a platform until the petition has been heard. Concurrently with the petition, a motion was filed for a temporary order and interim order which are intended to prevent the provision of Leviathan's Emission Permit until the petition has been heard. On September 5, 2019, the Court denied the motion for an interim order. On December 19, 2019, the Court's judgement was received, dismissing the petition with prejudice charging the Petitioner with the respondents' costs in a total amount of ILS 60 thousand. On February 3, 2020, the Petitioner appealed to the Supreme Court from the said judgment of the District Court. The Supreme Court scheduled the appeal to be heard on October 20, 2021. On October 26, 2020 the Petitioner filed the summary of its arguments and on March 1, 2021 Noble filed closing arguments on its behalf. As of the date of approval of the financial statements, in the Partnership's estimation, based on the opinion of legal counsel representing the operator in the proceeding, the chances of the appeal being denied are higher than the chances it is granted.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

K. Legal proceedings (Cont.):

11. On November 21, 2019, a petition was served on Noble which was filed by the Zichron Yaakov Local Council, Zalul Environmental Association, Jisr az-Zarqa Local Council, Megiddo Regional Council, Pardes Hanna-Karkur Local Council and Emek Hefer Regional Council (in this section: the "**Petition**" and the "**Petitioners**", respectively) against the Head of the Air Quality Division in the Ministry of Environmental Protection and against Noble (in this section: the "**Respondents**") with the Jerusalem District Court. In the Petition, the Court was asked to order the nullification of Leviathan's Emission Permit and to determine that there will be no activity in the Leviathan platform which involves the emission of gases. Alternately, the Court was asked to determine that approval of the rig's running-in plan will be cancelled. Also, an interim order was requested to prevent activity in the platform which requires an emission permit. On December 17, 2019, the Court decided to grant a temporary order whereby, until a decision otherwise, the Respondents will refrain from conducting operations in the Leviathan platform which involve emission of gases and that the emissions permit will be frozen (in this section: the "**Temporary Order**").

    On December 19, 2019, the court's decision was received, revoking the Temporary Order and denying the motion for an interim order. On January 5, 2020, a preliminary hearing was held on the Petition. On March 15, 2020, the court's judgment was issued dismissing the Petition with prejudice. On June 22, 2020, an appeal from the judgment was filed with the Supreme Court (in this section: the "**Appeal**"). In the Appeal it is sought to amend the emission permit and order that the pollutants emitted from the platform will not be monitored by Noble or an entity with which it engaged, but by the Head of the Air Quality Division with the Ministry of Environmental Protection or an entity selected by him; and to amend the emission permit such that all the provisions pertaining to maintenance, environmental management, environmental protection and identification and treatment of leaks will be determined in the emission permit itself, and not in an external program. A hearing in the Appeal was scheduled for June 30, 2021. In November 2020, the Petitioners filed a motion to bring forward the hearing. The hearing was scheduled for April 5, 2021. As of the date of approval of the financial statements, in the Partnership's estimation, based on the opinion of legal counsel representing the operator in the proceeding, at this stage the chances of the Appeal being rejected are greater than the chances it is granted.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

K. Legal proceedings (Cont.):

12. On January 19, 2020, the Homeland Guards Association (in this section: the "**Petitioner**") petitioned the Jerusalem District Court against the Ministry of Environmental Protection and Noble Inc., to order the Ministry of Environmental Protection to publish a reasoned decision regarding Noble Inc.'s request to deem the information on the Leviathan reservoir well flow as such that contains information which amounts to a trade secret. According to the Petitioner, the non-publication of a reasoned decision constitutes a violation of the provisions of the Clean Air Law by the Ministry of Environmental Protection. It was further argued that the Ministry of Environmental Protection violated its internal procedures which contemplate the examination of requests to recognize trade secrets. On June 3, 2020, Noble responded to the petition and argued that, since the petition does not move for a remedy of publication of any information or another remedy from Noble, Noble leaves the decision in the petition to the court's discretion. At the same time, it was argued that the Ministry of Environmental Protection did not violate the Clean Air Law or the internal procedures thereof. On June 17, 2020, the Ministry of Environmental Protection filed its answer in the petition claiming that the court ought to dismiss the petition with prejudice because it did not violate the Clean Air Law or the internal procedures thereof. A preliminary hearing on the petition was scheduled for May 23, 2021. As of the date of approval of the financial statements, in the Partnership's estimation, based on the opinion of legal counsel representing the operator in the proceeding, at this stage the chances of the Appeal being rejected are greater than the chances it is granted.

13. On December 15, 2020, a motion for class certification 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 environment pollution, due to prohibited emissions from the gas platform operated by the Respondents in the sea, which is located opposite Dor Beach, and treats the natural gas reservoir, Leviathan, in the period from the commencement of the platform's activity in December 2019 until a judgment is issued in the claim" (in this section: the "**Petitioner**" and the "**Class Members**"). The certification motion was filed against Noble and Chevron (in this section: the "**Respondents**"). In essence, the certification motion 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 certification motion) and damage of injury to autonomy due to the concern of health damage as aforesaid. The main remedy sought in the certification motion is compensation for the class for the damage it allegedly incurred which is estimated at approx. ILS 50 million. In addition, the Petitioner moved for a remedy of an order instructing the Respondents to immediately fulfill the obligations imposed thereon in the Clean Air Law and the regulations promulgated thereunder. A pre-trial hearing is scheduled for January 19, 2022. In the Partnership's estimation, based on the opinion of legal counsel representing the operator in the proceeding, at this stage the chances of the Appeal being rejected are greater than the chances it is granted.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

K. Legal proceedings (Cont.):

14. On August 26, 2019, PTT, which owns 25% of the shares of EMG, filed a claim with the Economic Court in Port Sa'id, Egypt, against EMG and other parties. In the complaint, PTT seeks revocation of the resolutions of the general meeting of EMG of June 10, 2019, including revocation of the resolution to approve the signing of the CLOA. PTT argues that such resolutions constitute minority oppression and are against the company's best interests, in violation of the Egyptian companies law, which applies to EMG. As of the date of approval of the financial statements, the hearing of the claim was postponed to April 2021.

15. On December 30, 2018, ORL submitted an application to the International Chamber of Commerce for institution of arbitration against EMG in accordance with the agreement for the sale of natural gas that was signed between them on December 12, 2010 (the "**EMG-ORL Agreement**"). ORL's main argument is that due to non-supply of natural gas in the term of the EMG-ORL Agreement and termination of the agreement, it suffered estimated damage of approx. $350 million. In addition, ORL's secondary argument is that contractual restrictions apply to liability which are estimated at approx. $45 million, plus interest. EMG asserts that ORL is not entitled to damages at all since the EMG-ORL Agreement was suspended due to *force majeure* events, and that ORL's claims are time-barred. EMG further claims that even if it is found that ORL is entitled to compensation for its damage, the sum of the compensation is limited to approx. $20 million in accordance with the terms and conditions of the EMG-ORL Agreement. Arbitration hearings were held from October 12, 2020 until October 16, 2020, and included written pleading submissions which continued until December 18, 2020. The arbitration award was issued to the parties on March 5, 2021, in which all of the claims against EMG were rejected, and ORL was charged with costs.

L. Regulation:

1. The Gas Framework:

a) On August 16, 2015, Government Resolution No. 476 (readopted by the Government Resolution of May 22, 2016) was adopted with respect to a framework for the increase of the natural gas quantity produced from the "Tamar" natural gas field and the expeditious development of the "Leviathan", "Karish" and "Tanin" natural gas fields and other natural gas fields (in this section: the "**Government Resolution**"), which took effect on December 17, 2015, upon the grant of an exemption from certain provisions of the Restrictive Trade Practices Law to the Partnership, Ratio and Noble (in this section: the "**Parties**") by the Prime Minister, in his capacity as Minister of Economy, pursuant to the provisions of Section 52 of the Economic Competition Law, 5748-1988 (in this section: the "**Exemption**" or the "**Exemption pursuant to the Restrictive Trade Practices Law**"), the main principles of which are presented below.

b) The restrictive trade practices in relation to which the Exemption was granted are as follows:

1) The restrictive trade practice that was ostensibly created, according to the Competition Commissioner's position, as a result of the acquisition of the rights in the Ratio-Yam permit by the Parties; and the restrictive trade practice that was ostensibly created as a result of the Parties' coming together as joint holders of the Ratio-Yam permit and the Leviathan reservoir.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

L. Regulation (Cont.):

1. **The Gas Framework (Cont.):**

   b) **The restrictive trade practices in relation to which the Exemption was granted are as follows (Cont.):**

      2) The restrictive trade practice that shall ostensibly be created in a case in which the Parties or some of them jointly market the gas that shall be extracted from the Leviathan reservoir to the domestic market until January 1, 2025.

      3) The restrictive trade practice that shall ostensibly be created in a case in which the Parties or some of them market the gas that shall be extracted from the Leviathan reservoir jointly for export only.

      4) The restrictive trade practice which may be created as a result of a certain agreement for the purchase of natural gas from the Leviathan reservoir, provided that such agreement is signed by January 1, 2025.

      5) With respect to their activity in the Tamar and Leviathan reservoirs only, the Partnership and Noble being the holders of a monopoly according to the Competition Commissioner's declarations.

   c) The exemption from the restrictive trade practices detailed in Paragraph (b) above is contingent, *inter alia*, on the fulfillment of the following conditions: Sale of the Partnership's full rights in the Karish and Tanin leases, sale of the Partnership's full rights in the Tamar and Dalit Leases within 72 months from the date of granting of the exemption under the Economic 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 instructions in connection with the development of the Tamar SW reservoir[34], an undertaking to invest in local content[35]. The Gas Framework also regulated issues pertaining to the export of natural gas, the existence of a stable regulatory environment and various taxation issues. And all subject to the conditions and directives set forth in the Gas Framework.

   d) As of the date of approval of the financial statements, the Partnership has sold its all of its holdings in the Karish and Tanin reservoirs (see Note 8B above), 9.25% (out of 100%) of its rights in the Tamar and Dalit Leases, and the Partnership continues to act to ensure its compliance with the conditions and provisions of the Gas Framework.

[34] For details regarding the mediation settlement, in which it was agreed to divide the Tamar SW Reservoir between the Tamar lease area (78%) and the Eran license area (22%), see Note 7C9B above.
[35] This undertaking regarding investment in local content was fully fulfilled.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

L. Regulation (Cont.):

2. **Environmental Regulation:**

   The Partnership acts to prevent and/or minimize the environmental hazards that may occur in the course of its operations, has prepared for the financial, legal and operating implications deriving from such laws, regulations and directives and allocates budgets for compliance therewith in the framework of its annual work plans for its various assets.

   a. On April 27, 2020, Noble received a notice from the Ministry of Environmental Protection of the intention to impose an administrative financial penalty due to alleged violations of the Prevention of Sea Pollution Law, and the sea discharge permit given to the Leviathan platform, while some of the alleged violations are with respect to the running-in period. On July 26, 2020, Noble filed written arguments in response to the aforesaid notice, and on November 12, 2020 the Ministry of Environmental Protection's decision was received whereby it was decided to cancel two of the four penalties which the Ministry intended to impose, and to partially reduce the amount of the two remaining penalties. Payment for this administrative financial penalty was transferred to the Ministry of Environmental Protection on December 11, 2020.

   b. On May 20, 2020, Noble received a notice from the Ministry of Environmental Protection of the intention to impose a financial penalty, in an immaterial amount, due to alleged violations of the emission permit given to the Leviathan platform and the Clean Air Law, and the Supervisor's instruction given by virtue thereof in connection with the continuous monitoring systems in the Leviathan platform. Noble informed the Partnership that that it submitted a request to the Ministry of Environmental Protection to receive information by virtue of the Freedom of Information Law, 5758-1998, which directly contemplates arguments raised in said notice and that the Ministry of Environmental Protection authorized to postpone the date of submission of arguments with regard to said administrative financial penalty and to schedule it 30 days after receipt of the information. As of the date of approval of the financial statements, it is impossible to estimate the chance of receipt of additional reductions in the administrative financial penalty amount or Noble's ability to bring about the cancellation of part of the components of the administrative financial penalty on the merit.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

L. Regulation (Cont.):

2. Environmental Regulation (Cont.):

b. (Cont.):

On July 1, 2020, Noble received an additional notice from the Ministry of Environmental Protection of the intention to impose a financial penalty, in an immaterial amount, due to alleged violations of the terms and conditions of the emission permit of the Leviathan platform and the Clean Air Law, with respect to the operation of flares on the production platform. On August 16, 2020, Noble filed its arguments with respect to this penalty with the Ministry of Environmental Protection. On December 13, 2020, the decision of the Ministry of Environmental Protection was received whereby it was decided to consolidate some of the penalties which the Ministry of Environmental Protection intended to impose and to cancel some, such that 4 penalties will be imposed on Noble, and to partially reduce the amount of one of the penalties. Payment for these administrative financial penalties was transferred to the Ministry of Environmental Protection on January 12, 2021. On January 28, 2021, another decision by the Ministry of Environmental Protection was received, cancelling one administrative financial penalty which was imposed in the context of its aforesaid decision and concurrently notifying that it intends to impose this administrative financial penalty while affording Noble the opportunity to supplement its arguments with respect thereto until February 28, 2021. However, Noble informed the Partnership that it had filed an application with the Ministry of Environmental Protection for information by virtue of the Freedom of Information Law, which directly concerns the claims that were raised in the administrative financial penalty notice as aforesaid, and concurrently, an application for an extension for the filing of its arguments within 30 days from the date of receipt of the requested information. At present, the freedom of information application and the extension application have not been granted, and therefore on March 7, 2021, Noble filed its arguments.

c. On January 19, 2021 (after the date of the Statement of Financial Position), Noble received a warning and an invitation to a hearing from the Ministry of Environmental Protection with regard to an alleged violation of the sea discharge permit that was given to the Leviathan platform, with respect to the open system waste standards set forth in the permit. On February 28, 2021, Noble sent the Ministry of Environmental Protection a letter of arguments in response to the warning and the invitation to a hearing. The hearing at the Ministry of Environmental Protection was scheduled for March 22, 2021.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

L. Regulation (Cont.):

3. **Directives on the provision of collateral in connection with the petroleum rights:**

   In September 2014, pursuant to Section 57 of the Petroleum Law, the Commissioner published directives for the provision of collateral in connection with petroleum rights.

   As of the date of the statement of financial position, the Partnership has deposited autonomous bank guarantees with the Ministry of Energy, in the amount of approx. $64 million in respect of the holding of the Leviathan, Tamar, Dalit, Ashkelon and Noa leases and the Alon D, New Ofek and New Yahel licenses, against bank credit.

   It is noted that the guarantee in respect of the Tamar Lease includes a guarantee that was provided in connection with approval that the Tamar partners received for the operation of a system for natural gas and condensate production from the Tamar Project.

4. **Directives on the manner of calculation of the value of the royalty at the wellhead:**

   a. In May 2020, the Director of Natural Resources at the Ministry of Energy released the final version of the directives on the method of calculation of the royalty value at the wellhead in accordance with Section 32(b) of the Petroleum Law, 5712-1952 (in this section: the "**Directives**"):

      1) The Directives state that the value of the royalty at the wellhead shall be equal to 12.5% of the price of sale to customers at the point of sale, net of costs deemed essential 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 purposes of calculation of the royalty value at the wellhead shall be expenses actually incurred by the lease holder between the wellhead and the point of sale specified above, provided that the Commissioner deems them essential for the sale of the petroleum: (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 transmission system; and (2) operating expenses (opex) arising directly from the types of capital expenses.

      2) The Commissioner shall from time to time determine, for each lease holder, specific directives for each lease, listing the deductible expenses for purposes of calculation of the royalty, according to the specific characteristics of the lease.

      3) Expenses due to assets will be recognized in such a way that the depreciation rate in respect of the fixed assets will be calculated according to the depletion method, starting from the date on which the fixed asset started to operate (i.e., only when the fixed asset reached the location and condition required for its operation, and started to operate). The total depreciation expenses which shall be recognized shall not exceed the cost of the fixed assets. The depreciation expenses shall be recognized for the fixed assets such that at the end of the "asset's life", the asset's value shall 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 – Contingent Liabilities, Engagements and Pledges (Cont.):

L. Regulation (Cont.):

4. Directives on the manner of calculation of the value of the royalty at the wellhead (Cont.):

a. (Cont.):

3) (Cont.):

Insofar as an agreement is signed which grants third parties an ownership right in the fixed assets or a right of use in the fixed assets, with or without consideration, or if an agreement is signed which includes the receipt of payment from third parties for the transportation or processing of petroleum, the assessment of the fixed asset value will be adjusted in the year in which an 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 purposes of calculation of the royalty value at the wellhead.

The assessment will be adjusted in the year in which the transaction in the relevant asset was made, in accordance with the "disposal principle". The lease holder may be required to pay royalties to the State for such value, even if it generated no income in that year.

The economic value for purposes of adjustment of the assessment will be limited to the amount recognized and depreciated for royalty purposes, in respect of the fixed asset sold or the rights of use in which were transferred.

4) The Directives determine additional provisions, including a specification of the types of expenses which will not be recognized, the method of recognition of abandonment 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 of Natural Resources at the Ministry of Energy released the "Directives of the Petroleum Commissioner regarding calculation of the royalty value at the wellhead – Tamar lease". Below is a summary of the directives received regarding the calculation of the royalty value at the wellhead in the Tamar lease:

1) Capex that will be recognized for purposes of calculation of 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 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 up to the entrance to the terminal in Ashdod will be recognized at a rate of 100%.

2) Operating expenses arising directly from the types *[sic]* specified in Paragraph (a) above, will be recognized at a rate of 82%: salary expenses of the worker 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 consulting; insurance expenses.

3) In the event that the sale price the contract *[sic]* includes a component of a transmission tariff that is paid to INGL, all of the transmission expenses paid by the lease holder will be recognized.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

L. Regulation (Cont.):

4. Directives on the manner of calculation of the value of the royalty at the wellhead (Cont.):

b. (Cont.):

4) Abandonment costs will be recognized for calculation of the royalty according to the provisions set forth in the general directives, and provided that at least 170 BCM in the aggregate were produced from the Tamar lease and the abandonment plan has been approved by the Commissioner.

5. Financing of projects for export through the national transmission system:

On March 23, 2020 the Natural Gas Commission released an addendum to the decision of September 7, 2014 on the financing of projects for export through the Israeli transmission system and the sharing of the construction costs of the Ashdod-Ashkelon combined section. In the Dolphinus agreements as provided in Sections C1C and C2D above, it was agreed that the Tamar partners and the Leviathan partners, as the case may be, will bear the costs of piping of the gas in INGL's transmission system. The addendum to the decision determines, *inter alia*, that the offshore segment of the transmission system that is due to be constructed such that it begins in the terminal in Ashdod and ends in the connection facility in the export facilities of Prima Gas Ltd. (the "**Combined Section**"); approx. 43.5% of the Combined Section cost, as the same will be determined, will be financed by the licensee and approx. 56.5% of the Combined Section cost will be financed by the exporter in accordance with the milestones to be determined in the transmission agreement between the exporter and the transmission licensee.

It is noted that on June 23, 2020, the Director General of the Natural Gas Authority announced that his ruling was that the cost of the section be estimated at the sum total of approx. ILS 738 million (the Partnership's share of which is estimated at approx. ILS 159 million). In addition, the amount of approx. ILS 48 million of which the exporter shall pay ILS 27 million to the holder of the transmission license (the Partnership's share of which is estimated at approx. ILS 6 million), for the bringing forward of doubling of specific transmission segments. Such costs shall be updated in accordance with a mechanism of update and accounting between the parties that would be incorporated into the transmission agreement and presented for his approval.

With regard to Noble's engagement with INGL in an agreement for transmission on a firm basis for the purpose of piping of natural gas from the Tamar reservoir and Leviathan reservoir to the EMG terminal in Ashkelon for the transmission thereof to Egypt see Section M below.

6. The decision of the Natural Gas Commission on regulation of criteria and rates regarding the operation of the transmission system in a flow control regime

On January 3, 2021, the Natural Gas Commission released an amendment to the Commission's decision on criteria and rates regarding the operation of the transmission system in a flow control regime, Decision No. 5/2020 (Amendment No. 2) (in this section: the "**Decision**"). The Decision stipulates that the costs for the UFG in the transmission system deriving from reasons that cannot be attributed to malfunction of the transmission system, but to factors that cannot be prevented or controlled such as measurement timing, pressure differences and temperature differences, will be borne by the gas suppliers. The Decision further stipulates that the UFG-T ranges from 0%-0.5% (positively or negatively). The costs for UFG-T will be divided equally between the gas suppliers and the gas consumers. The Decision shall take effect on April 1, 2021.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

L. Regulation (Cont.):

6. **The decision of the Natural Gas Commission on regulation of criteria and rates regarding the operation of the transmission system in a flow control regime (Cont.):**

   After the release of the Decision, INGL contacted Noble with 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 also forwarded for the inspection of Noble, a notice in this spirit which it provided to its customers. Further to the above 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 of the date of approval of the financial statements, Noble is considering its steps with regard to the Decision. In the Partnership's estimation, the aforesaid Decision entails costs in immaterial amounts. As of the date of approval of the financial statements, the Partnership is examining the implications of the Decision before taking legal action.

M. Engagement in a transmission agreement for the purpose of export of gas to Egypt:

On January 18, 2021 (after the date of the Statement of Financial Position), Noble engaged with INGL in an agreement for provision of transmission services on a firm basis as aforesaid for the purpose of piping of natural gas from the Tamar reservoir and Leviathan reservoir to EMG's terminal in Ashkelon for the transmission thereof to Egypt (the "**Transmission Agreement**").

1) In the Transmission Agreement, INGL undertook to provide transmission services for the natural gas that shall be supplied from the Tamar Reservoir and from the Leviathan Reservoir, including maintaining an annual base capacity in the transmission system of approx. 5.5 BCM (the "**Base Capacity**"). For the transmission services in relation to the Base Capacity, Noble will pay capacity fees and a payment for the gas quantity that shall actually be piped (throughput), in accordance with the accepted transmission rates in Israel, as shall be updated from time to time. In addition, INGL undertook to provide non-continuous transmission services, on an interruptible basis, of additional gas quantities over and above the Base Capacity, subject to the capacity that shall be available in the transmission system. For transmission of the additional quantities as aforesaid, Noble will pay a transmission rate for non-continuous transmission services in relation to the quantities that shall actually be piped. In the Partnership's estimation, the transmission system was planned in a manner that will allow transmission of the full contract quantity set forth in the export agreements.

2) In the Transmission Agreement, Noble committed to payment for the piping of a gas quantity that shall be no less than 44 BCM throughout the term of the agreement. If the parties agree on an increase in the Base Capacity, the minimum quantity for piping as aforesaid will be increased accordingly.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

M. Engagement in a transmission agreement for the purpose of export of gas to Egypt (Cont.):

3) The gas flow according to the Transmission Agreement will begin on the date on which INGL shall complete the construction of the Ashdod-Ashkelon transmission system section, in accordance with the provisions of the decision of the Natural Gas Council in connection with the financing of projects for export via the Israeli transmission system, and division of the costs of the construction of the Ashdod-Ashkelon combined section (see Paragraph 6) (the "**Council's Decision**"), and the doubling of the Sorek-Nesher and Dor-Hagit transmission system sections in a manner which will allow the piping of the full quantities under the Transmission Agreement (the "**Date of Commencement of the Piping**"). According to the Transmission Agreement, the Date of Commencement of the Piping is expected to be in the period between July 2022 and April 2023. With regard to quantities of gas that are supplied under the Tamar-Dolphinus and Leviathan-Dolphinus agreements see Sections C1C and C2D.

4) The transmission period under the 2019 agreement will be extended until January 1, 2024 or until the Date of Commencement of the Piping under the Transmission Agreement, whichever is earlier.

5) The Transmission Agreement will end on the earlier of: (1) the date on which the total quantity that is piped is 44 BCM; (2) 8 years after the Date of Commencement of the Piping; or (3) upon expiration of INGL's transmission license. In the Partnership's estimation, upon expiration of the term of the Agreement, no difficulty is expected with extending it at the transmission license holder's standard capacity and transmission rates at such time.

6) In accordance with the principles determined in the Council's Decision, Noble undertook to pay for the partners' share (56.5%) in the total cost of construction of the Ashdod-Ashkelon combined section, which is estimated at ILS 738 million. Noble also undertook to pay ILS 27 million for the partners' share in the costs of accelerating the doubling of the Sorek-Nesher and Dor-Hagit sections.

7) In accordance with the Council's Decision, the Leviathan partners and the Tamar partners will provide a bank guarantee to secure INGL's share in the cost of construction of the foregoing infrastructure, and to cover Noble's commitment to pay the capacity and transmission fees. In February 2021 (after the date of the Statement of Financial Position), the Partnership provided guarantees of approx. ILS 172.9 million for the benefit of INGL (see Note 12J8).

8) The Leviathan partners and the Tamar partners will bear the costs stated in Paragraph 6 and will provide the guarantees stated in Paragraph 7 at the rates of 69% and 31%, respectively.

9) In the Partnership's estimation, its share in the cost of construction of the Ashdod-Ashkelon combined section, the costs of accelerating the doubling of the Sorek-Nesher and Dor-Hagit transmission system sections may total approx. ILS 165 million.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

M. Engagement in a transmission agreement for the purpose of export of gas to Egypt (Cont.):

10) The Transmission Agreement determines that if the export of natural gas from the Tamar Project and from the Leviathan project to Egypt stops, Noble will be entitled to terminate the Transmission Agreement subject to payment of compensation to INGL due to the early termination, in an amount equal to 120% of the costs of construction of the Ashdod-Ashkelon combined section, plus the costs of accelerating the doubling of the Sorek-Nesher and Dor-Hagit sections, net of the amounts Noble paid until the date of the termination in respect of such construction and acceleration costs and in respect of the piping of the gas under the Transmission Agreement.

    If, after the termination of the Transmission Agreement, export to Egypt resumes, the Transmission Agreement will be renewed subject to and in accordance with the capacity that will be available in the transmission system at such time.

11) On February 15, 2021 all the closing conditions to the taking effect of the Transmission Agreement were met.

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 which determined that the Leviathan partners and the Tamar partners will be entitled to transmit gas (through Noble) under the Transmission Agreement, and will be responsible for fulfillment of Noble's undertakings under the Transmission Agreement, as if the Leviathan partners and the Tamar partners were a party to the Transmission Agreement in Noble's stead, each according to its share, as determined in the Capacity Allocation Agreement between the Leviathan partners and the Tamar partners. The services agreement further determined that the Base Capacity that is kept in the transmission system for Noble will be allocated between the Leviathan partners and the Tamar partners according to the rates specified in Paragraph 8 above, and according to the order set forth in the Capacity Allocation Agreement. The aforesaid notwithstanding, the Leviathan partners and the Tamar partners will bear capacity fees at a fixed ratio of 69% (the Leviathan partners) and 31% (the Tamar partners), except in a case where a party (the Leviathan partners or the Tamar partners, as the case may be) used the available share in the capacity of the other party.

N. Balancing agreement for separate sales from the Tamar reservoir:

On February 23, 2021 (after the date of the Statement of Financial Position), the Tamar partners signed a detailed agreement, the purpose of which is to determine the detailed mechanisms and rules in connection with the taking of the share of any one of the Tamar partners in the gas output in accordance with the JOA, and balancing arrangements that shall apply between the partners in the event that the marketing of the gas is not performed according to the proportionate share of the partners in the output as aforesaid (the "**Balancing Agreement**" or the "**Agreement**"). Below are the main principles of the Agreement:

1) Each one of the partners will be entitled to join a contract for the supply of gas from the Tamar reservoir ("**Supply Contract**") that shall be signed by another partner, as a full party, according to its proportionate share in the reservoir and the mechanisms and terms and conditions determined in the Agreement (the "**Tag Along Right**"). With respect to a Supply Contract for export, the Tag Along Right is subject to arrangements that shall be agreed between the partners on a specific basis in relation to each Supply Contract for export.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

N. Balancing agreement for separate sales from the Tamar reservoir (Cont.):

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 ("**Oversupply Partner**"), after each one of the other partners has first been afforded the possibility of nominating its full proportionate share in the output, and a certain partner shall not have marketed its full share in the daily output ("**Undersupply Partner**"). In such a case, balancing arrangements shall 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 (i.e.: through a payment to be made by an Oversupply Partner to an Undersupply Partner) or in gas (i.e.: 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 determined mandatory monetary balancing arrangements in each one of the following cases: (1) when excess gas quantities have accrued in favor of an Undersupply Partner in a volume exceeding a cap determined in the Agreement; (2) on the date on which the operator shall have determined 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 forth in the Agreement.

3) The operator will be responsible, *inter alia,* for implementing the provisions of the Agreement and managing the nominations thereunder, as well as for supplying the gas at the delivery point in accordance with its instructions. 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 JOA.

4) In the case of a discrepancy between the Agreement and the JOA, the provisions of the Agreement shall prevail.

5) Each party to the Agreement will bear the payment of the taxes, the statutory royalties, the levies and the statutory payments that apply in respect of 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 taking effect of the Balancing Agreement is subject to the approval of the Competition Authority. In the event that such approval is not received by May 31, 2021, the Agreement will be terminated by the giving of prior notice of 30 days by any of the parties thereto (unless the said approval is received prior to conclusion of the Agreement). The Agreement will be in effect until the conclusion of the JOA.

7) Insofar as any of the partners shall seek to transfer its interests in the Tamar lease to another/others, the said interests shall be transferred together with the rights and undertakings of the partner under the Balancing Agreement.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

N. Balancing agreement for separate sales from the Tamar reservoir (Cont.):

8) The law that governs the Agreement is the law of England and Wales. Any dispute between the parties that is not resolved in accordance with the mechanism set forth in the Agreement shall 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 which pertain, *inter alia*, to the available output, the allocation of nominations and the date stated in Section 2(2) above, or a determination of any party to the Agreement regarding the relevant prices for the performance of monetary balancing, may refer the issue to be decided by an expert who shall 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. Insofar as the expert does not decide the dispute, the dispute will be referred to arbitration as aforesaid.
9) Implementation of the provisions of the Agreement requires the establishment of various systems and the adoption of procedures as well as receipt of approvals and clarifications from the tax authorities and various 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).

Note 13 – Equity:

A. The participation units are issued by the limited partner (the Trustee) and confer upon the holders thereof a working interest in the rights of the limited partner in the Partnership. The units are held thereby in trust in favor of the unit holders and under the supervision of the Supervisor.

B. The unit holders' register records, as of December 31, 2020: 1,173,814,691 units (identical to December 31, 2019: 1,173,814,691), of par value ILS 1 which are listed on TASE.

C. Distribution of Profits:

1. The partnership agreement and the trust agreement:

a) The limited partnership agreement, as amended, prescribes rules regarding the profit distribution in the Partnership, and, *inter alia*, entitles the General Partner to refrain from or delay a profit distribution, to the extent required, for the purpose of financing the Partnership's operations, in the manner and on the terms and conditions stipulated by the agreement and by the general meetings. On the date of approval of the financial statements, there are no external limitations which may affect the Partnership's ability to distribute profits in the future, other than limitations deriving from the provisions of Section 19 of the Natural Resources Profit Taxation Law (see Note 20A), and limitations stipulated in the financing agreements.

b) The trust agreement, as amended, prescribes rules regarding the manner of distribution of profits that shall be received from the partners by the Trustee to the unit holders, and the portion that shall remain with the Trustee as sums required thereby, *inter alia*, for the payment of payments and expenses and for the performance of actions set forth in the trust agreement, the amount of which will be determined from time to time, by the Trustee with approval from the Supervisor.

Note 13 – Equity (Cont.):

C. Distribution of Profits (Cont.):

2. The profit distribution amounts:

Date of declaration of profit distribution	Date of profit distribution	Overall distribution amount in millions	Distribution amount per participation unit
24.12.2018	14.1.2019	ILS 130[36]	ILS 0.1107500
13.8.2019	5.9.2019	$150	$0.12779
7.12.2020	17.11.2020	$65	$0.05537

3. Distributions to the limited partner:

a) On November 20, 2018, the board of directors of the General Partner approved a distribution to the limited partner in the sum of approx. ILS 1 million (approx. $270 thousand).

b) On May 1, 2019, the board of directors of the General Partner approved a distribution to the limited partner in the sum of approx. ILS 1.2 million (approx. $334 thousand).

c) On February 12, 2020, the General Partner's board approved a distribution to the limited partner in the sum of ILS 1 million (approx. $290 thousand).

d) On November 1, 2020, the General Partner's board approved a distribution to the limited partner in the sum of ILS 1 million (approx. $298 thousand).

Such distributions will be used for payment of the fees of the Supervisor and Trustee, in accordance with the provisions of the trust agreement.

D. Payments of Tax Advances, Tax and Balancing Payments:

1. In accordance with the provisions of Section 19, the General Partner paid the Income Tax Authority, on account of the tax owed by participation unit holders due to the tax years (for further details see Notes 20A and 20C), as specified below:

Tax Year	Tax Advances in ILS millions	ILS per Participation Unit
2018	Approx. 102.3	0.0871
2019	Approx. 143.2	0.1219
2020	Approx. 112.3	0.0957

2. On December 23, 2019, the Partnership declared tax payments to individual holders and balancing payments to non-individual holders in the amount of approx. ILS 116.3 million that constitute approx. 0.0990945 per participation unit that were distributed on January 9, 2020.

3. On December 27, 2020, the Partnership declared tax payments to individual holders and balancing payments to non-individual holders in the amount of approx. ILS 117.2 million that constitute approx. 0.0998676 per participation unit that were distributed on January 20, 2021.

[36] In accordance with the Supreme Court's decision regarding Section 19 as specified in Note 20A, the main part of these payments which constitute tax payments pursuant to Section 19 with respect to the taxable income of the Partnership and balancing payments to holders which are a body corporate, do not constitute a "distribution" within its definition in the law.

Notes to the Financial Statements for December 31, 2020 (Dollars in thousands)

Note 13 – Equity (Cont.):

E. The composition of equity as of December 31, 2020 is as follows:

	The Limited Partner	The General Partner	Total
The Partnership's equity	154,776	15	154,791
Capital reserves	(48,611)	(5)	(48,616)
Retained earnings	891,431	89	891,520
Balance as of December 31, 2020	997,596	99	997,695

The limited partner's share in the Partnership is 99.99%, and the share of the General Partner is 0.01%. The General Partner in the Partnership has also an indirect holding through participation units that were issued by the limited partner (the Trustee).

F. On May 14, 2019, the Partnership released a shelf prospectus report, for the issue of various securities, including *inter alia* participation units, bonds and warrants. The shelf prospectus is in effect for 24 months, with an option for extension by 12 more months.

G. Capital reserve for transactions between a corporation and the control holder thereof – The Partnership recorded in the statements of comprehensive income expenses against a capital reserve for transactions between a corporation and a control holder thereof in respect of the costs of employment of officers of the General Partner including the employment terms of the CEO of the General Partner and in respect of additional expenses borne by the General Partner, over and above the payment of the management fees that the Partnership pays the General Partner.

H. Option plan:

On July 13, 2016, the board of the General Partner resolved to adopt a phantom unit plan (the "**Plan**") for several senior officers of the Partnership and the General Partner.

According to the terms and conditions of the Plan, 1,600,278 phantom units were granted (out of which the General Partner granted 72,740 phantom units), whose underlying asset is a participation unit conferring a working interest in the rights of the limited partner in the Partnership, that expired during October 2019.

In 2019, income was recorded of approx. $171 thousand pursuant to an update to the liability with respect to the options (2018: income of approx. $11 thousand). In the report period, income was recorded on the comprehensive income statement of approx. $13 thousand (pursuant to an update to the liability with respect to the options) for options granted to an officer of the Partnership for 174,064 phantom units granted in March 2018.

With respect to the phantom units granted to the CEO of the General Partner in the Partnership, see Note 21C.

Notes to the Financial Statements for December 31, 2020 (Dollars in thousands)

Note 14 – Revenues from the Sale of Natural Gas and Condensate:

A. The Partnership's revenues originate from natural gas and condensate sales to its customers, all in accordance with engagement agreements signed therewith, as specified in Note 12 above.

B. The percentage of sales to the IEC in 2020 was approx. 32% (2019: approx. 46%; 2018: approx. 48%) of the sales, to NEPCO and Dolphinus in 2020 approx. 19% and approx. 17% of the sales, respectively. See also Note 22G below.

C. The total quantity of natural gas sold in the report year in the Leviathan and Tamar projects amounted to approx. 15.5 BCM (2019: approx. 10.5 BCM; 2018: approx. 10.5 BCM) and the total quantity of condensate sold at the Leviathan and Tamar Projects in 2020 amounted to approx. 417.2 thousand barrels (2019: approx. 482.3 thousand barrels; 2018: approx. 477 thousand barrels).

D. The Partnership's share in the revenues and in the quantities of natural gas sold in the report period to the domestic market and to the regional market (i.e. sales to Egypt and Jordan) totaled approx. $574.7 million (constituting approx. 3.3 BCM) and approx. $344.4 million (constituting approx. 1.8 BCM), respectively. In 2019, the volume of sales to the regional market was immaterial.

E. The recognition of the revenues from the sale of natural gas from the Leviathan project began in January 2020. Note that the production from the Yam Tethys project was discontinued in May 2019 due to exhaustion of the reservoirs in the project.

Note 15 – Royalties:

A. Composition:

	For the year ended		
	31.12.2020	**31.12.2019**	**31.12.2018**
Royalties to the State (Note 12B above and Paragraph B below)	101,465	52,657	51,123
Royalties to interested parties (Note 12B above and Paragraph B below)	25,201	32,726	32,123
Royalties to a third party (Note 12B above and Paragraph B below)	27,598	8,935	8,087
Total	154,264	94,318	91,333

B. Royalties to the State and overriding royalties (to interested and third parties) as included on the Partnership's books:

	For the year ended		
	31.12.2020	**31.12.2019**	**31.12.2018**
Rate of the royalties in Tamar Project:			
To the State	11.34%	11.3%	11.22%
To interested parties	4.75%	7.18%	6.85%
To a third party	4.26%	1.8%	1.78%
Rate of the royalties in Leviathan project:			
To the State	10.81%	-	-
To interested parties	1.61%	-	-
To a third party	2.28%	-	-
Rate of the royalties in Yam Tethys Project:			
To the State	-	11.61%	11.28%
To interested parties	-	7.62%	7.4%
To a third party	-	1.38%	1.34%

Note 15 – Royalties (Cont.):

B. Royalties to the State and overriding royalties (to interested and third parties) as included on the Partnership's books (Cont.):

1. From the start of production from the Tamar reservoir the Partnership pays, under protest, advances on account of royalties to the State at rates between 11.3%-12% as determined by the Ministry of Energy.
2. In September 2020, the Director of Natural Resources at the Ministry of Energy published specific directives on the method of calculation of the royalty value at the wellhead in the Tamar project (the "**Specific Directives**"), which determined the rate of the deductible expenses in the calculation of the royalty value at the wellhead. Based on the estimates and appraisals of the Partnership, there are no material differences between the amounts recorded in the Statement of Comprehensive Income in the report period as expenses for royalties and the royalty expenses as would have been calculated in accordance with the Specific Directives. It is clarified that there are material differences between the royalties actually paid to the Ministry of Energy in the aggregate from commencement of production from the Tamar project and the amounts recorded in the Statement of Comprehensive Income as royalty expenses (see Paragraph 7 below).
3. From the date of commencement of the supply of gas from the Leviathan reservoir, the Leviathan partners have been paying the State advances on account of the State's royalties on revenues from the Leviathan project, at the rate of 11.26% and the specific directives on the method of calculation of the royalty value at the wellhead for the Leviathan lease have not yet been published.
4. It is noted that it is the position of the Partnership that the calculation of the actual rate of the State's royalties from the Tamar and Leviathan project should reflect the complexity of the project, the risks involved therein and the amount of the investments in the project.
5. In February 2019 an agreement was signed between the Yam Tethys partners and the Ministry of Energy in connection with final royalties reports for the years 2011-2013. The agreement determines that the Yam Tethys partners are entitled to the amount of approx. $4.4 million (100%) that was repaid by way of setoff against royalty payments in the Yam Tethys project.
6. For details regarding a claim for the restitution of royalties paid to the State by the Partnership and Noble in respect of their revenues deriving from the supply of natural gas from their share in the Tamar Project to their customers, under the Yam Tethys project agreements, see Note 12K1 above.
7. The difference between the royalties that were actually paid to the State and the effective royalty rate applied by the Partnership in its financial statements in the Tamar and Leviathan projects amounted to approx. $19.5 million (2019: approx. $17.6 million), and was included in the other long-term assets item. See Note 8A above.
8. The manner of calculation of the royalties to the State, is also used for calculation of the market value at the wellhead of the overriding royalties paid by the Partnership to interested parties and to third parties. The difference between the royalties that were actually paid to related parties and to third parties and the effective royalty rate on which the Partnership relied in its financial statements of the Tamar Project and the Leviathan project, in an amount of approx. $7.8 million (2019: approx. $5.6 million), is included in the other long-term assets item, see Note 8A above.

Note 15 – Royalties (Cont.):

B. Royalties to the State and overriding royalties (to interested and third parties) as included on the Partnership's books (Cont.):

9. As of the date of approval of the financial statements, no royalties are paid from the Tamar project to interested parties.

10. Further to Note 12B2 and in view of the fact that the Royalty Interest Owners include the Partnership's control holders, the board of the General Partner decided to authorize the audit committee (which comprises external and independent directors only) to handle the issue of the investment recovery date in the Tamar Lease, including an examination of issues arising from a report prepared by an external economic advisor (the "**Advisor**" and the "**Advisor's Report**", respectively), who was appointed by the Supervisor, clarifying the various issues vis-à-vis the Royalty Interest Owners and taking any other step as the committee deems fit, at its discretion, and all in the best interests of the Partnership.

    According to the board's resolution, the audit committee was authorized to retain the services of external, independent professional advisors at its discretion and at the Partnership's expense, to provide legal and economic support to the process, and to determine the terms of compensation of such advisors. The audit committee has been asked to form its recommendations on the matter and present the same to the board. On September 4, 2018, the audit committee and subsequently the board (without directors who hold office in the control holder) approved a calculation of the investment recovery date, whereby the investment recovery date falls in January 2018.

    It is noted that the calculation was approved by the audit committee and the board of directors after the receipt of a special report by the auditors upon completion of a special audit by them, and based on independent legal advice to the audit committee.

    In view of the arbitrator's decision regarding a dispute on the electricity production tariff (PUA) with OPC pursuant to which the Partnership updated its results for the period which was in dispute, the Partnership approached the Royalty Interest Owners on July 31, 2019, with a demand for reimbursement of overpaid royalties in the sum of approx. $0.3 million (the "**Reimbursement Amount**"), due to the update of the investment recovery date arising from the arbitrator's decision (the "**Letter of Demand**"). Since the Royalty Interest Owners objected to the Letter of Demand and denied the Partnership's demand for reimbursement of royalties, the Partnership performed a setoff of the Reimbursement Amount. For additional details, see Note 12K6 above.

Notes to the Financial Statements for December 31, 2020 (Dollars in thousands)

Note 16 – Cost of Natural Gas and Condensate Production:[37]

Composition:	For the year ended		
	31.12.2020	31.12.2019	31.12.2018
Salaries and social benefits	29,212	6,278	6,737
Guarding and security	4,090	1,980	1,976
Insurance	21,031	4,535	4,460
Transmission and transportation costs	18,893	5,127	4,346
Operation management and operator fee	17,253	5,307	5,416
Maintenance and others	23,478	17,504	9,785
Total	113,957	40,731	32,720

Note 17 – Other General Expenses[38]:

Composition:	For the year ended		
	31.12.2020	31.12.2019	31.12.2018
Seismic surveys	-	1,028	834
Direct and other expenses, including professional services[39]	3,611	13,270	8,886
Total	3,611	14,298	9,720

Note 18 – G&A Expenses:

Composition:	For the year ended		
	31.12.2020	31.12.2019	31.12.2018
Salaries and social benefits[40]	3,748	3,155	2,883
General Partner management fee expenses	960	960	960
Cost of participation unit-based payment to the CEO (see Note 21C below)	487	411	182
Professional services, net[41]	6,559	5,439	4,745
Other	2,876	1,165	1,041
Total	14,630	11,130	9,811

[37] Mostly through the joint ventures.
[38] Mostly through the joint ventures.
[39] Mostly G&A expenses of the Leviathan (for the years 2018-2019) and Cyprus projects.
[40] In previous years, including revenues from the revaluation of compensation to employees including a liability of share-based payment to the Partnership's employees 2019: approx. $171 thousand; 2018: approx. $66 thousand.
[41] Including expenses in the account year in the sum of approx. $1,964 thousand (2019: $2,467 thousand, 2018: $1,654 thousand) carried against a capital reserve (see Note 13G above).

Notes to the Financial Statements for December 31, 2020 (Dollars in thousands)

Note 19 – Financial Expenses and Income:

A. Composition:

	For the year ended		
	31.12.2020	31.12.2019	31.12.2018
Expenses:			
Due to bonds (Notes 10B, 10C and 10E)	122,294	35,898	48,954
Due to liability to banking corporations (Note 10D)	99,428	4,173	800
Due to transactions in financial derivatives (hedge accounting)	7,394	373	-
Due to revaluation of short-term investments	-	-	1,594
Due to a guarantee fee to Delek Group (Note 12J4)	368	368	402
Due to changes in oil and gas asset retirement obligation due to lapse of time	2,189	4,637	5,070
Other	839	2,038	612
Total expenses	232,512	47,487	57,432
Income:			
Due to deposits in banks and short-term investments	1,781	9,476	9,811
Revaluation of royalties receivable and a loan that was extended (Note 8B)	82,743	57,342	48,350
Dividend from a financial asset	-	9,040	-
Other	3,799	2,532	988
Total income	88,323	78,390	59,149
Total financial income (expenses), net	(144,189)	30,903	1,717

B. In 2020 credit costs were not capitalized to oil and gas assets, 2019: approx. $150,862 thousand were capitalized, 2018: approx. $108,940 thousand were capitalized. The cap rates used to determine the amount of the capitalized credit costs in 2019: approx. 5.2%-7.4%, 2018: approx. 5.0%-7.8%.

Note 20 – Oil and Gas Profit Levy and Taxes:

A. Information regarding income tax rules and the main arrangements existing as of the date of the statement of financial position:

1. The Partnership was approved by the Director General of the Tax Authority as a "partnership" for the purpose of the Income Tax Regulations (Rules for the Calculation of Tax due to the Holding and Selling of Participation Units in an Oil Exploration Partnership), 5749-1988 (the "**Participation Unit Regulations**"). The term of the Participation Unit Regulations has been extended on an annual basis until June 30, 2015. However, another extension of the term of these regulations has not yet been issued.

Note 20 – Oil and Gas Profit Levy and Taxes (Cont.):

A. Information regarding income tax rules and the main arrangements existing as of the date of the statement of financial position (Cont.):

2. The Partnership is a "transparent" entity for tax purposes according to the provisions of the Income Tax Ordinance (New Version) 5721-1961 (the "**Income Tax Ordinance**") and the Taxation of Profits from Natural Resources Law, 5771-2011 (the "**Law**") and the taxable income, and losses of the Partnership are attributed to the unit holders who are an "Entitled Holder", as this term is defined in the Participation Unit Regulations, according to the ratio of their holdings in the Partnership. An "Entitled Holder" is an entity that held participation units at the end of December 31 of the tax year.

3. According to Section 19 of the Law ("**Section 19**") regarding Section 63(a)(1) of the Ordinance, the share of each partner in the tax year will be calculated from the taxable income of the Partnership or from the losses thereof.

Because the Partners bear the tax results of the revenues and expenses of the Partnership, the financial statements do not include taxes on income.

4. During October 2020, the draft Income Tax Regulations (Rules for the Calculation of Tax due to the Holding and Sale of Participation Units in Oil Exploration Partnerships) (Amendment), 5781-2020 (the "**Draft Regulations**"), were published for public comment. According to the Draft Regulations, it is proposed to determine, *inter alia*, that from the tax year 2021, petroleum partnerships whose units are listed on TASE will be taxed as a company, using the two-stage tax method, from the tax year in which the petroleum partnership generated taxable income or distributed profits.

As of the date of approval of the financial statements, the Partnership is examining the potential implications of the Draft Regulations on its operations. In accordance with the Partnership's initial estimate according to the data as of the date of the statement, approval of the Draft Regulations in the current format thereof may create for the Partnership, *inter alia*, a one-time accounting obligation to record a liability for deferred taxes in the sum of approx. $294 million (out of total equity of approx. $998 million as of December 31, 2020) which will affect the Partnership's results and reduce its profits available for distribution, and later, to record current and deferred tax expenses on an ongoing basis.

It is noted that on November 4, 2020, the Partnership submitted its comments on the Draft Regulations to the Tax Authority.

5. According to approvals given to the Partnership in the past by the Tax Authority, the Partnership undertook not to take loans in an amount exceeding 3% of the amount to be raised from the investors in the Partnership, other than in coordination with and subject to the advance approval of the Tax Authority. For the purpose of raising loans to fund the Partnership's operations, the Partnership applies to the Tax Authority from time to time to obtain the approval required as aforesaid.

Note 20 – Oil and Gas Profit Levy and Taxes (Cont.):

A. Information regarding income tax rules and the main arrangements existing as of the date of the statement of financial position (Cont.):

6. According to the provisions of Section 19, the General Partner is obligated to submit to the assessing officer a report on the taxable income of the Partnership and to pay the tax deriving therefrom, on account of the tax for which the partners in the Partnership are liable in the tax year in respect of which the report was filed (i.e., on account of the tax for which the holders of the participation units, as being on December 31 of each tax year, are liable) (the "**Entitled Holders**"). Pursuant to the provisions of Section 19, the tax that the General Partner is required to pay upon the filing of the report shall be calculated according to the share in the Partnership of the Entitled Holders who are a body corporate ("**Corporate Holders**") and the share in the Partnership of the Entitled Holders who are individuals ("**Individual Holders**"), while for this purpose, the liable income of Individual Holders shall be deemed to be subject to the maximum tax rate, unless it is proven to the assessing officer that the tax rate applicable to such individual is lower than the said rate ("**Calculation of the Tax Pursuant to Section 19**").

7. In the context of a motion for instructions that the Supervisor filed with the court on October 30, 2016, the interpretation and manner of implementation of Section 19 was discussed for the first time. On November 1, 2017, the District Court's judgment was received, in which it was ruled *inter alia* that: (a) the tax payment that derives from the provisions of Section 19 should not be deemed as an equal distribution, in a uniform amount per unit, but rather as a differential payment according to the various tax rates which apply to individuals and corporations; (b) payment of the tax under Section 19 creates a difference in the expense incurred by the Partnership between individuals and corporations, but Section 19 concerns the collection of tax and not regulation of the relations between the holders of the participation units; and (c) as long as the collection arrangement prescribed in Section 19 is in effect, the Partnership and/or the General Partner are required to find the appropriate method to balance between the additional expense entailed by the tax rate applicable to Individual Holders and the expense entailed by the tax rate applicable to Corporate Holders.

On December 31, 2017, the Partnership's General Partner filed an appeal from the judgment of the District Court (in this section: the "**Partnership's Appeal**").

On July 28, 2019, the Supreme Court's judgment was received, denying the appeal filed by the Partnership and the appeal filed by another petroleum partnership (in this section: the "**Appeal Judgment**"). The Supreme Court adopted the judgment of the District Court and ruled, *inter alia*, that an arrangement in which the Partnership shall bear the full tax rate of the holders, individuals and corporations alike, as mandated by Section 19, and in addition or further thereto, shall make balancing payments to Corporate Holders, is not a "distribution" as defined in the law, but rather an outcome mandated by the fact that payments were made out of the profits on account of the tax. However, the Supreme Court clarified that it does not purport to make recommendations or to set hard and fast rules regarding the balancing payments technique.

Note 20 – Oil and Gas Profit Levy and Taxes (Cont.):

A. Information regarding income tax rules and the main arrangements existing as of the date of the statement of financial position (Cont.):

7. (Cont.):

In proximity to the end of the tax years 2017-2020, alongside payments on account of the tax that applies to Individual Holders, the Partnership made balancing payments to Corporate Holders. It is noted that the balancing payments that were made as aforesaid in respect of these tax years do not necessarily constitute full balancing between the payment derived from the tax rate applicable to Individual Holders and the payment derived from the tax rate applicable to Corporate Holders, since insofar as there is a gap between the estimated liable income according to which the payments were made and the final assessment that shall be issued to the Partnership in the future (the "**Differences**"), the Partnership shall be required to pay the Tax Authority (or receive as a refund therefrom) the tax difference mandated by the Differences. It is noted that as of the date of approval of the financial statements, there is ambiguity as to the appropriate balancing arrangement in relation to tax payments deriving from the Differences, if any (see also Section 9 and 10 below). Since, in respect of the tax years 2015 and 2016 (the "**Past Periods"**), balancing payments were not made, as were made in respect of the tax years 2017-2020, on the date of the financial statements there is ambiguity as to the proper balancing arrangement that the Partnership should implement with respect to the Past Periods.

In view of the existing ambiguity regarding the proper balancing arrangements which the Partnership should apply, in respect of both the Past Periods and the Differences that will transpire only in the future, the Partnership and the General Partner filed an originating application with the Tel Aviv District Court, in the context of which the court was moved, *inter alia*, to determine the appropriate arrangements for striking a balance between individuals and corporations holding Participation Units of the Partnership, in view of tax payments the Partnership is required to make pursuant to Section 19, including: (a) Tax payments insofar as any derive as a result of a difference between the estimation of the taxable income made by the Partnership toward the end of the tax year and the self-assessment submitted by the Partnership; and/or tax payments insofar as any derive from a difference between the self-assessment submitted by the Partnership and the final tax assessment issued therefor (the "**Assessment Differences**"); and (b) Tax payments made due to the past period; considering the fact that it is possible that an Entitled Holder that held a Participation Unit on the record date for a tax year in Past Periods, will no longer hold the same when it transpires (if at all) that the Partnership is required to pay an additional tax for that tax year (or vice versa) and considering the difference in the rates of the tax which apply to individuals and corporations. In the originating application, the court was presented with various possible alternatives for arrangements in connection with the tax payments due to Assessment Differences and due to Past Periods, for it to rule what such proper arrangements are. In this context, the Partnership presented the court with several possible solutions, including:

Note 20 – Oil and Gas Profit Levy and Taxes (Cont.):

A. Information regarding income tax rules and the main arrangements existing as of the date of the statement of financial position (Cont.):

7. (Cont.)

(a) A solution based on balancing by way of reimbursement[42]; (b) A solution whereby no balancing payments shall be made to Corporate Holders (in respect of both the past period and Assessment Differences); and (c) A solution whereby the Partnership shall make balancing payments to Corporate Holders, according to a number of alternatives. In respect of the past period, the alternatives for the making of balancing payments to corporations which held the participation units at the end of each one of the tax years 2015-2016 shall include, *inter alia:* (1) Payment to the said Corporate Holders in the amount of the "surplus" amount which was paid for Individual Holders in the past period, in a total amount of approx. $13.1 million; (2) Payment in the amount which would have been paid to the said Corporate Holders, had full balancing payments been made in the past period, in a total amount of approx. $73.9 million; (3) A combined method payment, which takes into account that some of the Corporate Holders no longer currently hold the units. Regarding the solutions and alternatives existing in respect of the past period as specified above, in the Partnership's estimation, based on an opinion of its legal advisors, there is a more than 50% chance that the Partnership will be required to make balancing payments to Corporate Holders in respect of the past period in the amount of at least $13.1 million, but in view of the ambiguity with respect to the court's decision regarding the past period, and in view of the disadvantages of each one of the said alternatives, and in consideration of the gamut of circumstances and considerations, as well as the complexity of the case, the Partnership and its legal advisors are unable to estimate the probability that any one of the said alternatives will be adopted by the court, and therefore they are unable to estimate the probability that the Partnership will be required to pay more than $13.1 million. Accordingly, in 2019 the Partnership recognized a provision of approx. $12.3 million which was recorded against the profit balance in the Partnership’s capital and which was updated in view of changes in the exchange rate in the report year to approx. $13.1 million. It is noted that the estimated amount of the balancing payments in respect of the tax year 2016 is based on a self-assessment report of the Partnership, in respect of which disputes have arisen between the Partnership and the Tax Authority. It is noted that decisions on such disputes may materially change the Partnership's liable income for 2016, and accordingly the amount of the balancing payments deriving therefrom. 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 held thereby shall 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 translated from shekels to dollars according to the dollar rate known as of December 31, 2020.

[42] According to this solution, in respect of the past period, Individual Holders will repay, at the end of the applicable tax year, a relative portion of the tax payments that the Partnership paid on their behalf, and such sums will be distributed to Corporate Holders on the same dates, in order to achieve equality between the different holders. Regarding Assessment Differences, according to this solution the holders will repay, at the end of the applicable tax year (individuals and corporations) to the Partnership, the tax amounts for the Assessment Differences that will be paid on their behalf by the Partnership.

Note 20 – Oil and Gas Profit Levy and Taxes (Cont.):

A. Information regarding income tax rules and the main arrangements existing as of the date of the statement of financial position (Cont.):

7. (Cont.):

On October 18, 2020, the court approved the motion of the Partnership and the General Partner to effect alternative service of process on holders of participation units by way of advertising a public notice, which enabled each holder of a participation unit of the Partnership on the dates that are relevant to the originating application (including all the holders of participation units of the Partnership at the time of filing of the proceeding) to join the proceeding as a party. The court also ordered that the originating application be heard together with an originating application filed by the partnership Isramco on the same matter (O.A. 32178-03-20). On December 29, 2020, another pre-trial hearing was held, in which the court asked for 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 ordered that the parties may apply to the Tax Authority to find out its detailed position with respect to such proposals and thereafter submit to the court a summary document which presents 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 updated the estimate of its taxable income for each of the tax years 2019 and 2020. Since as of the date of the financial statements there is unclarity regarding the proper balancing arrangement that the Partnership should adopt regarding Assessment Differences, considering the complexity of the matter and the inability to assess the probability regarding the amount 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 has recorded no provision in the financial statements in respect of the aforesaid.

8. The income tax audit for the Partnerships' tax reports for 2015 has ended and an assessment agreement has been signed in July 2018, but a final tax certificate has not yet been released since the Income Tax Regulations have not yet been extended.

According to the assessment agreement, the taxable income of the Partnership and the Avner Partnership in 2015 is approx. ILS 317.4 million and approx. ILS 293.3 million, respectively, in respect of which the Partnership and the Avner Partnership paid tax on account of the holders of the units in the Partnership and the Avner Partnership in the sum of approx. ILS 92 million and approx. ILS 88 million, respectively.

9. On December 13, 2017, the Partnership published a temporary tax certificate for an entitled holder for the holding of a participation unit for the tax year 2016 (in each of the Partnerships). A final tax certificate will be issued upon conclusion of the proceedings described below with respect to the 2016 tax assessment, and subject to the extension of the Participation Unit Regulations. The final tax certificate may be materially different than the temporary tax certificate.

Note 20 – Oil and Gas Profit Levy and Taxes (Cont.):

A. Information regarding income tax rules and the main arrangements existing as of the date of the statement of financial position (Cont.):

9. (Cont.):

It is further noted that against the background of the disputes that have arisen between the Partnership and the Tax Authority and disagreements regarding the amount of the partnerships' taxable income for 2016, assessments to the best of judgment were received from the Tax Authority on November 22, 2018, pursuant to Section 145(a)(2)(b) of the Income Tax Ordinance (in this section: the "**Tax Assessment**"), whereby the taxable income from a business for 2016 of the Partnership and the Avner Partnership is approx. \$149.8 million and approx. \$135.7 million, respectively (instead of approx. \$124.1 million and approx. \$110.1 million, respectively, as included in the partnerships' tax reports, which were filed with the Tax Authority). The capital gain for 2016 of the Partnership and the Avner Partnership is approx. \$54 million and approx. \$71.8 million, respectively (instead of approx. \$7.4 million and approx. \$17 million, respectively, as included in the partnerships' tax reports, which were filed with the Tax Authority). It is noted that the aforesaid amounts were translated from shekels to dollars according to the dollar rate known as of December 31, 2020.

The dispute pertains primarily to the interpretation of the manner of recognition of various expenses actually incurred by the partnerships, and the manner of calculation of the capital gain from the sale of the Karish and Tanin leases.

Further to an administrative objection filed by the Partnership against the tax assessments, the partnerships were issued assessments in an order under Section 152(b) of the Ordinance (the "**Orders**") by the Tax Authority which were primarily concerned, as aforesaid, with the method of recognition of financial expenses and additional expenses borne by the partnerships in practice and the method of calculation of the capital gain from the sale of the Karish and Tanin leases.

According to the assessments in the order, and insofar as all of the Tax Authority's arguments are accepted, the Partnership will be required to make an additional tax payment (including linkage differentials and interest) on account of the tax owed by holders of participation units in the partnerships in the sum total of approx. \$46.3 million. The Partnership filed an appeal from the Orders with the Tel Aviv District Court. The assessment reasons in this appeal were filed by the Assessing Officer on December 9, 2020 and according to the Court's decision, the Partnership is required to file a notice stating the grounds for the appeal by May 3, 2021.

In view of the aforesaid, the issuance of a final tax certificate for an entitled holder for holding participating units of the partnerships for the tax year 2016 may be delayed, pending conclusion of the proceedings required to determine the final assessment. In the Partnership's estimation, based on the opinion of its legal counsel, the chances of the Partnership's main arguments being accepted are higher than 50% and therefore the Partnership intends to exhaust the administrative and legal proceedings that are available thereto.

Note 20 – Oil and Gas Profit Levy and Taxes (Cont.):

A. Information regarding income tax rules and the main arrangements existing as of the date of the statement of financial position (Cont.):

10. In view of the disputes that have arisen between the Partnership and the Tax Authority and disagreements in respect of the amount of the Partnership's taxable income for 2017, the Partnership received a tax assessment to the best of judgment was received pursuant to Section 145(a)(2)(b) of the Ordinance, 5721-1961 (the "**Tax Assessment**" and the "**Ordinance**", respectively), whereby the Partnership's taxable business income in 2017 is approx. $392.6 million (*in lieu* of approx. $231.8 million, as included in the Partnership's tax report filed with the Tax Authority) and the Partnership's capital gain in 2017 is approx. $705 million (*in lieu* of approx. $578.3 million as included in the Partnership's tax report filed with the Tax Authority). It is noted that the aforesaid amounts were translated from shekels to dollars according to the dollar rate known as of December 31, 2020.

The disputes primarily pertain to the interpretation of the manner of recognition of financial expenses and other expenses actually incurred by the Partnership, attribution of financial income deriving from exchange rate differences to an asset under construction, the manner of implementation of Section 20(b) of the Law regarding the deduction of depreciation expenses; and the manner of calculation of the capital gain from the sale of 9.25% (out of 100%) of the interests in the Tamar and Dalit Leases.

As of the date of the financial statements and according to the Tax Assessment, and insofar as all of the Tax Authority's arguments are accepted, the Partnership will be required to make an additional tax payment (including linkage differentials and interest), on account of the holders of participation units of the Partnership, in the amount of approx. $87 million.

On December 10, 2020, the Partnership filed an administrative objection regarding the 2017 tax assessment issued therefor.

It is noted that in view of the aforesaid, the issuance of a final tax certificate for an entitled holder for holding participation units of the Partnership for the tax year 2017 may be delayed, pending conclusion of the proceedings required to determine the final assessment.

In the Partnership's estimation, based on the opinion of its legal counsel, the chances of the Partnership's main arguments being accepted are higher than 50%, and the Partnership therefore intends to exhaust the administrative and legal proceedings available thereto.

11. On November 8, 2018 the Partnership published a temporary tax certificate for an entitled holder for the holding of a participation unit for the 2017 tax year. A final tax certificate will be produced upon conclusion of the proceedings described above with respect to the 2017 tax assessment and subject to the extension of the Participation Unit Regulations. The final tax certificate may materially differ from the temporary tax certificate.

In December 2017, the Partnership and the Tax Assessor for Large Enterprises signed an agreement for collection of tax on account of the tax for which the unit holders are liable due to the estimated taxable income from a business of the Partnership for 2017 (2017 tax agreement). In the agreement, the Partnership made-up additional tax advances according to the maximum tax rate which applies to individuals due to the said estimated taxable income.

Note 20 – Oil and Gas Profit Levy and Taxes (Cont.):

A. Information regarding income tax rules and the main arrangements existing as of the date of the statement of financial position (Cont.):

12. On February 19, 2020, the Partnership published a temporary tax certificate for an entitled holder for the holding of a participation unit for the 2018 tax year. A final tax certificate will be produced upon conclusion of the audit proceeding of the Tax Authority and subject to the extension of the income tax regulations. The final tax certificate may materially differ from the temporary tax certificate.

Note that in December 2019, the Partnership acted based on the 2017 tax agreement, in the context of which the Partnership made-up advances according to the maximum tax rate which applies to individuals due to the said estimated taxable income.

13. In December 2019, the board of the General Partner and the Trustee approved a payment to the holders of the participation units, in the context of which the Partnership made-up advances according to the maximum tax rate which applies to individuals due to the estimated taxable income for 2019. According to the tax report filed by the Partnership the tax reports for 2019, which is subject *[sic]* to an audit by the Tax Authority, the taxable income is approx. ILS 573.6 million. The Partnership is working toward the issuance of a temporary tax certificate.

14. In December 2020, the board of the General Partner and the Trustee approved a payment to the holders of the participation units, in the context of which the Partnership made up advances according to the maximum tax rate which applies to individuals due to the estimated taxable income for 2020.

In the context of preparation of the Partnership's financial statements, upon conclusion of the audit, the estimated taxable income of the Partnership for the 2020 tax year was updated based, *inter alia*, on the estimations of the General Partner, various tax opinions and assumptions, to the total amount of approx. ILS 594 million.

15. It is clarified that participation unit holders in the Partnership will be entitled (but not obligated) to include in their tax reports, for each one of the years 2015 through 2018, their share in the liable income of the Partnership and their share in the tax amount that was paid by the Partnership, including tax that was deducted in the framework of the additional payments that the Partnership made (see Note 13) in respect of such tax years, in accordance with the temporary tax certificates.

Unit holders that will act according to the aforesaid shall be required to amend their reports in accordance with the final tax certificates that will be released by the Partnership, in which case the amount of the refund or the payment to which the entitled holder is entitled or for which it is liable may decrease or increase as a result of the aforesaid, and accordingly, unit holders may also be required to repay the Tax Authority amounts that were received thereby based on the temporary certificate.

Note 20 – Oil and Gas Profit Levy and Taxes (Cont.):

A. Information regarding income tax rules and the main arrangements existing as of the date of the statement of financial position (Cont.):

16. It is clarified that in respect of each of the tax years 2016 forth, regarding which final income tax assessments have not yet been issued, it may transpire, after completion of the proceedings vis-à-vis the relevant bodies, that Assessment Differences exist, such that the final tax assessment is higher than the estimated assessment which was used for the calculation of the tax payments which were made by the Partnership (net of refunds paid thereto), in which case the Partnership will be required to pay the Tax Authority, on account of the holders, the tax balance that derives from the Assessment Differences, according to the Calculation of the Tax Pursuant to Section 19.

17. According to the Law, a petroleum interest holder shall be given fixed annual accelerated depreciation on a deductible asset which is owned thereby at a rate of up to 10% (at the petroleum interest holder's choice) or, alternatively, variable current annual depreciation up to taxable income the amount for such year (and not more than 10%). Furthermore, the said maximum depreciation rate with respect to an asset purchased in the years 2011-2013 will be 15% in lieu of 10% (see Paragraph B below).

18. The Partnership implements the provisions of Section 20(b)(2) of the Law, according to which the Partnership recognizes, in each tax year, depreciation expenses in the amount of the taxable income, if any, before the deduction of depreciation expenses which were required in such tax year, provided that the deduction will not exceed the rate specified in the Law.

19. The tax issues, including the implementation of the Law (as specified in Paragraph C below), which are related to the operations of the limited partnership have not yet been contemplated in case law of the Israeli courts (other than as stated below), and it is difficult to foresee or determine how the courts shall rule if and when said legal questions will be presented for their adjudication. In addition, in respect of some of the legal questions, it is difficult to foresee the position of the tax authorities.

Since the Partnership's operations are subject to a unique tax regime, the changes that shall be caused due to an amendment of the law, case law or a change in the position of the Tax Authority, as aforesaid, may have material consequences on the tax regime applying to the Partnership.

20. It is clarified that the estimated taxable income, which was calculated toward each of the years 2016-2020, was calculated based on estimates and appraisals and financial figures that are unaudited.

21. Taxation in Cyprus:

In accordance with the production sharing contract with the Cypriot Government, payment of the Cypriot Government's share in the gas and/or petroleum that shall be produced from Block 12, to the extent produced, includes a gross-up of the corporate tax payments that the owners of the rights in such project, including the Partnership, must pay the Republic of Cyprus.

Note 20 – Oil and Gas Profit Levy and Taxes (Cont.):

A. Information regarding income tax rules and the main arrangements existing as of the date of the statement of financial position (Cont.):

21.Taxation in Cyprus (Cont.):

The production sharing contract determines a new mechanism for the distribution of the natural gas output, as noted, which is based on a factor of the R-Factor type. According to such mechanism, the partners will be entitled to 55% of the annual revenues to be derived from the natural gas output, up to the coverage of all of their recognized capital and current expenditures (the "**Expenditure Coverage Output**"), whereas the balance (the "**Distributable Output**") will be distributed among the partners and the Government of Cyprus according to the R-Factor, the numerator of which consists of the total of Net Accrued Revenues and the denominator of which consists of the total of Accrued Capital Investments. Under the new mechanism, the share of the Government of Cyprus in the Distributable Output linearly increases as a function of the factor and will reach the maximum rate when the R-Factor equals 2.5. For this purpose:

"Net Accrued Revenues" shall mean, the partners' share in revenues actually received from the gas output (including the Expenditure Coverage Output), net of the operating expenses borne by the partners in the area of the PSC, from the date of signing of the Production Sharing Contract (October 28, 2008) to the end of the quarter preceding the day of the calculation (the "**Calculation Period**").

"Accrued Capital Investments" shall mean, the development expenses, production expenses of a capital nature (excluding operating expenses) and all exploration expenses, in respect of the area to which the Production Sharing Contract pertains, which were actually expended during the Calculation Period.

The Partnership received an approval from the Israel Tax Authority in respect of its operations in Block 12. Said approval prescribes, *inter alia*, the following provisions – the Partnership operations in Block 12 shall not prejudice the Partnership's status as a "partnership" for the purposes of the Income Tax Regulations (Rules for the Calculation of Tax due to the Holding and Selling of Participation Units in an Oil Exploration Partnership), 5749-1988; the income that shall be generated in Block 12 shall be considered income that is taxable in Israel and the tax shall be calculated according to Israeli law; should the exploration investments prove to be investments which do not justify production (dry well), said investments shall be recognized as an expense that will be spread over a five-year period; should the exploration investments prove to be recoverable investments, the Block 12 operations will be deemed a separate standalone sector for tax purposes, and the exploration investments will be recognized in Israel as an expense, solely against income from Cyprus (thus, expenses incurred by the Partnership in Cyprus for its operations in Block 12 will not be included in its tax reports in the context of expenses which may be deducted in Israel, but rather shall be deducted in the future from income that the Partnership will generate from Block 12), all subject to the law applying in Israel; the recognition method of income, including credit for taxes paid in Cyprus, will be effected according to the instructions of the Tax Authority Director, considering the conditions that will be relevant at the prevailing time and the conditions that were known at the time of issuance of the approval.

Note 20 – Oil and Gas Profit Levy and Taxes (Cont.):

A. Information regarding income tax rules and the main arrangements existing as of the date of the statement of financial position (Cont.):

21.Taxation in Cyprus (Cont.):

It is noted that the Petroleum Commissioner gave his approval, in accordance with Regulation 8 of Income Tax Regulations (Deductions from Income of Petroleum Right Holders), 5716-1956, for application of the Regulations to the Partnership also in Block 12, subject to conditions prescribed by him.

B. Taxation of Profits and Natural Resources Law, 5771-2011:

In April 2011, the Knesset passed the Taxation of Profits and Natural Resources Law, 5771-2011 (the "**Law**"). Implementation of the Law has led to a change in the taxation rules applicable to the Partnership's revenues, which include, *inter alia*, the introduction of a oil and gas profits levy according to a mechanism specified in the Law and cancellation of the depletion deduction. The Law includes transitional provisions with respect to producing ventures or ones that commenced production by 2014.

The Law's main provisions are as follows:

1. The introduction of an oil and gas profits levy at a rate to be determined as stated below. The rate of the levy will be calculated according to a proposed R-factor mechanism, according to the ratio between the net aggregate revenues from the project and the aggregate investments as defined in the Law. A minimum levy of 20% will be collected commencing from the point when the R-factor ratio reaches 1.5, *[sic]* the levy will progressively increase up to a maximum rate when the ratio reaches 2.3. The maximum rate of the levy is 50% minus the product of 0.64 and the difference between the corporate tax rate set forth in Section 126 of the Income Tax Ordinance, 5721-1961 (in respect of each tax year) and the 18% tax rate. According to the corporate tax rate in 2020, the maximum rate is 46.8%.

   Additional provisions were also determined regarding the levy, *inter alia*, the levy will be recognized as an expense for the purpose of calculation of income tax; the levy limits shall not include transmission plants that are used for export; the levy shall be calculated and imposed in relation to each lease separately (ring fencing); the charge of a recipient of payment from a holder of a petroleum interest which is calculated, *inter alia*, as a percentage of the petroleum produced, (the "**Derivative Payment**") *[sic]* in accordance with the amount of the Derivative Payment received thereby, while the amount of the levy attributed to the recipient of the Derivative Payment will concurrently be deducted from the levy amount owed by the holder of the petroleum right.

   In addition, the Law prescribes rules for consolidation or separation of petroleum ventures for purposes of the Law.

   The provisions regarding the imposition of an oil and gas profits levy apply from April 10, 2011 and include transition provisions with respect to ventures that began commercial production by January 1, 2014.

   a) A venture with respect to which the commercial production commencement date occurs before the commencement date, will be subject to the provisions of this law with the following changes:

Note 20 – Oil and Gas Profit Levy and Taxes (Cont.):

B. Taxation of Profits and Natural Resources Law, 5771-2011 (Cont.):

1. (Cont.):

a) (Cont.):

1) If a levy payment duty applies with respect to such venture in the tax year which the commencement date occurs, the rate of the levy in such tax year will be half of the rate of the levy that would have been imposed on the petroleum profits if not for the provisions of this paragraph and no more than 10%;

2) In the event that the levy coefficient in the tax year in which the commencement date occurs exceeds 1.5, rules were set for the manner of calculation of the levy coefficient in each tax year thereafter;

3) The rate of the levy which will be imposed on the petroleum profits of the venture in each of the tax years 2012 to 2015 will be equal to half the rate of the levy that would have been imposed on the petroleum profits as aforesaid, if not for the provisions of this paragraph.

Note 20 – Oil and Gas Profit Levy and Taxes (Cont.):

B. Taxation of Profits and Natural Resources Law, 5771-2011 (Cont.):

1. (Cont.):

   b) A venture with respect to which the commercial production commencement date occurs in the period between the commencement date and January 1, 2014, will be subject, *inter alia*, to the following provisions:

      1. The minimal levy coefficient will be at a rate of 2 instead of 1.5 and the maximal rate will be 2.8 instead of 2.3;

      2. The accelerated annual depreciation rate regarding a deductible asset purchased in the years 2011-2013 will be 15% instead of 10%.

2. The Law includes provisions regarding the taxation of petroleum partnerships as of 2011 - see Paragraph A above.

3. Pursuant to the Law, the reporting partner of the petroleum project files reports that include, *inter alia*, accrued data regarding proceeds and investments for the purpose of calculating the R-factor, as specified in Section 1 above.

4. It is noted that disputes have arisen between the Assessing Officer for Large Enterprises and the holders of the rights in the Leviathan Leases regarding the levy reports for the Leviathan Leases for the years 2013-2015, which disputes chiefly pertained to the method of classification and quantification of data in the levy reports for the Leviathan Leases for the said years. In October 2018 the parties reached agreements with respect to the said disputes in the framework of a levy assessment agreement for the years 2013-2015, which, in October 2018, was sanctioned as a judgment by the Tel Aviv District Court.

   Furthermore, a levy assessment agreement was signed in December 2019 between the Assessing Officer for Large Enterprises and the holders of the rights, with respect to the levy reports for the years 2016-2017. It is further noted that, as of the date of approval of the financial statements, several interpretive disputes are being heard in the context of administrative objection proceedings vis-à-vis the assessing officer with respect to the implementation of the Law in the levy reports of the Leviathan leases for 2018.

   In addition, the right holders in the Leviathan venture reached agreements with the Tax Authority on the consolidation of the Leviathan Leases (north and south) as a single petroleum venture for purposes of the Law and the reports thereunder, according to the provisions of Section 8(a) of the Law.

5. It is noted that disputes have arisen between the Assessing Officer for Large Enterprises and the holders of rights in the Tamar venture as to the Tamar venture levy reports for the years 2013-2018, which disputes chiefly pertain to the recording of notional revenues and the method of recognition and classification of exploration and construction investments in the Tamar SW reservoir and Tamar SW reservoir construction payments (jointly below, the "**Disputed Issues**"). It is noted that the disputes as to the levy reports for the years 2013-2017 are adjudicated between the parties in the context of appeals conducted before the Tel Aviv District Court, whereas the disputes pertaining to the levy report for 2018 are adjudicated in the context of an administrative objection before the Assessing Officer for Large Enterprises.

   In the Partnership's estimation, based on the opinion of its legal counsel with respect to the Disputed Issues, the chances that the Partnership's arguments with respect to most of the Disputed Issues will be accepted are higher than the chances of rejection thereof.

Note 20 – Oil and Gas Profit Levy and Taxes (Cont.):

B. Taxation of Profits and Natural Resources Law, 5771-2011 (Cont.):

6. It is noted that disputes have arisen between the Assessing Officer for Large Enterprises and the holders of rights in the Ashkelon venture, in respect of the levy report of the venture for 2018. The Partnership's share in the disputed amounts is approx. $1.3 million. In March 2021 an administrative objection was filed by the holders of rights in the venture.

7. **Taxation of Profits from Natural Resources Regulations:**

   On December 2, 2020, the Taxation of Profits from Natural Resources Regulations (Advances due to the Petroleum Profit Levy), 5781-2020 (in this section: the "**Regulations**") were published, regulating the payment of the advances that shall be paid by holders of petroleum interests in a petroleum project, including the method of calculation of the advances, the dates of payment thereof, and the reporting thereon.

   The Regulations were promulgated by virtue of Sections 10(b) and 51 of the Law and their purpose is to regulate the issue of payment of the advance payments that will be made by the holders of a petroleum interest in a petroleum project. The Regulations pertain to the determination of the calculation of the advances, the dates of payment thereof, and the reporting thereon, as defined in the Law.

   In 2020, the Partnership paid advances due to a petroleum profit levy in the amount of approx. $2 million, due to 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 due to an oil and gas profit levy in the amount of approx. $3.8 million.

Note 20 – Oil and Gas Profit Levy and Taxes (Cont.):

C. Tax Advances on account of the tax owed by the participation unit holders:

1. The tax advances for 2018-2020 were calculated according to the tax rates applicable to companies, i.e. 23%.
2. According to the provisions of Section 19 of the Law ("**Section 19**"), the General Partner is obligated to file to the assessing officer a report (certified by an accountant) on the taxable income of the Partnership. Section 19 prescribes that upon the filing of the report, the General Partner is required to pay the tax deriving therefrom, on account of the tax owed by the entitled holders in the tax year for which the report was filed (i.e. on account of the entitled participation unit holders, as they will be on December 31 of each tax year).

   According to the provisions of Section 19, the tax that the General Partner is due to pay upon the filing of the report, shall be calculated according to the pro rate share in the Partnership of the entitled holders who are corporations and the pro rate share in the Partnership of the entitled holders who are individuals. For such purpose, the taxable income of the individuals shall be deemed to be subject to the maximal tax rate, unless it was proven to the assessing officer that the tax rate applying to such individual is lower than said rate.

D. Taxation of Profits from Natural Resources Legislative Memorandum (Amendment), 5781-2021:

On January 7, 2021 (after the date of the Statement of Financial Position), the Taxation of Profits from Natural Resources Legislative Memorandum (Amendment), 5781-2021 (the "**Proposed Memorandum**") was released for public comment. It includes several proposed amendments to the law, including the following: (1) Amending Section 11 of the law to allow the Tax Authority to collect a disputed levy already after the Tax Authority's decision in the administrative objection to the levy assessment, and before the dispute is resolved in court; (2) Amending Section 13 of the law to require approval of the levy reports by a CPA as defined in the Certified Public Accountants Law, 5715-1955; (3) Amending Sections 14-15 of the law to enable extension of the period of assessment of levy reports from one year from the date of filing of the levy reports to four years from the end of the year in which the levy report was filed; (4) Adding Section 16A to the law, which concerns the application of the provisions of Section 86 of the Ordinance regarding the authority of the Assessing Officer to ignore certain transactions; and (5) Adding Section 41A to the law which concerns authorizing the Assessing Officer to impose a fine 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).

Notes to the Financial Statements for December 31, 2020 (Dollars in thousands)

Note 21 – Transactions and Balances vis-à-vis Interested Parties, Related Parties and Control Holders:

A. Balances:

		December 31, 2020		December 31, 2019	
	Note	Parent companies	Related parties and other interested parties	Parent companies	Related parties and other interested parties
Trade receivables		-	3,097	1	1,958
Trade and other receivables	5	8	933	28	3
Other long-term assets	8A	2,199	23,125	1,946	33,002
Trade and other payables	9	2,119	2,366	2,243	2,348
The highest current debt balance this year		38	1,523	56	3,352

B. Transactions with related parties and interested parties:

For the year ended December 31, 2020:

	Note	Parent companies	Related parties and other interested parties
Revenues from gas sale[43]	14	384	21,868
Expenses due to overriding royalties	15	6,127	19,074
Expenses of General Partner management fees	12A	960	-
Compensation of directors		-	276
Compensation of directors of a company accounted for at equity	6	-	66
Reimbursement of expenses from a parent company	21F4	(44)	-
Guarantee fee to Delek Group	12J4	368	-
Expenses due to control holder benefit against a capital reserve	13G	2,954	-
D&O insurance	21F5	131	-

[43] Including the share of a related party in the Commercial Arrangement, as stated in Note 7C5.

Notes to the Financial Statements for December 31, 2020 (Dollars in thousands)

Note 21 – Transactions and Balances vis-à-vis Interested Parties, Related Parties and Control Holders (Cont.):

B. Transactions with related parties and interested parties (Cont.):

For the year ended December 31, 2019:

	Note	Parent companies	Related parties and other interested parties
Revenues from gas sale[44]	14	-	14,451
Gas purchase costs as part of Commercial Arrangement	7C5	(29)	217
Expenses due to overriding royalties	15	6,374	26,363
Expenses of General Partner management fees	12A	960	-
Compensation of directors		-	249
Compensation of directors of a company accounted for at equity	6	-	151
Reimbursement of expenses from a parent company	21F4	68	-
Guarantee fee to Delek Group	12J4	368	-
Expenses due to control holder benefit against a capital reserve	13F	2,375	-
D&O insurance	21F5	257	-
Dividend	19A	-	9,040

For the year ended December 31, 2018:

	Note	Parent companies	Related parties and other interested parties
Revenues from gas sale[45]	14	-	13,581
Gas purchase costs as part of Commercial Arrangement	7C5	(105)	-
Expenses due to overriding royalties	15	14,481	17,642
Expenses of General Partner management fees	12A	960	-
Compensation of directors		-	193
Reimbursement of expenses from a parent company	21F4	16	-
Guarantee fee to Delek Group	12J4	402	-
Expenses due to control holder benefit against a capital reserve	13G	1,836	-
D&O insurance	21F5	-	177

[44] Including the share of a related party in the Commercial Arrangement, as stated in Note 7C5.

[45] Including the share of the parent company and a related party in the Commercial Arrangement, as stated in Note 7C5.

Note 21 – Transactions and Balances vis-à-vis Interested Parties, Related Parties and Control Holders (Cont.):

C. Terms of Employment of the CEO of the General Partner, Mr. Yossi Abu ("Mr. Abu"):

Mr. Yossi Abu ("**Mr. Abu**" or the "**CEO**") serves as CEO of the General Partner in a full-time position (100%) since April 1, 2011. In the period from July 3, 2018 until March 14, 2020, Mr. Abu served in his current position as CEO of the General Partner in an 80% (instead of 100%) position, and simultaneously served as the CEO of Delek Energy in a 20% position.

It is clarified that the cost of employment of Mr. Abu is imposed on the General Partner only in the framework of the management services provided by the General Partner to the Partnership.

On July 10, 2019, the general meeting of the holders of the Partnership's participation units approved the terms of office and employment of Mr. Abu, according to which, *inter alia*, the term of his employment will be extended by an additional 3 years, i.e. until April 30, 2024; his total monthly salary from May 1, 2019 is ILS 160 thousand (in gross terms) (100%) (the "**Monthly Salary**"), updated according to changes in the Consumer Price Index (positive only) once every three months; the CEO will be entitled to the related benefits standard in the market among executives; the CEO will be entitled to an annual bonus every calendar year and a special one-time bonus, in accordance with the compensation policy; in the event that his employment comes to an end, the CEO will be entitled to an adjustment bonus and to a retirement bonus, in accordance with the compensation policy. The CEO is entitled to 2,742,231 phantom units (whose underlying asset is a participation unit conferring a working interest in the rights of the limited partner in the Partnership (in this section: the "**Participation Units**")) (subject to adjustments as specified in the employment agreement) (the "**New Phantom Units**"). The New Phantom Units are in addition to the Existing Phantom Units, as defined below in this section. The New Phantom Units shall vest in three installments (the "**Overall Package**"), with each one of the installments included in the Overall Package being exercisable from the vesting date of such installment until the lapse of one year from the vesting date of the third installment (i.e. June 1, 2023).

The fair value of the New Phantom Units which were granted to the CEO as of July 10, 2019 is approx. ILS 5.4 million (the fair value valuation was prepared using the binomial model). The main assumptions on which the said valuation was based are as follows: (1) an exercise price of ILS 10.79 for the first installment, with an addition of 5% each year; (2) a participation unit price of approx. ILS 9.96; (3) a standard deviation rate of 32.2%; (4) a risk-free interest rate of 0.71%; (5) a contractual life of approx. 3.9 years; (6) rate of abandonment after the vesting period 0%; (7) benefit limitation as specified above.

Within his terms of employment, and his employment agreements of 2016, the General Partner granted Mr. Abu approx. 2,959,860[46] phantom units (the underlying asset of which is a participation unit granting a working interest in the rights of the limited partner in the Partnership (subject to adjustments as specified in the employment agreement) (the "**Existing Phantom Units**").

[46] Within the Merger of Partnerships, 7,734,410 phantom units of Avner Partnership were exchanged with 1,453,835 phantom units of the Partnership.

Note 21 – Transactions and Balances vis-à-vis Interested Parties, Related Parties and Control Holders (Cont.):

C. Terms of Employment of the CEO of the General Partner, Mr. Yossi Abu ("Mr. Abu") (Cont.):

The Existing Phantom Units will vest in five installments, with the first and second installments vested on September 1, 2017 and the third installment vested on September 1, 2018, and the fourth installment vested on September 1, 2019 and the fifth installment vested on September 1, 2020 (the "**Overall Package**"). Each of the installments included in the Overall Package is exercisable as of the vesting date of such installment and until the lapse of 90 days after the termination of Mr. Abu's employment under the employment agreement (i.e., June 30, 2021). The exercise price of the phantom units is ILS 11.33 for the first installment, plus 5% for every installment as of the second installment. The fair value of the phantom units granted to the CEO totals approx. ILS 7.4 million as of April 13, 2016 (the fair value estimate was performed according to the binomial model). The principal assumptions underpinning such valuation are as follows: (1) exercise price of ILS 11.33 for the first installment with an addition of 5% every year; (2) participation unit price of approx. ILS 10.79; (3) Standard deviation rate of 33.17%; (4) Risk-free interest rate of 1.02%; (5) Contractual duration of 5.22 years; (6) Abandonment rate after vesting period of 0%; (7) restriction of the maximal benefit which will be generated for Mr. Abu from the exercise of each Phantom Unit shall not exceed 100% of the exercise price specified for the Phantom Unit included in the exercised installment on the date of grant.

In 2020 Mr. Abu received an annual bonus in the amount of ILS 2,169 thousand for 2019 (2019: ILS 1,650 thousand for 2018; 2018: ILS 2,200 thousand for 2017). The aforesaid grants were paid according to the goals predefined by the compensation committee and the board of directors.

D. On January 8, 2020, Mr. Gabi Last was appointed to serve as Chairman of the Board of the General Partner after Mr. Assi Bartfeld's retirement. In addition, on January 7, 2020, Mr. Idan Wallace, CEO of Delek Group, was appointed as a director of the General Partner and on September 10, 2020 Mr. Tamir Polikar, Deputy CEO and CFO of Delek Group was appointed as a director of the General Partner following the retirement of Mr. Barak Mashraki.

E. Further to Note 7C4 in respect of the Partnership's exploration rights in Block 12 in Cyprus, as a condition for the endorsement, the Cypriot Government requested, in accordance with terms of the production sharing contract, that a performance guarantee, unlimited in amount, shall be provided in favor of the Republic of Cyprus to secure the fulfillment of all of the undertakings under the production sharing contract (the "**Guarantee**"), that was provided on the date of transfer of the rights by Delek Group.

Delek Group agreed to provide the Guarantee, against payment of a guarantee fee by the Partnership (see Note 12J4 above), as approved by the general meeting of participation unit holders in the Partnership, and subject to several conditions as summarized below:

1. The purchase of insurance coverage to the satisfaction of Delek Group.
2. In addition, the Partnership undertook that from the date of provision of the Guarantee and for as long as the Guarantee is in effect, the following provisions shall apply:
   a) In the event that the Partnership sells its rights to Block 12, the Partnership will act to release Delek Group from the Guarantee, or from its relative share (in the event of any partial sale of the rights);

Note 21 – Transactions and Balances vis-à-vis Interested Parties, Related Parties and Control Holders (Cont.):

E. (Cont.):

2. (Cont.):

   b) Delek Group will be entitled to demand that the Partnership, by written notice, at any time and at its discretion, shall cause the release of Delek Group from the Guarantee, or in the alternative, shall sign an agreement for the sale of the rights in Block 12;

   c) The Partnership will indemnify Delek Group for any damage of any kind whatsoever and/or expenses of any kind whatsoever and/or payments that shall be incurred by Delek Group, without any sum limitation.

   d) Since the undertakings of the Partnership and Noble Cyprus under the production sharing contract are jointly and severally, the Partnership shall act to the best of its ability vis-à-vis Noble Cyprus and the parent company of Noble Cyprus, Noble Energy Inc. ("**Noble Inc.**"), which provided a guarantee, as aforesaid, for its subsidiary, Noble Cyprus, by virtue of the production sharing contract – in an attempt to reach arrangements for the division of responsibilities and mutual indemnification between the Partnership, Delek Group and Noble Cyprus and Noble Inc., in respect of the operations in Block 12, according to the respective holding percentage of the rights in Block 12;

   e) The Partnership shall provide Delek Group with a copy of any resolution and/or notice by the Cypriot authorities in connection with the production sharing contract and/or the Guarantee and will also act to inform Delek Energy of any event that may, to the best of its knowledge, result in the enforcement of the Guarantee.

According to the production sharing contract, any change in control of the Delek Group or the Partnership, directly or indirectly, is subject to advance approval by the Republic of Cyprus.

F. Additional information regarding transactions with related parties and interested parties:

1. See Notes 12B and 15 above regarding the payment of royalties between the Partnership and its control holders and to an affiliate.

2. The Partnership has gas sale agreements with I.P.P. Delek Ashkelon Ltd. ("**Delek Ashkelon**") and I.P.P. Delek Sorek Ltd. and Delek Israel Ltd. (affiliates) (see Notes 12C1 and 12C2 above). For information regarding sale volumes, see Section B above regarding revenues from the sale of gas to other interested parties.

   Following are details with respect to the Delek Ashkelon natural gas supply agreement:

   In August 2005, a gas supply agreement was signed between the partners in the Yam Tethys project and Delek Ashkelon, whereby Delek Ashkelon was granted an option to purchase an additional quantity of natural gas, on an interruptible basis, over and above the quantities contemplated in the original agreement between the parties (the "**Original Agreement**").

Note 21 – Transactions and Balances vis-à-vis Interested Parties, Related Parties and Control Holders (Cont.):

F. Additional information regarding transactions with related parties and interested parties (Cont.):

In view of the continuous decline in the ability to supply natural gas from the Mari B reservoir, an amendment to the agreement was signed in November 2012, whereby it was agreed to update the maximum daily quantity that Delek Ashkelon would be entitled to purchase, subject to the limit on the maximum hourly quantity specified in the Original Agreement. For the additional daily quantity, Delek Ashkelon will pay a price that will be calculated according to a formula that is based on the electricity production tariff and includes a "floor price". The agreement is effective until June 30, 2022, and the balance of the contract quantity to be supplied is approx. 0.35 BCM.

3. The General Partner of the Partnership entered into a lease agreement with Delek Group with respect to offices used by the General Partner and the Partnership, including a management fee agreement (see Note 12A). The Partnership recorded expenses in the statement of comprehensive income against a capital reserve (see Note 13G) for its share in the aforesaid benefit in the sum of approx. $339 thousand (2019: approx. $394 thousand; 2018: approx. $367 thousand).

4. On July 24, 2018, the general meeting of the participation unit holders in the Partnership approved an engagement with Delek Group in an agreement regulating the division of worker employment costs. The terms of the engagement provide, *inter alia*, that the engagement is for a period of three years commencement on the date of approval by the general meeting.

   The arrangement will apply to employees and officers in pre-determined areas, the scope of employment of the workers by Delek Group companies shall not exceed a 5% position on an annual average, [and?] the total cost of employment to be borne by the Delek Group includes, *inter alia*, salary, options, related benefits, a proportionate share of office costs and other office overhead.

5. In December 2018, the Partnership and the General Partner engaged in a policy for insurance of the liability of directors and offices of the Partnership and of the General Partner, in the framework of a policy taken out by Delek Group for the period between January 1, 2019 and June 30, 2020, the premium amount for the entire insurance period shall be approx. $380 thousand. The sum of the expense recorded in the statement of comprehensive income totaled approx. $131 thousand (2019: $257 thousand; 2018: $178 thousand). On May 27, 2020 the compensation committee and the audit committee approved and on June 25, 2020 the board of directors of the General Partner approved to authorize the General Partner and/or the Partnership to engage in a D&O liability insurance policy, in the context of a group insurance policy of Delek Group by way of exercise of an option for an extended disclosure period (run off) for the period starting on July 1, 2020 and ending on June 30, 2027 at a premium of approx. $632 thousand for the aforesaid period, under conditions that comply with the framework conditions.

6. With respect to commercial arrangement for supply of natural gas between the Yam Tethys partners and the Tamar partners and also between the Yam Tethys partners and the Leviathan partners, see Note 7C5 above. In 2020, the Partnership's share of the revenues from the sale of gas to Delek Group's share of the Yam Tethys project amounted to approx. $384 thousand.

Note 21 – Transactions and Balances vis-à-vis Interested Parties, Related Parties and Control Holders (Cont.):

F. Additional information regarding transactions with related parties and interested parties (Cont.):

7. The Partnership had, in the report year, additional engagements in which Delek Group has a personal interest, which are classified as negligible transactions, such as the receipt of "*Dalkan*" services [automatic billing for fueling] from Delek Israel, receipt of V.A.T reporting services from Delek Group, and receipt of services from the NYX Herzliya Hotel of the Fattal Hotels Chain.

Note 22 – Financial Instruments:

A. Manner of determining the fair value of the financial instruments:

Due to their nature, the fair value of financial instruments, such as cash and cash equivalents, trade and short-term receivables, and trade and short-term payables, is an adequate approximation to their book value.

Short-term non-negotiable assets and liabilities bearing interest with a fixed maturity date	-	Their book value reflects their fair value as of the date of the statements of financial position, since the average interest rate thereon is not materially different from the interest rate customary in the market for similar items as of the date of the statements of financial position.
Short-term receivables and payables	-	The book value constitutes an approximation of their fair value.
Assets and liabilities with no maturity date	-	The fair value is determined according to the payable amount per demand on the report date.
Assets and liabilities at variable interest	-	The fair value of assets and liabilities at variable interest, due to which no material changes have occurred, was determined based on the contractual conditions of the instrument.
Interest rate SWAP and forward contracts	-	The fair value is based on the market price. In the absence of market price, the fair value is based on economic models.

Notes to the Financial Statements for December 31, 2020 (Dollars in thousands)

Note 22 – Financial Instruments (Cont.):

B. Fair value hierarchy:

For disclosure purposes, the Partnership classifies fair value measurements under one of the levels in the fair value hierarchy that reflects the significance of the data used when making the measurements. The fair value hierarchy is:

Level 1	- Quoted prices (unadjusted) in active markets for identical assets or identical liabilities.
Level 2	- Inputs other than quoted prices included within Level 1, which are observable directly or indirectly.
Level 3	- Inputs that are not based on observable market data (valuation techniques that use inputs which are not based on observable market data).

Below are figures on the fair value hierarchy of the financial instruments that are measured in fair value that were recognized in the statement of financial position:

	31.12.2020			
	Level 1	**Level 2**	**Level 3**	**Total**
Financial assets at fair value through profit or loss:				
-Royalties receivable from the Karish and Tanin leases (see Note 8B above)	-	-	242,200	242,200
- Loan to Energean from the sale of the Karish and Tanin leases (see Note 8B above)	-	72,300	-	72,300
Total Financial assets at fair value through profit or loss:	-	72,300	242,200	314,500
Financial assets at fair value through other comprehensive income:				
- Investments in equity instruments designated for measurement at fair value through other comprehensive income	17,033	-	-	17,033
Total financial assets	17,033	72,300	242,200	331,533

Notes to the Financial Statements for December 31, 2020 (Dollars in thousands)

Note 22 – Financial Instruments (Cont.):

B. Fair value hierarchy (Cont.):

	31.12.2019			
	Level 1	**Level 2**	**Level 3**	**Total**
Financial assets at fair value through profit or loss:				
-Royalties receivable from the Karish and Tanin leases (see Note 8B above)	-	-	161,900	161,900
- Loan to Energean from the sale of the Karish and Tanin leases (see Note 8B above)	-	84,700	-	84,700
Total Financial assets at fair value through profit or loss:	-	84,700	161,900	246,600
Financial assets at fair value through other comprehensive income:				
- Investments in equity instruments designated for measurement at fair value through other comprehensive income	46,354	-	-	46,354
Total financial assets	46,354	84,700	161,900	292,954
Financial liabilities at fair value through other comprehensive income				
Cash flow hedging transactions for Leviathan project financing interest	-	-	5,523	5,523
Total financial liabilities	-	-	5,523	5,523

Notes to the Financial Statements for December 31, 2020 (Dollars in thousands)

Note 22 – Financial Instruments (Cont.):

B. Fair value hierarchy (Cont.):

Adjustment due to fair value measurements classified as level 3 in the financial instruments fair value hierarchy:

	For the year ended December 31, 2020		
	Future production-based royalties	Cash flow hedging transactions	Total
Balance as of January 1	161,900	(5,523)	156,377
Remeasurement recognized in profit or loss	80,300	(34)	80,266
Disposals / revenues	-	10,314	10,314
Remeasurement recognized in other comprehensive profit	-	(4,757)	(4,757)
Balance as of December 31	242,200	-	242,200

	For the year ended December 31, 2019			
	Financial derivatives	Future production-based royalties	Cash flow hedging transactions	Total
Balance as of January 1	4,974	113,100	-	118,074
Remeasurement recognized in profit or loss	26	48,800	(373)	48,453
Acquisitions				
Disposals / revenues	(5,000)	-	-	(5,000)
Remeasurement recognized in other comprehensive profit	-	-	(5,150)	(5,150)
Balance as of December 31	-	161,900	(5,523)	156,377

Notes to the Financial Statements for December 31, 2020 (Dollars in thousands)

Note 22 – Financial Instruments (Cont.):

C. Fair value of financial instruments:

The fair value of the financial instruments presented in the financial statements matches or is close to their book value, with the exception of the bonds issued as stated in Note 10:

	As of December 31, 2020	
	Fair value	Book value
Bonds:		
Series A	391,716	393,806
Tamar Bond	666,022	635,359
Leviathan Bond	2,500,236	2,219,341
Total	3,557,974	3,248,506

	As of December 31, 2019	
	Fair value	Book value
Bonds:		
Series A	395,136	397,211
Tamar Bond	995,024	953,619
Total	1,390,160	1,350,830

D. Groups of financial instruments:

	As of December 31,	
	2020	2019
Financial assets:		
Cash and cash equivalents	69,979	171,046
Investments and deposits	269,896	166,377
Trade receivables	145,681	46,862
Trade and other receivables	20,212	78,586
Other long-term assets	340,697	312,228
Total financial assets	846,465	775,099
Financial liabilities:		
Trade and other payables	36,075	155,572
Financial derivatives	-	5,523
Bonds (see Note 10 above)	3,248,505	1,350,831
Liabilities to banking corporations (see Note 10D above)	-	1,927,271
Total financial liabilities	3,284,580	3,439,197

Note 22 – Financial Instruments (Cont.):

E. Risk Management policy:

The Partnership's transactions expose the Partnership to various financial risks, such as: market risk (including currency risk, fair value risk due to interest rate, linkage to the U.S. CPI and price risk), credit risk, liquidity risk and cash flow risk due to the exposure to the LIBOR interest rate. The general risk management plan of the Partnership focuses on acts to minimize possible negative effects on the Partnership's financial performances. The Partnership at time uses derivative financial instruments to hedge certain exposures to risks.

F. Market risks:

Market risks derive from the risk that the fair value or future cash flow of a financial instrument will change as a result of changes in market prices. Market risks include three types of risks: currency risk, other price risk and fair value risk due to interest rate as follows:

1. **Currency risk**:

   As of the date of approval of the financial statements, the Partnership has Shekel balances in the sum of approx. $6.8 million which were purchased in proximity to the date of the statement for distribution to participation unit holders in January 2020. Exchange rate risk derives mainly from assets and liabilities stated in ILS and from the fact that the tax advances paid by the Partnership for holders of the participation units pursuant to Section 19 are determined based on a Shekel tax report.

2. **Interest risk**:

   An interest risk is the risk that the fair value or the future cash flows of financial assets will change as a result of changes in the market interest rates. The financial instruments that bear variable interest expose the Partnership to a cash flow risk due to changes in the interest rate. In addition, until August 2020, the Partnership was exposed to possible changes in the cash flow that may derive from changes in the LIBOR interest rate, mainly from an agreement for financing the share of the Partnership in the Leviathan project development costs, the liabilities in respect of which were paid in the context of the issuance of the bonds of Leviathan bond as provided in Note 10C above. In the context of the Partnership's risk management policy, the Partnership performed during 2019 IRS-type cash flow hedging transactions which hedge the chances with LIBOR interest in the sum of approx. $743.9 million that were paid in August 2020 in the context of the issuance of the bonds of Leviathan bond, as aforesaid, the liability due to the hedging transactions on the payment date was approx. $10.3 million. In 2019 the Partnership had short-term investments that bear variable interest.

   Following are the balances of financial instruments that bear interest according to their book value:

Notes to the Financial Statements for December 31, 2020 (Dollars in thousands)

Note 22 – Financial Instruments (Cont.):

F. Market risks (Cont.):

2. Interest risk (Cont.):

	As of December 31, 2020	As of December 31, 2019
Financial instruments at variable interest:		
Assets:		
Deposits in banks (including cash and cash equivalents)	333,029	313,996
Trade and other receivables in the context of joint ventures	4,603	63,721
Long-term receivables in the context of joint ventures	1,256	2,266
	338,888	379,983
Liabilities:		
Financial derivatives	-	5,523
Long-term liabilities to banking corporations	-	1,927,271
	-	1,932,794
Surplus of assets (liabilities)	338,888	(1,552,811)

Following is the effect of the change in the event of a 0.5% change in the LIBOR interest rate, with the other variables remaining constant:

	Effect on Profit or Loss	
	Increase in interest rate	**Decrease in interest rate**
	0.5%	**0.5%**
2020	1,694	(1,694)
2019	(7,764)	7,764

Further to the provisions of Note 8B in connection with the sale of the Partnership's interests in the Karish and Tanin leases, the Partnership recorded royalties receivable from the Karish and Tanin leases in the sum of approx. $242.2 million (as of December 31, 2019 in the sum of approx. $161.9 million) and amounts receivable in connection with a loan extended to Energean in the context of the sale of the Karish and Tanin leases in the sum of approx. $72.3 million (as of December 31, 2019: in the sum of approx. $84.7 million).

Notes to the Financial Statements for December 31, 2020 (Dollars in thousands)

Note 22 – Financial Instruments (Cont.):

F. Market risks (Cont.):

2. Interest risk (Cont.):

Following are tests of sensitivity to a change in the capitalization interest, with the other variables remaining constant:

	As of December 31, 2020				
	Profit (loss) from the change in the capitalization interest				
	2%	1%	Fair value	-1%	-2%
Royalties receivable from the Karish and Tanin leases	(733,21)	(11,728)	242,200	12,188	25,386
Loan to Energean in the context of the sale of the Karish and Tanin leases (See Note 8B above)	(3,657)	(1,872)	72,300	1,965	4,029
Total	(25,390)	(13,600)	314,500	14,153	29,415

	As of December 31, 2019				
	Profit (loss) from the change in the capitalization interest				
	2%	1%	Fair value	-1%	-2%
Royalties receivable from the Karish and Tanin leases	(18,188)	(9,535)	161,900	10,541	22,231
Loan to Energean in the context of the sale of the Karish and Tanin leases (See Note 8B above)	(4,853)	(2,492)	84,700	2,631	5,412
Total	(23,041)	(12,027)	246,600	13,172	27,643

3. Price risk:

Natural gas and condensate prices risk:

Contracts for the supply of natural gas determined the gas price according to price formulas which include various linkage components, including linkage to the Electricity Production Tariff, linkage to the U.S. CPI, linkage to the Brent barrel price and linkage to the ILS/$ exchange rate (see Notes 12C1 and 12C2 below). Contracts for the supply of natural gas signed by the Partnership determined, in addition to the price formulas, also floor prices which limit, to a certain extent, the exposure to fluctuations in the linkage components, but there is no certainty that the Partnership will be able to determine such floor prices also in new contracts that shall be signed thereby in the future.

A decrease in the Electricity Production Tariff (*inter alia* as a result of a price adjustment that shall be requested by the IEC, if any, in accordance with the mechanism determined in the IEC-Tamar Agreement (see Notes 12C1b and 12C1d) and/or a decline in the Brent prices and/or a decline in the U.S. CPI and/or a rise in the ILS/$ exchange rate (a devaluation of the ILS against the dollar), may have an adverse effect on the Partnership's revenues from the existing and future gas sale agreements.

Note 22 – Financial Instruments (Cont.):

F. Market risks (Cont.):

3. Price risk (Cont.):

It is noted that the frequent methodological changes made by the Electricity Authority to the method of calculation of the Electricity Production Tariff make it difficult to predict the same, and may lead to disputes between the gas suppliers and customers in connection with the method of calculation thereof. In this context it is noted that with respect to some of the private power plants (including plants that were sold by the IEC)), the Electricity Authority introduced system marginal price (SMP) regulation whereby every 30 minutes, the wholesale electricity price is determined according to the marginal cost for production of one additional kilowatt-hour in the economy, based on half-hour tenders conducted by the manager of the electricity system between the various power producers each day.

The said pricing method may have an effect on the prices of the natural gas that shall be sold by the Partnership to power producers in the domestic market in a case where the gas prices in future contracts shall be linked to the said pricing.

The demand for natural gas of customers of the Partnership and the price thereof are affected, *inter alia*, also by significant changes in the prices of natural gas produced from the Tamar and Leviathan reservoirs, both in the domestic market and in the international markets. Thus, for example, low LNG prices in the international markets may lead to increased import of LNG to Israel and/or to the regional markets, reduce the demand for natural gas in the markets relevant to the Partnership and adversely affect the Partnership's revenues from the Tamar and Leviathan reservoirs. An increase in supply, a decrease in demand or a decrease in prices of energy sources which are alternatives to natural gas (including coal and other products) in the domestic market or in the international markets may reduce the demand on the part of existing and potential customers, and lead to a decrease in the price of natural gas sold by the Partnership, which may have an adverse effect on the Partnership, its financial position and its results of operations.

Reforms and decisions relating to the electricity sector and the energy sector generally, including changes to environmental laws, may also reduce the demand for the natural gas sold by the Partnership and/or affect the price thereof.

In addition, material events in the global economy such as an economic slowdown, recession, inflation, irregular volatility in foreign exchange rates, trade wars, an impairment of the efficient functioning of the global manufacture and supply chains in general, and 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 eruption of epidemics such as Covid-19 and natural disasters, may also reduce the demand for the natural gas sold by the Partnership and/or affect the price thereof and/or adversely affect the Partnership's revenues from existing and future gas sale agreements, as well as the making of decisions on investment in new natural gas projects and/or expansion of existing projects.

Notes to the Financial Statements for December 31, 2020 (Dollars in thousands)

Note 22 – Financial Instruments (Cont.):

F. Market risks (Cont.):

4. Securities and commodities prices risk:

The Partnership sometimes invests some of its surplus cash in dollar bonds, thereby exposing itself to the fluctuations in the bond prices, which is inherent to such market. The Partnership also invested in ETFs and structured deposits, the yield deriving from which is dependent on the performance of indices or commodities. Investment decisions are made by the management of the Partnership's General Partner, based on the recommendations of professional advisors and the guidance of the investment committee of the board of the Partnership's General Partner. The Partnership has an investment in Tamar Petroleum Ltd. which is classified as a capital instrument designed for measurement at fair value through other comprehensive profit and is exposed to the volatility of securities prices.

Further to Note 8B and Section 2 above with respect to the sale of all of the Partnership's rights in the Karish and Tanin reservoirs, and to Note 1F above regarding the spread of Covid-19 and its possible impact on the Partnership's business, below are expanded tests of sensitivity following the said occurrence, due to a change in the prices of the natural gas and condensate, with the other variables remaining constant:

	As of December 31, 2020								
	Profit (loss) from the change in the price of natural gas								
	30%	20%	10%	5%	Fair value	-5%	-10%	-20%	-30%
Royalties receivable from the Karish and Tanin leases	18,910	14,614	4,383	(1,421)	242,200	(5,478)	(10,981)	(15,775)	(22,832)

	As of December 31, 2020								
	Profit (loss) from the change in the price of condensate								
	30%	20%	10%	5%	Fair value	-5%	-10%	-20%	-30%
Royalties receivable from the Karish and Tanin leases	13,378	6,577	(276)	3,490	242,200	(3,198)	(6,424)	(12,958)	(15,048)

Notes to the Financial Statements for December 31, 2020 (Dollars in thousands)

Note 22 – Financial Instruments (Cont.):

F. Market risks (Cont.):

4. Securities and commodities prices risk (Cont.):

	As of December 31, 2019								
	Profit (loss) from the change in the price of natural gas								
	30%	20%	10%	5%	Fair value	-5%	-10%	-20%	-30%
Royalties receivable from the Karish and Tanin leases	23,186	17,085	7,773	5,447	161,900	(2,337)	(7,797)	(13,335)	(22,773)

	As of December 31, 2019								
	Profit (loss) from the change in the price of condensate								
	30%	20%	10%	5%	Fair value	-5%	-10%	-20%	-30%
Royalties receivable from the Karish and Tanin leases	7,325	6,911	3,467	1,737	161,900	(1,743)	(1,943)	(3,865)	(7,273)

G. Credit risks:

Credit risk is the risk that one party to financial instruments will cause a financial loss to the other party by failure to meet liabilities. A credit risk derives mainly from trade accounts receivable and deposits in banks. The Partnership's principal customers in the report period is the IEC which accounted for approx. 32% of the sales in 2020 (approx. 46% of the sales in 2019), NEPCO which accounted for approx. 19% of the sales in 2020 and Dolphinus which accounted for approx.17% of the sales in 2020. The trade receivables balance as of December 31, 2020 is a current balance. The Partnership estimates that the credit risk vis-à-vis the IEC is low and that the credit risk relative to the produced gas vis-à-vis Dolphinus and NEPCO is low since the current balances against them are backed up by collateral that was provided thereby.

Notes to the Financial Statements for December 31, 2020 (Dollars in thousands)

Note 22 – Financial Instruments (Cont.):

G. Credit risks (Cont.):

1. Turnover and aging of trade receivables, the value of which was not affected:

	Revenues for the year ended December 31, 2020	Trade receivables balance as of December 31, 2020			
		Total	Current balance	In dispute for more than 30 days	In dispute for more than 60 days
IEC	296,582	17,774	17,774	-	-
NEPCO	178,963	39,428	39,428	-	-
Dolphinus	153,770	65,806	65,806	-	-
Other customers	289,807	22,673	22,673	-	-
Total	919,122	145,681	145,681	-	-

	Revenues for the year ended December 31, 2019	Trade receivables balance as of December 31, 2019			
		Total	Current balance	In dispute for more than 30 days	In dispute for more than 60 days
IEC	209,669	17,028	17,028	-	-
Dalia	44,890	3,915	3,915	-	-
Other customers	198,784	25,919	25,919	-	-
Total	453,344	46,862	46,862	-	-

2. The Partnership has cash and cash equivalents and deposits that are mostly held with large banking corporations in Israel and overseas. Accordingly, the Partnership expects no losses due to credit risks for said balances.
3. The balance of the financial assets in the statement of financial position as presented in Paragraph D above reflects the maximal exposure to credit risk as of the date of the statement of financial position.
4. The Partnership has amounts receivable in respect of a company accounted for at equity in the sum of approx. $22.5 million, which were included under other long-term assets. The amounts were revaluated according to the effective interest rate method, based on the Partnership's estimation in respect of their date of return, and interest reflecting the credit risk that reflects the business environment of the company accounted for at equity.

Notes to the Financial Statements for December 31, 2020 (Dollars in thousands)

Note 22 – Financial Instruments (Cont.):

H. Liquidity risk:

Liquidity risks result from the management of the Partnership's working capital, and from the financial expenses and principal repayments of the debt instruments of the Partnership. A liquidity risk is the risk that the Partnership will have difficulties in fulfilling undertakings related to financial liabilities.

The management of the General Partner reviews the cash flow forecasts on a monthly basis for a 12-month period at least, as well as information regarding the cash balances and the deposits.

The Partnership strives to ensure that the cash, the held deposits and short-term investments, together with the forecasted income, shall always be sufficient to cover liabilities on the respective maturity dates thereof. The foregoing does not take into account the effects of extreme scenarios that cannot be foreseen.

The contractual maturities of the financial liabilities subsequent to the date of the statement of financial position (according to the various stated payment values that are different to their value in the books), based on the interest rates and exchange rates as of the date of the statement of financial position, are as follows:

2020	Up to 3 months	More than 3 months and up to 1 year	1-3 years	3-5 years	More than 5 years	Total
Trade and other payables	36,075	-	-	-	-	36,075
Bonds	-	588,289	1,156,037	1,162,012	1,375,563	4,281,901
Total	36,075	588,289	1,156,037	1,162,012	1,375,563	4,317,976

2019	Up to 3 months	More than 3 months and up to 1 year	1-3 years	3-5 years	More than 5 years	Total
Trade and other payables	131,359	-	-	-	-	131,359
Long-term liabilities to banking corporations	6,639	314,290	1,789,420	-	-	2,110,349
Cash flow hedging transactions	1,030	489	4,004	-	-	5,523
Bonds	-	385,784	485,417	708,218	-	1,579,419
Total	139,028	700,563	2,278,841	708,218	-	3,826,650

Notes to the Financial Statements for December 31, 2020 (Dollars in thousands)

Note 22 – Financial Instruments (Cont.):

H. Liquidity risk (Cont.):

Changes in liabilities deriving from financing activity:

	Balance as of Jan. 1, 2020	Cash Flow	Effect of changes in amortized cost	Other changes	Balance as of Dec. 31, 2020
Bonds	1,350,830	1,892,393	5,283	-	3,248,506
Liabilities to banking corporations	1,927,271	(1,946,169)	18,898	-	-
Profits for distribution, declared and provision for balancing and tax payments	33,657	(134,141)	-	136,946	36,462
Total liabilities deriving from financing activity	3,311,758	(187,917)	24,181	136,946	3,284,968

	Balance as of Jan. 1, 2019	Cash Flow	Effect of changes in amortized cost	Other changes	Balance as of Dec. 31, 2019
Bonds	1,347,574	-	3,256	-	1,350,830
Liabilities to banking corporations	1,238,143	688,136	992	-	1,927,271
Profits for distribution, declared and provision for balancing and tax payments	34,685	(211,451)	-	210,423	33,657
Total liabilities deriving from financing activity	2,620,402	476,685	4,248	210,423	3,311,758

Note 23 – Material Subsequent Events:

a. See Note 7C5d for details regarding the Petroleum Commissioner's approval in connection with the decommissioning and abandonment of the Yam Tethys project's facilities.
b. See Note 7C6b for details regarding the recommendation of the Concentration Committee not to allow the Partnership to win the competitive process in the Alon D license.
c. See Note 8B for details regarding the updated data regarding the resources attributed to the Karish, Tanin and Karish North reservoirs.
d. See Note 12C1d for details regarding a settlement agreement between the Tamar partners and the IEC.
e. See Note 12C2b for details regarding a settlement agreement between the Leviathan partners and the IEC.
f. See Note 12L2c for details regarding a notice and a summons to a hearing regarding an ostensible violation of the marine discharge permit issued to Noble in connection with the Leviathan platform.
g. See Note 12M and Note 12J8 for details regarding engagement in a transmission agreement for the export of gas to Egypt.
h. See Note 12N for details regarding a balancing agreement for separate sale from the Tamar reservoir.
i. See Note 20D for details regarding the Legislative Memorandum on Taxation of Profits from Natural Resources (Amendment), 5781-2021.

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Delek Drilling

Additional Information about the partnership

2020

Delek Drilling – Limited Partnership

Chapter D

Additional Details regarding the Partnership

For the year ended December 31, 2020

This report is a translation of Delek Drilling - Limited Partnership's Hebrew-language Additional Details regarding the Partnership, prepared solely for convenience purposes. Please note that the Hebrew version is the binding version, and in the event of any discrepancy, the Hebrew version shall prevail.

Name of Corporation:	Delek Drilling – Limited Partnership	**Corporation No. at the Registrar:**	550013098
Address:	19 Abba Even Blvd., Herzliya Pituach, 4612001		
Telephone:	09-9712424	**Facsimile:**	09-9712425
Balance Sheet Date:	December 31, 2020	**Report Date:**	March 14, 2021

Below are additional details regarding the Partnership, according to the Securities Regulations (Periodic and Immediate Reports), 5730-1970 (the "**Reports Regulations**"):

Regulation 8B: **Valuations**

Below are details of a very material valuation, which is attached hereto, regarding royalties receivable from the "Tanin" I/16 and "Karish" I/17 leases[1] ("**Karish and Tanin Leases**") which are owned by Energean Israel Limited ("**Energean**") (for further details see Note 8B to the financial statements (Chapter C of this report)):

(a) Valuation of royalties receivable from the sale of the Partnership's rights in Karish and Tanin leases

Identification of the subject matter of the valuation:	Royalties receivable from the Karish and Tanin Leases.
Timing of the valuation:	As of December 31, 2020.
Value of the subject matter of the valuation shortly before the valuation date, had GAAP, including depreciation and amortization, not mandated changing its value in accordance with the valuation:	n/a
Value of the subject matter of the valuation that was determined in accordance with the valuation:	Approx. U.S. 242$ ("**$**" or "**Dollar**") 242 million, which are included in the Partnership's other long-term assets.

[1] The "Karish" I/17 lease includes the reservoirs "Karish Center" and "Karish North".

Identification of the Valuator and his qualifications, including education, experience in performing valuations for accounting purposes in reporting corporations and in scopes that are similar to or exceed those of the reported valuation, and dependence on the entity commissioning the valuation, including reference to indemnification agreements with the Valuator:	GSE Financial Advisory Ltd. is a subsidiary of Giza Singer Even Ltd. (collectively, the "**Valuator**"), which is a leading financial advisory and investment banking firm in Israel. The firm has vast experience in advising the major companies, the prominent privatizations and the important transactions in the Israeli economy, which it acquired over the course of its thirty years of activity. Giza Singer Even operates in three areas, through autonomous and independent business divisions: economic advisory services; investment banking, analytical research and corporate governance. The work was performed by a team headed by Eitan Cohen, CPA, a partner and Head of the Economic Department at Giza Singer Even, who has more than ten years of experience in the fields of economic and business consulting, valuations of companies and financial instruments. Eitan is an accountant who holds a B.A. in Economics and Business Administration from Ben Gurion University and an M.Sc. in Financial Mathematics from Bar Ilan University. The Valuator does not have any personal interest in and/or dependence on the Partnership and/or the General Partner of the Partnership, other than the fact that it received a fee for the valuation. Furthermore, the Valuator has confirmed that its fee is not dependent on the results of the valuation. Furthermore, insofar as the Valuator shall be bound by a peremptory judgment to pay any sum to a third party in connection with the work, the Partnership shall pay the Valuator the sum charged to the Valuator in excess of the fee paid

	for the work multiplied by 3. This indemnification undertaking shall not apply should it be ruled that the Valuator acted with negligence or intentional misconduct in connection with the performance of the work.
The valuation model used by the Valuator:	Discounted expected cash flows while adjusting the discounting rates to the risks embodied in the cash flow projections.
The assumptions according to which the Valuator performed the valuation, in accordance with the valuation model:	Below are the main assumptions underlying the valuation: 1. Term of production from the Karish lease: April 1, 2021 through December 31, 2040; 2. Average annual rate of natural gas production from the Karish lease: approx. 3.91 BCM; average annual rate of condensate production from the Karish lease of approx. 5.0 million barrels; 3. Term of gas production from the Tanin reservoir: January 1, 2027 through December 31, 2036; 4. Average annual rate of natural gas production from the Tanin lease: approx. 2.51 BCM; average annual rate of production of condensate from the Tanin lease of approx. 0.44 million barrels; 5. Royalties component capitalization rate: 12.0%; 6. Effective royalty rate to be paid to the State in respect of the gas and condensate: 11.5%; 7. Gas price formula: the base price in the contracts according to which the valuation was

	performed, is estimated using the formula specified in the price mechanism between Energean and ICL and ORL and Energean and OPC and the weighting of the gas price in the Ramat Hovav contract; 8. Condensate price: the condensate price forecast was made based on the average long-term oil prices forecast of the World Bank[2] and the EIA[3] and the forward prices of Brent according to Bloomberg data and based on the assumption that the condensate price will be derived from the Brent price, adjusted to differences in the oil quality; 9. On February 11, 2021, Energean published an updated resource report by D&M (the "**Updated Report**"), a certified reserves and resources evaluator, for the Karish and Tanin leases. According to the Updated Report, the quantity of gas in Karish Center is approx. 40.2 BCM and the quantity of hydrocarbon liquids is approx. 65.1 MMBBL; in Karish North, the quantity of gas is approx. 33.1 BCM and the quantity of hydrocarbon liquids is approx. 30.6 MMBBL; and in Tanin the quantity of gas is approx. 25.1 BCM and the quantity of hydrocarbon liquids is approx. 3.9 MMBBL. 10. Petroleum profit levy: In accordance with the Petroleum Profit Taxation Law, 5771-2011; 11. Corporate tax rate: 23%.

[2] A World Bank Quarterly Report: Commodity Markets Outlook, October 2020.
[3] U.S. Energy Information Administration: Analysis & Projections, February 2021.

Regulation 9D: **Status of liabilities report according to payment dates**

Concurrently with the release of this periodic report, the Partnership is releasing an immediate report regarding the status of the liabilities of the Partnership and the companies consolidated in its financial statements, according to payment dates, which constitutes an integral part of the periodic report.

Regulation 10A: **Summary of the Partnership's statements of comprehensive income for each one of the quarters in 2020 and for the entire Y2020**

See Section 2B of Part One of Chapter B of this report (the board of directors' report).

Regulation 10C: **Use of the proceeds from securities in reference to the proceeds' goals according to the prospectus**

On May 14, 2019 the Partnership released a shelf prospectus. For details see the Partnership's immediate report dated May 14, 2019 (Ref.: 2019-01-041106), the information appearing in which is incorporated herein by reference.

Regulation 11: List of the Partnership's investments in subsidiaries and associated companies thereof[4]

Name of the company	Type of security	No. of shares	Total par value	Share value in the Partnership's separate financial statement as of December 31, 2020	Price of the shares listed for trade on TASE as of December 31, 2020 (in Agorot)	% of the holding in the capital, in voting and in the authority to appoint directors	Balance of loans to subsidiaries and to associated companies as of December 31, 2020 (Dollars in thousands)	Main terms of the loans		
								Final maturity date	Linkage terms	Additional details
Yam Tethys Ltd.	Ordinary shares	48,500	ILS 48,500	-	-	48.5	-	-	-	-
Delek Drilling (Leviathan Financing) Ltd.[5]	Ordinary shares	100	ILS 100	-	-	100	-	-	-	-
Leviathan Bond Ltd.[6]	Ordinary shares	100	ILS 100	-	-	100	100,000	June 2030	Dollar	[7]_
Delek & Avner (Tamar Bond) Ltd.[8]	Ordinary shares	200	ILS 200	-	-	100	-	December 2025	Dollar	[9]_

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4 For further details regarding the Partnership's subsidiaries and associates, see Section 1.7 of Chapter A of this report.

5 A Special Purpose Company (SPC) incorporated for the purpose of raising funding for the Partnership's share in the development costs of the Leviathan project. Upon the completion of the issue of the bonds by Leviathan Bond Ltd., the loans extended to the Partnership for the purpose of raising funding for the Partnership's share in the development costs of the Leviathan project as aforesaid were fully repaid, therefore, as of the date of the approval of the report, Delek Drilling (Leviathan Financing) Ltd. is undergoing a voluntary dissolution process.

6 An SPC incorporated for the purpose of capital-raising. For further details, see Sections 1.7.9 and 7.20.2 of Chapter A of this report and Note 10C to the financial statements (Chapter C of this report).

7 The loan funds were deposited with the bank and are used as a safety cushion for the repayment of the principal of the bonds issued by the subsidiary. For further details, see Notes 4 and 10C to the financial statements (Chapter C of this report) and Part Five of the Board of Directors' Report. The loan principal does not include accrued interest in the amount of approx. $29 thousand . Additionally, approx. $134 million are deposited in the subsidiary's accounts.

8 An SPC incorporated for the purpose of capital-raising. For further details, see Sections 1.7.1 and 7.3.4(b) of Chapter A of this report and Note 10B to the financial statements (Chapter C of this report).

9 The loan funds were used for prepayment of the principal of the bonds issued by the subsidiary, which was made in July 2020. For further details, see Note 10B to the financial statements (Chapter C of this report) and Part Five of the Board of Directors' Report. In addition, approx. $34.8 million are deposited in the subsidiary's accounts.

Name of the company	Type of security	No. of shares	Total par value	Share value in the Partnership's separate financial statement as of December 31, 2020	Price of the shares listed for trade on TASE as of December 31, 2020 (in Agorot)	% of the holding in the capital, in voting and in the authority to appoint directors	Balance of loans to subsidiaries and to associated companies as of December 31, 2020 (Dollars in thousands)	Main terms of the loans		
								Final maturity date	Linkage terms	Additional details
Tamar 10 Inch Pipeline Ltd.[10]	Ordinary shares	22,000	ILS 2,200	-	-	22	-	-	-	-
Leviathan Transportation System Ltd.[11]	Ordinary shares	45,340	ILS 4,534	-	-	45.34	-	-	-	-
NBL Jordan Marketing Limited[12]	Ordinary shares	4,534	$4,534	-	-	45.34	-	-	-	-
EMED Pipeline B.V. (**EMED B.V.**)[13]	Ordinary shares	5,000	$5,000	$75,000,000	-	25	47,950	[14]–	Dollar	-
EMED Pipeline Holding Limited[15]	Ordinary shares	5,000	€5,000	-	-	100	-	-	-	-
Eastern Mediterranean Gas Company S.A.E (**EMG**)[16]	Ordinary shares	57,330,000	$57,330,000	-	-	9.75	-	-	-	-

10 An SPC incorporated for the purpose of obtaining a license for transportation of natural gas from the Tamar project. For further details see Sections 1.7.3 and 7.3.4(b) of Chapter A of this report.

11 An SPC incorporated for the purpose of obtaining a license for transportation of natural gas from the Leviathan project. For further details see Sections 1.7.4 and 7.23.5(l)3 of Chapter A of this report.

12 The company was incorporated for the purpose of engagement in the gas supply agreement with the Jordan National Electric Power Company. For further details see Sections 1.7.5, 7.11.5(a)1 and 7.11.5(b)1 of Chapter A of this report.

13 An SPC incorporated in the Netherlands in connection with the EMG transaction (as this term is defined in section 7.25.5 of Chapter A of this report, whose shares are held as follows: EMED Pipeline Holding Limited (see Footnote 15 below) – 25%; Noble Energy International Ltd. – 25%; and Sphinx EG BV, a fully owned (100%) subsidiary of East Gas Company S.A.E. (**East Gas**) – 50% (for further details, see Section 1.7.7 of Chapter A of this report).

14 The loan is for the Partnership's investments in bringing the EMG pipeline into use, performed through EMED B.V. As of the date of approval of the report, the loan agreement has not yet been signed and a final repayment date has not yet been defined.

15 An SPC incorporated in Cyprus in connection with the EMG transaction (for further details see Sections 1.7.7 and 7.25.6 of Chapter A of this report).

16 EMG is a private company incorporated in Egypt, which owns the EMG pipeline, and whose shares are held as follows: EMED B.V. – 39% (see Footnote 13 above) – 25%; PTT Energy Resources Company Limited – 25%; Mediterranean Gas Pipeline Ltd. – 17%; East Gas – 9%; Egyptian General Petroleum Corporation – 10% (for further details see Sections 1.7.8 and 7.25.5 of Chapter A of this report).

Regulation 12: **Changes in investments in subsidiaries and associated companies in the report period**

In the report period, changes were not made in investments in subsidiaries and in associated companies.

Regulation 13: **Revenues of subsidiaries and associated companies of the Partnership and revenues therefrom (Dollars in thousands)**

Company name	Profit (loss) before tax	Other comprehensive income (loss)	Profit (loss) after tax	Dividends received (or receivable by the Partnership) as of December 31, 2020	Dividends received (or receivable by the Partnership) after December 31, 2020	Dividend payment dates after December 31, 2020	Management fees received as of December 31, 2020	Management fees received (or receivable by the Partnership) after December 31, 2020	Management fees payment dates after December 31, 2020	Interest	Interest payment dates
Delek & Avner (Tamar Bond) Ltd.	650	650	650	-	-	-	-	-	-	-	-
Leviathan Bond Ltd.	(2,389)	(2,389)	(2,389)	-	-	-	-	-	-	-	-
Delek Drilling (Leviathan Financing) Ltd.[17]	-	-	-	-	-	-	-	-	-	-	-
EMED Pipeline Holding Limited	(7,804)	(8,756)	(8,756)	-	-	-	-	-	-	-	-
EMED B.V.	(30,738)	(30,827)	(30,827)	-	-	-	-	-	-	-	-

[17] See Footnote 5 above.

Regulation 21: **Compensation of interested parties and senior officers**[18]

(a) Set forth below is a specification regarding the compensation granted in the report year, to the highest-paid senior officers of the General Partner and/or the Partnership and/or corporations controlled thereby in connection with their term of office at the General Partner and/or the Partnership and/or corporations controlled thereby, as well as regarding the compensation granted to interested parties of the General Partner and/or the Partnership in connection with services they provided as office holders at the General Partner and/or the Partnership in 2020 (Dollars in thousands), as recognized in the 2020 financial statements[19]:

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[18] For further details regarding the terms of employment of the officers and the interested parties mentioned in the table, see Regulation 21(b) below. The compensation given to some of the officers listed in the table include a sum of approx. $17.4 thousand in accordance with an agreement that arranges for the manner of distribution of employment costs, as specified in Regulation 22(i) below.

[19] As the cost of provision of the management services by the General Partner to the Partnership (which includes, *inter alia*, the cost of Mr. Abu's employment) is higher than the management fees and reimbursement of expenses that are paid to the General Partner (in accordance with the Partnership Agreement as set forth in Regulation 21(b)(7) below), the Partnership's financial statements include the total cost of the management services that exceeds such management fees in a capital reserve recorded due to a benefit granted to the Partnership by the General Partner and/or the General Partner's controlling shareholder and in the context of G&A expenses, in the amount of approx. $3 million. For further details see Regulation 21(b)(7) below.

Senior officers of the Partnership and/or the General Partner														
Details of Compensation Recipient				**Compensation for Services**							**Other Compensation**			**Total**
Name	**Title**	**Position percentage**	**% of holding in participation units**	**Salary**	**Bonus**	**Share-based payment**	**Manage-ment fees**	**Consult-ing fees**	**Comm-ission**	**Other**	**Interest**	**Rent**	**Other**	
Yossi Abu[20]	CEO of Delek Drilling Management (1993) Ltd. (the "**General Partner**")	100%	0.05%	682.9	630.1	645.9	-	-	-	-	-	-	95.9[21]	2,054.8
Yossi Gvura[22]	Deputy CEO	100%	-	483.5	254.2	-	-	-	-	-	-	-	98	835.7
Yaniv Friedman	Deputy CEO	100%	-	446	203.3	-	-	-	-	-	-	-	53.4[23]	702.7
Zvi Karcz	VP Exploration	100%	-	319.8	82	-[24]	-	-	-	-	-	-	42.5	444.3
Sari Singer Kaufman	General Counsel, VP	100%	-	274.8	52.8	-	-	-	-	-	-	-	35.9	363.5

20 From July 3, 2018 and until March 14, 2020, Mr. Yossi Abu served as CEO of Delek Energy Systems Ltd. ("**Delek Energy**") at a 20% position, simultaneously with his office as CEO of the General Partner of the Partnership at an 80% position. Commencing from March 15, 2020, Mr. Abu returned to serve as CEO of the Partnership's General Partner at a full-time (100%) position, as extensively detailed in Regulation 21(b)(2) below. As Mr. Abu is employed by the General Partner, which also bears the cost of his employment, the position percentage stated in the table is as of December 31, 2020.

21 Including leave cash-in.

22 Mr. Yossi Gvura serves as Deputy CEO at the Partnership (at a 90% position) and at the General Partner (at a 10% position), and accordingly, the Partnership (90%) and the General Partner (10%) bear the cost of his employment..

23 Including leave cash-in.

24 Excluding revaluation (income) of warrants that were granted, in the sum of approx. $14 thousand.

Interested parties of the General Partner and/or the Partnership														
Details of Compensation Recipient				Compensation for Services							Other Compensation			Total
Name	Title	Position percentage	% of holding in participation units	Salary	Bonus	Share-based payment	Management fees	Consulting fees	Commission	Other	Interest	Rent	Other	
Delek Drilling Management (1993) Ltd.	General Partner	-	-	-	-	-	960[25]	-	-	-	-	-	-	960
Fahn Kanne & Co., CPAs, and CPA Micha Blumenthal together with Keidar Supervision and Management (collectively, the "**Supervisors**")	Supervisor	-	-	238	-		-	-	-	42	-	-		280
Delek Drilling Trusts Ltd.	Trustee and limited partner	-	-	1	-	-	-	-	-	-	-	-	-	1
External directors[26]	-	-	-	275.8	-	-	-	-	-	-	-	-	-	275.8

25 For further details on management fees which are paid to the General Partner by the Partnership, see Regulation 21(b)(7) below.

26 Messrs. Amos Yaron and Jacob Zack have been serving as external directors on the board of directors of the Partnership's General Partner since October 22, 2015 (an initial term of office which was extended on October 10, 2018 for an additional 3-year term of office, up to October 22, 2021). Mr. Efraim Sadka has been serving as an external director on the board of directors of the General Partner since April 1, 2019 for the 3-year term of office, until April 1, 2022.

(b) Set forth below is a specification regarding the terms of office and employment of officers of the Partnership and/or the General Partner:

(1) Compensation policy

With respect to the compensation policy for officers in the Partnership and the General Partner, that was approved by the meeting of the participation unit holders on July 10, 2019 for a 3-year period commencing as of said date, see immediate reports dated May 23, 2019, June 3, 2019, July 1, 2019, July 2, 2019, July 3, 2019 and July 10, 2019 (Ref. : 2019-01-043911, 2019-01-047886, 2019-01-056580, 2019-01-056889, 2019-01-057213 and 2019-01-059625, respectively), the information appearing in which is incorporated herein by way of reference (the "**Notice of Meeting Reports**" and the "**Compensation Policy**", respectively).

On August 18, 2020 the meeting of the participation unit holders approved an amendment to Section 13 of the Compensation Policy, according to which the compensation committee was authorized to determine the amounts of the premiums and excess in the policies for liability insurance for directors and officers of the Partnership and the General Partner, to be purchased by the Partnership, in accordance with market conditions as being at the date of purchase of the policies, and after consultation with an expert advisor in this field of insurance, subject to the liability limits in the insurance policies as defined in the policy, which remain unchanged. For additional details see immediate reports of July 13, 2020, August 6, 2020, August 10, 2020 and August 18, 2020 (Ref. : 2020-01-067288, 2020-01-085728, 2020-01-076858 and 2020-01-080758, respectively), the information appearing in which is incorporated herein by reference.

(2) Yossi Abu

Mr. Yossi Abu ("**Mr. Abu**" or the "**CEO**") serves as the General Partner's CEO at a full-time (100%) position commencing as of April 1, 2011. In the period from July 3, 2018 until March 14, 2020, Mr. Abu continued to serve in his present position as CEO of the General Partner at an 80%-position (instead of a full-time position), and also simultaneously served as CEO of Delek Energy at a 20%-position.

The former terms of service and employment of Mr. Abu were set forth in an employment agreement from June 2016, whose terms were approved on April 14, 2016 by the compensation committee and the board of directors of the General Partner and on June 5, 2016 by the meeting of the participation unit holders, according to the Former Compensation Policy[27] (the "**2016 Agreement**").

On July 10, 2019 the meeting of the participation unit holders approved updated terms of office and employment for Mr. Abu commencing as of May 1, 2019 and until April 30, 2024 according to the Compensation Policy (the "**2019 Terms**")[28], such that Mr. Abu's terms of office and employment are as follows:

Mr. Abu's monthly salary is approx. ILS 160 thousand gross (100%)[29] (the salary is updated every 3 months in accordance with the CPI). Mr. Abu is entitled to the related benefits that are customary among managers in the economy, including: contributions to a pension fund and/or managers' insurance; contributions to a study fund; work disability insurance; a car (the car's value in use is grossed-up and paid by the employer); bearing of communication expenses (mobile phone, internet, newspapers, etc.); participation in professional training; annual leave (including entitlement to leave cash-in); recuperation pay; sick pay pursuant to the law; health insurance; severance pay (as of the date of the 2016 Agreement, Mr. Abu has a signed arrangement under Section 14 of the Severance Pay Law, 5723-1963, and therefore the severance pay to which he is entitled is pursuant to the said law); reimbursement of *per diem* expenses from the General Partner in the context and for the purpose of performing his duties at the General Partner, including expenses of overseas travel, all in accordance with the Compensation Policy and as it shall be updated from time to time. Furthermore, Mr. Abu is included in insurance arrangements and is entitled to officers' indemnification and exemption. Mr. Abu is entitled to an annual bonus in each calendar year in the period of the employment agreement and to a special one-time bonus, in accordance with the Compensation Policy and as it shall be updated from time to time. In the event of discontinuation of his employment, Mr. Abu will be entitled

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27 Regarding the Former Compensation Policy, see the Partnership's immediate reports dated April 15, 2016, May 30, 2016 and June 5, 2016 (Ref.: 2016-01-049417, 2016-01-039408 and 2016-01-044880, respectively), the information appearing in which is incorporated herein by reference (the "**Former Compensation Policy**"). Note that, on December 27, 2018, the meeting of the participation unit holders approved an amendment to Section 13 of the Former Compensation Policy on the issue of insurance and indemnification for the directors and officers. For details see immediate reports of the Partnership dated November 20, 2018, November 21, 2018, December 26, 2018 and December 27, 2018 (Ref..: 2018-01-105829, 2018-01-106279, 2018-01-119173 and 2018-01-119824, respectively), the information appearing in which is incorporated herein by reference.

28 For further details see the Partnership's immediate reports of July 10, 2019 and July 3, 2019, (Ref..: 2019-01-059625, and 2019-01-057213, respectively), the information appearing in which is incorporated herein by reference.

29 As of December 31, 2020.

to an adjustment bonus and a retirement bonus, in accordance with the Compensation Policy.

In addition, in the context of the 2016 Agreement, the General Partner granted Mr. Abu 2,959,860 phantom units (whose underlying asset is a participation unit which confers a right of participation in the rights of the limited partner of the Partnership, subject to adjustments as specified in the 2016 Agreement) (the "**Original Phantom Units**")[30]. As of this date, all the Original Phantom Units have vested and they are exercisable until the expiration of 90 days from the discontinuation of Mr. Abu's employment pursuant to the 2016 Agreement (i.e. June 30, 2021). The exercise price of the Original Phantom Units that were issued by the General Partner (in this section: "**Delek Options**") is ILS 11.33 for the first installment; the exercise price of the Original Phantom Units that were issued by the General Partner of Avner Partnership (in this section: "**Avner Options**") is ILS 10.55 for the first installment (according to the adjustment mechanism set forth in the Employment Agreement), plus 5% for each installment from the first installment.

According to a valuation received by the General Partner, the economic value of the Original Phantom Units as of December 31, 2020, was approx. ILS 340 thousand, and was calculated using the Binomial model, based on the following assumptions: (1) price of participation unit as of December 31, 2020 – ILS 3.88; (2) the exercise price of each option (adjusted to profit distribution and tax advances) was calculated according to ILS 6.95 (Delek Options)/ ILS 7.32 (Avner Options) for the first installment, ILS 7.51 (Delek Options)/ ILS 7.9 (Avner Options) for the second installment, ILS 8.11 (Delek Options)/ ILS 8.54 (Avner Options) for the third installment, ILS 8.73 (Delek Options)/ ILS 9.16 (Avner Options) for the fourth installment and ILS 9.39 (Delek Options)/ ILS 9.86 (Avner Options) for the fifth installment; (3) standard deviation at the rate of 76.91%; (4) risk-free interest rate of approx. 0.035%; (5) contractual life of approx. 0.5 years; (6) rate of abandonment after the vesting period that was taken into account - 0%; (7) limitation of the maximum benefit to derive for Mr. Abu from the exercise of each phantom unit shall not exceed 100% of the

[30] It is noted that simultaneously with the granting of 1,506,025 phantom units whose underlying asset is a participation unit which confers a right of participation in the rights of the limited partner in the Partnership, Mr. Abu was granted 7,734,410 phantom units whose underlying asset is a participation unit which confers a right of participation in the rights of the limited partner in the Avner Partnership (in this footnote: the "**Phantom Units in Avner**"). Upon the closing of the merger of the partnerships, the Phantom Units in Avner were exchanged for additional phantom units in the Partnership, in accordance with the adjustment mechanism that is prescribed in the Employment Agreement, such that as of the date of approval of this report, Mr. Abu holds 2,959,860 phantom units in the Partnership.

exercise price that was determined for the phantom unit that is included in the installment exercised on the granting date.

In addition, in the context of the 2019 Terms, the General Partner granted Mr. Abu 2,742,231 phantom units (whose underlying asset is a participation unit which confers a right of participation in the rights of the limited partner of the Partnership)[31] (in this section: the "**Current Phantom Units**"). The Current Phantom Units will vest in three installments[32], such that the first installment vested on June 1, 2020, the second installment will vest on June 1, 2021 and the third installment will vest on June 1, 2022. Each one of the installments included in the Total Package is exercisable from the vesting date of such installment until the expiration of one year from the vesting date of third installment (i.e., June 1, 2023). The exercise price of the Current Phantom Units is ILS 10.79 for the first installment; ILS 11.33 for the second installment; and ILS 11.89 for the third installment.

According to a valuation received by the General Partner, the economic value of the Current Phantom Units as of December 31, 2020, was approx. ILS 1.1 million, and was calculated using the Binomial model, based on the following assumptions: (1) price of participation unit as of December 31, 2020 – ILS 3.88; (2) the exercise price of each option (adjusted to profit distribution and tax advances) was calculated according to ILS 10.05 for the first installment, ILS 10.59 for the second installment, and ILS 11.15 for the third installment; (3) standard deviation at the rate of 61.7%; (4) risk-free interest rate of approx. 0.13%; (5) contractual life of approx. 2.42 years; (6) rate of abandonment after the vesting period that was taken into account - 0%; (7) limitation of the maximum benefit to derive for Mr. Abu from the exercise of each phantom unit shall not exceed 100% of the exercise price that was determined for the phantom unit. In 2020 Mr. Abu received an annual bonus in the amount of ILS 2,169 thousand for 2019. The annual bonus was granted to Mr. Abu based on the following components:

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31 The exercise prices, as specified above, and/or the number of New Phantom Units, are subject to adjustments in circumstances of profit distributions and/or in circumstances of payment of tax advances by the General Partner on account of the tax owed by the participation unit holders and/or in circumstances of a distribution of bonus securities and/or in circumstances of capital splits and consolidations and/or in circumstances of a restructuring and/or in circumstances of securities offerings by way of rights and/or in circumstances of mergers and acquisitions.

32 The General Partner shall be entitled, subject to the approval of the compensation committee and the board of directors, to approve an acceleration of the vesting period for all or part of the equity compensation, according to conditions determined for such purpose in the Current Compensation Policy.

(a) A component depending on a business target (40%) – (1) commencement of piping of natural gas from Leviathan reservoir; (2) release of an updated resources report for a deep prospect in the Leviathan leases; (3) entrance into an additional petroleum asset/s, the work plan for which includes drilling; (4) obtaining a production license in Aphrodite reservoir in Cyprus; (5) obtaining a license to export to Egypt for an agreement in the overall scope of 30 BCM. Mr. Abu met the criteria specified in this section, and was thus entitled, due to that component, to an annual bonus of approx. ILS 880 thousand; (b) A component dependent on the following quantitative tests (35%): (1) change in the annual adjusted profit[33] (7%): the bonus for the change in the adjusted net profit[34] is paid linearly due to change of 90%-120%, the threshold condition for compliance with this criterion being the adjusted net profit for the year in respect of which the bonus is granted not falling below $50 million. In 2019, the change in the adjusted net profit was in the determined range (approx. 96%), and therefore Mr. Abu was entitled, due to that criterion, to an annual bonus of approx. ILS 123 thousand; (2) performance of investments/adoption of an investment decision (14%): performance of actual investments by the Partnership in a petroleum asset in the amount of no less than $50 million or alternatively, adoption of a decision to invest in a petroleum asset in an amount exceeding $300 million (100%). In 2019 Mr. Abu met the criterion specified in Subsection (2) above, when investments were made in the Leviathan project and the Tamar Project in the total scope of approx. $475 million, and therefore Mr. Abu was entitled, due to that criterion, to an annual bonus of approx. ILS 308 thousand; (3) raising of money/signing of natural gas sale agreements/signing of export agreements (14%): raising of money with the Partnership's share not falling below $200 million, or alternatively the signing of binding agreements for the sale of gas in a scope exceeding 25 BCM or alternatively, the signing of export agreements. Mr. Abu met the criterion specified in subsection (3) above, due to the loans provided to the Partnership in the total scope of $300 million, and therefore Mr. Abu was entitled, due to that criterion, to an annual bonus of approx. ILS 308 thousand; (c) Board of directors' discretion component (25%): approx. ILS 550 thousand.

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[33] The rate received from division of the adjusted net profit (as defined below) in the year for which the bonus is paid, by the average adjusted net profit of the Partnership in the three years preceding the year for which the bonus is paid ("**Change of the Adjusted Net Profit**").

[34] In this regard, "**Adjusted Net Profit**" shall mean the net profit attributed to holders of the participation units in the Partnership in the year for which the bonus is granted, without considering expenses for exploration wells as presented in the Partnership's statement of comprehensive income for that year.

For further details regarding the 2019 Terms, see the meeting's immediate reports dated July 3, 2019 and July 10, 2019 (Ref. : 2019-01-057213 and 2019-01-059625, respectively), the information appearing in which is incorporated herein by reference.

(3) Yossi Gvura

Commencing on July 19, 2012 and until July 31, 2017, Mr. Yossi Gvura ("**Mr. Gvura**") served as Deputy CEO of Financial Affairs at the Partnership. Since August 1, 2017 Mr. Gvura has been serving as Deputy CEO at the Partnership (at a 90% position), and at the General Partner (at a 10% position) and accordingly, the Partnership (90%) and the General Partner (10%) bear the cost of his employment, respectively (in this section: the "**Employer**").

Mr. Gvura's monthly salary is approx. ILS 125 thousand gross[35] (the salary is updated every 3 months according to the CPI). In accordance with the terms and conditions of his employment (in this section: the "**Employment Agreement**"), Mr. Gvura is entitled to customary social benefits, a study fund, full contributions to a pension plan, annual leave (including entitlement to leave cash-in), sick days and recuperation pay. The Employer further provides Mr. Gvura with a car, as customary for his position in the Partnership and in the General Partner, and bears any and all expenses entailed by use of the car. The car's value in use is grossed-up and paid by the employer. Mr. Gvura is further entitled to additional related benefits, such as his inclusion in officer insurance, indemnification and exemption arrangements, maintenance of a landline and a mobile telephone and bearing the costs of reasonable use thereof, subscription to a daily newspaper at Mr. Gvura's choice, reimbursement of expenses for the performance of his duties, and reimbursement of *per diem* expenses in accordance with the Employer's procedures, as being from time to time, participation in professional training, medical assessments and private health insurance at the Employer's expense. The Employer will be entitled to give Mr. Gvura an annual bonus, each year, in respect of the previous calendar year, provided that he will be employed by the Employer at least 3 months in that year and a special one-time bonus and a signing/retention bonus, all in accordance with the Compensation Policy. In addition, the Employment Agreement includes provisions regarding maintaining confidentiality and a non-competition clause for a period of 3 months.

[35] As of December 31, 2020. In September 2020 the compensation committee and the board of directors approved an update to the monthly salary of Mr. Gvura, commencing from the September 2020 salary, to a sum of ILS 125 thousand.

In 2020 Mr. Gvura received an annual bonus in the amount of ILS 875 thousand for 2019, as a derivative of the components of the annual bonus of the CEO.

(4) Yaniv Friedman

Mr. Yaniv Friedman ("**Mr. Friedman**") serves as Deputy CEO at the Partnership in a full-time position. Note that on March 31, 2021, Mr. Friedman will step down as Deputy CEO at the Partnership. For additional details, see the Partnership's immediate report dated January 26, 2021 (Ref. : 2021-01-010639), the information appearing in which is hereby incorporated by reference.

Mr. Friedman's monthly salary is approx. ILS 100 thousand gross[36] (the salary is updated every 3 months according to the CPI). In accordance with the terms and conditions of his employment (in this section: the "**Employment Agreement**"), Mr. Friedman is entitled to customary social benefits, a study fund, full contributions to a pension plan, annual leave (including entitlement to leave cash-in), sick days and recuperation pay. The Partnership further provides Mr. Friedman with a car, as customary for his position at the Partnership, and bears any and all expenses entailed by use of the car. The value of the use of the car is grossed-up and paid by the Partnership. Mr. Friedman is further entitled to additional related benefits, such as his inclusion in officer insurance, indemnification and exemption arrangements, maintenance of a landline and a mobile telephone and bearing of costs of reasonable use thereof, subscription to a daily newspaper at Mr. Friedman's choice, reimbursement of expenses for the performance of his duties, reimbursement of *per diem* expenses in accordance with the Partnership's procedures, as being from time to time, participation in professional training, medical assessments and private health insurance at the Partnership's expense. The Partnership will be entitled to give Mr. Friedman an annual bonus, each year, in respect of the previous calendar year, provided that he will be employed by the Partnership at least 3 months in that year and a special one-time bonus and a signing/retention bonus, and all in accordance with the Compensation Policy. In addition, the Employment Agreement includes provisions regarding maintaining confidentiality and a non-competition clause for a period of 3 months. The Partnership bears the full cost of his employment (100%).

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36 As of December 31, 2020.

In 2020, Mr. Friedman received an annual bonus in the amount of ILS 700 thousand for 2019, as a derivative of the components of the annual bonus of the CEO.

(5) Zvi Karcz

Mr. Zvi Karcz ("**Mr. Karcz**") serves as VP Exploration at the Partnership in a full-time position since August 12, 2014 (prior to which he was employed as Chief Geologist).

Mr. Karcz's gross monthly salary is approx. ILS 71 thousand[37] (the salary is updated every 3 months in accordance with the CPI). In accordance with the terms of his employment (in this section: the "**Employment Agreement**"), Mr. Karcz is entitled to customary social benefits, a study fund, a pension plan, annual leave days (including entitlement to leave cash-in), sick days and recuperation pay. The Partnership provides Mr. Karcz with a car, as customary for his position, and bears any and all expenses entailed by use of the car. The car's value in use is grossed-up and paid by the Partnership. Mr. Karcz is further entitled to additional related benefits, such as his inclusion in officer insurance and indemnification arrangements, mobile telephone maintenance, payment of expenses in respect of reasonable use of his home phone, subscription to a daily newspaper, reimbursement of expenses for the performance of his duties, and reimbursement of *per diem* expenses during foreign travel on behalf of the Partnership. The parties may terminate the Employment Agreement at any time by giving a 3-month prior written notice. In addition, the Employment Agreement includes provisions regarding maintaining confidentiality and a non-competition clause for a period of 9 months. Mr. Karcz is entitled to an adjustment bonus at a sum equal to 50% of his gross salary for the entire non-competition period (i.e., a bonus in a total amount of up to 4.5 gross monthly salaries). In that period the Partnership shall make the car and the mobile telephone available to Mr. Karcz. The Partnership bears the full cost of his employment (100%).

In addition to the aforesaid, in March 2018, the compensation committee and board of directors of the General Partner approved the granting of approx. 174,064 phantom units to Mr. Karcz, whose underlying asset is a participation unit which confers a right of participation in the rights of the limited partner of the Partnership, the cost of which is borne by the Partnership (in this section: the "**Phantom Units**"). The Phantom Units will vest in three equal installments, the first installment has vested and is exercisable from March 12, 2020

[37] As of December 31, 2020.

until March 12, 2021, and the second and third installments will be exercisable during the period commencing from March 12, 2021 and ending on March 12, 2022, subject to adjustments. The exercise price of the Phantom Units is ILS 11.75 for the first installment plus 5% for each installment from the second installment, subject to adjustments. According to a valuation received by the Partnership, as of December 31, 2020 the economic value of the Phantom Units which were granted to Mr. Karcz, totaled approx. ILS 36 thousand, and was calculated using the Binomial model, based on the following assumptions: assumptions: (1) price of participation unit as of December 31, 2020 – ILS 3.88; (2) the exercise price of each option was calculated according to ILS 10.68 for the first installment, ILS 11.27 for the second installment and ILS 11.88 for the third installment; (3) standard deviation – 29.5% for the first installment, 33.1% for the second and third installments; (4) risk-free interest rate of approx. 0.13% for the first installment and 0.2% for the second and third installments; (5) contractual life of 0 years for the first installment and 0.2 years for the second and third installments; (6) rate of abandonment after the vesting period that was taken into account - 0%; (7) limitation of the maximum benefit to derive for Mr. Karcz from the exercise of each Phantom Unit shall not exceed 100% of the exercise price that was determined for the Phantom Unit that is included in the installment exercised on the date of grant.

Furthermore, in 2020, Mr. Karcz received an annual bonus from the Partnership in the sum of approx. ILS 213 thousand for 2020, as a derivative of the components of the annual bonus of the CEO.

(6) Sari Singer Kaufman

Ms. Sari Singer Kaufman ("**Ms. Singer**") has been serving as VP, General Counsel on a full-time basis since May 2018 (prior to which, from March 2012, she served as an attorney and later as legal counsel).

Ms. Singer's monthly salary is approx. ILS 60 thousand gross[38], (the salary updates every three months according to the CPI). In accordance with the terms of her employment (in this section: the "**Employment Agreement**"), Ms. Singer is entitled to customary social benefits, a study fund, a pension plan, annual leave days (including entitlement to leave cash-in), sick days and recuperation pay. The Partnership provides Ms. Singer with a car, as customary for her position and bears any and all expenses entailed by use of the car. The car's value in use is

[38] As of December 31, 2020.

grossed-up and paid by the Partnership. Ms. Singer is further entitled to additional related benefits, such as her inclusion in officer insurance and indemnification arrangements, bearing of communication expenses (mobile phone, internet, newspapers, etc.), medical assessments and private health insurance at the Partnership's expense, participation in professional training, reimbursement of expenses incurred in the performance of her position and payment of reimbursement of *per diem* expenses during foreign travel on behalf of the Partnership. The parties may terminate the Employment Agreement at any time by giving prior written notice of 3 months. In addition, the Employment Agreement includes provisions regarding maintaining confidentiality and a non-competition clause for a period of 3 months. The Partnership bears the full cost of her employment (100%).

In 2020 Ms. Singer received an annual bonus from the Partnership in the sum of approx. ILS 180 thousand for 2019, as a derivative of the components of the annual bonus of the CEO.

(7) The General Partner

The General Partner is entitled, according to the Partnership Agreement, to 0.01% of the Partnership's income and bears 0.01% of the expenses and losses of the Partnership and expenses and losses of the Partnership which, due to the limitation of the limited partner's liability for liabilities of the Partnership, are not borne by the limited partner.

The General Partner is entitled, according to the Partnership Agreement, to regular management fees in an amount in ILS equal to U.S. $40,000 per month[39] and in addition, to a management fee at a rate of 7.5% of half of the Partnership's expenses for petroleum exploration activities, on a quarterly basis, and no less than a total amount of $120,000 per quarter.

The General Partner is also entitled to reimbursement of any and all direct expenses entailed by management of the Partnership and incurred by the General Partner. Unless the

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[39] It is noted that the management fees are paid for management of the Partnership, including in respect of the services of the General Partner's directors (who are not external directors), the General Partner's CEO, comptroller services, secretarial services and rent for the Partnership's offices. The Partnership's offices are located in a building that is owned by Delek Group, the Partnership's control holder. Since the cost of provision of the management services by the General Partner to the Partnership is higher than the management fees and the reimbursements of expenses that are paid to the General Partner as aforesaid, the Partnership's financial statements include the total costs exceeding management fees, in a capital reserve, that amounted to approx. $3 million.

Supervisor's approval is received for expenses of other types, the said expenses shall include only the following expenses:

Fees for accounting services, legal advice, geological advice, investment advice, reservoir engineering and geophysical advice, engineering advice, economic (financial) advice, insurance advice, strategic and media advice, investor relations advice, regulatory advice, marketing advice and reimbursement of expenses in connection with financing and marketing activity, and expenses in respect of preparation of financial statements for the joint transactions, expenses of preparing financial statements and reports pursuant to the Securities Law, 5728-1968 and expenses of preparing certificates for tax purposes, payments that are required to be made to the ISA, to TASE, to the Registrar of Companies and to the Registrar of Partnerships.

The aforesaid notwithstanding, the Partnership may directly employ employees and/or officers who will provide the Partnership with services of the type for which the General Partner is entitled to reimbursement of expenses as aforesaid, in which case the Partnership shall bear the full cost of their salary, and the General Partner will not be entitled to reimbursement of expenses in respect of such services.

(8) The Supervisor

1. The Supervisor is entitled to receive from the trustee, out of the trust assets, compensation of approx. ILS 60 thousand[40] per month (plus V.A.T). The monthly compensation will be updated every three months in accordance with changes in the CPI in relation to the index rate for May 2017.

   Notwithstanding the aforesaid, in the event of the publication of a prospectus (including a shelf prospectus), the Supervisor will be entitled to additional compensation for his additional work that is entailed by the publication of the prospectus, in the amount equal in ILS to $40,000 (plus V.A.T, if applicable), irrespective of the actual working hours (in this section: the "**Additional Compensation**"). It is clarified that in the case of a shelf prospectus, the Additional Compensation also includes compensation in respect of all of the work that shall be required of the Supervisor after publication of a shelf prospectus, in connection with a shelf

[40] As of December 31, 2020. In the period from January 1, 2020 until May 30, 2020, the Supervisor was entitled to a monthly salary of approx. ILS 80 thousand.

prospectus in respect of which the Supervisor received the Additional Compensation, insofar as required, including shelf offering reports published according to a shelf prospectus and/or any offering performed according to a shelf prospectus and/or any financing round carried out according to a shelf prospectus ("**Work After the Publication of the Shelf Prospectus**"). After the Supervisor is paid the Additional Compensation, the Supervisor will not be entitled to any additional payment for his work in connection with the publication of a prospectus as aforesaid, in respect of which the Additional Compensation was paid to the Supervisor, as well as in connection with Work After the Publication of the Shelf Prospectus as aforesaid.

The Supervisor is further entitled to a payment equal in ILS to $40,000 (plus V.A.T), irrespective of actual working hours, for his work, insofar as required, in connection with the closing of financing agreements made against a pledge of a petroleum asset of the Partnership.

In addition, the Supervisor is entitled to reimbursement of additional expenses, subject to the approval of a meeting of the participation unit holders, or that the expenses are in an amount and of a type approved by a general meeting as aforesaid. Note that on December 22, 2016, the meeting of the participation unit holders, without derogating from the provisions of the Partnership Agreement and the Trust Agreement, approved that the type of expenses for which the Supervisor will be entitled to a reimbursement of expenses from the trust assets will include travel expenses to meetings of the organs of the Partnership, meetings with the General Partner's management and meetings with the representatives of the General Partner vis-à-vis various regulators, courier services, and parking expenses due to all of the aforesaid and that the expense reimbursement amount as aforesaid shall not exceed ILS 1,000 (plus VAT) per month.

2. On August 18, 2020 the meeting of the participation unit holders approved the Supervisor's budget for the purpose of its representation as a respondent in the legal proceeding with respect to Section 19 of the Taxation of Profits from Natural Resources Law, 5771-2011. For further details regarding the aforesaid meeting, see immediate reports of August 10, 2020 and August 18, 2020 (Ref. : 2020-01-076858 and 2020-01-080758,

respectively) the information appearing in which is incorporated herein by reference.

3. Pursuant to the approval by the meeting of the participation unit holders of a budget for the Supervisor due to overseeing the restructuring process of July 17, 2019, on March 3, 2021 the meeting of the participation unit holders approved an additional budget for the Supervisor, for his continued engagement with professional experts and a fee in addition to his monthly salary for the Supervisor's overseeing of the restructuring process. For further details on the aforesaid meetings, see immediate reports dated July 2, 2019, July 17, 2019, February 8, 2021 and March 3, 2021(Ref.: 2019-01-056910, 2019-01-061854, 2021-01-015963 and 2021-01-025905, respectively), the information appearing in which is incorporated herein by reference.

4. Further to the approval by the meeting of the participation unit holders of a budget for advising the Supervisor in the process of examination of the investment recovery date in the Tamar Project (the "**Supervisor's Claim**") dated September 6, 2018, on June 1, 2020, the meeting of the participation unit holders approved the Supervisor's budget for the purpose of an additional engagement with an expert for the purpose of advising the Supervisor in the Supervisor's Claim and engaging therewith for the purpose of examination of the draft directives released by the Ministry of Energy, in an amount that shall not exceed ILS 200 thousand, plus VAT. For additional details on the aforesaid meetings, see immediate reports dated September 2, 2018, September 12, 2018, May 25, 2020 and June 1, 2020 (Ref.: 2018-01-081628, 2018-01-083635, 2020-01-052383 and 2020-01-056283, respectively), the information appearing in which is incorporated herein by reference. In addition, on March 3, 2021 the meeting of the participation unit holders approved for the Supervisor to use the legal and economic consultants retained by him for the purpose of conduct of the Supervisor's Claim also for the purpose of monitoring and supervision of the Partnership's conduct of the defense in the counterclaim regarding the investment recovery date. For additional details on the aforesaid meeting, see immediate reports dated February 8, 2021 and March 3, 2021 (Ref.: 2021-01-015963 and 2021-01-025905, respectively), the information appearing in which is incorporated herein by reference.

(9) The Trustee

The trustee is entitled to receive out of the trust assets a fee equal to U.S. $1,000 (plus V.A.T) for every year in which it serves as a trustee according to the Trust Agreement (or a proportionate share of such amount in respect of part of a year). This amount will be paid to the trustee on the last day of the year in respect of which it is being paid. In addition, the trustee is entitled to receive expenses explicitly permitted in the Trust Agreement or which were approved in advance and in writing by the Supervisor.

(10) External directors

On October 22, 2015, the meeting of the participation units holders decided that *Messrs.* Amos Yaron and Jacob Zack, who were appointed on such date as external directors by such meeting, would be entitled to annual compensation and participation compensation, in accordance with the fixed amounts appearing in the Second Schedule and Third Schedule to the Companies Regulations (Rules Regarding Compensation and Expenses for an External Director), 5760-2000 (the "**Compensation Regulations**"), as being from time to time, and in accordance with the Partnership's rank, as being from time to time. Commencing from the beginning of his second term of office (i.e., October 22, 2018), Mr. Zack, who is classified as an expert external director, as such term is defined in the Compensation Regulations, will be entitled to participation compensation and annual compensation at the "maximum amount" set forth in the Fourth Schedule to the Compensation Regulations, as being from time to time, and according to the rank of the Partnership, as being from time to time.

For further details regarding the appointment of the aforesaid external directors for a second term of office, see immediate reports dated September 20, 2018 and October 10, 2018 (Ref. nos.: 2018-01-085579 and 2018-01-091300, respectively) the information appearing in which is incorporated herein by reference.

Pursuant to the decision adopted by the meeting of the participation unit holders on January 28, 2019 on the appointment of Mr. Efraim Sadka as an external director (commencing on April 1, 2019), it was resolved that Mr. Sadka, who is classified as an expert external director, as such term is defined in the Compensation Regulations, will be entitled, commencing from the beginning of his office as aforesaid, to participation compensation and annual compensation at the "maximum amount" set forth in the Fourth Schedule to the Compensation Regulations, as being from time to time, and according to the rank of the Partnership, as being from time to time.

For further details on the appointment of the aforementioned external director, see immediate reports dated December 16, 2018 and January 28, 2019 (Ref.: 2018-01-115258 and 2019-01-008335, respectively), the information appearing in which is incorporated herein by reference.

Regulation 21A: **The Partnership's controlling interest holder**

The controlling interest holder (indirectly) of the Partnership is Mr. Yitzhak Sharon (Tshuva).

As of the date of approval of the report, Delek Group Ltd. ("**Delek Group**"), which is controlled by Mr. Yitzhak Sharon (Tshuva), holds, directly and indirectly (through Delek Energy and the General Partner, and through indirect holding of Avner Oil and Gas Ltd.) approx. 54.66% of the issued unit capital of the Partnership[41].

Regulation 22: **Transactions of the Partnership with the General Partner or transactions in which the General Partner's controlling shareholder has a personal interest**

Set forth below are details, according to the best of the Partnership's knowledge, regarding any transaction with the General Partner or the General Partner's controlling shareholder, or in the approval of which the General Partner's controlling shareholder has a personal interest, in which the Partnership or a corporation controlled thereby or an affiliate of the Partnership engaged during or after the report year until the date of approval of the report or which is still in effect on the date of approval of the report, with the exception of negligible transactions, as defined in Section 6 of Part Three of Chapter B of this report (the board of directors' report):

(a) According to the Partnership Agreement, as updated from time to time, the General Partner is entitled to management fees as specified in Regulation 21(b)(7) above. It is noted in this context that according to the transitional provisions of the Amendment to the Partnerships Ordinance (No. 5) Law, 5775-2015, engagement with the General Partner Company, which

[41] To the best of the Partnership's knowledge, and according to the reports of Delek Group, as of the date of approval of the report, the vast majority of the units held by Delek Group is pledged to holders of bonds issued by Delek Group.

was approved prior to the date of commencement of the Law (April 23, 2015), and which should be reapproved after the date of commencement, should be approved within six years of the date of commencement (i.e., April 23, 2021). As of the date of approval of the report, the Partnership is examining, with the help of its legal counsel, the implications of the said transitional provisions on the arrangement that was determined in this respect by the Limited Partnership Agreement.

(b) According to an agreement from 1993, Delek Group and Delek Energy are entitled to receive royalties from the Partnership, as specified in Section 7.25.10(d)2 of Chapter A of this report and, in such context, they will be entitled to royalties for the Partnership's share in the Tamar Project (the "**Tamar Royalties**") and for the Partnership's share in the Leviathan project (the "**Leviathan Royalties**"). Following the sale of the Tamar Royalties by Delek Group and Delek Energy, commencing from June 1, 2018, the Partnership pays Delek Energy's share in the Tamar Royalties to Delek Royalties (2012) Ltd. ("**Delek Royalties**")[42] and commencing from December 1, 2019, the Partnership pays Delek Energy's share in the Tamar Royalties to the Teacher and Kindergarten Teacher Funds. In addition, further to the sale of the Leviathan Royalties by Delek Group and Delek Energy to Delek Leviathan Overriding Royalty Ltd. ("**Delek Overriding Royalty**"), starting from October 28, 2020, the Partnership pays the Leviathan North and Leviathan South royalties for the share of Delek Group and Delek Energy to Delek Overriding Royalty. In 2020, the Partnership recorded expenses due to royalties paid to Delek Group and Delek Energy for the Leviathan project in the total sum of approx. \$6.1 million, to Delek Royalties for the Tamar Project, in the total sum of approx. \$14.7 million and to Delek Overriding Royalty due to the Leviathan project, in the total amount of \$1.5 million.

(c) Upon the closing of the merger of the partnerships (as this term is defined in Section 1.6 of Chapter A of this report), Cohen Gas and Oil Development Ltd. ("**Cohen Development**")[43] is entitled to royalties from the

[42] Note that the aforesaid transaction is no longer classified as a transaction in which the controlling shareholder of the General Partner has a personal interest, as a result of the closing of a transaction for the sale of the holdings of Delek Group in Delek Royalties, of December 29, 2020.

[43] Note that the aforesaid transaction is no longer classified as a transaction in which the controlling shareholder of the General Partner has a personal interest, as a result of the closing of a transaction for the sale of the holdings of Delek Group in Cohen Development. For additional details, see the

Partnership, as specified in Section 7.25.10(d)3 of Chapter A of this report. In 2020, the Partnership recorded expenses for royalties paid to Cohen Development for the Leviathan and Tamar projects in a total sum of approx. $11.6 million.

(d) With respect to engagements in agreements for the supply of natural gas with affiliates:

1. According to an agreement of August 2005, as amended in November 2012, the Partnership, together with its partners in the Yam Tethys project, supplies natural gas to I.P.P Delek Ashkelon Ltd. ("**Delek Ashkelon**")[44], a company which was (indirectly) held by Delek Group. The agreement is in effect until June 30, 2022 and the remaining contract quantity for supply is approx. 0.35 BCM. In 2020, the Partnership's share in revenues from the sale of natural gas to Delek Ashkelon was approx. $6.5 million.

2. On December 3, 2013, the Partnership engaged[45], together with its other partners in the Tamar Project (in this section: the "**Sellers**"), in an agreement for the supply of natural gas (in this section: the "**Supply Agreement**" or the "**Agreement**") with Delek the Israel Fuel Corporation Ltd. ("**Delek Israel**"), a subsidiary of Delek Group, in respect of a total amount of up to approx. 0.46 BCM (in this section: the "**Total Contract Quantity**"), according to the conditions specified in the Supply Agreement. The term of the Supply Agreement began during Q1/2015 and is expected to end upon the expiration of approx. 7 years or on the date which Delek Israel will have consumed the Total Contract Quantity, whichever is earlier. Delek Israel undertook to Take or Pay for a minimal annual quantity of gas at a scope and according to the mechanism set in the Supply Agreement. The gas price set in the Agreement

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Partnership's immediate report dated April 20, 2020 (Ref.: 2020-01-035077), the information appearing in which is hereby incorporated by reference.

44 Note that the aforesaid transaction is no longer classified as a transaction in which the controlling shareholder of the General Partner has a personal interest, as a result of the closing of a transaction dated February 22, 2021, for the sale of Delek Israel's holdings in Delek Ashkelon.

45 Said engagement was approved on December 3, 2013 by the board of directors of the General Partner.

will be linked to the Brent prices including a "floor price" and a "cap price", all according to the formula set in the Agreement. In 2020, the Partnership's share in the income from the sale of natural gas to Delek Israel was approx. $729 thousand.

3. On March 6, 2014 the Partnership engaged,[46] together with its other partners in the Tamar project (in this section: the "**Tamar Partners**"), in an agreement for the supply of natural gas (which was amended on May 18, 2015) (in this section: the "**Agreement from Tamar**") with IPP Delek Sorek Ltd. ("**Delek Sorek**")[47], a company controlled (indirectly) by Delek Group. Within the Agreement from Tamar, the Tamar Partners undertook to supply Delek Sorek with natural gas in a total amount of up to approx. 3.3 BCM (in this section: the "**Total Contract Quantity**") according to the conditions specified in the Agreement from Tamar. The term of the Agreement from Tamar began during Q3/2016 and is expected to end upon the expiration of approx. 15 years or on the date which Delek Sorek shall have consumed the Total Contract Quantity, whichever is earlier. The parties have a right to extend the term of the Agreement from Tamar until such time as the Total Contract Quantity is consumed and for a term of two more years at the most. Delek Sorek undertook to Take or Pay for a minimum annual quantity of gas in an amount and according to the mechanism set forth in the Agreement from Tamar. Furthermore, it was determined that the gas price in the Agreement from Tamar will be linked to the weighted production tariff as shall be determined from time to time by the Public Utility Authority – Electricity and includes a "bottom" price, all according to the formula set in the Agreement from Tamar. It is noted, that according to the provisions of the Agreement from Tamar, upon the fulfillment of the conditions specified in the Agreement from Tamar, Delek Sorek may notify the Tamar Partners of the early termination of

[46] Said engagement was approved on March 6, 2014 by the board of directors of the General Partner.

[47] Note that the aforesaid transaction is no longer classified as a transaction in which the controlling shareholder of the General Partner has a personal interest, as a result of the closing of a transaction for the sale of the holdings of Delek Israel in Delek Sorek, of February 22, 2021.

the Agreement from Tamar. Accordingly, on November 11, 2019, Delek Sorek notified the Tamar Partners of the termination of the Agreement from Tamar, commencing as of February 9, 2020.

On September 19, 2019[48], an agreement for the supply of natural gas was signed between the Leviathan partners (in this section: the "**Leviathan Partners**") and Delek Sorek[49] (the "**Agreement from Leviathan**"). Within the Agreement from Leviathan, the Leviathan Partners undertook to supply Delek Sorek with natural gas in a total annual amount of up to approx. 0.24 BCM according to the conditions specified in the Agreement from Leviathan. The supply period according to the Agreement from Leviathan began in proximity to the date of commencement of gas transmission from the Leviathan project and will end upon the expiration of 9 years from the date of commercial operation of the Leviathan Project (the "**Period of the Supply Agreement**"), while Delek Sorek will be entitled to extend the Agreement from Leviathan by five additional years, by sending a notice to the Leviathan Partners of its wish to so do, no later than the end of the seventh year from the date of commercial operation of the Leviathan project. Delek Sorek undertook to Take or Pay for a minimum annual quantity of gas in an amount and according to the mechanism set forth in the Agreement from Leviathan (the "**Take-or-Pay Quantity**"). The gas price determined in the Agreement from Leviathan will be linked to the Electricity Production Tariff as shall be determined from time to time by the Electricity Authority and includes a "bottom price". The Partnership's estimates that the aggregate revenues from the sale of natural gas to Delek Sorek (in respect of 100% of the rights in the Leviathan project) in the Period of the Supply Agreement (based on an estimation of the price and quantity of natural gas that will be purchased in the term of the Agreement from Leviathan) may amount to approx. U.S. $600

48 Said engagement was approved on September 19, 2019 by the audit committee and the board of directors of the General Partner.

49 See Footnote 47 above.

million in the term of the Agreement from Leviathan. It is clarified that the actual revenues will be derived from several factors, including the gas quantities that will actually be purchased by Delek Sorek, the Electricity Production Tariff and the Dollar-Shekel exchange rate.

In 2020, the Partnership's share in the revenues from the sale of natural gas to Delek Sorek from the Leviathan and Tamar Projects was approx. $14.6 million.

(e) According to the terms and conditions of the PSC in Block 12, the Partnership is required by the Republic of Cyprus to provide a performance guarantee for its undertakings by the Partnership's parent company. Accordingly, on April 18, 2013 Delek Group issued a performance guarantee at an unlimited amount, to the benefit of the Republic of Cyprus for securing the fulfillment of all of the undertakings of the Partnership under the PSC (the "**Guarantee**"), all as specified below:

1. For the provision of the Guarantee by Delek Group, the Partnership pays a fee, on an annual basis, as of the date of provision of the Guarantee and for as long as the Guarantee is in effect. The annual fee paid by the Partnership in the first five years after the date of provision of the Guarantee was $490 thousand, and from the sixth year and until the lapse of 25 years from the date of provision of the Guarantee the amount of $368 thousand. In the event that the holding rate of the Partnership in Block 12 will decrease, then the amount of the fee will decrease *pro rata* to the decrease in the holding in the asset. In addition, in a case where Delek Group is absolutely released from the Guarantee, whether due to the finding of an alternative guarantor or due to the sale of the rights in Block 12 by the Partnership, the Partnership and Delek Group agreed that the payment of the fee will be discontinued immediately. The total amount of the Guarantee fee paid by the Partnership to Delek Group in 2020 was approx. $368 thousand.[50]

[50] The aforesaid engagement was approved on April 14, 2013 by the board of directors of the General Partner and on April 18, 2013 by the meeting of the holders of the participation units. For further details, see the Partnership's immediate reports of April 18, 2013 and April 14, 2013 (Ref.: 2013-01-

2. Commencing from the date of provision of the Guarantee and for as long as the Guarantee is in effect, the Partnership will not approve a new work plan/s in Block 12 and/or in relation to any other activity in Block 12 by virtue of the joint operating agreement with Noble Energy International Ltd. ("**Noble Cyprus**" and the "**Block 12 Work Plan**", respectively)[51], in the absence of: (1) insurance covering expenses of taking control of a well which went out of control, including coverage for bodily injuries and property damage and cleaning expenses deriving from the risks of accidental contamination in respect of the Partnership's activity in Block 12 to the satisfaction of Delek Group (Insurances for loss of control over well and third party liability)[52]; (2) Approval pursuant to the law of the competent organs in the Partnership of the engagement conditions with Delek Group, as specified above and below and of the arrangements regarding the payment of a Guarantee fee by the Partnership to the Delek Group.

3. In addition, the Partnership undertook that commencing from the date of providing the Guarantee and for as long as the Guarantee is in effect, the following provisions will apply:

a. In case that the Partnership will sell its rights in Block 12, the Partnership will act for releasing Delek Group from the Guarantee, or from its *pro rata* share (in case of a partial sale of the rights) within such sale, all subject to the provisions of the PSC and the decisions of the authorities in Cyprus on the matter. It shall be stated that the sale of some of the rights in Block 12 will be possible only subject to reaching arrangements for liability distribution and mutual

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039418 and 2013-01-036844, respectively), which are incorporated herein by reference. On July 8, 2018, the audit committee approved that fixing the payment due to the Guarantee for a 25-year guarantee period that was determined on the date of approval of the Guarantee transaction for the first time is a reasonable period.

[51] The Partnership will provide Delek Group with an advance notice in respect of any intention to approve a Block 12 Work Plan.

[52] The Partnership engaged in insurance policies that provide it with coverage in respect of accidental and unexpected damage related to expenses due to loss of control of well and in third party liability insurance in relation to the activity in Block 12.

indemnification with the potential buyer of some of the rights as aforesaid, in respect of its *pro rata* share.

b. Delek Group will have the right to require the Partnership, in a written notice, at any time and according to the discretion thereof that it shall release it from the Guarantee. In case of such requirement, the Partnership undertakes to perform the actions required for the release of Delek Group from the Guarantee, including, if and to the extent required for the release of Delek Group from the Guarantee as aforesaid, the sale of its rights, in whole or in part, in Block 12 and/or waiver thereof, without requiring the receipt of additional approvals at the Partnership. In case of such requirement, the Partnership undertakes that within 12 months from the date of provision of a written requirement, it will cause the release of Delek Group from the Guarantee or alternatively execute an agreement for the sale of the rights in Block 12. In case of such sale, the Partnership undertakes to consummate the sale within 6 months from the date of execution of the sale agreement.

c. The Partnership will indemnify Delek Group for damage of any type whatsoever and/or any type of expenses and/or payments borne by the Delek Group (including expenses and/or legal fees and/or expert fees) in respect of the enforcement of the Guarantee and/or a claim and/or demand, whose cause is related to the Guarantee and/or the enforcement thereof, with no limitation on amount. Without derogating from the aforesaid, Delek Group will deliver to the Partnership, without delay, a notice regarding the filing of such claim and/or demand upon its receipt thereby and will allow the Partnership and/or another on its behalf to conduct proper and necessary legal defense as deemed necessary by the Partnership in the circumstances of the matter, against any demand and/or claim as aforesaid and/or negotiations for settlement as aforesaid and/or reduce the damage to the extent it is able to do so.

4. Whereas the undertakings of the Partnership and Noble Cyprus according to the PSC are joint and several, an agreement was executed between Delek Group and the parent company of Noble Cyprus (the “**Noble Parent Company**”), and the parent company of BG Cyprus, regarding liability distribution and mutual indemnification between them, regarding the activity in Block 12, according to the holding percentage of the Partnership, Noble Cyprus and BG Cyprus in the rights in Block 12 (in this section: the "**Agreement**"). The Agreement determines, *inter alia*, that:

a. Each party to the Agreement will be liable for damage or liability related to the activity in Block 12 according to the participation rate of the corporation in respect of which it had issued a guarantee to the benefit of the Republic of Cyprus as aforesaid, in Block 12 (i.e.: Delek Group at a rate of 30%, the Noble Parent Company at a rate of 35%, and the parent company of BG Cyprus at a rate of 35%).

b. Therefore, each party to the Agreement undertook to indemnify or release the other party from liability, in respect of damage and/or liability related to the activity in Block 12 which are beyond the participation rate of the corporation in respect of which it had issued a guarantee to the benefit of the Republic of Cyprus, as aforesaid, in Block 12 (in this section: the "**Indemnification Undertaking**").

c. The parties' undertaking as aforesaid is not limited by amount or by scope of the insurance coverage of the Partnership, Noble Cyprus and BG Cyprus within their activity in Block 12.

d. Each party to the Agreement undertook to receive from its insurer a waiver of subrogation right against the other party to the Agreement in respect of damage or liability related to the activity thereof in Block 12.

e. The Agreement sets forth a binding arbitration mechanism for the resolution of disputes between the parties.

f. The Agreement will be in effect until the termination of the joint operating agreement applicable to Block 12, subject to a final accounting between the parties with respect to the Agreement.

(f) With respect to the engagement of the Yam Tethys partners with the Tamar Partners in an agreement of July 23, 2012, whereby the Yam Tethys partners will grant the Tamar Partners rights to use the existing facilities in the Yam Tethys project as well as the right to upgrade and/or build facilities for the purpose of transporting and storing natural gas from the Tamar Project, see Section 7.25.11 of Chapter A of this report[53].

(g) On May 3, 2020, the Partnership, Noble Energy Mediterranean Ltd. ("**Noble**"), Delek Group and Ratio Oil Exploration (1992) – Limited Partnership ("**Ratio**") signed an agreement for the supply of natural gas in the context of which, the gas for customers which signed previous agreements with each of the Yam Tethys partners will be supplied from the Leviathan reservoir. Accordingly, the Yam Tethys partners that are Leviathan Partners (the Partnership and Noble), take from the gas which is in their possession, in accordance with the rate of their holdings in the Yam Tethys project, while the remainder of the gas required to be supplied by each of the Yam Tethys partners will be purchased from Ratio, according to the consideration determined in the agreement as aforesaid which is the average monthly price set forth in the agreements which were signed between the Leviathan Partners and their customers in the domestic market. For additional details see Section 7.7 of Chapter A of this report.

(h) With respect to the accounting mechanism between the Yam Tethys partners and the Tamar Partners, see Section 7.25.11 of Chapter A of this report and Notes 7C5A and 7C5B to the financial statements (Chapter C of this report). In 2020, the Partnership's share in the gas sale revenues to the share of Delek Group in the

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[53] The said engagement was approved on July 23, 2012 by the board of directors of the General Partner.

Yam Tethys project amounted to a total of approx. $384 thousand.

(i) On July 24, 2018, the meeting of the participation unit holders, approved, further to the approval by the audit committee dated March 7, 2018 and May 10, 2018 and the approval of the board of directors of the General Partner dated March 12, 2018, May 14, 2018 and June 14, 2018, the engagement of the Partnership with Delek Group in an agreement which regulates the manner of distribution of the costs of employment of professional employees of the partnership which would be employed by Delek Group and its subsidiaries, according and subject to the terms of the arrangement, for a 3-year period commencing on the date of approval by the meeting as aforesaid. On December 25, 2020 the audit committee and the board of directors of the General Partner of the Partnership approved the Partnership's engagement with Delek Group in an addendum to the agreement which limits the liability of the Partnership and/or the employees and officers thereof. For the cost of the transaction as aforesaid, in 2020 the Partnership charged Delek Group the sum of approx. $41 thousand. For further details, see the Partnership's immediate reports dated July 24, 2018 and June 17, 2018 (Ref.: 2018-01-070039 and 2018-01-058279, respectively).

(j) In respect of the approval of framework conditions for a period of three years for future engagements of the General Partner and/or the Partnership in a policy for the insurance of liability of directors and officers, within a group insurance policy taken out by Delek Group (the "**Framework Conditions**" and the "**Group Policy**", respectively), and the Partnership's engagement in a policy for insurance of the liability of directors and officers under the Group Policy and according to the Framework Conditions, for the period commencing on January 1, 2019 until June 30, 2020 (the "**Previous Independent Policy**"), see Regulation 22(i) of Chapter D (Additional Details on the Partnership) in the Partnership's 2019 periodic Report, as released on March 30, 2020 (Ref.: 2020-01-032010), the information appearing in which is incorporated herein by reference.

(k) On May 27, 2020 the compensation committee authorized the General Partner and the Partnership to engage in a D&O liability insurance policy in the context of the Previous Independent Policy by way of exercise of an option for an extended run off period, for the period starting on July 1, 2020 and expiring on June 30, 2027 with a premium of approx. $345 thousand for the period as aforesaid under conditions complying with the conditions determined in the Former Compensation Policy on this matter (as specified in Regulation 21(b)(1) above). In addition, on May 27, 2020 the compensation committee and the audit committee authorized and on June 25, 2020 the board of directors of the General Partner authorized to give approval to the General Partner and/or the Partnership to engage in a D&O liability insurance policy in the context of a group insurance policy of Delek Group by way of exercise of an option for an extended run off period for the period starting on July 1, 2020 and expiring on June 30, 2027 with a premium of approx. $1,518 thousand for the period as aforesaid (the Partnership's share, approx. $632 thousand for the insurance period) under conditions complying with the conditions determined in the Framework Conditions.

(l) For details regarding the compensation policy for officers of the Partnership and the General Partner, see Regulation 21(b)(1) above.

(m) For details regarding the office of Mr. Abu as CEO of the General Partner at an 80% position, and his simultaneous office as CEO of Delek Energy at a 20% position (which is not in effect as of the date of approval of the report), see Regulation 21(b)(2) above.

(n) For details regarding the office of Mr. Gvura as Deputy CEO of the Partnership (at a 90% position) and the General Partner (at a 10% position), and for the manner by which the cost of his employment is distributed between the Partnership (90%) and the General Partner (10%), see Regulation 21(b)(3) above.

(o) Mr. Ronen Edward serves as CFO of the Partnership and the General Partner, and accordingly, the cost of his employment is borne by the Partnership (30%) and the General Partner (70%).

Negligible transactions – Over and above the transactions specified above, the Partnership has other engagements in which the Partnership's controlling interest holder has a personal interest, which are classified as negligible transactions, as defined in Section 6 of Part Three of Chapter B of this report (the board of directors' report), such as: receipt of "*dalkan*" [automatic billing for fueling] services from Delek Israel, receipt of V.A.T reporting services from Delek Israel, receipt of services from NYX Hotel Herzliya of the Fattal Hotel Chain, an accounting with Delek Group and with Mr. Yitzhak Sharon (Tshuva) in relation to legal costs in the context of a class certification motion and engagement in the Previous Independent Policy, as specified in Regulation 22(j) above.

Regulation 24: **Holdings of interested parties and senior officers[54]**

For details regarding holdings of interested parties and senior officers of the Partnership and/or of the General Partner as of December 31, 2020, see the Partnership's immediate report of January 5, 2021 (Ref.: 2021-01-001794), the information appearing in which is incorporated herein by reference.

Regulation 24A: **Authorized capital, issued capital and convertible securities**

	Authorized Capital Par Value	**Issued and Paid-Up Capital Par Value**
Participation units of par value ILS 1 each	1,173,814,690.76	1,173,814,690.76

As of the date of approval of the report, the Partnership has no convertible securities.

[54] For details regarding changes in interested party holdings in the Partnership that were carried out after the date hereof, see the Partnership's immediate report dated January 5, 2021 (Ref.: 2020-01-001882), the information appearing in which is incorporated herein by reference.

Regulation 24B: **Register of the Partnership's participation unit holders**

Name of Holder	Quantity Held
Delek Group	1
The Transfer Agent of Israel Discount Bank Ltd.	1,173,116,181.89
Chaya Leventhal	1.19
Nathan Turkia	1
Yaakov Maroz	1
Moshe Kramer	1.19
Avner Andera	1
Ariel Yanko	289.47
Ran Levy	184.8
Tova Berger	12
Azriel Zolti	1.19
Varda and Baruch Kotlarsky	143,562.10
Daniel Goldstein	18.80
Tuvia Even	1,317.67
Daniel Dayan	234,962.37
Dorit Dayan	234,962.37
Yosef Vank	52,505.44
Amikam Reshef	590.60
Tamar and Avraham Adani	62.59
Sarah Morah	30,032.89
Yehuda Luria	0.19
Total	**1,173,814,690.76**

Regulation 25A: **Registered address**

Address: 19 Abba Even Blvd., Herzliya Pituach, 4612001.

Telephone: 09-9712424
Facsimile: 09-9712425

E-mail address: saris@delekng.co.il

Regulation 26: **The directors of the General Partner**[55]

	Details	Gabriel Last	Leora Pratt Levin	Idan Wells	**Tamir Polikar**
1	I.D. number:	004787933	057906919	033658246	059749408
2	Position at the General Partner:	Chairman of the Board	Director	Director	Director
3	Date of birth:	September 9, 1946	October 12, 1962	January 8, 1977	August 14, 1965
4	Address for service of process:	19 Abba Even Blvd., Herzliya	19 Abba Even Blvd., Herzliya	19 Abba Even Blvd., Herzliya	48 Herzfeld St., Kiryat Ono
5	Nationality:	Israeli	Israeli	Israeli	Israeli and Portuguese
6	Membership in board committees:	No	No	No	No
7	(a) Is he an external director:	No	No	No	No
	(b) Does he hold accounting and financial expertise or professional qualifications:	Holds professional qualifications	Holds professional qualifications	Holds professional qualifications	Holds accounting and financial expertise
	(c) Is he an expert external director[56] :	No	No	No	No
	(d) Is he an independent director:	No	No	No	No
8	Is he an employee of the General Partner, a subsidiary, an affiliate or of an interested party:	Chairman of the Board of Delek Group and Delek Science, Education and Culture Foundation (CIC) and a director in subsidiaries of Delek Group	Senior VP, Chief Legal Counsel and Secretary of Delek Group and director in subsidiaries of Delek Group	CEO of Delek Group	Deputy CEO and CFO of Delek Group Ltd. and director of subsidiaries of Delek Group
9	The date on which his office as director began:	May 17, 2001 and as Chairman of the Board from January 8, 2020	August 26, 2015	January 7, 2020	September 10, 2020
10	His education:	LL.B from Tel Aviv University, M.A. in Social Sciences and Mathematics from the University of Haifa and A.M.P (a management program for senior officers) from Harvard University, U.S.A.	LLB from the University of Reading, England, B.A. in Political Science from Tel Aviv University.	LL.B from Tel Aviv University	B.A. in Accounting from the College of Management, MBA from Heriot Watt University, CPA
11	His occupation in the last five years:	Chairman of the Board of Delek Group, Delek Energy and Delek Science, Education and Culture Foundation (CIC) and director in subsidiaries of Delek Group	Senior VP, Chief Legal Counsel and Secretary of Delek Group and director in various subsidiaries of Delek Group	CEO of Delek Group, Deputy CEO of Delek Group, director of Delek Group, CEO and representative of the controlling shareholder (Tshuva group (through El-Ad USA Holdings; and Tashluz Investments and Holdings Ltd.), strategic consultant at Delek Group	Real estate developer in Israel and overseas, business consultant and director in Polikar Holdings Ltd., CEO of Aspen Group Ltd. and director in subsidiaries of Delek Group and other private companies

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55 The specification of this Regulation presents the directors holding office on the board of directors of the General Partner as of the date of approval of the report. It is noted that on January 7, 2020, Mr. Assi Bartfeld stepped down as director and as Chairman of the Board and on September 10, 2020, Mr. Barak Mashraki stepped down as director.

56 Within the meaning of the term in Section 1 of the Companies Regulations (Rules regarding Compensation and Expenses of External Directors), 5760-2000.

	Details	Gabriel Last	Leora Pratt Levin	Idan Wells	**Tamir Polikar**
12	Other corporations in which he serves as a director:	Chairman of the Board of Delek Group and the Delek Foundation for Education, Culture and Science (CIC), and serves as a director of the following companies: Delek Energy, Delek Power Plant Management Ltd., Delek Petroleum Ltd., Delek Infrastructures Ltd., Delek Group Royalty Ltd., Avner Oil & Gas Ltd., and private subsidiaries of the partnerships (SPCs).	Delek Energy, Delek Sea Maagan 2011 Ltd., Delek Israel Holdings Group Ltd., Delek Leviathan Overriding Royalty Ltd., Delek North Sea Limited and DKL Energy Limited	Delek Energy, Keshet Broadcasting Ltd. ("**Keshet**") and Israel Television News Company Ltd. (the "**News Company**").	Delek Sea Maagan (2011) Ltd., Delek Israel Holdings Group Ltd., Delek Energy, Delek Power Plant Management Ltd., Delek Petroleum Ltd., Delek Infrastructures Ltd., Delek Group Royalty Ltd., Delek Property Development Ltd., Leviathan Overriding Royalty Ltd., Delek Hungary Limited, Ithaca Energy Limited, Polikar Holdings Ltd., Gallipoli Real Estate Investments Ltd., Briza Lgyrp Ltd., and subsidiaries thereof and Elysee Downtown Ltd.
13	Is he a relative of another interested party of the General Partner:	No	No	No	No
14	Does the General Partner deem him as having accounting and financial expertise for purposes of compliance with the minimum number determined by the board of directors pursuant to Section 92(a)(12) of the Companies Law, 5759-1999 (the "**Companies Law**"):	No	No	No	Yes

	Details	Amos Yaron	Jacob Zack	Efraim Sadka	Roni Bar-on
1	I.D. number:	005301262	004868048	046002747	008516262
2	Position at the General Partner:	External Director	External Director	External Director	Independent director
3	Date of birth:	February 5, 1940	April 11, 1946	July 10, 1947	June 2, 1948
4	Address for service of process:	22 Shazar St., Ramat Gan	5 Hashoftim St., Herzliya	5 Dulchin Arieh St., Tel Aviv	8 Unitzman St., Tel Aviv
5	Nationality:	Israeli	Israeli	Israeli	Israeli
6	Membership in board committees:	Audit committee member Compensation committee member Member of the Financial Statements Review Committee ("**Finance Committee**" Investment committee member	Audit committee member Finance committee member Compensation committee member	Audit committee member Finance committee member Compensation committee member Investment committee member[57]	Audit committee member Finance committee member Compensation committee member Investment committee member
7	(a) Is he an external director:	Yes[58]	No	Yes	No
	(b) Does he hold accounting and financial expertise or professional qualifications:	Holds professional qualification	Holds accounting and financial expertise	Holds accounting and financial expertise	Holds accounting and financial expertise
	(c) Is he an expert external director[59] :	No	Yes	Yes	No
	(d) Is he an independent director:	Yes	Yes	Yes	Yes
8	Is he an employee of the General Partner, a subsidiary, an affiliate or of an interested party:	No	No.	No	No
9	The date on which his office as director began:	October 22, 2015	October 22, 2015	April 1, 2019	January 4, 2016
10	His education:	B.A. in General History, Tel Aviv University, Graduate of the National Security College.	B.A. in Accounting and Economics from the Tel Aviv University, MBA from Tel Aviv University, CPA	B.A. in Economics and Statistics from the Tel Aviv University, Ph.D. in Economics from the Massachusetts Institute of Technology (MIT)	LL.B in Law from the Hebrew University of Jerusalem, Attorney-at-law, member of the Israel Bar Association
11	His occupation in the last five years:	Consultant to the Israel Aerospace Industries Ltd., director at ICIC – Israeli Credit Insurance Company Ltd. of the Harel Group		Paz (external director), Ravad Ltd. (independent director), director in other companies and NPOs (see next section).	Member of the board of the following companies: Gazit-Globe Ltd., Alrov Properties and Lodgings Ltd., IDB Development Corp. Ltd., Migdal Makefet Pension and Provident Funds Ltd., IDB Development Corp. Ltd.
12	Other corporations in which he serves as a director:	-	-	Atidim High Tech Industries Co. Ltd., The Sports Center at Tel Aviv University, Artzdka Ltd. (Chairman), Babylonian Jewry Heritage Center (Chairman), The Pinhas	Gazit-Globe Ltd., Alrov Properties and Lodgings Ltd.

57 Commencing from February 12, 2020.

58 Note that Mr. Amos Yaron's son works at the News Company, of which Keshet is the control holder. Ms. Gal Naor, daughter of Mr. Yitzhak Sharon (Tshuva), the (indirect) control holder of the Partnership, holds office as a director in Keshet and (indirectly) holds approx. 21% of Keshet. On August 17, 2020, the audit committee approved that the aforesaid ties do not constitute a link pursuant to Regulation 5(b) of the Companies Regulations (Matters that do not Constitute a Link), 5767-2006.

59 Within the meaning of the term in Section 1 of the Companies Regulations (Rules regarding Compensation and Expenses of External Directors), 5760-2000.

				Sapir Center for Development (Chairman).	
13	Is he a relative of another interested party of the General Partner:	No	No	No	No
14	Does the General Partner deem him as having accounting and financial expertise for the purpose of compliance with the minimum number determined by the board of directors pursuant to Section 92(a)(12) of the Companies Law, 5759-1999 (the "**Companies Law**"):	No	Yes	Yes	Yes

Regulation 26A: Senior officers of the General Partner and/or the Partnership[60]

Officer	I.D. number	Date of birth	Date of commencement of office	Position at the General Partner, a subsidiary, an affiliate or an interested party	Is he an interested party in the General Partner and/or in the Partnership	Is he a relative of another senior officer or of an interested party of the General Partner	His education	His experience in the last five years
Yossi Abu	033840372	December 7, 1977	April 1, 2011	CEO of the General Partner,[62] director of private subsidiaries of the Partnership (SPCs).	Yes	No	LL.B in Law from the Hebrew University of Jerusalem. Attorney-at-law, member of the Israel Bar Association.	CEO of Delek Energy, CEO of Avner Partnership, Chairman of the board of Tamar Petroleum Ltd.[61] ("**Tamar Petroleum**"), director of Ithaca (until March 1, 2018), in private subsidiaries of the Partnership and in private companies owned by him.
Yossi Gvura[63]	027790997	June 9, 1970	Deputy CEO since August 1, 2018. Prior thereto served as CFO at the General Partner – from April 1, 2011, and as Deputy CEO of	Deputy CEO at the Partnership and the General Partner and director of private subsidiaries of the Partnership (SPCs).	No	No	B.A. in Economics and Accounting from Ruppin Academic Center, LL.M in law from Bar-Ilan University, CPA	CFO at the Partnership and the General Partner, Deputy CEO of Financial Affairs at the Partnership, the General Partner, Avner Partnership and Avner Oil & Gas Ltd., director in private subsidiaries of the Partnership.

60 The specification of this regulation presents the officers holding office at the General Partner and/or the Partnership as of the date of approval of the report. Note that, on December 20, 2020 Mr. Ofer Oberlander stepped down as project manager.

61 Tamar Petroleum is a public company holding 16.75% of the Tamar and Dalit leases. For additional details, see Section 1.7.6 of Chapter A of this report.

62 Regarding the office of Mr. Abu as CEO of Delek Energy until March 14, 2020, see Regulation 21(b)(2) above.

63 Serves as an officer of the Partnership at a 90% position.

Officer	I.D. number	Date of birth	Date of commencement of office	Position at the General Partner, a subsidiary, an affiliate or an interested party	Is he an interested party in the General Partner and/or in the Partnership	Is he a relative of another senior officer or of an interested party of the General Partner	His education	His experience in the last five years
			Financial Affairs at the Partnership and the General Partner – from July 19, 2012.					
Yaniv Friedman	027300300	April 1, 1974	November 1, 2015	Deputy CEO of the Partnership.	No	No	LL.B in Law from Tel Aviv University, Attorney-at-law, member of the Bar Association in Israel and New York	VP Strategy at the Avner Partnership.
Zvi Karcz	059784355	February 24, 1967	August 12, 2014	VP Exploration	No	No	B.Sc. in Geology from the Hebrew University of Jerusalem, M.Sc. in Geology from the Hebrew University of Jerusalem and Ph.D. in Geology from Columbia University, New York, U.S.A.	Chief Geologist of the Partnership and Avner Partnership.
Ronen Edward[64]	024652745	October 13, 1969	August 1, 2017	CFO at the Partnership and the General Partner.	No	No	B.A. in Accounting and Business Administration from the College of Management	CFO at the Avner Partnership and Avner Oil & Gas Ltd.
Sari Singer Kaufman	037485174	February 22, 1980	May 14, 2018, Legal Counsel, VP, August 1, 2017-May 14, 2018 Legal Counsel March 10, 2012 – August 1, 2017-Attorney	General Counsel, VP	No	No	LL.B in Law from Tel Aviv University, Attorney-at-law, member of the Israel Bar Association	Attorney at the Partnership and Avner Partnership.
Nadav Perry	040365447	April 24, 1980	June 14, 2015	VP Regulatory & Public Affairs	No	No	B.A. in Government, Diplomacy and Strategy from the Interdisciplinary Center Herzliya, MBA from Bar Ilan University.	Heads the Public Affairs segment of the Partnership.
Saar Prag	037693942	October 17, 1975	August 1, 2017	Manager of Natural Gas Trade at the Partnership.	No	No	LL.B in Law from the Hebrew University of Jerusalem, Attorney-at-law, member of the Israel Bar Association	Partner at Shlomo Nass & Co. law office

64 The Partnership bears 30% of his employment cost.

Officer	**I.D. number**	**Date of birth**	**Date of commencement of office**	**Position at the General Partner, a subsidiary, an affiliate or an interested party**	**Is he an interested party in the General Partner and/or in the Partnership**	**Is he a relative of another senior officer or of an interested party of the General Partner**	**His education**	**His experience in the last five years**
Gali Gana	059674770	June 2, 1965	February 1, 2016	Internal auditor of the Partnership and the General Partner of the Partnership, and chief internal auditor of Delek Group	No	No	CPA, B.A. in Business Administration, majoring in accounting, from the College of Management and M.A. in Public Administration and Internal Audit from Bar-Ilan University, certified information system auditor (CISA), certified internal auditor (CIA), certification in risk management assurance (CRMA), and certified in Risk and Information Systems Control (CRISC).	Partner at Rosenblum-Holtzman, CPAs

Regulation 26B: **Independent authorized signatories**

As of December 31, 2020, and as of the date of approval of the report, there are no independent authorized signatories at the General Partner or at the Partnership.

Regulation 27: **The Partnership's CPAs**

Ziv Haft CPAs, of 46-48 Menachem Begin Rd., Tel Aviv and the accounting firm of Kost, Forrer, Gabbay & Kasierer of 144 Menachem Begin Rd., Tel Aviv, jointly serve as the auditors of the Partnership.

Regulation 28: **Change in the Trust Agreement**

Regarding a change in the Trust Agreement, see Regulation 29(c)(a) below and the Partnership's immediate report dated June 7, 2020 (Ref.: 2020-01-058218), the information appearing in which is incorporated herein by reference.

Regulation 29: **Recommendations and decisions of the directors**

Regulation 29(a):

(a) Regarding the approval by the board of directors of the General Partner of plans to purchase Series A bonds and Delek and Avner bonds (Tamar Bond) Ltd., see the Partnership's immediate reports dated July 27, 2020 and November 18, 2020 (Ref.: 2020-01-072868 and 2020-01-115468, respectively), the details appearing in which are incorporated herein by reference, and Chapter E of the first part of the board of directors' report (Chapter B hereof).

(b) On November 17, 2020 the board of directors of the Partnership's General Partner, resolved, after receiving the recommendation of the Partnership's General Partner's Financial Statements Review Committee to distribute profits in a total amount of $65 million, with the effective date for distribution being November 25, 2020 and the distribution date being December 7, 2020. For further details see the Partnership's immediate report dated November 18, 2020 (Ref.: 2020-01-115519), the information appearing in which is incorporated herein by reference.

(c) On July 15, 2020, the Partnership partially repaid the third series of the bonds issued to accredited investors in the US, Israel and other countries through Delek and Avner (Tamar Bond) Ltd., in the amount of $240 million, of its total amount of $320 million, instead of on its original repayment date, December 30, 2020. The amount of partial repayment of the third series as aforesaid includes the amount of the principal, plus accrued interest in the amount of approx. $0.4 million, plus a prepayment fee of approx. $4.2 million. For additional details, see the Partnership's immediate report dated June 14, 2020 (Ref.: 2020-01-061266), the details appearing in which are incorporated herein by reference.

<u>Regulation 29(c)</u>:

(a) On June 1, 2020, the meeting of the participation unit holders approved the appointment of Fahn Kanne & Co., Accountants, together with Keidar Supervision and Management, to hold office together as the Partnership Supervisor, with CPA Micha Blumenthal on behalf of Fahn Kanne & Co., Accountants, and Adv. Uri Keidar on behalf of Keidar Supervision and Management, holding office as the Supervisor individuals, starting from the date of approval by the general meeting and for a three-year term, and the terms of office and employment of the Supervisor, in accordance with the provisions of Section 2.3.1 of the Notice of Meeting Report. For details see the Partnership's immediate reports of April 7, 2020, April 27, 2020, May 12, 2020, May 25, 2020 and June 1, 2020 (Ref.: 2020-01-033073, 2020-01-042183, 2020-01-042195, 2020-01-047112, 2020-01-052383 and 2020-01-056283, respectively), the details appearing in which are incorporated herein by reference.

(b) With respect to the decision of the meeting of the participation unit holders of June 1, 2020 to authorize the Supervisor's budget for the purpose of an additional engagement with an expert for the purpose of advising the Supervisor in the Supervisor's Claim and engagement with him for the purpose of examination of the draft directives released by the Ministry of Energy, and with respect to the decision of the meeting of the participation unit holders of March 3, 2021 to authorize the Supervisor to use the legal and economic consultants retained by him for the conduct of the Supervisor's Claim also for the monitoring and supervision of the Partnership's conduct of the defense in the counterclaim regarding the investment recovery date, see Regulation 21(b)(8) above.

(c) With respect to the decision of the meeting of the participation unit holders of August 18, 2020 to approve an amendment to Section 13 of the Compensation Policy, on the subject of director and officer insurance and indemnification, see Regulation 21(b)(1) above.

(d) With respect to the decision of the meeting of the participation unit holders of August 18, 2020 to approve the Supervisor's budget for the purpose of its representation as a respondent in the legal proceeding in relation to Section 19 of the Taxation of Profits from Natural Resources Law, 5771-2011, see Regulation 21(b)(8) above.

(e) With respect to the decision of the meeting of the participation unit holders of March 3, 2021 to approve an additional budget for the Supervisor for the purpose of its engagement with professional consultants and a fee in addition to its monthly fee for overseeing the restructuring process, see Regulation 21(b)(8) above.

Regulation 29A: Decisions of the Partnership

Regulation 29A(4): Exemption, insurance or undertaking to indemnify an officer

For details regarding insurance, indemnification and exemption from liability that may be granted to the officers of the Partnership and the General Partner, see Section 13 of the Compensation Policy, as set forth in Regulation 21(b)(1) above.

(a) On July 17, 2012, the Partnership's meeting of participation unit holders approved the amendment of the Partnership Agreement to include the granting of indemnification undertakings and letters of exemption from liability to directors of the General Partner who are not controlling shareholders of the General Partner and/or controlling interest holders of the Partnership and/or their relatives, who shall hold office, from time to time, at the General Partner and/or at subsidiaries of the Partnership (and who are not external directors). In accordance with amendments made in the Partnership Agreement as provided in the resolution of the meeting of July 17, 2012, the board of directors of the General Partner resolved on July 19, 2012 to approve the granting of letters of exemption and indemnification to officers of the General Partner and the Partnership.

(b) For details regarding indemnification undertakings granted to the external directors of the General Partner's board of directors, *Messrs.* Jacob Zack and Amos Yaron, see the Partnership's immediate reports dated October 14, 2015 and October 22, 2015 (Ref. nos.: 2015-01-135165 and 2015-01-140634, respectively), the information appearing in which is included herein by way of reference.

(c) For details regarding an indemnification undertaking granted to Mr. Efraim Sadka, external director of the General Partner's board of directors, see the

Partnership's immediate reports dated December 16, 2018 and January 28, 2019 (Ref. nos.: 2018-01-115258 and 2019-01-008335, respectively), the information appearing in which is included herein by way of reference.

(d) On June 30, 2019, the compensation committee and the board of directors of the General Partner resolved, in accordance with Section 13 of the Compensation Policy, to approve the grant of letters of exemption and indemnification to the officers serving at the General Partner and/or the Partnership and to all the officers who will serve at the Partnership and/or the General Partner from time to time. Accordingly, the Partnership gave all the officers at the Partnership and/or the General Partner letters of indemnification undertakings and letters of exemption from liability, without derogating from the validity of the exemption and indemnification letters that were granted in the past to officers of the Partnership and/or the General Partner. For details see Regulation 21(b)(1) above.

(e) On July 10, 2019, the meeting of the participation unit holders approved the amendment of Section 11 of the Limited Partnership Agreement dated July 1, 1993, as amended from time to time, regarding exemption, indemnification and insurance of officers of the Partnership and the General Partner. For details see the Notice of Meeting Reports, the provisions of which are incorporated herein by reference.

(f) On August 4, 2020, the board of directors of the General Partner approved authorizing the Partnership's management to sign on behalf of the Partnership as the only shareholder in Leviathan Bond Ltd. a written resolution to give letters of exemption and indemnification to the officers holding office in Leviathan Bond Ltd., who will hold office therein from time to time.

(g) On February 4, 2020, the compensation committee approved, in accordance with the Compensation Policy, the inclusion of Mr. Idan Wells, who serves as a director of the board of directors of the General Partner, and of any director and/or officer holding office from time to time, in the (group and independent) policies for liability insurance for directors and officers of the Partnership and/or the General Partner. Note that Mr. Tamir Polikar, who holds office as a director on the board of directors of the General Partner since

September 10, 2020, is included in the (group and independent) D&O liability insurance policies of the Partnership and/or the General Partner, according to the resolution as aforesaid.

(h) With respect to the approval of the engagement in a D&O liability insurance policy, in the context of the Previous Independent Policy and in the context of the Group Policy by way of exercise of an option for an extended run off period, see Regulation 22(j) above.

(i) On June 30, 2020, the compensation committee and the board of directors of the General Partner approved the Partnership's engagement in a D&O liability insurance policy with a liability cap of $110 million per occurrence and for a one-year period starting from July 1, 2020, at a premium of approx. $1.1 million for a period as aforesaid (the "**Independent Policy**"), and authorized the Partnership's management to buy additional insurance coverage in the amount of up to $40 million above $110 million for additional consideration such that the total annual premium for the Independent Policy shall not exceed $1.5 million, all under terms and conditions that comply with the Compensation Policy, as provided in Regulation 21(b)(1) above.

(j) On July 26, 2020, the compensation committee and the board of directors of the General Partner approved the engagement for the extension of the Independent Policy for insurance of the liability of the officers of the Partnership, the General Partner, Leviathan Bond Ltd. (the "**Issuer**") and the officers of the Issuer, in relation to the issuance of the bonds through the Issuer for the period from July 1, 2020 until June 30, 2021, at a premium of approx. $402 thousand for the aforesaid period, and the authorization of the Partnership's management to increase the limit of liability for the coverage of the issuance to a total limit of liability of up to $150 million per claim and in the aggregate in consideration for an additional premium of up to $150 thousand per period.

(k) On August 18, 2020, the meeting of participation unit holders approved an amendment to Section 13 of the Compensation Policy, on the subject of D&O insurance. For details see Regulation 21(b)(1) above.

Delek Drilling - Limited Partnership

By the General Partner, Delek Drilling Management (1993) Ltd.

Names and position of signatories:

Gabi Last, Chairman of the Board

Yossi Abu, CEO

Date: March 14, 2021

Delek Drilling

Report on the Effectiveness of Internal Controls for Financial Reporting and Disclosure

2020

<u>Delek Drilling – Limited Partnership</u>

Chapter E

Annual Report on the Effectiveness of Internal Control

over Financial Reporting and Disclosure

Pursuant to Regulation 9B(a) of the Securities Regulations (Immediate and Periodic Reports), 5730-1970

This report is a translation of Delek Drilling - Limited Partnership's Hebrew-language Annual Report on the Effectiveness of Internal Control over Financial Reporting and Disclosure Pursuant to Regulation 9B(a) of the Securities Regulations (Immediate and Periodic Reports), 5730-1970), prepared solely for convenience purposes. Please note that the Hebrew version is the binding version, and in any event of discrepancy, the Hebrew version shall prevail.

Delek Drilling – Limited Partnership

Annual report for 2020 on the effectiveness of internal control over financial reporting and disclosure pursuant to Regulation 9B(a) of the Securities Regulations (Immediate and Periodic Reports), 5730-1970:

The management of the general partner in Delek Drilling – Limited Partnership (the "**General Partner**" and the "**Partnership**", respectively), under the supervision of the board of directors of the General Partner, is responsible for setting and maintaining proper internal control over financial reporting and disclosure at the Partnership.

For this purpose, the members of management are:

1. Gabi Last, Chairman of the Board of the General Partner;
2. Yossi Abu, CEO of the General Partner;
3. Yossi Gvura, Deputy CEO and Market Risk Manager;
4. Yaniv Friedman, Deputy CEO.

Internal control over financial reporting and disclosure consists of controls and procedures existing at the Partnership, designed by, or under the supervision of, the CEO and the most senior financial officer, or by anyone actually performing such functions, under the supervision of the board of directors of the General Partner, which are designed to provide reasonable assurance regarding the reliability of the financial reporting and the preparation of the reports according to the provisions of the law, and to ensure that information which the Partnership is required to disclose in reports released thereby according to the law is gathered, processed, summarized and reported within the time frames and in the format set forth by the law.

Internal control includes, *inter alia*, controls and procedures designed to ensure that information which the Partnership is thus required to disclose, is gathered and transferred to the management of the General Partner, including the CEO and the most senior financial officer, or anyone actually performing such functions, in order to enable the timely decision making in reference to the disclosure requirement.

Due to its inherent limitations, internal control over financial reporting and disclosure is not designed to provide absolute assurance that misrepresentation or omission of information in the reports will be avoided or discovered.

The management of the General Partner, under the supervision of the board of directors of the General Partner, has performed an examination and evaluation of the internal control over financial reporting and disclosure in the Partnership and of the effectiveness thereof;

The evaluation of the effectiveness of the internal control over financial reporting and disclosure carried out by the General Partner's management under the supervision of the board of directors of the General Partner included: entity-level controls, including control over the process of preparation and closing of financial reporting, general control over information systems, control over the accounting process vis-à-vis the operators of the joint transactions, and controls over the process of management of cash, including investments and process of raising and management of bonds and loans.

Based on the evaluation of the effectiveness performed by the management of the General Partner under the supervision of the board of directors of the General Partner, as specified above, the board of directors and the management of the General Partner came to the conclusion that the internal control over financial reporting and disclosure at the Partnership, as of December 31, 2020, is effective.

Statement of CEO pursuant to Regulation 9B(d)(1):

Statement of Managers

Statement of CEO

I, Yossi Abu, represent that:

(1) I have reviewed the periodic report of Delek Drilling – Limited Partnership (the "**Partnership**") for 2020 (the "**Reports**");

(2) To my knowledge, the Reports do not contain any misrepresentation nor an omission of a material fact required for the representations included therein, given the circumstances under which such representations were included, not to be misleading with regard to the period of the Reports;

(3) To my knowledge, the financial statements and other financial information included in the Reports adequately reflect, in all material respects, the financial position, operating results and cash flows of the Partnership for the periods and as of the dates covered by the Reports;

(4) I have disclosed to the Partnership's auditors, the board of directors and the audit and financial statements review committees of the General Partner in the Partnership, based on my most current evaluation of internal control over financial reporting and disclosure:

(a) Any and all significant flaws and material weaknesses in the setting or maintaining internal control over financial reporting and disclosure which may reasonably adversely affect the Partnership's ability to gather, process, summarize or report financial information in a manner which casts a doubt on the reliability of the financial reporting and preparation of the financial statements in conformity with the provisions of the law; and –

(b) Any fraud, either material or immaterial, which involves the CEO or anyone reporting to him directly or which involves other employees who play a significant role in internal control over financial reporting and disclosure;

(5) I, myself or jointly with others in the General Partner of the Partnership:

(a) Have set controls and procedures or confirmed that such controls and procedures have been set and maintained under my supervision, which are designed to ensure that material information in reference to the Partnership is brought to my knowledge by others at the General Partner in the Partnership, particularly during the preparation of the Reports; and –

(b) Have set controls and procedures or confirmed that such controls and procedures have been set and maintained under my supervision, which are designed to reasonably ensure reliability of financial reporting and preparation of the financial statements in conformity with the provisions of the law, including in conformity with GAAP;

(c) Have evaluated the effectiveness of internal control over financial reporting and disclosure, and presented in this report the conclusions of the board of directors and the management of the General Partner in the Partnership with regard to the effectiveness of the internal control as aforesaid, as of the date of the Reports.

The aforesaid does not derogate from my responsibility or from the responsibility of any other person, pursuant to any law.

March 14, 2021	Yossi Abu	CEO	
Date	Full Name	Position	Signature

Statement of the most senior financial officer pursuant to Regulation 9B(d)(2):

Statement of Managers

Statement of the most senior financial officer

I, Yossi Gvura, represent that:

(1) I have reviewed the financial statements and other financial information included in the reports of Delek Drilling – Limited Partnership (the "**Partnership**") for 2020 (the "**Reports**");

(2) To my knowledge, the financial statements and the other financial information included in the Reports do not contain any misrepresentation nor omission of a material fact required for the representations included therein, given the circumstances under which such representations were included, not to be misleading with regard to the period of the Reports;

(3) To my knowledge, the financial statements and other financial information included in the Reports adequately reflect, in all material respects, the financial position, operating results of operations and cash flows of the Partnership for the periods and as of the dates covered by the Reports;

(4) I have disclosed to the Partnership's auditors and to the board of directors and the audit and financial statement review committees of the General Partner in the Partnership, based on my most current evaluation of internal control over financial reporting and disclosure:

(a) Any and all significant flaws and material weaknesses in the setting or maintaining internal control over financial reporting and disclosure insofar as it relates to the financial statements and the other financial information included in the Reports, which may reasonably adversely affect the Partnership's ability to gather, process, summarize or report financial information in a manner which casts a doubt on the reliability of the financial reporting and preparation of the financial statements in conformity with the provisions of the law; and –

(b) Any fraud, either material or immaterial, which involves the CEO or anyone reporting to him directly or which involves other employees who play a significant role in internal control over financial reporting and disclosure;

(5) I, myself or jointly with others in the General Partner of the Partnership:

(a) Have set controls and procedures, or confirmed that such controls and procedures have been set and maintained under my supervision, which are designed to ensure that material information in reference to the Partnership, insofar as the same is relevant to the financial statements and other financial information included in the Reports, is brought to my knowledge by others at the Partnership, particularly during the preparation of the Reports; and

(b) Have set controls and procedures or confirmed that such controls and procedures have been set and maintained under our supervision, which are designed to reasonably ensure reliability of financial reporting and preparation of the financial statements in conformity with the provisions of the law, including in conformity with GAAP;

(c) Have evaluated the effectiveness of the internal controls over financial reporting and disclosure, insofar as the same pertain to the financial statements and the other financial information included in the Reports, as of the date of the Reports; My conclusions with regard to my aforesaid evaluation were presented to the board of directors and the management of the General Partner in the Partnership, and are incorporated in this report.

The aforesaid does not derogate from my responsibility or from the responsibility of any other person, pursuant to any law.

March 14, 2021	Yossi Gvura, CPA	Deputy CEO	
Date	Full Name	Position	Signature

Delek Drilling

Valuation

2020

Delek Drilling - Limited Partnership

Valuation of Royalties

From the Sale of the I/16 “Tanin” and I/17 “Karish” Leases

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March 2021

This document is a translation of the original Hebrew-language document of Giza Singer Even Ltd. of March 2021. It is prepared solely for convenience purposes. Please note that the Hebrew version is the binding version, and in any event of discrepancy – the Hebrew version shall prevail.

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1. Introduction and Disclaimer

1.1 General

This paper (the "**Paper**" and/or the "**Opinion**") was prepared by GSE Financial Advisory Ltd. ("**GSE**") for the purpose of valuation of the royalties to which the limited partnership Delek Drilling[1] ("**Delek Drilling**" and/or the "**Partnership**") is entitled for the sale of its rights in the I/16 "Tanin" and I/17 "Karish" Leases (the "**Royalties**") as of December 31, 2020 (the "**Valuation Date**"). We are aware that the Paper is intended to be used by Delek Drilling, *inter alia*¸ for quarterly and periodic financial statements, and therefore we agree that the Paper will be referred to and/or included in any report released by the Partnership and the interested parties therein, according to the Securities Law, 5728-1968 and the regulations thereunder.

For the preparation of the Paper we relied, *inter alia*, on representations, forecasts and explanations (the "**Information**") which we received from the Partnership and/or anyone on its behalf. GSE assumes that this Information is reliable and it does not carry out an independent examination of the Information, nor have we become aware of anything which could indicate it being unreasonable. The Information was not examined independently, and therefore the Paper furnished to you does not constitute verification to the correctness, integrity and accuracy of this Information. An economic valuation is supposed to reflect in a reasonable and fair manner a given situation at a certain time, based on known data and while referring to basic assumptions and forecasts which were evaluated.

This Opinion includes a description of the methodology and the main assumptions and analyses which were used for the determination of the fair value of the Royalties to which the Partnership is entitled. However, the description does not purport to be a full and detailed description of all of the procedures which we implemented upon the formulation of the Opinion.

This Paper does not constitute a due diligence inspection and does not replace it. Furthermore, the Paper is also not intended to determine the value of the Royalties for the specific investor and it does not constitute legal advice or opinion.

The Paper does not include accounting auditing regarding the compliance with the accounting principles. GSE Financial Advisory is not responsible for the manner of accounting presentation of the financial statements of the Partnership regarding the accuracy and integrity of the data and the implications of such accounting presentation, if any.

Should the Information and data on which GSE relied, be incomplete, inaccurate or unreliable, the results of this Paper may change. We reserve the right for ourselves, to re-update the Paper in view of new data which were not presented to us. For the avoidance of doubt, this Paper is valid as of the date of signing hereof only.

[1] On May 17, 2017, Delek Drilling merged with the partnership Avner Oil Exploration – Limited Partnership ("**Avner**", hereinafter jointly: the "**Partnerships**") and as a result, Avner partnership was stricken off with no dissolution.

It is emphasized that the Information specified in this Paper, including with respect to forecasts and the primary commercial terms in the agreement for the sale of the reservoirs, its total financial scope, the rights transferred thereunder, and the Royalties agreed therein, constitute forward-looking information in the meaning thereof in the Securities Law, 5728-1968, of which there is no certainty that it will materialize, in whole or in part, in the said manner or otherwise. The actual performance of the said Information may differ materially due to various factors such as delays in the timetables for the development of the reservoirs, etc.

We hereby confirm that we have no personal interest and/or dependence on the Partnership and/or on the general partner in the Partnership, apart from the fact that we are receiving a fee for this Paper. Furthermore, we confirm that our fee is not dependent on the results of the Paper.

In accordance with the engagement agreement, if we are charged with payment of any amount to a third party in connection with performance of the services specified in the engagement agreement in a legal proceeding or in another binding proceeding, the Partnership undertakes to indemnify us for any such amount that shall be paid by us over and above an amount equal to three times our fees. The indemnity undertaking shall not apply if it is ruled that we acted in performance of the work maliciously or with gross negligence.

Neither GSE nor any company controlled thereby directly and/or indirectly as well as any controlling shareholder, officer and employee therein, are responsible for any damage, loss or expense whatsoever, including direct and/or indirect, which will be incurred by anyone relying on the contents of this Paper in whole or in part.

1.2 Sources of information

<u>The main sources of information used in the preparation of the Opinion are specified below:</u>

- Information regarding the terms of the transaction for the sale of the Partnership's rights in the I/16 Tanin and I/17 Karish leases.
- Reports and publications released by Energean Oil & Gas plc (the parent company of Energean Israel Limited), including a resources and reserves report as of December 31, 2020 prepared by DeGolyer and MacNaughton ("**D&M CPR**").
- Immediate reports of publicly traded companies and public information released on websites (including Energean's website), journalistic articles or other public sources.
- Internal sources and databases of Giza Singer Even.
- Meetings and/or phone calls with office holders at the Partnership.

1.3 Details of the valuating company

GSE Financial Advisory Ltd. is a subsidiary of Giza Singer Even Ltd., which is a leading financial advisory and investment banking firm in Israel. The firm has extensive experience in the advising of the large companies, the prominent privatizations and the important transactions in the Israeli market, which it accrued over its thirty years of operation. Giza Singer Even operates in three fields, through independent business divisions: financial advisory; investment banking; analytical research and corporate governance.

The Paper was carried out by a team headed by CPA Eitan Cohen, a partner and head of the economic department at Giza Singer Even with experience of over 13 years in the fields of economic and business advisory, company valuations and financial instruments. In the past he served as the head of the economic department in an entrepreneurial company in the field of infrastructures and as a manager at the economic department of KPMG (Somekh Chaikin). Eitan is an accountant, holds a BA in economics and business administration from the Ben Gurion University and an MSc in Financial Mathematics from Bar Ilan University.

Sincerely,

GSE Financial Advisory

March 2021

2. Executive Summary

2.1 Background

Delek Drilling is a public limited partnership (in the meaning thereof in the Partnerships Ordinance) listed on the Tel Aviv Stock Exchange (TASE). The Partnership engages in the exploration, development and production of petroleum, natural gas and Condensate.

During the years 2012 and 2013 the Partnership reported to TASE that the Tanin and Karish gas reservoirs constitute natural gas discoveries.

Following the decision of the Israeli government on a framework for the increasing of the amount of natural gas produced from the Tamar natural gas field and the quick development of the Leviathan, Karish and Tanin natural gas fields and other natural gas fields (the "**Gas Framework**"), Delek Drilling and Avner Oil Exploration – Limited Partnership ("**Avner**") (jointly, the "**Partnerships**") (which jointly held (in equal shares between them) 52.941% of the reservoirs) and Noble Energy Mediterranean ("**Noble**") (which held 47.059% of the reservoirs) were required, *inter alia*, to sell their holdings in the Karish and Tanin reservoirs within 14 months of the signing date of the exemption resolutions related to the Gas Framework (December 17, 2015) in order to comply with the conditions which would entitle them to an exemption from several provisions of the Restrictive Trade Practices Law, 5748-1988 (the "**Restrictive Trade Practices Law**").

On August 16, 2016, an agreement was executed for the sale of all of the rights in Karish and Tanin between the Partnerships and Energean, within which the Partnerships are entitled to consideration in the amount of $148.5 million, comprising cash payment of $40 million (paid on the date of the transaction closing) and $108.5 million which will be paid spread into 10 annual equal payments plus interest, with this amount depending on the Purchaser's decision to develop the reservoir, or on the date on which the Purchaser's total expenses in respect of the development of the leases will exceed $150 million, whichever is earlier (the "**Debt Component**"). Furthermore, the Partnerships will be entitled to royalties from the revenues generated for the Purchaser from the sale of natural gas and Condensate produced from the leases, at the rates of 7.5% (before the payment of petroleum profit levy) and 8.25% (after payment of petroleum profit levy), net of the rate of the existing royalties,[2] by which the Partnerships are charged regarding the original share of Delek Drilling and Avner in the leases (the "**Royalties**'). The first payment for the Debt Component was made by Energean to Delek Drilling[3] on March 29, 2018, and has since been regularly paid each year on that date.

[2] As defined in the reports of Delek Drilling and Avner to the TASE on December 25, 2016.
[3] In May 2017, Delek Drilling merged with Avner, as a result of which Avner was delisted from the stock exchange.

Following are the quantities of natural gas and hydrocarbon liquids (Condensate and natural gas liquids) at the Karish and Tanin reservoirs (100%) as released in D&M CPR's report of February 11, 2021 by Energean Oil & Gas plc,[4] the parent company of Energean Israel Limited[5] ("**Energean**" and/or the "**Purchaser**"):

Lease	Reserves and Contingent Resources	
	Natural Gas (BCM)	Hydrocarbon Liquids (MMBBL)
	2P	2P
Karish Center	40.2	65.1
Karish North	33.1	30.6
Tanin	25.1	3.9
Total	**98.4**	**99.6**

2.2 Result of the valuation

The value of the Royalties in the transaction of sale of the Karish and Tanin leases was estimated through the Discounted Cash Flow method, while adjusting the discounting rates to the risks embodied in the development of the reservoirs and the cash flow (including the impact of the COVID-19 crisis). According to the assumptions specified in the Paper itself, the value of the Royalties as of December 31, 2020 is estimated at approx. $242.2 million.

Below is the sensitivity analysis for the value of the Royalties in relation to changes in the cap rate and the changes in the natural gas prices (U.S. $ in millions):

Change in Cap Rates (in Base Points)		Change in the Natural Gas Price Vector (U.S. $ per MMBTU)						
		(1.50)	(1.00)	(0.50)	-	0.50	1.00	1.50
	+250 bp	186.6	195.1	203.9	215.6	222.1	234.0	238.8
	+150 bp	195.3	204.2	213.5	225.6	232.6	245.0	250.1
	+50 bp	204.6	214.0	223.8	236.5	243.8	256.8	262.3
	-	209.6	219.2	229.2	**242.2**	249.8	263.0	268.7
	-50 bp	214.8	224.6	234.9	248.2	256.0	269.5	275.5
	-150 bp	225.7	236.0	247.0	260.9	269.1	283.4	289.7
	-250 bp	237.6	248.4	260.1	274.6	283.4	298.3	305.2

[4] https://www.energean.com/media/4751/energean-israel-2020-cpr.pdf.
[5] Formerly Ocean Energean Oil and Gas Ltd.

3. Description of the Transaction of Sale of Rights in the Karish and Tanin Leases

3.1 Description of the Partnership

Delek Drilling is a limited partnership (within the meaning thereof in the Partnerships Ordinance) listed on the TASE. The Partnership engages in the exploration, development and production of petroleum, natural gas and Condensate. Following is a description of the overriding royalties' mechanisms due to offshore petroleum assets applicable to the Partnership as of the date hereof with respect to its original share in the Karish and Tanin leases (approx. 52.941%):

For 50% of the Revenues from the Karish and Tanin Leases	For 50% of the Revenues from the Karish and Tanin Leases
3% before the Investment Recovery Date[6] (0.794% of the total revenues of the reservoir)	6% (1.588% of the total revenues of the reservoir)
13% after the Investment Recovery Date (3.441% of the total revenues of the reservoir)	

3.2 The sold rights

On February 7, 2012, and on May 22, 2013, the Partnerships reported to TASE that significant quantities of natural gas were discovered in the Tanin-1 and Karish-1 wells in the area of the exploration licenses Alon A and Alon C, respectively. In December 2015, the Petroleum Commissioner at the Ministry of Energy award the holders of rights in the exploration licenses, Delek Drilling (26.4705%), Avner (26.4705%) and Noble (47.059%), the lease deeds of "Tanin" and "Karish", respectively. It is noted that in May 2017, Delek Drilling merged with Avner and consequently the Avner partnership was stricken off without dissolution.

[6] The term "**Investment Recovery Date**" means the date after the signing of the agreement for the transfer of rights between the Partnership and Delek Energy Systems and Delek Israel (now Delek Group) which was signed in 1993 (as amended from time to time) according to which the Net Proceeds Value which the Partnership received or is entitled to receive for oil and/or gas and/or other valuable materials which were produced and used from the Petroleum Asset (i.e. – license or lease) where the finding is located, calculated in Dollars shall reach an amount which is equal to the full Value of All of the Partnership's Expenses in such Petroleum Asset calculated in Dollars.
The term "**Net Proceeds Value**" means the value of all of the proceeds as shall be approved by the accountants of the Partnership for oil and/or gas and/or other valuables which were produced and used from the Petroleum Asset (i.e. – license or lease) (the "**Gross Proceeds Value**") net of any and all production expenses thereof and royalties paid in respect thereof.
The term the "**Value of All of the Partnership's Expenses**" means all of the expenses incurred by the Partnership in the Petroleum Asset (i.e. – license or lease) where the oil and/or the gas and/or the other valuables are produced but excluding expenses (up to the Net Proceeds Value) which were deducted from the Gross Proceeds Value for the determination of the amount of the all of the Net Proceeds Value and as they shall be approved by the Partnership's accountants.
For details and elaboration regarding agreements pertaining to the payment of royalties to the State, to interested parties and to third parties of the Partnership, see Section 7.25.10 of Delek Drilling's periodic report for 2020.

On August 16, 2015, a government resolution was made regarding a framework for the regulation of the natural gas market in Israel including with respect to the rights of the Partnership in the natural gas reservoirs Tamar, Leviathan, Karish and Tanin (the "**Gas Framework**" or the "**Framework**"). Within the Framework the gas and petroleum corporations active in the gas market in Israel, including the Partnerships, were granted an exemption from several provisions of the Restrictive Trade Practices Law given compliance with several conditions, including the sale of Karish and Tanin leases within 14 months.

On November 14, 2015, the Partnerships announced that they purchased from Noble the right to sell the share of Noble in the Karish and Tanin leases, in equal parts, in consideration for a total amount of approx. $67 million. According to the agreement between the Partnerships and Noble, the latter will not be entitled to any further consideration for the sale of the rights to a third party.

On December 17, 2015, the Prime Minister (in his capacity as Minister of Economic Affairs) signed several exemptions from the Antitrust Law which were adopted in the context of the government resolution on the Gas Framework.

On August 16, 2016, an agreement was executed for the sale of all of the rights in the Karish and Tanin leases between Delek Drilling and Avner and Energean Israel Ltd. (formerly Ocean Energean Oil and Gas Ltd.), a company registered in Cyprus which is a subsidiary of Energean E&P Holdings Ltd. ("**Energean**" and/or the "**Purchaser**").[7] The main activity of the Purchaser is exploration, development and production of gas and petroleum reservoirs in Greece and other countries in the Balkan and Middle East area.

On December 27, 2016, the Partnerships announced that the closing conditions for the transaction were fulfilled. On March 27, 2018, Energean notified the Partnerships of the adoption of an investment decision for the development of the Karish reservoir.

3.3 The consideration

Following is a description of the consideration components in the purchase agreement:

a. The Purchaser will purchase from Delek Drilling and Avner (the "**Sellers**") all of the rights of the Sellers and of Noble in Karish and Tanin leases (the "**Sold Rights**").

b. In consideration for the Sold Rights, the Purchaser will pay the Sellers a total amount of $148.5 million which will be received in the following manner:

    i. Cash payment of $10 million which was paid to the Sellers on the transaction closing date;

    ii. An additional payment of $30 million which was paid to the Sellers on the transaction closing date;

    iii. The consideration balance, in an amount of $108.5 million, will be paid to the Sellers in ten annual equal installments plus interest according to the

[7] Energean Israel Ltd. serves as the operational arm of Energean E&P Holdings Ltd. in Israel.

mechanism set in the agreement. These payments will be made immediately after the date on which a Final Investment Decision (FID) will be adopted regarding the development of the leases, or on the date which the total expenses of the Purchaser in relation to the development of the leases will exceed $150 million, whichever is earlier;[8]

iv. The Purchaser will transfer to the Sellers royalties for natural gas and Condensate which will be produced from the leases at a rate of 7.5% before payment of a petroleum profits levy by virtue of the Natural Resources Taxation Law (the "**Levy**") and 8.25% after the commencement of payment of the Levy, net of the rate of the existing royalties[9] borne by the Sellers in respect of their original share in the leases. Such rates are in 'wellhead' terms, while the effective payment rate is expected to be adjusted to hydrocarbon sales at the point of entry to the Israeli transmission system.

[8] On March 27, 2018 Energean notified the Partnerships of the adoption of an investment decision for the development of the Karish reservoir, and in March 2018, March 2019 and March 2020 it paid Delek Drilling the first, second and third payments, respectively.

[9] As defined in the reports of Delek Drilling and Avner to the TASE on December 25, 2016.

4. Description of the Business Environment

4.1 General

The natural resources exploration, development and production activity in Israel is subject to the provision of approvals under the Petroleum Law, 5712-1952 (the "**Petroleum Law**") which controls the regulation in the field and defines the type of approvals given to defined field blocks and subject to the approval of a work plan for the performance of exploration and production work.

The natural gas sector in Israel began developing upon the discoveries of the natural gas reservoirs Noa and Mari B in the years 1999 and 2000, respectively. These discoveries allowed companies in the market, headed by the Israel Electric Corporation ("**IEC**"), to transition to more extensive use of natural gas instead of the use of more expensive contaminating fuels such as coal, diesel oil and fuel oil. The development of the sector was accelerated upon the discovery of the Tamar and Leviathan reservoirs in the years 2009 and 2010 respectively. These discoveries materially affect the energy independence of Israel and the development and expansion of uses of natural gas in the Israeli market.

Pursuant to the development of the industry, the natural gas sector in Israel is undergoing significant changes that include *inter alia* regulatory, economic and environmental changes. Within a few years, the natural gas in the Israeli economy has become the central component in the power production fuel basket, and a significant source of energy for the Israeli industry. The natural gas resources discovered in Israel are able to provide all of the gas needs of the domestic market in the coming decades and the majority of its energy needs and thus, significantly reduce the dependence of the State of Israel on foreign energy sources.

The economic merit of investments in exploration and development of natural gas reservoirs is largely influenced by the oil and gas prices worldwide, and the demand for natural gas in the domestic, regional and global market, and the ability to export natural gas which requires, *inter alia*, the discovery of gas resources in significant scopes and the engagement in long-term agreements for the sale of natural gas in significant quantities, that will justify the high cost of construction of such infrastructures.

The use of natural gas holds many benefits for the Israeli market, including:

- **Saving of energy costs in industry and in electricity production –** The low price of natural gas compared with currently common alternative fuels such as diesel oil and fuel oil, leads to significant saving of production costs, and thereby also to a decrease in the final product prices whose production costs mainly consist of the costs of electricity. Most of the power plants constructed in recent years in Israel generate electricity through turbines which are operated by natural gas combustion and are characterized by low construction costs,[10] shorter construction time, smaller areas of land[11] and many operational advantages. In addition to the relatively low price, power plants operated by natural gas are more efficient than plants which are operated by other fuels and therefore

[10] About one half of the cost of a coal power plant, about one third of the cost of a nuclear power plant and about 15% of a wind energy operated plant.

[11] The natural gas is transported by an underground pipe and unlike other fuels, requires no storage areas. Furthermore, power plants which are based on natural gas need a considerably smaller area compared to plants which are based on coal or solar energy.

power plants and enterprises operate with a high energetic efficiency level which is also ultimately reflected in cost saving.[12] According to the estimates of the Natural Gas Authority,[13] the transition to natural gas in the years 2004-2019 saved the Israeli market an estimated total of approx. ILS 71.3 billion. Most of such saving derives from the electricity sector (approx. ILS 55.7 billion), total consumption by which in 2019 amounted to approx. 8.8 BCM, which represents 78% of the demand for natural gas. The rest of the amount saved due to the transition to use of natural gas is primarily attributed to industrial plants (approx. ILS 15.6 billion), total consumption by which in 2019 amounted to approx. 2.4 BCM which represents an increase of 20% versus 2018.

- **Clean energy** – The main substances emitted from the burning of natural gas are carbon dioxide and water vapor. Since coal and petroleum are more complex fuels, with higher ratios of Carbon and Nitrogen and Sulphur components, then upon their combustion more contaminants are released, including ash particles of materials which are not burned and are emitted into the atmosphere and add to the air pollution. Natural gas combustion on the other hand, releases a relatively small quantity of contaminants, and therefore the use thereof reduces the air pollution. In such context it is noted that thanks to the conversion of most of the electricity production in Israel from coal, fuel oil and diesel oil to use of natural gas, air pollution levels caused by electricity production in Israel have been reduced by tens of percentage points.

- **Energy independence** – The geopolitical characteristics of Israel make it an energetic island with limited ability to import fuels from neighboring countries, which forced it to rely for many years on costly fuels import from Europe. Israel's energetic isolation was somewhat reduced between the years 2008 and 2012 upon the commencement of supply of natural gas from Egypt, however, the sudden cut of supply illustrated the importance of the development of local energy sources. The development of the natural gas market in Israel provides the Israeli industry with energetic security in the long term and will reduce its dependence on international energy prices.

- **Natural gas as a governmental source of income through taxation -** The Israeli natural gas market is directly benefiting and is expected to continue to directly benefit the local economy through governmental revenues from the taxation of the companies and from the VAT from sales to the ultimate consumer. Moreover, the Israeli market has a few unique taxation systems which apply to the natural gas sector, in addition to excise tax, which apply to natural gas, similarly to all of the other fuel products[14]. Furthermore, according to the Petroleum Law, the State charges royalties at a rate of up to. 12.5% of the total sales of natural gas at the wellhead. Moreover, following the conclusions of the Sheshinski Committee the State is entitled to proceeds of petroleum and gas profits levy at a rate of up to 50% (depending, *inter alia*, on the corporate tax rate) of the revenues of the holders of the petroleum rights, net of royalties, operation costs and development costs.

[12] A combined cycle power plant combining gas and steam turbines is characterized by an efficiency rate of 55%, significantly higher than power plants which are operated by other fuels. Cogeneration plants utilizing the thermal energy produced in the production process reach an efficiency rate of approx. 80%.

[13] https://www.gov.il/BlobFolder/reports/ng_2019/he/ng_2019.pdf.

[14] Other than the electricity and industry sectors in which consumers do not pay excise tax for the gas.

- **Israel's geostrategic position has been upgraded** – Thanks to the development of the gas reservoirs in Israel's EEZ, the State has at its disposal gas resources at a scope that exceeds the existing and expected needs of the domestic market. Thus, and further to Government Resolution 442 of June 13, 2014 regarding the policy on the export of natural gas, commercial quantities of natural gas are being exported from Israel to the countries in the region. In such context, export from the Tamar reservoir to industrial enterprises located on the Jordanian side of the Dead Sea commenced in 2017, and from 2020, with the beginning of production from the Leviathan reservoir, very significant quantities of natural gas are being exported to Jordan and Egypt.

4.2 Consumers

The natural gas market in Israel comprises several groups of consumers differentiated from each other in the nature of their activity and the characteristics of the natural gas consumption:

- **Israel Electric Corporation** – The IEC is a governmental company supervised by the Electricity Authority ("PUA-E"), *inter alia*, regarding the costs of inputs for electricity production, particularly, the costs of natural gas. In 2018, the IEC purchased approx. 4.66 BCM and in 2019 approx. 4.23 BCM of natural gas from the Tamar partnership (a decrease of approx. 9% relative to 2018) and also imported and consumed approx. 0.8 BCM of LNG in addition. The rate of electricity produced by the IEC through natural and liquefied gas is estimated in 2018 and 2019 at approx. 56.5% and approx. 53.1%, respectively.[15] In such context it is noted that recently, the Minister of Energy decided to stop the engagement with the regasification vessel used by the IEC for reception and regasification of imported LNG until the end of 2022.

- **Independent power producers** – The independent power producers ("**IPPs**") are divided into several types, according to the production technologies which they use: conventional IPP, cogeneration facilities, pumped energy, renewable energies IPPs and large enterprises that constructed power plants for themselves for which they received a self-production license. Section 93 of the Natural Gas Sector Law defines that natural gas sold to an independent power producer is a product subject to control under the Control of Prices of Commodities and Services Law, 5756-1996. In 2019, the consumption of the IPPs amounted to approx. 3.62 BCM, which represents approx. 32% of the overall consumption of natural gas in that year.

- **Large industry consumers** – This tier of consumers comprises several significant consumers, which are essential to the development of the Israeli gas sector. Consumers with significant power and reputation in the Israeli market, having extensive experience and knowledge pertaining to the operations of Israeli industry in general and the operations of the natural gas sector in Israel in particular. Most of the large industrial enterprises in the market executed agreements for the purchase of natural gas within the construction of private power plants at the enterprise's premises, for the supply of the enterprise's needs of electricity and heat (by generating steam from the residual heat of the power plants), constituting only part of the production capacity of the power plant, and the sale of the produced electricity to external consumers or to the IEC. Accordingly,

[15] Source: 2019 financial statement of IEC.

the natural gas purchase agreements signed by most of the large industrial enterprises thus far also have the characteristics of agreements with private power plants. In 2019, natural gas consumption by the industry sector amounted to approx. 2.4 BCM, an increase of 20% compared with 2018. The increase chiefly derives from the connection of new consumers to the distribution network.[16]

- **Medium and small consumers** – The distribution networks' consumers sector which includes mainly medium and small enterprises and businesses, is a relatively new sector in the natural gas sector which began executing agreements for purchase and infrastructure conversion performance only in recent years. These consumers typically consume low gas pressure, at a relatively small amount, non-continuous over a whole day (24 hours), some of which not yet connected to the onshore transmission systems, or the distribution, and therefore consuming Condensed Natural Gas (CNG) – a temporary and not optimal solution, since the cost of consumption can reach twice the cost of the natural gas which is transmitted through the distribution network. It is noted that according to the regulation in this respect, some of these consumers are building or planning to build small scale, natural gas-fired power plants, which are intended to provide electricity and heat to the enterprise on the premises of which such power plants are built.

- **Additional markets and consumers** – In addition to the electricity and industry sectors, several other sectors are expected to develop in the coming years and increase the demand for natural gas, including the transportation sector which is expected to significantly increase the scope of use of natural gas, in view of a forecast for entry into the market of electric vehicles and steps promoting use of CNG-fueled heavy vehicles and construction of CNG fueling stations, as well as enterprises using natural gas as a feedstock. In addition, the government is promoting measures designed to enable integration of natural gas in the housing sector for purposes of various household uses.

4.3 Regulatory environment

The production of natural gas from reservoirs in the territorial waters of the State of Israel and the sale thereof are subject to regulatory restrictions pertaining to the amount of gas produced, restrictions on exporting the gas outside of Israel, pertaining to the gas prices, etc. 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 specified below:

- **Royalties to the State of Israel** – Under the Petroleum Law, a lease holder is liable for a royalty of 12.5% of the amount of natural gas or petroleum produced in the lease and the lease holder will pay the State the market value of the royalty at the wellhead. The method of calculation of the market value of the royalty at the wellhead for the Tamar reservoir is under discussion between the Petroleum Commissioner and the partners in the Tamar reservoir and has not yet been finalized.[17] Commencing from 2019, the partners in the Tamar project made annual advance payments on account of royalties at the rate of

[16] Excluding gas consumption by industrial plants for electricity production purposes.
[17] In May 2020 the Natural Resources Administration at the Ministry of Energy published the final version of the directives on the method of calculation of the value of the royalty at the wellhead pursuant to Section 32(B) of the Petroleum Law, 5712-1952.

11.3% of the Tamar project revenues, and in 2017 and 2018 at the rate of 11.65%. In the Leviathan reservoir, the partners in the reservoir are paying royalties to the State of Israel at the rate of approx. 11.26%. In H1/2020, the Natural Resources Administration at the Ministry of Energy published directives that include general instructions on the method of calculation of the royalty value at the wellhead with respect to offshore petroleum rights. The directives further determine that the Commissioner will prescribe for each lease owner, from time to time, specific instructions for each lease, which will specify the deductible expenses, for purposes of calculating the royalty, according to the particular characteristics of the lease.

- **Taxation of Profits from Natural Resources Law** – The Resources Taxation Law prescribes a levy on petroleum and gas profits according to a mechanism which relates the rate of the levy and the ratio of the net accrued revenues from the petroleum and gas production project and the total accrued investments for the initial exploration and development of the reservoir ("**Investment Coverage Ratio**"). The minimal levy at a rate of 20% will be charged when the Investment Coverage Ratio will reach 1.5 and will increase gradually to a rate of 50% (depending, *inter alia*, on the Corporate Tax rate) when the Investment Coverage Ratio shall reach 2.3. The levy will be calculated and imposed on each reservoir separately. On January 7, 2021, the Ministry of Finance released a legislative memorandum which prescribes, *inter alia*, payment rules regarding assessments under dispute.[18]

- **Antitrust and exemption from the provisions of the Economic Competition Law** – In August 2015, a government resolution was made regarding a framework for the regulation of the natural gas market in Israel including with respect to the rights of the Partnership in the natural gas reservoirs Tamar, Leviathan, Karish and Tanin which took effect on December 17, 2015 upon the grant of an exemption from several provisions of the Economic Competition Law, 5748-1988 (the "**Gas Framework**").

  The Gas Framework grants an exemption to Delek Drilling, Noble and Ratio Oil Exploration (1992), Limited Partnership (jointly below, the "**Parties**"), from the restrictive arrangements pertaining to the Leviathan reservoir. Furthermore, The Gas Framework grants an exemption with respect to specific powers of the Commissioner (power to regulate acts of a monopoly through directives, power to order a holder of a monopoly to sell an asset, and power to order the separation of a monopoly), in connection with Delek Drilling and Noble being holders of a monopoly by virtue of the declaration thereon by the Commissioner in 2012 (the "**Exemption**").[19] The grant of the Exemption as described above is subject, *inter alia*, to the fulfillment of the following conditions:

[18] Taxation of Profits from Natural Resources Legislative Memorandum (Amendment), 5781-2021 – the Government Legislation Website, January 7, 2021.

[19] Declaration on holders of a monopoly under Section 26(a) of the Restrictive Trade Practices Law, 5748-1988: Delek Drilling Limited Partnership together with Avner Oil & Gas Exploration, Limited Partnership, Noble Energy Mediterranean Ltd., Isramco Negev 2, Limited Partnership, and Dor Gas Exploration, Limited Partnership – holders of a monopoly in the supply of natural gas to Israel starting from H2/2013 (November 13, 2012) Restrictive Trade Practices 500249.

- The sale of the rights of Delek Drilling and Noble in the Karish and Tanin reservoirs to a third party, not related to any of them, within 14 months from the date of grant of the Exemption or from the date of release of a new regulation draft by the Petroleum Commissioner pertaining to the qualifying conditions for an operator, whichever is later. On August 16, 2016, an agreement was executed for the sale of all of the rights in the Karish and Tanin leases between Delek Drilling and Energean.

- The sale of the entire rights of Delek Drilling in Tamar Reservoir to a third party unrelated thereto or to any of the holders of rights in the Leviathan, Karish and Tanin reservoirs as well as restriction of the rights of Noble in the Tamar reservoir to a maximum 25% rate within 72 months. In January 2018 Noble sold Tamar Petroleum Ltd. 7.5% of its rights in the Tamar reservoir, and as a result, it went down to a 25% holding rate in the Tamar reservoir. As of the date of the Paper, the Partnership holds directly 22% of the Tamar reservoir, and indirectly holds Tamar through its holdings in Tamar Petroleum, such that the total direct and indirect holdings amount to approx. 25.7855%.

- The imposition of restrictions on new agreements to be executed for the supply of gas from the Tamar and Leviathan reservoirs, such as a prohibition on limitations on purchase from other suppliers, in certain cases granting the consumers the right to unilaterally set the period of engagement and granting a unilateral option to the consumers to change the scope of supply in the agreement.

- **Stable regulatory environment** – In the original framework, the Israeli government undertook to maintain "regulatory stability" in the context of natural gas exploration and production for a period of 10 years. In March 2016, HCJ ruled that the issue of the regulatory stability in the Gas Framework in the existing version was illegal. In May 2016, the government re-adopted its resolution on the Gas Framework while setting an alternative arrangement pertaining to a "regulatory stable environment" in order to ensure a regulatory environment which encourages investments in the natural gas exploration and production sector.

- **Price regulation** – In the period between the taking effect of the Gas Framework, and until the date of fulfilment of all of the conditions of the Exemption, the price control in the natural gas sector by virtue of the Restrictive Trade Practices Law will be limited to the imposition of reporting requirements regarding profitability and the gas price, provided that during this period, the holders of the rights in Tamar and Leviathan shall offer potential consumers a price based on the weighted average price of the prices in the agreements that exist in the reservoirs, in several of the price and linkage alternatives published within Government Resolution 476 of August 16, 2015. Starting from Q3/2016, the Natural Gas Authority releases, each quarter, the weighted price of natural gas and the price of natural gas for independent power producers.

  On June 1, 2020, the decision of the Competition Commissioner was released, pursuant to Section 14 of the Economic Competition Law, 5748-1988, regarding amendment of the conditions for granting certain exemptions from approval of restrictive arrangements for several arrangements between the Tamar partners and their customers, cancelling the requirement for pre-approval of any agreement for the supply of gas from the Tamar project, in lieu of which the agreements will be subjected to a self-assessment regime, i.e.

the burden of examining the lawfulness thereof will be imposed on the Tamar partners and their customers, while the Competition Commissioner will be able to examine the agreements retroactively and even not in proximity to the date of the signing thereof, and to take enforcement measures insofar as it is found that arrangements were performed that harm competition.

4.4 Risk factors

The exploration and findings development operations of oil and natural gas involves significant monetary expenses in conditions of uncertainty resulting in a very high financial risk level. Following are risk and uncertainty factors with significant effect on the operations of the Purchaser of the Karish and Tanin reservoirs and the proceeds expected therefrom:

- **Changes in the electricity production tariff, price indices, alternative energy sources prices** – The prices paid by the consumers for the natural gas derive, *inter alia*, from the electricity production tariff as updated by the IEC on an annual basis, the Shekel/US Dollar exchange rate, the US consumer price index and the prices of fuels alternative to gas such as fuel oil, diesel oil and Brent. Furthermore, a significant change in alternative energy sources could lead to a change in the use model of the IEC such that priority shall be granted to power plants operated by gas alternatives. A decline in tariffs can also adversely affect the prices which will be obtained from the Karish and Tanin reservoirs and the economic merit in the development thereof. At the same time, according to Energean's reports, the selling price in the agreements include a "floor price".

- **Growth of the renewable energy sector** – Recent years have seen a rise in the share of renewable energies in the mix of fuels used to produce electricity in Israel. Renewable energy is defined as energy produced from heat and solar radiation, wind, bio-gas and bio-mass, or any other non-depletable source that is not fossil fuel. Approx. 5.7% of actual power production in the State of Israel in 2020 came from renewable sources, but this figure is expected to rise following the addition of the quotas initiated by the government with the aim of reaching the target of production from renewable sources of approx. 20% of the total demand for energy in 2025, and 30% by 2030.[20] The rates of renewable energies have been gradually reduced by the Authority since 2008 due to the decrease in the construction and financing costs and the holding of competitive processes. These trends indicate that renewable energies may account for a larger share of future power production in Israel.

- **Geopolitical risk** - The security and economic situation in Israel as well as the political situation in the Middle East may affect the willingness of states and foreign bodies, including in the Middle East, to engage in business relations with Israeli bodies and/or international bodies acting in Israel. Therefore, any deterioration in the geopolitical situation in the Middle East and/or deterioration in the relations between Israel and its neighbors, for security and/or political and/or economic reasons, may undermine the ability of the companies in the Israeli gas and oil market to promote their business with such states and bodies and export gas to neighboring states.

[20] "Electricity generation targets using solar power and natural gas" – the Ministry of Energy, July 22, 2020.

- **Competition for gas supply** – Over the past decade, several significant gas reservoirs were discovered in Israeli waters in amounts which significantly exceed the estimates of the Ministry of Energy regarding the needs of the local market. Israel granted exploration licenses in its EEZ, following two competitive processes (in 2017 and 2019), which could lead to further discoveries. In 2017, material production began from the Egyptian Zohr reservoir, which supplies gas to the Egyptian market. In addition, significant reservoirs were discovered in in the economic waters of Cyprus, in respect of which no development decisions have been made yet. Also, further findings may be discovered in the future, both in Israel and in other countries in the Eastern Mediterranean Basin, whose development could lead to the entrance of other competitors on the supply of natural gas to the local market and to neighboring countries, and thus increase the scope of competition in the sector.

- **Restrictions on export** – Limiting the amount of exportable gas may have adverse effects in the form of surplus supply in the domestic market and reduced tariffs which may also adversely affect the prices obtained from the Karish and Tanin reservoirs and the economic merit in the development thereof. In this context, it is noted that, according to the Adiri Committee's draft recommendations of July 2018, the gas export quotas as determined in Government Resolution 442 shall remain unchanged. However, according to the Committee's recommendations, the formula for calculating the export quota shall be changed, such that it will be higher relative to the formula determined by Government Resolution 442, solely for gas reservoirs that have not yet been discovered. On October 25, 2020, the government decided to form a professional team that will periodically examine the recommendations of the committee for the examination of the government's policy regarding the natural gas sector in Israel. The team's interim recommendations are expected to be released in the near future. Considering the government policy on the export of natural gas and the raising of the targets of use of renewable energies, no restriction is expected to reduce the scope of permitted export of natural gas to customers overseas. In such context it is noted that export permits were received in respect of all of the aforementioned export agreements. On January 6, 2019, the government approved the recommendations of the Adiri Committee in Government Resolution 4442.[21]

- **Dependence on the proper working order of the Israeli National Transmission System** – The ability to supply gas which will be produced from the reservoirs to the potential consumers is dependent, *inter alia*, on the proper working order of the Israeli National Transmission System for the supply of gas and of the regional distribution networks.

- **Dependence on contractors and on professional services and equipment providers –** As of the date hereof, there are in Israel no contractors that are performing most of the actions required for the construction and operation of natural gas and oil reservoirs, and therefore there is a dependence of the companies working in the sector on foreign contractors for the performance of such work. Furthermore, the number of facilities that are capable of drilling and performing development activities offshore, in general, and in deep-water, in particular, is relatively small and there is a chance that no suitable facility

[21] Website of the Ministry of Energy, Spokesman's Notice of January 10, 2019 https://www.gov.il/he/departments/news/ng_060119

will be found for performing the aforesaid actions on the dates to be scheduled therefor. Consequently, the aforesaid actions may entail high costs and/or considerable delays may be caused in the schedule determined for the performance of the work.

- **Operational risks and lack of sufficient insurance coverage** – Oil and gas exploration and production activities are exposed to a variety of technical and operational risks, such as loss of control over a drilling or a well and/or a malfunction in subsea facilities or facilities above sea level, which could damage the functioning of the production and transmission system, to the point of short or long-term shutdown. There is also a risk of liability for damage deriving from contamination due to the eruption and/or leakage of liquid and/or a gas leak. Despite the insurance existing in the market, not all of the possible risks are covered or are coverable.

- **Solely estimated costs and timetables and the option of lack of means** – Estimated costs for the performance of exploration and development activities and estimated timetables for the performance thereof are based solely on general estimates and could deviate significantly. The exploration plans could significantly change, *inter alia*, following failures and/or findings which will be obtained during the performance of such actions and lead to significant gaps in the timetables and the estimated costs of such activities. In certain cases, the holder of the lease may waive the performance of certain activities required according to the work plan of the reservoirs and lose the rights therein as a result.

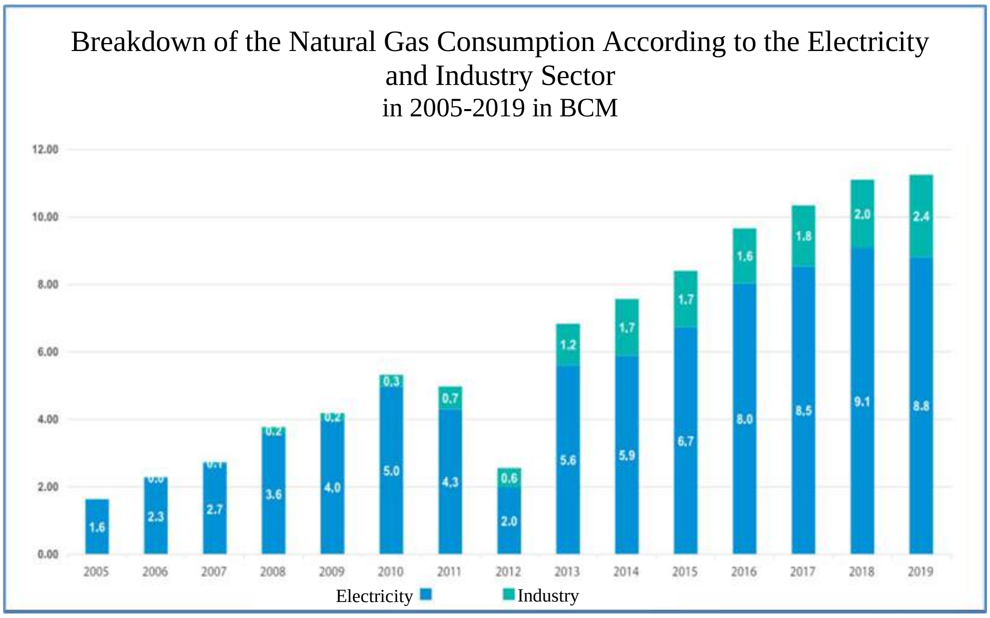
- **Regulatory changes** – The operating segment requires many regulatory approvals, mainly by the entities authorized under the Petroleum Law and the Natural Gas Sector Law, as well as related approvals of the State's authorities (including the Ministry of Energy, the Ministry of Defense, the Ministry of Environmental Protection, the tax authorities, the Competition Authority and the various planning authorities). In recent years several proposals were made for amendments of laws and/or regulations and/or directives relevant to the operating segment and several resolutions, laws and directives were released, the implementation of which could have a negative effect on the companies operating in the field.

- **Applicable environmental regulation** – The companies that operate in the natural gas sector are subject to a range of laws, regulations and directives on the issue of environmental protection, which relate to various matters such as: leaking of oil, natural gas or of other pollutants into the marine environment, the release into the sea of polluting substances and waste of various types (wastewater, residues of drilling equipment, drilling mud, slurry, etc.), chemical substances used at the various work stages, emission of pollutants into the air, light and noise nuisances, construction of piping infrastructures on the seabed and related facilities. In addition, the companies are required, through the operators of the projects, to obtain approvals from entities authorized under the Petroleum Law, the Natural Gas Sector Law and other laws (such as environmental protection laws) for the purpose of their activity.

- **Further risk factors** – There are other factors which contribute to the uncertainty prevailing in the operating segment including difficulties in obtaining financing, information security risks, dependence on material customers, dependence on weather and sea conditions, cancellation or expiration of rights and Petroleum Assets and more.

4.5 Demand

Chart 1 – Natural gas consumption in 2005-2019[22]



The consumption of natural gas in the Israeli market in 2019 amounted to approx. 11.25 BCM, of which approx. 93% were supplied from the Tamar reservoir and the balance from the import of LNG via the offshore LNG buoy.[23] According to the Partnership's estimations, the consumption of natural gas in the Israeli economy in 2020 amounted to approx. 12.0 BCM, of which approx. 7.8 BCM were supplied from the Tamar reservoir, approx. 3.5 BCM from the Leviathan reservoir and the balance from the offshore LNG buoy.

Below are the main factors expected to motivate growth in the demand for natural gas:

4.5.1 The electricity sector

In recent years, a trend is apparent of a significant reduction of use of petroleum and coal distillates in power production and transition to use of natural gas and renewable energies. This trend is led by the Ministry of Energy and government decisions determining goals for the reduction of use of polluting fuels, *inter alia*, by shutting down IEC power plants and conversion thereof to production with natural gas. Government decisions adopted in such regard are specified below:

- In August 2016, the Minister of Energy announced his decision to shut down four coal production units of IEC upon the connection of three gas reservoirs to the shore and the construction of new natural gas operated power plants within up to six years. Following that, in September 2016, emission permits were received by the IEC under the Clean Air Law, 5768-2008 with respect to its coal power plants sites, which included, *inter alia*, an

[22] Source: The Ministry of Energy http://online.fliphtml5.com/dldee/idah/
[23] The Natural Gas Authority at the Ministry of Energy http://fs.knesset.gov.il/23/Committees/23_cs_bg_582204.pdf

obligation to continue installing emission reduction measures, as well as the shutdown of units 1-4 in the coal power plant at the "Rabin Lights" site, no later than June 1, 2022.

- In November 2017, the Minister of Energy decided of principles of policy on the issue of minimal operation of coal production units, according to which natural gas electricity production shall be granted preference at any time to electricity production with coal, while operating the coal units at a minimal load which allows flexibility and reliability of the supply to the market.

- In March 2018, the Finance Committee of the Knesset and thereafter the Plenum of the Knesset approved the orders, in which it was provided, *inter alia*, that commencing on March 15, 2019 the excise tax on coal will be increased by approx. 125% in view of the government's policy to gross up external costs of fuels and encourage the expansion of use of natural gas. On February 20, 2019, the Minister of Finance signed an order postponing the expected rise in excise on coal, and it took effect on January 1, 2021. In addition, it was decided that from January 1, 2024, the excise tax on compressed natural gas (CNG) will increase gradually, subject to the existence of no less than 25 CNG fueling stations that shall receive all of the approvals required for operation. It was further determined that from May 1, 2018, the reimbursement of excise on diesel oil, which is used mainly for transportation purposes, will gradually be cancelled.

- In October 2018, the Minister of Energy presented a plan whose purpose is to lead to a reduction in the use of polluting energy, the principle of which is to decrease the use of polluting fuel products by 2030. According to the plan, targets have been set for the following sectors:

    a. The electricity sector – Electricity production using 80% natural gas and 20% renewable energies as of 2030, with a final shutdown of the coal-fired power plants in Hadera and in Ashkelon in 2028.

    b. The industry sector – Production of 95% of the energy and steam required by the industry by means of natural gas as of 2030.

    c. The transportation sector – A gradual transition to electric cars and natural gas trucks and the imposition of an absolute ban on the import of cars that operate on polluting fuels as of 2030.

- In November 2019, the Minister of Energy announced that it is possible to shorten the timetables for the conversion of the coal power plants in Hadera and in Ashkelon to natural gas to 2025. Consequently, in that year, the coal age in the State of Israel is expected to end. The aforesaid decision shortens the timetables that were previously determined, by 4 years.

- On June 8, 2020, a joint notice was released by the Ministry of Energy and the Ministry of Environmental Protection[24] on the Ministers' decision to instruct the IEC to expand the planned shutdown of the polluting coal-fired units 1-4 at the Rabin Lights site in Hadera,

[24] Website of the Ministry of Energy, Spokesman's Notice of June 8, 2020: https://www.gov.il/he/departments/news/press_080620

commencing from the second half of 2020 until the final shutdown thereof in 2022, thus bringing about another significant reduction of air pollutant emissions.

- On June 24, 2020, the Minister of Energy[25] announced his decision to further reduce approx. 20% of the use of coal in IEC's power plants, as compared with 2019. Therefore, the use of coal in 2020 will not exceed 24.9% (compared with 30% in 2019).

- According to the current forecast of the Electricity Authority, as stated in the annual report of the Electricity Authority for 2019,[26] as released at the end of June 2020, the production of electricity from natural gas is expected to increase significantly, amounting to approx. 83% in 2025.

- On October 25, 2020, a government resolution was adopted on the subject of promotion of renewable energy in the electricity market, a resolution which was based *inter alia* on the policy principles set forth by the Minister of Energy in July 2020, according to which, electricity production from renewable energies in 2030 shall be 30% of the total electricity consumption, and electricity production from natural gas shall be 70% of the total electricity consumption. In addition, the interim goal was updated such that electricity production from renewable energies shall be 20% by the end of 2025. The implementation of such policy may affect the demand for natural gas in the local market.

- On February 8, 2021, it was reported that the Minister of Energy had instructed the IEC to reduce the use of coal such that it shall not exceed 22.5% of the total electricity production in 2021, as part of the policy to end the coal era in Israel by 2025.[27]

4.5.2 Transition to use of natural gas in the industry

- Natural gas is a central component of the industry's energy consumption (approx. 37.5% of the total use of fuels in the Israeli industry in 2019).[28] The enterprises are connected to natural gas through transmission and distribution networks, with the transmission and distribution fees supervised by the Natural Gas Authority.

- According to an activity summary report of the Natural Gas Authority at the Ministry of Energy for 2019, until now, throughout Israel, approx. 508 km of distribution pipelines were laid out (of which, approx. 158 km in 2019) and approx. 737 km of transmission pipelines (of which, approx. 37 km in 2019). An expansion of the layout of the natural gas distribution network may enable the connection to the network, by 2030, of hundreds of potential industrial consumers whose consumption may amount to approx. 0.72 BCM per year, which represent approx. 80% of the light industrial consumption potential.

- According to the Natural Gas Authority's estimations, without additional policy steps, until 2025, approx. 150 consumers with a total consumption of approx. 0.45 BCM, which represents approx. one half of the overall connection potential of the light industry

[25] Website of the Ministry of Energy, Spokesman's Notice of June 24, 2020: https://www.gov.il/he/departments/news/press_240620
[26] https://www.gov.il/he/departments/general/dochmeshek.
[27] https://www.calcalist.co.il/local/articles/0,7340,L-3892470,00.html
[28] Source: 2019 Israeli Energy Sector Review - the Ministry of Energy https://www.gov.il/BlobFolder/reports/energy_sector_2019/he/energy_sector_review_2019.pdf

consumers, are expected to connect to the distribution network. Further potential consumption of approx. 0.27 BCM which derives from the connection of approx. 300 additional, smaller, plants, is expected to materialize following the implementation of additional policy steps (such as budgetary support in the layout of the distribution network, encouragement of consumers to use natural gas etc.).

- According to the Natural Gas Authority's estimations, in 2030, the total demand for natural gas in the industrial sector is expected to exceed 3 BCM, of which approx. 2.25 BCM are from consumption of natural gas in the industry for consumers that are connected to the transmission system, and approx. 0.84 BCM are from consumption of natural gas for consumers that are connected to the distribution network.

- On July 10, 2020, the Ministry of Energy released a legislative memorandum for the amendment of the Natural Gas Sector Law, whereby the Minister of Energy may grant a license for the construction of a particular distribution network to Israel Natural Gas Lines Ltd. ("**INGL**"), should he find that there is an urgent need therefor, and no private-sector body is able and willing to build the system. The purpose of the said legislative memorandum is to enable the acceleration of the connection of industry enterprises to the natural gas infrastructure.

4.5.3 Export

Recently, the relations with several neighboring countries, the business relations with which are strategic for the State of Israel in general, and for the gas companies in particular, have demonstrated a trend of improvement. The improvement in the relations has led to the signing of agreements for production of natural gas from Israel to its neighbors, as specified below:

- The Tamar partners signed agreements with NBL Eastern Mediterranean Marketing Limited ("**NBL**") for the purpose of export of natural gas to consumers in Jordan. Simultaneously, NBL signed an agreement with two companies from Jordan, Arab Potash Company and Jordan Bromine Company, whereby they will purchase natural gas from NBL which will be used by them at their plants which are located on the east bank of the Dead Sea in Jordan. The aforesaid agreements are for periods of approx. 15 years and the total quantity of natural gas in such agreements is approx. 3 BCM.

- On September 26, 2016, an agreement was signed between the Leviathan Partnership and the Jordanian electric power company (NEPCO) for the supply of up to approx. 45 BCM of natural gas for a period of approx. 15 years. According to a report of Delek Drilling dated December 31, 2019, flow of natural gas has begun from the Leviathan reservoir to the customers with which gas agreements were signed, and from January 1, 2020 also to NEPCO.

- On February 19, 2018, agreements were signed between Delek Drilling and Noble, and Egyptian Dolphinus, which were assigned on September 26, 2018 to the Tamar partners and the Leviathan partners. On September 26, 2019, amendments were signed to the said export agreements for the supply of natural gas from the Tamar reservoir and the Leviathan reservoir in quantities of approx. 25.3 BCM and approx. 60 BCM, respectively, for a period of approx. 15 years. The Take-or-Pay mechanism in the amended export agreements includes a reduction of the minimal annual consumption commitment to 50%

for a calendar year in which the average Brent price is lower than 50 dollars. On January 15, 2020 the Leviathan partners reported the commencement of the flow of gas to Egypt, and gas flow from the Tamar Reservoir to Egypt began in July 2020.

- On November 6, 2019, a transaction was closed for the acquisition of 39% of EMG, which owns a subsea pipeline for the transport of gas between Israel and Egypt, by EMED (a company held by Delek Drilling (25%), Noble Energy (25%) and the East Gas Company (50%)), in the context of which, the capacity and operation rights in connection with the EMG pipeline were transferred in their entirety to the purchaser (EMED), for execution of the agreements with Dolphinus, as described above.

- On March 26, 2020, the Natural Gas Commission released an addendum to the decision dated September 7, 2014 regarding the financing of export projects through the Israeli transmission system, and division of the costs of construction of the integrated Ashdod-Ashkelon segment. The addendum to the decision determines, *inter alia*, that the offshore segment of the transmission system, to be constructed in such a manner as to enable the flow to Egypt of the full quantity of gas as determined in the Dolphinus agreements, shall be financed by the owner of the transmission license (43.5%) and the exporter (56.5%), according to the milestones that will be set under the transmission agreement.

- On February 15, 2021, the partners in the Tamar and Leviathan reservoirs reported the fulfillment of the closing conditions in the transmission agreement that was signed with INGL for the export of gas to Egypt in a manner that will allow flow on a regular basis and increased sale quantities to Egypt according to the supply conditions in the gas sale agreements of the various partnerships.

4.5.4 Repercussions of the COVID-19 crisis

- During Q1/2020, international markets recorded sharp fluctuations and extremely steep declines in oil and natural gas prices. According to market estimates, the fluctuations may be attributed to the COVID-19 crisis, as well as other causes and factors that affect the demand for and supply of energy products. After correction of the markets for the crude oil production rate, trade in future crude oil contracts reverted to the price of $60 per barrel (as of February 9, 2021).

- According to a report by the Ministry of Energy on the effect of the COVID-19 crisis on the consumption of energy in Israel (in this section: the "**Ministry of Energy Report**"),[29] the consumption of natural gas for the production of electricity in March – April 2020 was lower by approx. 10%, relative to the same period last year. The consumption of natural gas by the large-scale industry in March – April 2020 was lower by approx. 13% relative to the same months in 2019. The consumption of natural gas by small and medium consumers in March – April 2020 was higher by approx. 14% relative to the same months in 2019. The consumption of refined oil products which were examined by the Ministry of Energy Report (diesel, petrol, kerosene and LPG) in March 2020 was lower by approx. 39%, compared with the same period last year, however, the overall electricity consumption in 2020 was similar in scope to electricity consumption in 2019.

[29] "The Effects of COVID-19 on Energy Consumption in Israel" – The Ministry of Energy, 01/06/2020 https://www.gov.il/BlobFolder/reports/corona_june_2020/he/corona_june_2020.pdf

- According to the Partnership's report, from mid-March 2020 until the end of Q2/2020, a drop in demand was recorded with a corresponding decrease in the sales of natural gas produced from the Leviathan and Tamar reservoirs, relative to previous forecasts which were updated by the Partnership in July 2020. However, in Q3/2020 the pace of sales from the reservoirs was higher than the pace of sales in each one of Q1/2020 and Q2/2020. In the Partnership's estimate, such increase derived, *inter alia*, from weather conditions and from the Israeli market learning to adjust to the COVID-19 crisis. Natural gas sales (100%) in 2020 from the Leviathan project totaled approx. 7.25 BCM (compared with approx. 7 BCM in the forecast of July 2020 and compared with approx. 9.3 BCM in the forecast of January 2019). Accordingly, the sales forecasts of the reservoirs for 2021 were raised. In respect of the Tamar reservoir, the forecasts have been updated to approx. 8.6 BCM (compared with approx. 8.2 BCM in the forecast of July 2020), and in respect of the Leviathan reservoir, the forecasts have been updated to approx. 9.9 BCM (compared with approx. 8.9 BCM in the forecast of July 2020). If the COVID-19 crisis and the slowdown in global economy shall persist, the demand for energy products and the prices thereof are expected to be further impacted thereby.

According to a forecast of an outside consultant which was prepared for the Partnership, the domestic demand for natural gas in 2021 is expected to amount to approx. 12 BCM and gradually increase to approx. 17.9 BCM in 2025. The increase in the domestic demand between 2020-2025 is expected to derive mainly from the addition of approx. 4.3 BCM as a result of the cessation of use of coal for electricity production, from an addition of approx. 1.4 BCM as a result of a natural increase in the demand for electricity (population growth, improvement in the standard of life and disposable income), and from an addition of approx. 0.6 BCM as a result of completion of the connection of industrial plants and small consumers to the natural gas distribution and transmission system. On the other hand, the demand forecast include a decline in domestic demand due to the impact of the COVID-19 crisis and the penetration of renewable energies to the domestic market, and in reference to the current target of the Ministry of Energy for electricity production from renewable energies to account for 30% of all power consumption in 2030, the outside consultant's forecast assumes partial meeting of this target in practice – at a rate of 25% of the entire power consumption in 2030, with the remaining 75% of power consumption in 2030 being generated using natural gas.

4.6 Market developments

4.6.1 The "Tamar and Leviathan" leases

- On December 31, 2019 the Leviathan partners reported the commencement of natural gas flow from the Leviathan reservoir to customers according to the agreements signed with them for the supply of natural gas from the reservoir, including the sale of natural gas to Jordan. Further thereto, it was reported that gas flow from the Leviathan reservoir to Egypt commenced on January 15, 2020.

- On October 2, 2020, Noble, which holds interests in the Tamar and Leviathan reservoirs and is the operator of such reservoirs, reported that the shareholders' meeting had officially approved the acquisition of the company by American company Chevron in consideration for approx. $5 billion. This transaction is a vote of confidence in the domestic gas market and in the economic potential of these assets.

- On August 30, 2020, some of the partners in the Tamar project (Tamar Petroleum Ltd., Isramco Negev 2 – Limited Partnership, Dor Gas Exploration Limited Partnership and Everest Infrastructures Limited Partnership, hereinafter jointly in this section: the "**Sellers**"), reported the signing of agreements for the supply of natural gas from the Tamar reservoir to Oil Refineries Ltd. (in this section: "**ORL**" and ICL Group Ltd. (in this section: "**ICL**"). In the Sellers' estimation, the aggregate revenues from the sale of natural gas to ORL is expected to amount to approx. U.S. $150 million, assuming that ORL uses natural gas under the supply agreement until the end of 2021. The aggregate revenues from the sale of natural gas to ICL is expected to amount to approx. 60% of the expected revenues under the ORL agreement. On October 4, 2020 it was reported that the agreements with ORL and ICL had been approved by all of the parties, including Delek Drilling.

- On September 13, 2020, Delek Group reported that Delek Energy, a wholly owned subsidiary of Delek Group, had entered into an agreement with Essence Royalties, Limited Partnership, for the acquisition of all of Delek Energy's holdings (approx. 39.93% as of such date) for a total consideration of approx. ILS 46 million.

- On September 23, 2020 Delek Drilling reported that the partners in the Leviathan project had signed a natural gas supply agreement with the Ramat Hovav partnership for a total volume of 1.3 BCM for a period of 30 months, or until the date of commercial operation of the Karish and Tanin reservoir, whichever is earlier.

- On October 28, 2020, Delek Group Ltd. (in this section: "**Delek Group**") reported the completion of the issue of bonds secured by a pledge of the rights thereof (25%) and of Delek Energy Systems Ltd. (75%) to overriding royalties from the Leviathan reservoir, in consideration for approx. $180 million, net of a safety cushion for interest payment and issue and underwriting expenses. The bonds bear a fixed annual dollar interest rate of 7.494% and have an international rating of +B (Fitch).

- On January 31, 2021, Delek Drilling reported that the partners in the Tamar project had signed a settlement agreement (the "**Tamar Settlement Agreement**"), which regulates the disputes regarding amendment of the agreement for the supply of gas to the IEC of 2019 (the "**IEC-Tamar Agreement**"), which the IEC and the Sellers (as defined above) signed on October 4, 2020. According to the Tamar Settlement Agreement, the IEC-Tamar Agreement will be terminated, and in its stead will be the settlement agreement, according to which by June 30, 2021, the IEC will be able to purchase a quantity of 1.25 BCM from the Tamar reservoir, at a price lower than the IEC-Tamar Agreement price, out of which approx. 0.81 BCM, which was already supplied in 2020, and additional gas quantities insofar as they are not supplied by the Leviathan partners according to the IEC-Leviathan Agreement (as specified below).

In addition, Delek Drilling reported that the partners in the Leviathan project have signed a settlement agreement (the "**Leviathan Settlement Agreement**"), which regulates the disputes regarding the gas supply agreement which was signed by the Leviathan partners with the IEC on June 12, 2019 (the "**IEC-Leviathan Agreement**"). According to the Leviathan Settlement Agreement, which amends the IEC-Leviathan Agreement, the IEC undertook to nominate from the Leviathan partners a quantity of approx. 1.2 BCM of natural gas during the first half of 2021. In addition, the Leviathan partners will give the IEC a price discount in respect of nomination of gas quantities that exceed approx. 0.5 BCM that are nominated from January 1, 2021. During 2020, a quantity of approx. 2.4 BCM was supplied to the IEC from the Leviathan reservoir. In the Partnership's estimation, in accordance with the Leviathan Settlement Agreement, during H1/2021, an additional quantity of 1.2 BCM will be supplied to the IEC.

- On January 19, 2021, the Partnership and INGL reported that INGL had entered into an agreement with Noble Energy for the provision of transmission services on a firm basis for the purpose of piping natural gas from the Leviathan reservoir and from the Tamar reservoir to EMG's terminal in Ashkelon for export to Egypt. According to the agreement, Noble Energy undertakes to purchase approx. 5.5 BCM of the piping capacity of the transmission system per year, and at least 44 BCM throughout the term of the agreement. Conversely, INGL undertook to transmit no less than the aforesaid gas quantity on a firm basis, while the remaining required quantity will be piped on an interruptible basis. It was further clarified that the transmission system was planned in a manner enabling the piping of the full quantities of gas required under the agreement. In the Partnership's estimation, INGL's expected income under the agreement is expected to total approx. ILS 170 million per year. The transmission agreement will end on the earlier of: (1) the date on which the total quantity piped is 44 BCM; (2) 8 years after the date of commencement of the flow (between July 2022 and April 2023); or (3) upon expiration of the company's transmission license. On February 15, 2021, INGL reported the fulfillment of the closing conditions determined in the agreement.

- On February 23, 2021, Delek Drilling reported that the partners in the Tamar reservoir had signed an agreement intended to allow each one of them separate marketing of its proportionate share in the natural gas produced from the Tamar reservoir, without derogating from the possibility of joint marketing of the gas produced from the reservoir. The agreement determined mechanisms for compensation in money or in gas in cases where one of the partners chooses to increase the daily gas output over and above its proportionate share in the daily output, on account of its partner which is not using its full proportionate share in the daily output. The agreement's taking effect is subject to approval by the Competition Authority, insofar as required.

4.6.2 "Karish and Tanin" leases

- **Adoption of an investment decision** – On March 27, 2018, Energean notified the Partnership of the adoption of an investment decision for the development of the Karish reservoir, and in March 2018, March 2019 and March 2020 it paid the Partnership the first, second and third payments in the sum of $10.85 million, $15.34 million and $14.84 million, respectively.

- **Listing of Energean on the Israeli stock exchange** – On October 29, 2018, trading of Energean's parent company, Energean Oil & Gas plc, was launched on the Tel Aviv Stock Exchange as a cross-listed company whose shares are additionally also premium-listed on the London Stock Exchange.

- **Commencement of manufacture of Energean's floating production facility** – On November 27, 2018, Energean announced commencement of manufacture, in China, of the floating platform (FPSO) that is due to be used by the Karish and Tanin reservoirs. The platform is intended to treat the natural gas to be produced at the Karish-Tanin project in Israel's EEZ. The process of production and treatment of gas will be carried out at the wellhead, at a distance of approx. 90 km from the shore.

- **Signing of an agreement for the construction and delivery of the eastern segment of the infrastructure for gas transmission from the leases** – On June 25, 2019, Energean announced that it signed an agreement with INGL, whereby it will build and transfer to INGL the eastern segment of the gas infrastructure, which includes an offshore segment at a distance of approx. 10 km from the shore and an onshore segment. In consideration therefor, INGL will pay Energean approx. ILS 369 million.

- **Signing of agreements for the sale of natural gas to the Alon Tavor power plant**– On November 21, 2019, Rapac Energy Ltd. reported that MRC Group, the winner of IEC's tender for the purchase of the Alon Tavor power plant, engaged in an agreement with Energean for the supply of natural gas in an annual amount of approx. 0.5 BCM for a period of 15 yeas (and in total up to 8 BCM). On December 17, 2020, Energean reported that it had engaged with Rapac Energy Ltd. in an additional agreement for supply of natural gas in an average annual amount of approx. 0.4 BCM for a period of 6 to 15 years, in addition to the existing signed agreements between Energean and Rapac Energy.

- **The signing of an MOU between Energean and Greece's gas transmission corporation (DEPA) for the sale of natural gas** – Ahead of the expected signing of the East Med Pipeline agreement by the governments and Energy Ministers of Cyprus, Greece and Israel, on January 2, 2020, Energean signed an MOU with DEPA for the possible sale of up to 2 BCM of natural gas per year from the reservoirs held by the company in Israel, the gas from which will be produced through the FPSO rig.

- **The dispute between Energean and Delek Drilling in connection with the entitlement to receipt of royalties from the reservoirs** – Further to Energean's report of April 9, 2020 regarding an update of the scope of the resources in the "Karish North" well, in April 2020, Energean and the Partnership exchanged letters in connection with the Partnership's entitlement to receive royalties from the leases. Energean claims, *inter alia*, that its undertaking to pay royalties does not apply with respect to hydrocarbons from the

"Karish North" well, and in addition that not all of the hydrocarbon liquids produced from the Karish lease meet the definition of condensate under the agreement for the sale of the Partnership's interests in the leases. It is the Partnership's position, based on legal and professional advice received, that according to the agreement for the sale of the Partnership's interests in the leases, the royalty documents and the registration in the Petroleum Register, Energean's obligation to pay royalties applies with respect to natural gas and condensate produced from the Karish lease, including from the "Karish North" well, and that the hydrocarbon liquids to be produced from the leases constitute condensate, as defined in the agreement.

- **Sale of the overriding royalties of Delek Group and Delek Energy to the Noy Fund** – On May 25, 2020, Delek Group and Delek Energy, a subsidiary of Delek Group, engaged with the Noy Fund in an agreement for the sale of their rights to overriding royalties from the Karish and Tanin leases. In consideration, the Noy Fund paid the sum of ILS 318 million, which was divided between Delek Group and Delek Energy according to their proportionate share in the royalties (25% and 75%, respectively).

- **Signing of an agreement for the sale of natural gas with Ramat Hovav partnership** – On September 16, 2020 Energean reported its engagement in agreements for the supply of natural gas from the Karish reservoir with the Ramat Hovav partnership (Edeltech and Shikun & Binui). According to the agreements, Energean will sell the Ramat Hovav partnership natural gas from the date of commencement of natural gas flow from the Karish field, at an annual quantity of approx. 1.4 BCM. The agreements include provisions on a price floor and a Take-or-Pay mechanism, and are expected to generate for Energean approx. $2.5 billion throughout the life of the contracts. According to the first agreement, which will be valid until expiration of 20 years from the date of the engagement therein, the main quantity sold in the context of the agreements is for the Ramat Hovav power station. Under another agreement, the rest of the gas will be supplied to other power stations held by the owners of the Ramat Hovav partnership – for a period of up to 15 years.

- **Agreement for the acquisition of all of the holdings in Energean Israel** – On December 30, 2020, Energean reported that it had signed an agreement for the acquisition of the remaining 30% of the issued and paid-up share capital of Energean Israel Ltd. ("**Energean Israel**") from Kerogen Investments No. 38 Ltd. ("**Kerogen Fund**"). In consideration for the holdings of Kerogen Fund in Energean Israel, Energean will pay an amount ranging between $380 million and $405 million. On February 25, 2021, Energean reported the closing of the transaction, and commencing from such date, Energean holds 100% of the issued and paid-up share capital of Energean Israel.

- **Final investment decision (FID) in the "Karish North" reservoir** – On January 14, 2021, Energean reported on the adoption of a final investment decision (FID) in the 'Karish North' reservoir in the sum of approx. $150 million. Energean estimates that the IRR of the project will be approx. 40%, and that natural gas will be produced from this reservoir for the first time in H2/2023.

- **$700 million loan from the banks J.P. Morgan and Morgan Stanley** – On January 14, 2021, Energean reported that it had signed a loan agreement with the banks J.P. Morgan and Morgan Stanley in the sum of $700 million for a period of 18 months. The interest on the loan will be 5.75% and will rise by 0.25% every three months up to a maximum interest rate of 7%. The loan will be used, *inter alia*, for the financing of development of the 'Karish North' reservoir; for financing the transaction for the acquisition of the holdings of Kerogen Fund in Energean Israel; for additional investments in the Karish reservoir; and for the financing of another exploration campaign of the company in early 2022. Concurrently, Energean reached agreements with its existing lenders for the financing of the development of the Karish reservoir regarding postponement of the date of repayment of the loan in the sum of $1.45 billion by 9 months from December 2021 to September 2022.

- **Update of the volume of the resources attributed to the Karish, Karish North and Tanin reservoirs** – On February 11, 2021, Energean released a resources and reserves report as of December 31, 2020, which was prepared by the consulting firm DeGolyer and MacNaughton, whereby the Karish, Karish North and Tanin reservoirs (in this section: the "**Reservoirs**") have 2P reserves of natural gas and hydrocarbon liquids of approx. 98.4 BCM and approx. 99.6 million barrels, respectively.[30] Energean updated that production from the Karish North reservoir is expected from 2023, and for the first time released its forecasts with respect to the rate of production of the natural gas and hydrocarbon liquids from each one of the Reservoirs, as well as forecasts pertaining to the amounts of the capital investments, royalties, taxes and operating costs of the Reservoirs. In addition, Energean reported completion, as of December 31, 2020, of approx. 93% of the work on building the FPSO; approx. 90% of Energean's onshore work; 100% of the onshore work of TechnipFMC; approx. 76% of the subsea work; and 100% of the drilling work. In addition, it was noted that an increase is required in the workforce of TechnipFMC, which is managing the construction of the FPSO in Singapore therefor, in order to meet the expected date of commencement of production in the last quarter of 2021. Insofar as the workforce shall remain at its current level, this may delay the expected date of commencement of production from the Karish reservoir by around two-three months. It is noted that in the discounted cash flow released by Energean, commencement of sales during 2022 was assumed.

- On February 28, 2021, Energean reported that Energean Israel intends to issue four series of preferred secured bonds, for a total sum of approx. $2.5 billion with a duration of 3, 5, 7 and 10 years. Energean Israel intends to use such amount for the financing of an existing project, repayment of a loan in the sum of $700 million taken on January 21, 2021 and additional expenses of Energean and its subsidiaries.

[30] https://www.energean.com/media/4751/energean-israel-2020-cpr.pdf.

5. Valuation of Royalties

5.1 Methodology

According to IFRS 3, contingent consideration is defined as: "…*an obligation of the acquirer to transfer additional assets or equity interests to the former owners of an acquiree as part of the exchange for control of the acquiree if specified future events occur or conditions are met.*"

As specified in Chapter 4 above, the consideration to which the Partnership is entitled includes a possibility of receiving future proceeds, in addition to the amounts to be received in cash ($40 million), which are contingent upon the occurrence of future events as specified below:

i. Consideration in the amount of $108.5 million which will be paid to the Sellers in ten equal annual payments plus interest commencing from the date on which the Purchaser made a FID or the Purchaser invested in the development of the reservoir an aggregate sum exceeding $150 million (the "**Investment Decision**"), whichever is earlier. Therefore, this consideration component is similar in its nature to a financial debt of the Purchaser to the Sellers, which is contingent upon the development of the leases, whether by a FID or the actual performance of the investment (the "**Debt Component**"). On March 27, 2018, as aforesaid, Energean notified the Partnership of the adoption of an Investment Decision for the development of the Karish reservoir, and therefore the Debt Component is defined as deferred consideration.

ii. Royalties from revenues (net of existing royalties[31]) which will be paid to the Sellers at rates of 7.5% before the Levy and 8.25% after the Levy. Therefore, the royalties are also contingent upon the development of the leases and the ability of the Purchaser to produce revenues from natural gas and Condensate from the reservoirs (the "**Royalties**").

According to the characteristics of the consideration components specified above , the value of the Royalties in the transaction for the sale of Karish and Tanin leases is assessed through the Discounted Cash Flow method, while adjusting the cap rates to the risks involved in the completion of the development of the reservoirs and the cash flow.

5.2 Working hypotheses

5.2.1 General

The main working hypotheses as specified below are based primarily on a resources and reserves report as of December 31, 2020 that was prepared by the consulting firm DeGolyer and MacNaughton which is an authorized resource assessor ("**D&M CPR**"), and was published by Energean on February 11, 2021, and on the analysis of market data and releases of public companies in the oil and gas sector. **It is emphasized that the assumptions and information specified below, including with respect to forecasts and the main commercial conditions in the agreement for the sale of the reservoirs, as well as**

[31] The Sold Rights were transferred to the Purchaser together with the existing overriding royalties in the leases borne by each of the Sellers, with respect to their original share (26.4705%).

regarding the types of the hydrocarbon liquids which will be produced from the reservoirs and in respect of which royalties will be paid to the Partnership, constitute forward-looking information in the meaning thereof in the Securities Law, 5728-1968, which there is no certainty of the materialization thereof, in whole or in part, in the said manner or in any other manner.

5.2.2 Timetable

According to Energean's report of February 11, 2021, the completion rate of the development of the "Karish Center" reservoir is approx. 91%[32] and first gas production is expected in Q4/2021 but may be postponed to Q1/2022, assuming that the workforce of TechnipFMC, the company managing the construction of the FPSO in Singapore for Energean, will remain at its current level. It was further reported that the development of "Karish North" reservoir will begin in 2021 and first gas from the reservoir is expected in 2023and that the production of gas from the Tanin reservoir shall commence in 2027.

In the context of the valuation it was assumed that the production of gas from the Karish, Karish North and Tanin reservoirs would commence in Q2/2022, Q1/2023 and Q1/2027, respectively. It was further assumed that the natural gas reserves in the Karish, Karish North and Tanin reservoirs would be depleted in 2035, 2040 and 2036, respectively.

5.2.3 Quantity forecast and annual production rate

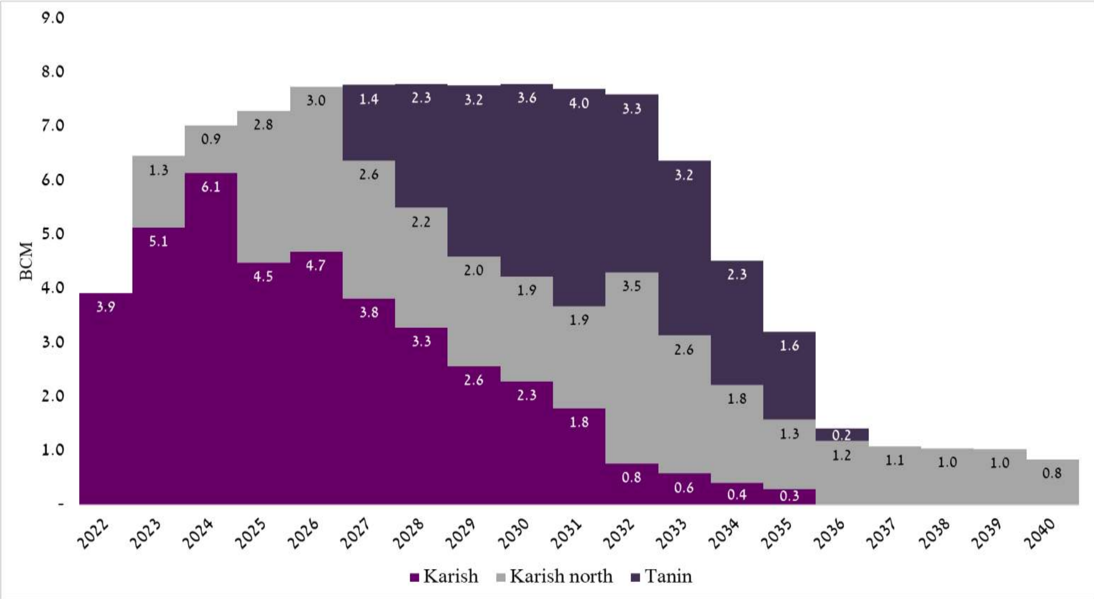
Below is a specification of the quantities of natural gas and hydrocarbon liquids (condensate and natural gas liquids) in the Karish and Tanin leases (100%) as published in the D&M CPR report:

Reservoir	Reserves and Contingent Resources	
	Natural Gas (BCM)	Hydrocarbon Liquids (MMBBL)
	2P	**2P**
Karish Center	40.2	65.1
Karish North	33.1	30.6
Tanin	25.1	3.9
Total	**98.4**	**99.6**

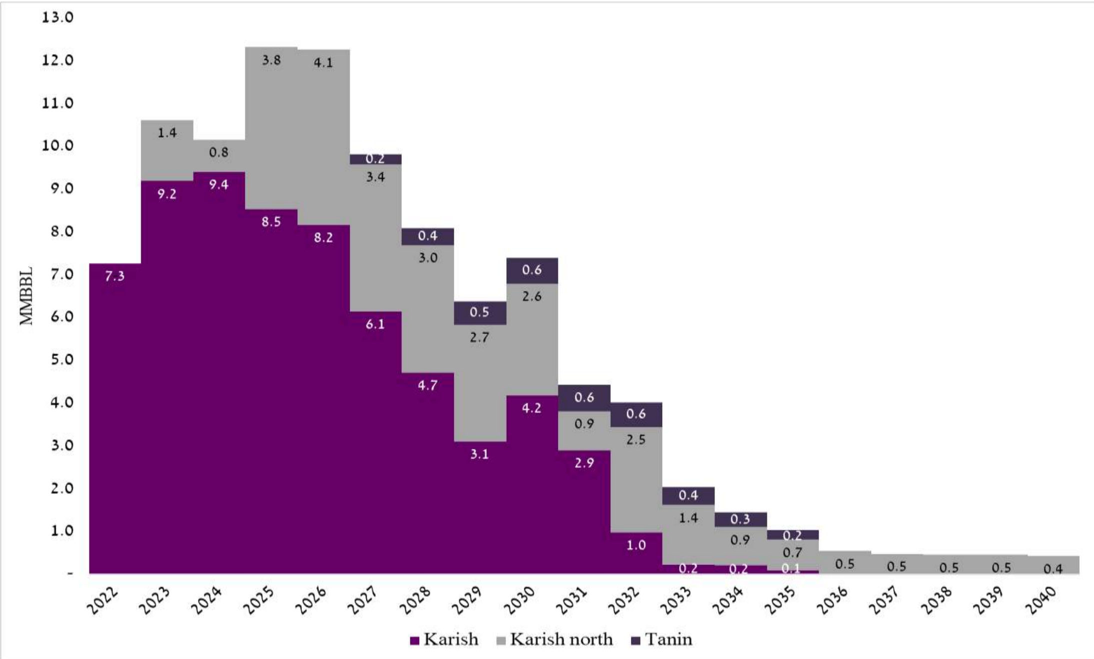
According to the D&M CPR report, Energean estimates that it is expected to sell up to 7.8 BCM per year throughout the years of the forecast, of which approx. 75% are within the Take-or-Pay mechanisms included in the agreements with its customers.

[32] According to the following breakdown: FPSO – 93%, Onshore – 90-100%, Subsea – 76%, Drilling – 100%.

The chart below describes the production rate of natural gas from the reservoirs according to the D&M CPR report:



The chart below describes the production rate of hydrocarbon liquids (condensate and natural gas liquids) from the reservoirs according to the D&M CPR report:



The forecast of the annual production rate of natural gas and condensate that was used in the valuation was based on the production rate specified in the D&M CPR report multiplied by a factor of 95% (the surplus quantities were spread across the remaining years of the forecast) reflecting, in our estimation, the likely scenario considering the public information available regarding contracts signed, the scope of the demand and the expected competition in the domestic market (for a specification of the forecast of the annual production rate of natural gas and condensate see Annex A).

In addition, according to the D&M CPR report, a conversion factor of 37.2 million [MMBTY to 1 BCM was assumed.

5.2.4 Natural gas prices forecast

The natural gas prices forecast relied on the following assumptions:

- The base price in the contracts under which the valuation was carried was estimated through the formulas specified in the price mechanism between Energean and ICL and ORL and between Energean and OPC, as well as in consideration of the price of the gas in the contract with Ramat Hovav power station and the parameters specified below:

  i. **The Production Component Tariff**: as of the Valuation Date, the production component tariff is 25.26 Agorot (January 2021). Throughout the other forecast years, it was assumed that the production component tariff would change according to the IEC's expected expenses in respect of electricity production, which are affected, *inter alia*, by the prices of natural gas, coal, changes in exchange rate (ILS/$), conversion of the coal-fired power plants to use of natural gas, the sale of power plants to independent power producers and other production costs. According to our forecasts, the production component tariff is expected to range between approx. 25.26-27.09 Agorot throughout 2021-2037.

  ii. **ICL and ORL** – floor price of U.S. $3.975 per MMBTU according to an agreement between the company and ICL and ORL.

  iii. **OPC** – floor price of U.S. $3.975 per MMBTU when the production component is larger or equal to 26.4 Agorot, and a floor price of U.S. $3.8 per MMBTU when the production component is lower than 26.4 according to an agreement between the company and OPC.

  iv. **Ramat Hovav** – fixed price of U.S. $3.95 per MMBTU.

- It was assumed that a gas amount of 1.0 BCM shall be regularly distributed to the Ramat Hovav power plant and that the remaining gas amount which will be sold will be equally distributed between independent power producers (contracts such as the contract with OPC) and industrial producers (contracts such as the contracts with ICL and ORL).

Note that for the base scenario and the low scenario, the D&M CPR report assumed a fixed natural gas price of approx. U.S. $4.04 per MMBTU throughout all of the years of the forecast.

5.2.5 Condensate prices forecast

The Condensate prices forecast was estimated based on the average of the long-term petroleum prices forecast of the World Bank,[33] the EIA[34] and the forward prices of Brent according to Bloomberg data.

Note that for the base scenario, the D&M CPR report assumed a condensate price of approx. U.S. $66 per barrel throughout all of the years of the forecast (fixed), based on the assumption that Energean will be able to sell the condensate in its reservoirs at a 10% premium over price of Brent.

5.2.6 The royalties rate

The rate of the royalties to be paid to the State was set, according to the Petroleum Law, at 12.5% of the value of the gas at the wellhead.[35] The actual royalties' rate is lower as a result of deduction of expenses for the transmission systems and the treatment of the gas up to the gas delivery point on shore. According to the Partnership's estimates, it was assumed that the effective royalty rate which will be paid to the State for the gas and Condensate is 11.5%. Furthermore, the rate of the existing royalties in the leases, borne by each of the Partnerships were similarly adjusted. We shall note that the actual rate of royalties could change and is not final.

5.2.7 Petroleum profits levy

The Petroleum Profits Levy is a progressive levy which is set according to a mechanism which connects the rate of the levy to the ratio of the net accrued revenues from the petroleum and gas production project and the total accrued investments for the exploration and initial development of the reservoir (the "**Investment Coverage Ratio**"). The minimal levy at a rate of 20% will be charged when the Investment Coverage Ratio will reach 1.5 and rise gradually to a rate of 50% (according to the corporate tax rate[36]) with the Investment Coverage Ratio reaching 2.3. The levy will be calculated and imposed for every reservoir separately.

Within the cash flow forecast for the Royalties, we deducted the levy from the net royalties (after offsetting the existing royalties) which will be received by the Partnership from each lease, based on the rate of the levy calculated in the financial model of each of the leases.

[33] A World Bank Quarterly Report: Commodity Markets Outlook, October 2020.
[34] U.S Energy Information Administration: Analysis & Projections, January 2021.
[35] On February 9, 2020, the Ministry of Energy released for public comment directives on the method of calculation of the value of the royalty at the wellhead in connection with offshore petroleum rights. For further details see: https://www.gov.il/he/departments/publications/Call_for_bids/os_090220
[36] Corporate tax of 23% was assumed according to the statutory tax rate known as of the Valuation Date.

5.2.8 Royalties cap rate

- The cap rate used in the valuation prepared by us as of December 31, 2019 (the "**12/19 Valuation**") was estimated at approx. 11% based on the cap rate of the Leviathan reservoir and adjustments due to the risk differences between the reservoirs and the cash flows (for further details, see Section 5.2.9 of the 12/19 Valuation).

- H1/2020 saw steep price drops in the financial markets around the world, including in Israel, as well as steep changes in currency exchange rates, and extreme drops in oil and natural gas prices on the international markets, as a result of the spread of COVID-19 and additional factors that affect the demand and supply of energy products worldwide. In addition, in January 2021, Energean updated the production commencement date to the end of 2021 (versus H2/2021 in a previous report). In view of these developments and in view of the third wave outbreak of the COVID-19 pandemic worldwide, we have added a 1% premium which, in our estimation, reflects the increase in the level of risk compared with the 12/19 Valuation, such that the total cap rate for the overriding royalties is 12%.

5.3 Results of the valuation

According to the assumptions specified in the Paper itself, the value of the Royalties is estimated at approx. $242.2 million. **To clarify, the valuation does not address the disputes, if any, between Energean and the Partnership, and the implications thereof** (for a specification see Section 4.6.2 above).

5.4 Sensitivity analyses

Following is an analysis of the sensitivity of the royalties' value to changes in the cap rate and to changes in the natural gas prices, in millions of U.S. $:

		Change in the Natural Gas Price Vector (U.S. $ per MMBTU)						
		(1.50)	(1.00)	(0.50)	-	0.50	1.00	1.50
Change in Cap Rates (in Base Points)	+250 bp	186.6	195.1	203.9	215.6	222.1	234.0	238.8
	+150 bp	195.3	204.2	213.5	225.6	232.6	245.0	250.1
	+50 bp	204.6	214.0	223.8	236.5	243.8	256.8	262.3
	-	209.6	219.2	229.2	**242.2**	249.8	263.0	268.7
	-50 bp	214.8	224.6	234.9	248.2	256.0	269.5	275.5
	-150 bp	225.7	236.0	247.0	260.9	269.1	283.4	289.7
	-250 bp	237.6	248.4	260.1	274.6	283.4	298.3	305.2

Following is an analysis of the sensitivity of the royalties' value to changes in the cap rate and to changes in the annual production quantity, in millions of U.S. $:

Change in Cap Rates (in Base Points)		Change in the Annual Production Rate of Natural Gas (BCM)						
		(1.00)	(0.50)	(0.25)	-	0.25	0.50	1.00
	+250 bp	182.0	198.3	207.0	215.6	217.7	223.1	228.5
	+150 bp	191.7	208.3	217.1	225.6	227.6	232.8	238.1
	+50 bp	202.3	219.2	227.9	236.5	238.2	243.3	248.2
	-	207.9	224.9	233.7	**242.2**	243.8	248.8	253.6
	-50 bp	213.9	231.0	239.7	248.2	249.7	254.6	259.1
	-150 bp	226.6	243.8	252.5	260.9	262.0	266.7	270.7
	-250 bp	240.5	257.9	226.4	274.6	275.3	279.7	283.2

Following is an analysis of the sensitivity of the royalties' value to changes in the cap rate and to changes in the Condensate prices, in millions of U.S. $:

Change in Cap Rates (in Base Points)		Change in the Condensate Price Vector (U.S. $ per bbl)						
		(30.00)	(20.00)	(10.00)	-	10.00	20.00	30.00
	+250 bp	191.5	198.4	205.3	215.6	220.0	224.3	234.5
	+150 bp	200.7	207.8	215.0	225.6	230.2	234.7	245.3
	+50 bp	210.6	218.0	225.5	236.5	241.2	245.9	257.0
	-	215.9	223.4	231.0	**242.2**	247.0	251.9	263.1
	-50 bp	221.3	229.0	236.8	248.2	253.1	258.1	269.5
	-150 bp	232.9	240.9	249.0	260.9	265.9	271.2	283.1
	-250 bp	245.5	253.7	262.3	274.6	279.9	285.4	297.8

Annex A – Cash Flow Forecast

Year	Unit	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Production											
*Gas production - Karish**	bcm/y	-	2.79	6.13	6.67	6.93	7.35	6.06	5.22	4.37	4.01
Gas production - Tanin	bcm/y	-	-	-	-	-	-	1.32	2.18	3.00	3.39
*Condensate production - Karish**	bbl/y m	-	5.18	10.08	9.65	11.70	11.65	9.10	7.31	5.55	6.45
Condensate production - Tanin	bbl/y m	-	-	-	-	-	-	0.23	0.37	0.51	0.58
Prices											
Natural gas price	US$	-	3.90	3.90	3.90	3.97	3.97	3.97	3.97	3.97	3.97
Condensate Price	US$	-	39.31	51.87	52.91	54.06	61.38	64.02	66.77	69.64	72.63
Revenues											
Karish - Revenues											
Natural Gas Revenues	US$ MM	-	405.7	888.6	966.6	1,023.2	1,085.3	894.3	771.2	645.2	592.9
Condensate Revenues	US$ MM	-	271.5	522.9	510.6	632.7	715.0	582.8	488.0	386.3	468.6
Total Gross Revenues	US$ MM	-	677.2	1,411.5	1,477.2	1,655.9	1,800.3	1,477.1	1,259.1	1,031.5	1,061.4
Tanin - Revenues											
Natural Gas Revenues	US$ MM	-	-	-	-	-	-	195.6	321.5	443.3	500.3
Condensate Revenues	US$ MM	-	-	-	-	-	-	14.5	24.8	35.7	42.0
Total Gross Revenues	US$ MM	-	-	-	-	-	-	210.0	346.3	479.0	542.2
K&T - Total Gross Revenues	US$ MM	-	677.2	1,411.5	1,477.2	1,655.9	1,800.3	1,687.1	1,605.5	1,510.5	1,603.6
Delek Drilling - Transaction Revenues											
*Transaction ORRI, Net***	US$ MM	-	31.9	66.5	60.6	32.5	33.7	33.2	36.2	38.8	35.7
Total Discounted Transaction Revenues	US$ MM	**-**	**26.5**	**50.1**	**41.0**	**19.6**	**18.1**	**15.9**	**15.5**	**14.8**	**12.2**

*Including Karish North

**Net of Existing ORRI net of Petroleum Tax

Year	Unit	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Production												
*Gas production - Karish**	*bcm/y*	*3.49*	*4.09*	*4.09*	*4.09*	*2.11*	*1.50*	*1.50*	*1.12*	*1.00*	*0.72*	-
Gas production - Tanin	*bcm/y*	*3.82*	*3.13*	*3.07*	*2.18*	*1.55*	*1.48*	-	-	-	-	-
*Condensate production - Karish**	*bbl/y m*	*3.62*	*3.28*	*3.28*	*3.28*	*1.54*	*1.54*	*1.05*	*0.77*	*0.45*	*0.22*	-
Condensate production - Tanin	*bbl/y m*	*0.59*	*0.59*	*0.54*	*0.40*	*0.14*	-	-	-	-	-	-
Prices												
Natural gas price	*US$*	*3.97*	*3.97*	*3.97*	*3.97*	*3.90*	*3.91*	*3.93*	*3.94*	*3.89*	*3.89*	-
Condensate Price	*US$*	*74.08*	*75.56*	*77.07*	*78.62*	*80.19*	*81.79*	*83.43*	*85.10*	*86.80*	*88.53*	-
Revenues												
Karish - Revenues												
Natural Gas Revenues	*US$ MM*	*515.6*	*603.4*	*603.4*	*603.3*	*306.9*	*218.1*	*219.3*	*164.5*	*144.0*	*104.1*	-
Condensate Revenues	*US$ MM*	*268.3*	*247.6*	*252.5*	*257.6*	*123.6*	*126.1*	*87.7*	*65.6*	*39.4*	*19.1*	-
Total Gross Revenues	*US$ MM*	*783.9*	*851.0*	*855.9*	*860.9*	*430.5*	*344.2*	*306.9*	*230.1*	*183.5*	*123.2*	-
Tanin - Revenues												
Natural Gas Revenues	*US$ MM*	*564.2*	*462.0*	*453.1*	*321.6*	*224.5*	*215.6*	-	-	-	-	-
Condensate Revenues	*US$ MM*	*43.4*	*44.3*	*41.4*	*31.4*	*11.5*	-	-	-	-	-	-
Total Gross Revenues	*US$ MM*	*607.7*	*506.3*	*494.6*	*353.1*	*236.0*	*215.6*	-	-	-	-	-
K&T - Total Gross Revenues	*US$ MM*	*1,391.6*	*1,357.2*	*1,350.5*	*1,214.0*	*666.5*	*559.9*	*306.9*	*230.1*	*183.5*	*123.2*	-
Delek Drilling - Transaction Revenues												
*Transaction ORRI, Net***	*US$ MM*	*23.6*	*23.1*	*22.5*	*19.3*	*10.5*	*8.8*	*4.8*	*3.6*	*2.9*	*1.9*	-
Total Discounted Transaction Revenues	*US$ MM*	***7.2***	***6.3***	***5.5***	***4.2***	***2.0***	***1.5***	***0.7***	***0.5***	***0.4***	***0.2***	-

*Including Karish North

**Net of Existing ORRI net of Petroleum Tax

Definitions

Delek Drilling Limited/the Partnership	Delek Drilling Limited Partnership
Avner	Avner Oil Exploration - Limited Partnership
Natural Gas	A gas mixture containing mainly Methane, used mainly for the production of electricity and as a source of energy for industry
The Purchaser/Energean	Energean E&P Holdings Ltd. through Energean Israel Limited (Formerly Ocean Energean Oil and Gas Ltd.).
The Partnerships/Sellers	Delek Drilling and Avner
The Petroleum Law	The Petroleum Law, 5712-1952
The Gas Framework or the Framework	The resolution of the Israeli government on the creation of a framework for increasing the amount of natural gas produced from the Tamar natural gas field and the quick development of the Leviathan, Karish and Tanin natural gas fields as well as other gas fields
Noble	Noble Energy Mediterranean Ltd**.**
Condensate	Hydrocarbon liquid created during the production of natural gas, used as raw material for the production of fuels and constitutes a petroleum substitute
Petroleum Asset	A preliminary permit, license or lease by virtue of the Petroleum Law in Israel or a right of similar meaning granted by the entity authorized therefor outside Israel
BCM	Billion Cubic Meters
DCF	Discounted Cash Flows
FID	The date on which the Purchaser adopted a decision for the investment for the development of Karish and Tanin natural gas reservoirs
LNG	Liquid Natural Gas
MMBTU	A Million BTU – an energy unit used as a basis for the determination of natural gas prices