NEWMEDENERGY

2022

Periodic Report

as of December 31, 2022

NEWMED IN NUMBERS

Number of employees[2] **24**

330 Area of Leviathan reservoirs (km^2)

6.17 Average price of natural gas sales from Leviathan ($) (MMBTU)

11.4 Natural gas sales from the Leviathan reservoir (BCM)

[2] **5,117** Value of the Partnership's share in Leviathan

[8] **813** EBITDA

483 Net Profit

1,144 Revenues

3,955 Total assets

7.6 Natural gas sales for export from the Leviathan reservoir (BCM)

1,300 Equity

[4] **2,618** Market value

Footnotes:

1. The above figures relate to 2022 in millions of dollars, unless stated otherwise.
2. NPV10 of reserves and contingent resources (2P+2C), as released in report on reserves, contingent resources, and DCF for the Leviathan leases of March 19, 2023.
3. EBITDA was calculated as operating income plus depreciation and amortization and the Partnership's share in the losses of the Company accounted for at equity.
4. The participation unit price quoted on TASE as of December 31, 2022 according to the representative exchange rate quoted as of such date.

OUR EVOLUTION

1991 Dr. David Cohen, geologist Eli Rosenberg, and Gideon Tadmor establish Avner Oil & Gas Exploration

1993 Delek Drilling Limited Partnership is founded as the energy arm of the Delek Group

1998 Yitzhak Tshuva acquires Delek Group, and works in collaboration with Noble Energy (now Chevron) for natural gas exploration in the Mediterranean Sea

1999 The first gas discovery is made offshore Israel - the Noa and Mari B reservoirs

2004 Yam Tethys pipes natural gas to the Israeli market, enabling Israel to produce power independently

2009 A new reservoir is discovered offshore of Israel - the Tamar reservoir

2010 The Leviathan reservoir, the largest natural gas field in the Mediterranean and one of the largest in the world, is discovered by NewMed Energy, Chevron, and Ratio

2011 The Aphrodite reservoir is the first natural gas discovery made offshore Cyprus

2012 Declaration of the Tanin gas discovery. Anchor agreement signed for the Tamar reservoir with the IEC

2013 Gas from the Tamar reservoir reaches the shores of Israel

2013 Another gas discovery, Karish, is declared

2014 Bond. Tamar Bond. Issuance of Tamar bonds

2014 The gas partnerships sign MOUs for gas export to Jordan and Egypt

2016 Sale of Karish and Tanin gas reservoirs to Energean

2017 From Tamar to Jordan – For the first time in history, Israel produces natural gas for Jordan

2017 Leviathan gets underway - NewMed Energy and Chevron begin developing the Leviathan reservoir

2018 Historic gas export agreements with the Egyptian company Dolphinus

2019 The piping of natural gas commences from the Leviathan reservoir to customers in Israel, Jordan, and Egypt

2021 Sale of the holdings in the Tamar reservoir

2022 The Group changes its name to NewMed Energy and launches new branding

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Part A

Description of the general development of the corporation's business

<u>**Chapter A – Description of the General Development of the Corporation's Business**</u>

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NEWMEDENERGY

This report is a translation of NewMed Energy - 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.

Chapter A – Description of the General Development of the Corporation's Business

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

1.1. NewMed Energy – Limited Partnership (the "**Partnership**")[2] is a public limited partnership, within the meaning thereof in the Partnerships Ordinance [New Version], 5735-1975 (the "**Partnerships Ordinance**"). Since its establishment, the Partnership is engaged primarily in the exploration, development, production and marketing of natural gas, condensate and oil in Israel and Cyprus.

1.2. The Partnership was established under a partnership agreement signed on July 1, 1993 between NewMed Energy Management Ltd. as general partner, of the first part (the "**General Partner**"), and NewMed Energy Trusts Ltd. as limited partner, of the second part (the "**Limited Partner**")[3], as amended from time to time (the "**Partnership Agreement**")[4]. The Partnership was incorporated on July 25, 1993, under the Partnerships Ordinance, according to which the Partnership Agreement, as amended from time to time, constitutes the Partnership's articles of association.

1.3. In accordance with prospectuses released by the Partnership between the years 1993-2003, the Limited Partner issued participation units to the public which confer a right to participate in the rights of the Limited Partner in the Partnership (the "**Participation Units**" or the "**Units**"), which are listed for trade on the Tel Aviv Stock Exchange Ltd. ("**TASE**"). The Limited Partner serves as trustee and holds in trust for the unit holders the Participation Units issued thereby.

1.4. 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 "**Supervisors**" or the "**Supervisor**").

On July 1, 1993, the Limited Partner and the Supervisor signed a trust agreement, as amended from time to time (the "**Trust Agreement**")[5], which confers on the

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[1] For definitions of some of the professional terms included in this chapter, see the professional terms glossary at the end of the chapter as well as **Annex A** to this chapter.
[2] The Partnership's previous name was Delek Drilling – Limited Partnership. On February 21, 2022, the Partnership's name was changed to its current name.
[3] The General Partner's previous name was Delek Drilling Management (1993) Ltd. and the Limited Partner's previous name was Delek Drilling Trusts Ltd. On February 24, 2022, their names were changed to their current names.
[4] As published in the Partnership's immediate report of January 2, 2023 (Ref. no.: 2023-01-001458).
[5] As published in the Partnership's immediate report of June 7, 2020 (Ref. no.: 2020-01-058218).

Supervisor powers of supervision over the Partnership's management by the General Partner, as well as powers of supervision over the fulfillment of the Limited Partner's obligations to the Unit holders.

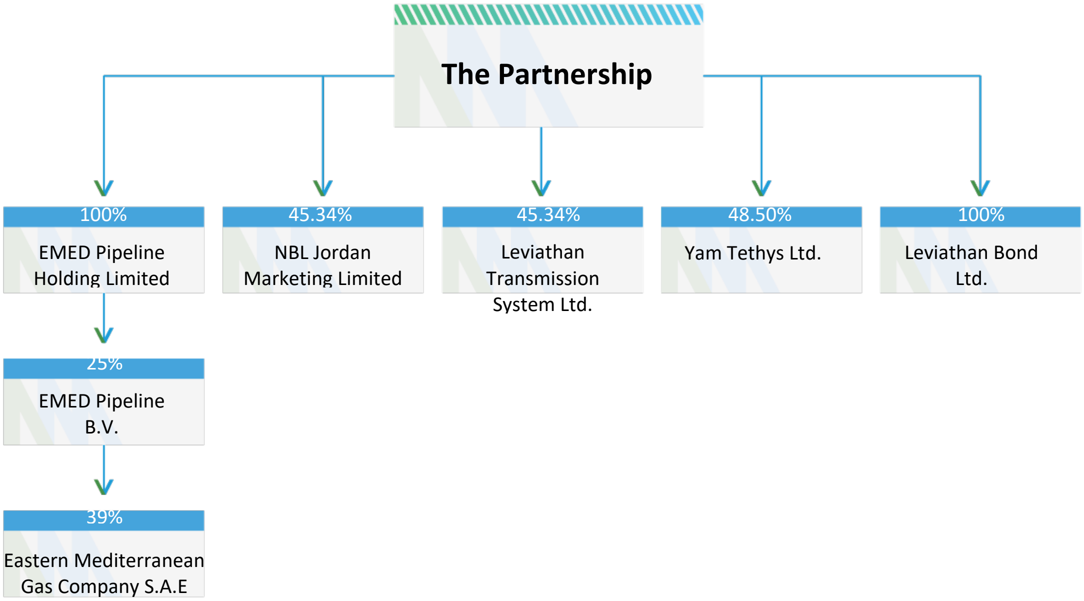
1.5. The General Partner and the Limited Partner are subsidiaries of Delek Energy Systems Ltd. ("**Delek Energy**"), a private company wholly owned by Delek Group Ltd. ("**Delek Group**"), the controlling shareholder of which is Mr. Yitzhak Sharon (Tshuva)[6]. To the best of the Partnership's knowledge, 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 Partnership's issued unit capital.[7]

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 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 of the Partnerships**").

1.7. The structure of principal holdings of the Partnership:

[6] As of the report approval date, Mr. Yitzhak Sharon (Tshuva) holds approx. 48.58% of the issued capital and approx. 50.18% of the voting rights in Delek Group.

[7] 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. In addition, as of the report approval date, all of the participation units held by the General Partner are pledged.



1.7.1. 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.

1.7.2. Leviathan Transmission System Ltd. is a special purpose company (SPC) ("**Leviathan Transmission System**"), 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.

1.7.3. NBL Jordan Marketing Limited is a special purpose company (SPC) 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 the company 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 7.10.3(b) below.

1.7.4. EMED Pipeline B.V. is an SPC ("**EMED**") which established for the EMG Transaction (as defined in Section 7.24.6 below) and is registered in the Netherlands. Its shares are held as follows: EMED Pipeline Holding Limited, a wholly owned subsidiary of the partnership that is registered in Cyprus – 25%; Chevron Cyprus Limited – 25%; and Sphinx EG BV, a wholly owned subsidiary of East Gas Company S.A.E., which holds, *inter alia*, a gas pipeline and infrastructures in Egypt (the "**Egyptian Partner**") – 50%.

1.7.5. 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%; Snam S.p.A ("**SNAM**") – 25%, Mediterranean Gas Pipeline Ltd. ("**MPGC**")[8] – 17%; Egyptian Partner – 9%, Egyptian General Petroleum Corporation ("**EGPC**")[9] – 10%. For further details see Section 7.24.6 below.

1.7.6. Leviathan Bond Ltd. is a special purpose company (SPC) ("**Leviathan Bond**") 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. For further details, see Section 7.19.2 below.

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

1.8. On March 27, 2023, the General Partner received a non-binding indicative offer (the "**Offer**") from Abu Dhabi National Oil Company (ADNOC) P.J.S.C. and BP Exploration Operating Company, two international energy companies

[8] A private company which, to the best of the Partnership's knowledge, is controlled by Evsen Group, a company headed by Dr. Ali Evsen.

[9] An Egyptian government-owned company.

(collectively: the "**Consortium**"), regarding a possible transaction in which the Consortium will purchase for cash all of the Participation Units held by the public and some of the units held by Delek Group, subject to certain conditions (in this section: the "**Transaction**").

Below is a concise description of the main terms of the Offer:

1.8.1. As part of the Transaction, the Consortium will purchase all of the issued unit capital held by the public (approx. 45%) and will purchase approx. 5% of the issued unit capital from Delek Group, such that after the closing of the Transaction, the Consortium and Delek Group will each hold 50% of the equity and controlling interests in the Partnership, by way of approval of an arrangement under Section 350 of the Companies Law, 5759-1999 (the “**Companies Law**”).

1.8.2. The Consortium’s Offer, which, as aforesaid, is non-binding and subject to conditions, is payment of ILS 12.05 per unit purchased. This price reflects a premium of approx. 72% relative to the closing price of the units on TASE on March 26, 2023 (ILS 6.996) or a premium of approx. 76% and approx. 60% relative to the average closing price of the units on TASE in the 30 and 90 trading days preceding the date of the Offer, respectively.

1.8.3. The Offer included conditions which the Consortium wishes to agree on with Delek Group regarding the joint control of the Partnership after the closing of the Transaction, as well as additional conditions for the Transaction, including the completion of due diligence, obtaining detailed agreements with Delek Group on all relevant issues and obtaining all of the other required approvals and consents.

1.8.4. The Consortium may withdraw and cancel the Offer at any time and for any reason.

On March 27, 2023, the General Partner’s board held a discussion regarding the Offer, and in view of Delek Group’s personal interest in the Transaction and the material nature of the Transaction, decided to appoint the audit committee, comprised solely of 3 external directors (in this section: the “**Committee**”), to explore and resolve any issue pertaining to the purchase of the publicly held units in the Transaction, and to take any and all actions required for the exercise of the Committee’s powers, at the Committee’s discretion, including engaging with outside and independent professional consultants for receipt of legal and economic advice on the price proposed for the units; determining the terms and conditions of such consultants’ compensation at the Partnership’s expense; conducting independent negotiations with the Consortium and with Delek Group, which shall be held, insofar as possible, at arm’s length, all in accordance with the best interests of the Partnership and the unitholders; drafting the Transaction documents as the Committee shall deem fit, and determining the terms and conditions thereof, if and insofar as the Committee shall deem fit; and formulating the Committee's recommendation to the board with respect to the Transaction. In addition, the Committee was authorized to decide also not to perform the Transaction or to make its approval conditional or to request, obtain and explore alternative offers, all as it shall deem fit. The Committee shall receive any and all information and assistance required from the Partnership and the General Partner and their officers, and the Committee's members are authorized to request any relevant information or document that is in the possession of the Partnership or the General Partner.

There is no assurance that the Transaction or the terms and conditions that the Consortium is seeking to agree with Delek Group in relation to the joint management of the Partnership after the closing of the Transaction will be acceptable to and agreed by Delek Group, or whether the parties will be able to reach an agreement. If the required agreements are reached with Delek Group and the Committee's recommendation is received to approve the Transaction, then approval of the Transaction by way of an arrangement under Section 350 of the Companies Law, and the closing of the Transaction and performance thereof, will be subject to the approval of the court, which will supervise the arrangement, approval of the arrangement by the meeting of the unitholders by a majority of 75% of all of the unitholders (including Delek Group and affiliates thereof), and approval by an ordinary majority of the public unitholders (without Delek Group and affiliates thereof), and receipt of the other regulatory approvals, and consents from third parties, as required for the closing of a transaction of this type. It is emphasized that, as of the report approval date, there is no certainty that it will be possible to obtain all of the said approvals and consents, and consequently the chances of the closing of the Transaction are uncertain.

Caution concerning forward-looking information – The above information in connection with the Transaction constitutes forward-looking information within the meaning thereof in the Securities Law, 5728-1968. It is emphasized that at this stage, there is no assurance with respect to the closing of the Transaction and performance thereof, since these are dependent on conditions that are beyond the Partnership's control.

2. <u>Field of Business</u>

2.1. As of the report approval date, the Partnership operates in the energy field and its primary business is exploration, development, production and marketing 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 the sales of natural gas produced by the Partnership. At the same time, the Partnership is exploring various business opportunities in the field of exploration, development, production and marketing of natural gas, condensate and oil in other countries (for additional details in relation to an exploration license in Morocco, see Section 7.6 below), is exploring and promoting possibilities for investing in renewable energy projects in the context of the collaboration with Enlight Renewable Energy Ltd. ("**Enlight**"), as specified in Section 7.8 below, and is also exploring possibilities for entry into the field of hydrogen, including blue hydrogen, which is produced from natural gas, and which can be a low-carbon substitute for energy consumers. For further details see Section 7.26 below.

2.2. The Partnership's primary petroleum asset on the report approval date, is a holding of 45.34% (out of 100%) of the Leviathan reservoir, the gas flow therefrom began in December 2019. The Leviathan reservoir currently supplies natural gas to a number of customers in the Israeli and regional market, and among its prominent customers are, *inter alia*, Blue Ocean Energy in Egypt ("**Blue Ocean**") and Jordan's national electricity company (NEPCO).
In addition to the rights in the Leviathan reservoir, the Partnership holds rights in the Aphrodite reservoir which was discovered in the area of Block 12 in Cyprus ("**Aphrodite**" or "**Block 12**") and in additional petroleum assets, as specified in Sections 7.2 to 7.7 below.

2.3. The operators of the Leviathan and Block 12 reservoirs are Chevron Mediterranean Limited ("**Chevron**") and Chevron Cyprus Limited ("**Chevron Cyprus**"), respectively, subsidiaries of a subsidiary wholly-owned by Chevron Corporation ("**Chevron Corp**").[10]

2.4. According to the directives of the Government Resolution on the "Gas Framework", as specified in Section 7.22.1 below, in December 2021, the Partnership sold the balance of its interests in the Tamar and Dalit leases. The operator in the Tamar Project is Chevron, which holds 25% of the rights in the Tamar Project. Following the aforesaid sale of the rights, the Tamar Reservoir and the partners therein are the Partnership's main competitors.[11] For further details with respect to the competition, see Section 7.13 below.

2.5. In accordance with the TASE Rules, the Partnership is entitled to only carry out gas and oil exploration, development and production projects, which were defined in

[10] Chevron Corp is a foreign public corporation, the shares of which are traded on NYSE. To the best of the Partnership's knowledge, there is no single shareholder holding more than 10% of Chevron Corp's issued share capital.

[11] To the best of the Partnership's knowledge, the partners in the Tamar Project, as of the report approval date, are: Chevron (25%), Isramco Negev 2, Limited Partnership (28.75%) ("**Isramco**"), Mubadala Energy (Tamar) RSC Ltd. (11%), Tamar Investment 2 RSC Limited (11%), Tamar Petroleum Ltd. (16.75%), Dor Gas Exploration, Limited Partnership (4%) ("**Dor**") and Everest Infrastructure, Limited Partnership (3.5%) ("**Everest**" and jointly, the "**Tamar Partners**").

the Partnership Agreement or in the amendment thereto to be approved by the meeting of the Unit holders. The Partnership Agreement defines the geographical areas included in the Partnership's existing petroleum assets, which are specified in Sections 7.2-7.7 below. Moreover, amendments made to the TASE Rules in March 2019 and July 2021 allow the Partnership, under specific terms and conditions, to invest in projects that were not expressly defined in the Partnership Agreement and to invest in renewable energy projects.[12] Accordingly, on September 21, 2022, the general meeting of the Unit holders authorized the amendment of the Partnership Agreement, *inter alia*, to enable the Partnership to participate in renewable energy projects. For details on a collaboration agreement with Enlight, see Section 7.8 below.

2.6. It is further provided in the Partnership Agreement, *inter alia*, that the principal part of the Partnership's expenses would be in accordance with the Partnership's objectives, as defined in Section 5 of the Partnership Agreement.

2.7. Below are details with respect to the optimal evaluation (best estimate) of the quantities of the reserves (2P), contingent resources (2C) and prospective resources (2U) attributed to the petroleum assets Leviathan and Block 12 in Cyprus (100%) as of December 31, 2022, as estimated by an independent evaluator, Netherland Sewell and Associates Inc. (the "**Evaluator**" or "**NSAI**").

	Rate of the Partnership's interests	Optimal Evaluation (2U) of the Total Quantity of the Prospective Resources[13] (100%)			Optimal Evaluation (2C) of the Quantity of Contingent Resources (100%)		Optimal Evaluation (2P) of the Total Quantity of Reserves (100%)	
		Natural Gas BCF	Condensate Million barrels	Oil Million barrels	Natural Gas BCF	Condensate Million barrels	Natural Gas BCF	Condensate Million barrels
Leviathan Reservoir	45.34%	-	-	-	6,292.8	13.9	15,569.2	34.3
Leviathan Deep Prospects	45.34%	390.2	-	379.2	-	-	-	-
Aphrodite Reservoir	30.00%	913	1.9	-	3,477	7.6	-	-

2.8. In addition to the said primary assets, the Partnership has rights in additional petroleum assets which, as of the report approval date, were classified by the Partnership as negligible petroleum assets, as follows:

[12] For details on the March 2019 amendment, see: https://mayafiles.tase.co.il/reports/1216001-1217000/E1216813.pdf.
For details on the July 2021 amendment, see: https://mayafiles.tase.co.il/reports/1384001-1385000/E1384631.pdf.

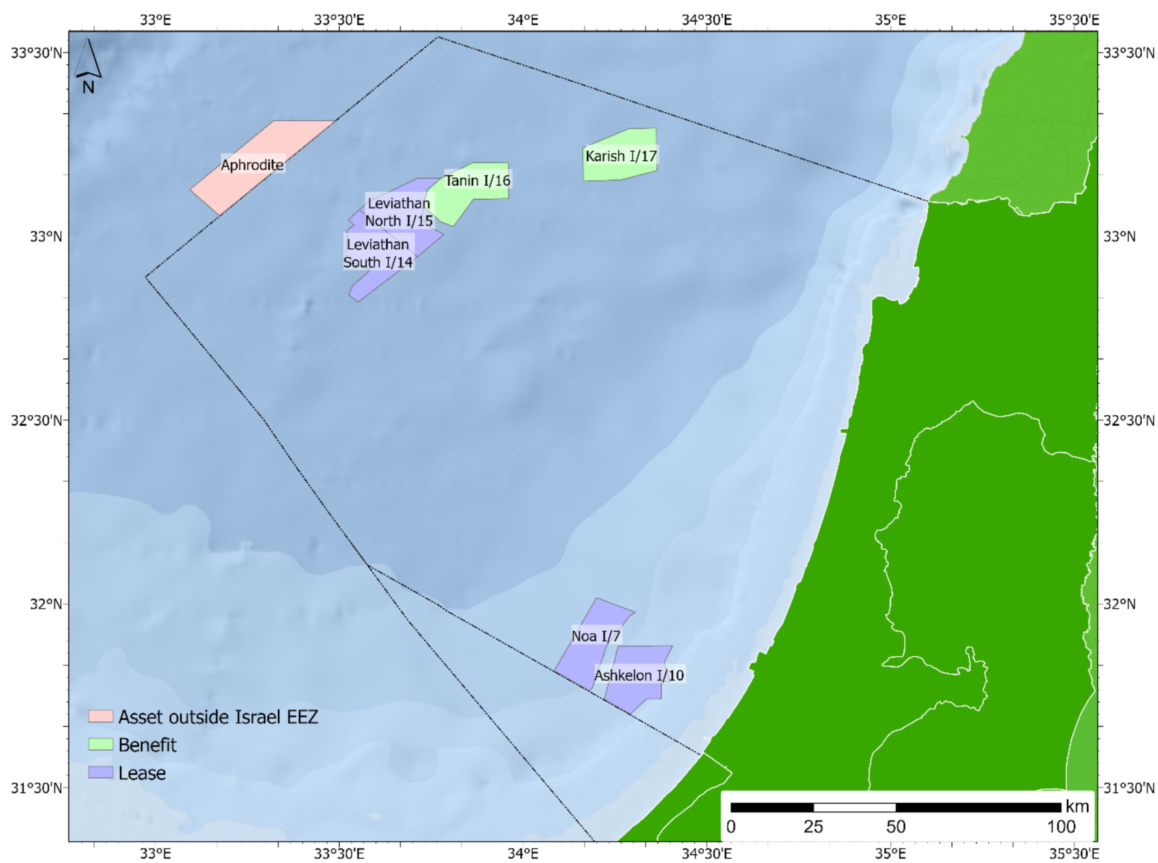
[13] The prospective resources stated below are located in several fault blocks and/or various prospects, the chances of the presence of which vary.

2.8.1 Rights to receive royalties from the I/16 "Tanin" and I/17 "Karish" leases (the "**Tanin Lease**" and the "**Karish Lease**", respectively);

2.8.2 Yam Tethys project in leases I/7 "Noa" and I/10 "Ashkelon" (the "**Noa Lease**" and the "**Ashkelon Lease**", respectively);

2.9 For details on the Partnership's petroleum assets on the report approval date, see Sections 7.2-7.6 below. For details on petroleum assets, the activity in which has been discontinued, see Section 7.7 below.

The following map shows the location of the Partnership's petroleum assets, as of the report approval date:



3. <u>Investments in the Partnership's Capital and Off Exchange Transactions made by Interested Parties in the Participation Units</u>

To the best of the Partnership's knowledge and according to the reports of the Delek Group, Delek Group pledged most of its Units owned thereby in favor of the holders of bonds issued by Delek Group. For details regarding the engagement between the General

Partner and Delek Group and Delek Energy regarding the pledge of the Participation Units owned by the General Partner, see Regulation 21A of Chapter D hereof.

4. Distribution of Profits

4.1. In the period from January 1, 2021 until the report approval date, 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
September 22, 2021	October 13, 2021	$0.08519	$100 million	Ref.: 2021-01-148473
December 9, 2021	December 23, 2021	$0.08519	$100 million	Ref.: 2021-01-178155
May 22, 2022	June 16, 2022	$0.04260	$50 million	Ref.: 2022-01-062296
August 17, 2022	September 22, 2022	$0.04260	$50 million	Ref.: 2022-01-104986
November 23, 2022	January 19, 2023	$0.04260	$50 million	Ref.: 2022-01-141307
March 27, 2023	April 20, 2023	$0.05112	$60 million	-

4.2. For details on the tax regime applicable to the Partnership and the change therein that took effect starting from the tax year 2022, following the taking effect 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) (Amendment), 5782-2021, see Section 7.20 below.

4.3. As of December 31, 2022, the Partnership has profits available for distribution in the amount of approx. 1,103.9 million U.S. Dollars ("**Dollars**" or "**$**").

4.4. Other than restrictions set forth in financing agreements, as specified in Section 7.19 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.

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

4.5.1 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.

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.

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.

4.5.2 On December 30, 2013, a general meeting of the Unit holders was held, in which it was resolved, *inter alia*, to approve refraining from distribution of profits (as defined in Section 9.4 of 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.

4.5.3 On September 21, 2022, a general meeting of the Unit holders was held at which it was resolved, *inter alia*, to authorize refrainment from distribution of profits (as defined in Section 9.4 of the Partnership Agreement) for the purpose of performance of the Block 12 Development Plan, in accordance with a workplan and budgets which either were and/or will be approved by the Block 12 partners and according to the terms and conditions of the Production Sharing Contract (PSC) signed with the Cypriot government, as amended from time to time, and to approve use of the surplus cash which was and will be accrued for the purpose of investment thereof in the Development Plan.

In addition, in the context of the aforesaid general meeting, it was decided to authorize the Partnership to act and make investments in renewable energy projects in the context of the collaboration with Enlight and in accordance with the provisions of TASE Rules, up to the aggregate investment amount (only the Partnership's share) of $100 million (in equity and/or a shareholders' loan, including a capital note or by way of a guarantee for loans to be provided). For additional details see the Partnership's immediate reports dated September 6, 2022 and September 21, 2022 (Ref.: 2022-01-092520 and 2022-01-120358, respectively), the information in which is incorporated herein by reference.

4.5.4 On January 2, 2023, a general meeting of the Unit holders was held at which it was resolved, *inter alia*, to approve the Partnership's engagement in agreements for the purchase of the rights in the Morocco license and participation in activities for oil and/or natural gas exploration and production in the license area, and to approve refrainment from distribution of profits (as defined in Section 9.4 of the Partnership Agreement) for the purpose of performance of the aforesaid actions in accordance with a work plan and budgets to be approved by the partners in the license and according to its terms. For additional details see the Partnership's immediate reports dated December 12, 2022 and January 3, 2023 (Ref.: 2022-01-150004 and 2023-01-002016, respectively), the information in which is incorporated herein by reference.

5. <u>Financial Information regarding the Partnership's field of business</u>

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, 2022 and December 31, 2021, 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, development and production in Israel and determines, *inter alia*, provisions in relation to payment of royalties to the State and 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 issues 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, 5771-2011 (the "**Natural Resources Tax Law**") regulates, *inter alia*, tax and petroleum profit levy issues. For further details with respect to the Petroleum Law, the Natural Gas Sector Law and the Natural Resources Tax Law, see Sections 7.22.4, 7.22.5 and 7.20.2 below, respectively.

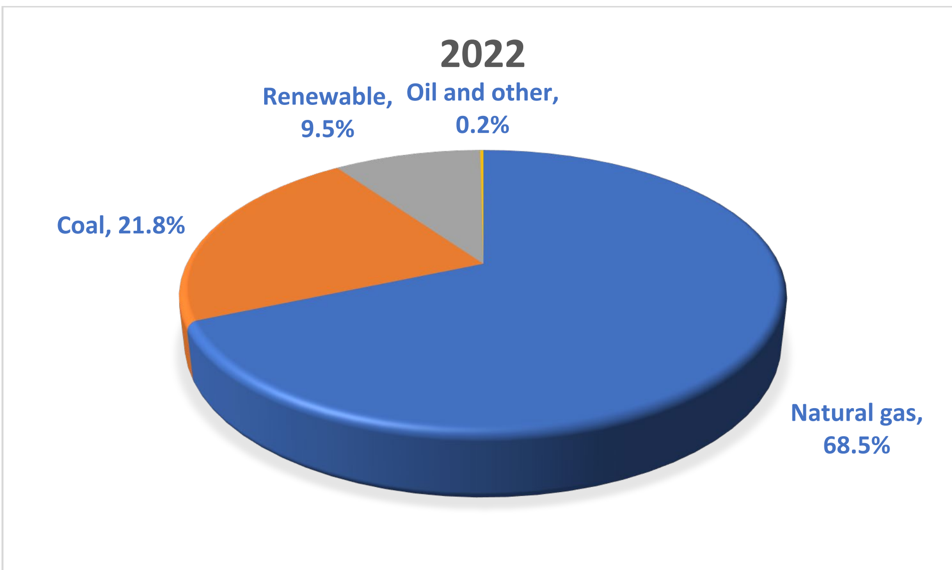
6.2. The economic merit of investments in the exploration for and development of natural gas reservoirs is greatly affected by oil and gas prices in the world, *inter alia* LNG prices, by the demand for natural gas in the global, regional and domestic markets and by the ability to export natural gas (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 payment of royalties 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. Later on, in 2009, the natural gas reservoirs Tamar and Dalit were discovered, in 2010, the Leviathan reservoir was discovered and thereafter, in 2012 and 2013, the Tanin and Karish reservoirs, respectively, were discovered. Note that the Partnership took part in all of the aforesaid discoveries.

In 2004, natural gas began to flow from the Yam Tethys project through the transmission system of INGL. Initially, the facilities of the Israel Electric Corporation Ltd. (the "**IEC**") and large industrial plants were connected. Subsequently, with the start of gas flow from the Tamar Project in 2013, private power plants and additional plants were connected, and 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 large consumers (including power plants of the IEC and private power plants) to the transmission system and of smaller consumers to the distribution network. In December 2019, commercial production to the domestic market from the Leviathan project, has commenced.

On October 26, 2022, Energean Oil and Gas Plc ("**Energean**") reported production of first gas from the Karish Lease and on October 28, 2022, it began to sell gas to its customers. For additional details, see Section 7.5.3 below.

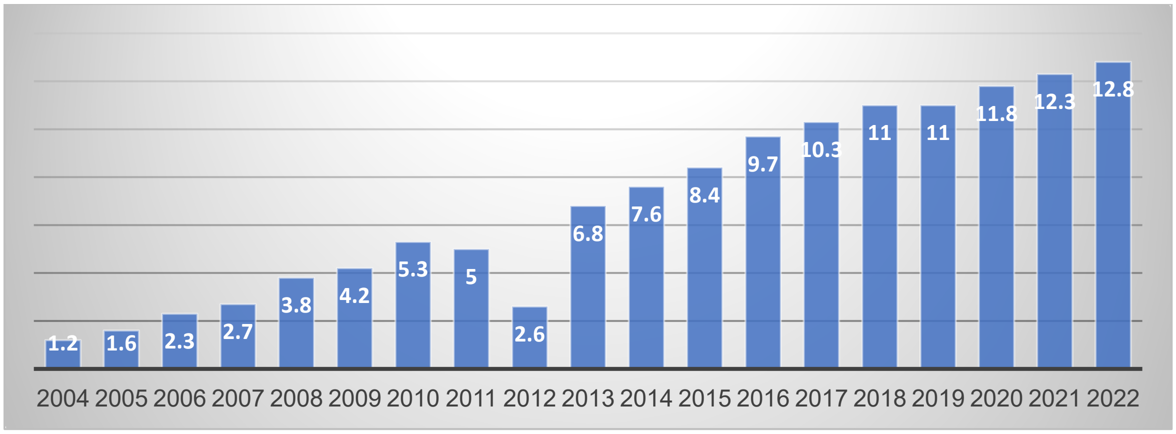
6.4. In the past two decades, the natural gas sector in Israel has been undergoing significant changes (which include, *inter alia*, regulatory, economic, commercial and environmental changes). Within a few years, natural gas has become the primary component in the Israeli economy in the range of fuels for electricity production and a significant energy source for the industry. The natural gas resources that have been discovered in Israel can provide for all of Israel's gas needs in the next decades, 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 regional and global markets.



* BDO Consulting Group Analysis of data of Noga – Israel Independent System Operator Ltd. and PUA-E.

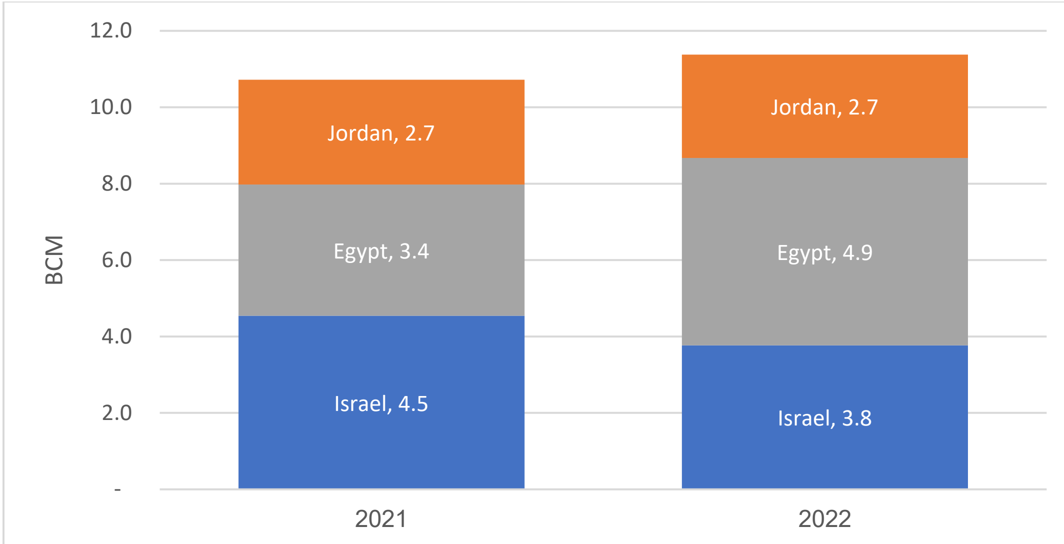
6.5. According to the data of the Ministry of Energy, the scope of consumption of natural gas in Israel increased from approx. 6.8 BCM in 2013 to approx. 12.3 BCM in 2021[14], while in 2022, the Partnership estimates that consumption was approx. 12.8 BCM, as specified in the graph below (in BCM terms):

[14] Source of data: The Ministry of Energy – Royalties, Accounting and Economics Department, Report on Income from Natural Resources – Y2022, https://www.gov.il/BlobFolder/reports/income_reporte/he/revenue_report-2022.pdf.



6.6. In 2017, natural gas began to be exported, for the first time, from the Tamar reservoir to Jordan, at a limited volume. July 2020 saw the beginning of export of natural gas from the Tamar reservoir to Egypt. To the best of the Partnership's knowledge, and according to the Ministry of Energy's publications, in 2022, approx. 10.3 BCM of natural gas and approx. 467 thousand barrels of byproduct condensate, of which, 1.57 BCM for export, were produced from the Tamar Reservoir.[15] 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 2021, approx. 4.5 BCM of natural gas was supplied from the Leviathan reservoir to the domestic market, and approx. 2.7 BCM and approx. 3.4 BCM to Jordan and to Egypt, respectively, and in 2022, approx. 3.8 BCM of natural gas was supplied from the Leviathan reservoir to the domestic market, and approx. 2.7 BCM and approx. 4.9 BCM to Jordan and to Egypt, respectively, as specified in the graph below:

[15] Source of data: Ministry of Energy, Royalties, Accounting and Economics Department, Report on Income from Natural Resources – Y2022, https://www.gov.il/BlobFolder/reports/income_reporte/he/revenue_report-2022.pdf.



6.7. In the Partnership's estimation, based, *inter alia*, on work performed by independent consulting firms, 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 a gradual discontinuation of electricity production using coal by the end of 2025, external increase in the scope of demand for electricity (*inter alia* as a result of significant penetration of electric vehicles and continued construction of water desalination facilities), the assimilation of compressed natural gas ("**CNG**") uses in some transportation sectors, accessibility to natural gas for additional industrial enterprises throughout Israel and for the agricultural sector, *inter alia*, through a government-sponsored program to supports companies that received a government franchise to lay down a distribution pipeline and government legislative moves for changes in the distribution segment, for the purpose of upgrading the distribution systems, implementation of the use of natural gas in additional segments, such as services, development and tapping of industries based on natural gas as feedstock (such as production of blue hydrogen and development of petrochemical plants for ammonia production, that use natural gas), all over and above the natural increase in demand for natural gas and for electricity in the Israeli economy due to external projects such as train electrification, construction of desalination facilities, etc., natural population growth and the rise in the standard of living. Notwithstanding the aforesaid, the increase in the demand for natural gas may moderate in the coming years against the backdrop of the government policy on reducing greenhouse gas emissions and promoting the use of renewable energies. For details see Section 7.22.10 below.

6.8. On April 24, 2022, the Ministry of Energy released a report reviewing the developments in the natural gas sector and summarizing 2021, which includes, *inter alia*, data regarding the increase in the volume of production, domestic consumption and export of natural gas in 2021, a review of the natural gas prices in the domestic and global market, a review with respect to the development of the transmission system and the distribution network and reference to the need to formulate a strategy in the field of hydrogen for the domestic market (in this section: the "**Review Report**"). According to the Review Report, in 2021 the Leviathan and Tamar reservoirs supplied approx. 10.67 BCM and approx. 8.62 BCM, respectively, and the offshore LNG buoy located off the coast of Hadera supplied approx. 0.2 BCM. To the best of the Partnership's knowledge, in December 2022, the regasification vessel that supplied LNG to the Israeli market through the offshore buoy ceased its activity and as of the report approval date, the offshore buoy is inactive. In addition, the total supply quantity from the natural gas reserves in Israel in 2021 was approx. 19.47 BCM, around 21% more than 2020. Alongside the increase in consumption, exceptional growth was evident in the export of natural gas to Egypt and to Jordan, which in 2021 totaled approx. 7.14 BCM, around 68% more than 2020.

Below are data from the Review Report which present a breakdown of the consumption of natural gas produced in 2021[16]:

Years	2016	2017	2018	2019	2020	2021	Change 2020-2021
1. Total natural gas supply (in BCM)	9.66	10.35	11.13	11.28	16.11	19.47	21%
2. Total natural gas consumption in the domestic market (in BCM)	9.66	10.27	10.97	11.03	11.8	12.33	4%
2.a Natural gas consumption for electricity production (in BCM)	8.04	8.54	9.08	8.81	9.29	9.71	5%
2.b Natural gas consumption in industry (in BCM)	1.62	1.73	1.89	2.22	2.51	2.62	4%
2.c Consumption in the distribution network (in MCM)	106	160	194	262	254	299	18%
3. Natural gas for export – BCM	0	0.07	0.13	0.22	4.25	7.14	68%

[16] For further details, see: https://www.gov.il/he/departments/publications/reports/ng_2021.

Years	2016	2017	2018	2019	2020	2021	Change 2020-2021
4. Layout of the distribution network (in km)	102	235	288	358	414	575	39%

For additional details with regard to the global energy crisis, the war in Ukraine, the global interest increases and rising inflation, and the impact of these events on the price of and demand for natural gas and other energy products, see Section 7.1.4 below and Sections 3G and 3H of Part One of the Board of Directors' Report (Chapter B of this report).

6.9. **The principal external factors that affect this sector are**:

6.9.1. 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 Leviathan project are based on various pricing formulas which mainly include linkage to the Brent barrel price, linkage to the electricity production tariff as determined from time to time by the PUA-E (the "**Electricity Production Tariff**"), linkage to the Shekel/Dollar exchange rate, and linkage to the general TAOZ index published by the PUA-E and the crack spread (jointly: the "**Linkage Components**")[17]. It is noted that the majority of natural gas sale agreements include floor prices and in the others, the price is fixed. Therefore, the Partnership's exposure to fluctuations in the Linkage Components in such agreements is hedged by a bottom threshold. For details on the possible effect of changes to the various Linkage Components on the Partnership's business, see Section 7.28.2 below.

6.9.2. Regulation

The sector of exploration, development, production and transportation of oil and natural gas is subject to regulation in countries where the activity is carried out. In Israel, the sector is subject to extensive regulation with respect to petroleum assets (including rules for granting, transferring and pledging the same), to conditions for development, production and supply (including the construction of transmission and distribution and consumer connection infrastructures), to royalties and taxation, export, environmental regulation, restrictive trade practices and so forth. Following the gas discoveries which were made by the Partnership and its partners throughout the years, in the various petroleum assets, in the

[17] 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 global markets. For further details, see Section 7.1.4 below.

State of Israel's EEZ, there has been a significant increase in the extent of regulation of the energy and environment sectors in Israel in general and in connection with the natural gas ventures in particular.

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 7.22 below.

6.9.3. Supply and demand conditions

For details on the supply and demand in the global markets and in the local market, see Sections 7.1.3, 7.11 and 7.14 below.

7. **Description of the Partnership's Business per field of business**

7.1. General information about the field of business

7.1.1. Structure of the field of business and changes occurring therein

The operation of exploration, development, production and transportation 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, the operating agreement that applies to the Leviathan Project, which is described in Section 7.24.7 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, building systems for transporting the gas and/or oil to customers and so forth.

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

(o) Decommissioning and abandonment of the field facilities after the reservoir is depleted, and after weighing various technical, economic and regulatory parameters. Decommissioning and abandonment acts may include, *inter alia*, plugging wells, rinsing, decommissioning and abandoning facilities and rehabilitating the lease area, insofar as necessary, in accordance with the various regulatory directives and 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.

As specified above, the commercial merit 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 significantly higher 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 variable 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. Thus, 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. Restrictions, legislation, standardization, directives and special constraints applicable to the field of business

For details, see Section 7.22 below.

7.1.3. Developments in markets or changes in customer characteristics

As of the report approval date, the Partnership sells natural gas from the Leviathan project to various customers in the domestic and regional markets, and mainly Blue Ocean in Egypt and NEPCO in Jordan, as specified in Section 7.10.3 below. At the same time, and in light of the significant volume of resources discovered off the shores of Israel, mainly in the Leviathan and Tamar 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 7.22.9 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 and additional ways to export the natural gas, including by way of the liquefaction (LNG) and/or compression (CNG) thereof. For further details, see Sections 7.11.2(k) and 7.11.2(l) below. The Partnership is also exploring and promoting possibilities for investing in renewable energy projects, in the context of the collaboration with Enlight, as specified in Section 7.8 below. In addition, the Partnership is conducting an initial examination of possibilities for the production of hydrogen and, *inter alia*, blue hydrogen which is produced from natural gas.

On November 8, 2022, the Partnership together with Uniper SE ("**Uniper**"), a German energy company with international operations, signed a non-binding MOU to examine the possibility of a collaboration for the supply of LNG to Europe and for the production of blue hydrogen and green hydrogen and its transportation from Israel to Europe. According to the said MOU, the parties will examine, *inter alia*, the supply of natural gas from the Leviathan project to Germany, with the natural gas liquefaction being performed through one of the existing liquefaction facilities in Egypt or through the construction of a floating liquefied natural gas facility ("**FLNG**") in Israel, as part of the development of Phase 1B of the development plan of the Leviathan project ("**Phase 1B** "). It is noted that there is no certainty as to whether and when the cooperation between the parties will be consummated, and whether the cooperation will lead to the Partnership's engagement in agreements for the sale of LNG.

In addition, on June 15, 2022, a memorandum of understanding was signed between Israel, Egypt and the European Union on collaboration in trade, transport and export of natural gas to the EU countries (in this section: the "**MOU**").[18] According to the MOU, the parties will act for regular supply of natural gas to the EU countries from Egypt, Israel and other locations, through liquefaction of natural gas in liquefaction facilities in Egypt, subject to preservation of the energy security in the domestic market of each of the countries that signed the MOU, and without Israel or Egypt impeding export of natural gas to other countries. In addition, according to the MOU, the EU will encourage European countries to participate in competitive processes and invest in natural gas exploration and production projects in Israel and Egypt.

7.1.4. <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 the prices of the various energy products and their alternative products, GDP (gross domestic product) growth rate, population growth rate, living standards, weather conditions, and the energy efficiency of electricity and gas consumers and producers.

In addition, the Government's policy and specifically 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 shutting-down and/or conversion of coal-fired power plants to natural gas use.

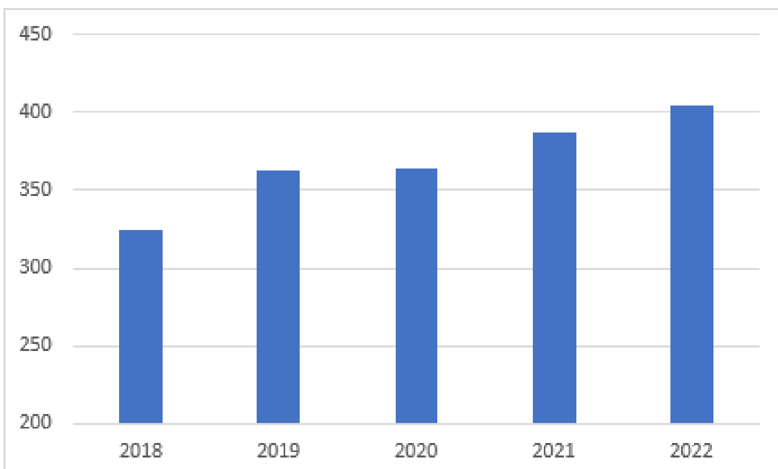
The prices of natural gas and LNG in the global markets and the prices of alternative energy products, including renewable energies, oil and coal, may also affect demand levels and the volume of the Partnership's natural gas sales and the sale prices of natural gas, both under existing agreements and 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 the global markets may lead to increased LNG import into the regional markets, reducing the demand for natural gas produced in Israel

[18] https://www.gov.il/he/departments/news/ng_150622.

in the regional markets relevant to the Partnership and reducing the Partnership's revenues from the Leviathan reservoir. Thus, high LNG prices reduce the import of LNG into the regional markets, and increase the demand for natural gas that is produced in Israel.

In recent years, there has been a significant global 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, and acceleration of the construction of liquefaction facilities and regasification facilities for LNG as a result, *inter alia*, of the war in Ukraine and the significant decrease in the volume of natural gas sold from Russia to the European market.

Below is a graph describing the global LNG supply quantities between 2018-2022, in millions of tons per year:



In addition, following the Covid pandemic, which began in H1/2020, a drop was recorded 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. On the other hand, in 2021, concurrently with the global recovery of the economic activity, the global energy sector underwent dramatic changes which led, *inter alia*, to a sharp rise in the prices of energy products. At the same time, the natural gas prices in Europe rose during 2021, even before the Ukraine war broke out, to $35 and more per MMBTU, more than 10 times the price in 2020.[19] This increase is explained, *inter alia*, through the increase in the demand in Europe, and the European reliance on increased import of natural gas, particularly import of LNG, and through China joining the global

[19] https://www.gov.il/BlobFolder/reports/energy_101121/he/energy_101121.pdf

competition for natural gas. Concurrently, a decrease in supply was recorded which derived, *inter alia*, from a decrease in export of natural gas from Norway and a decrease in the inland production capacity in Europe. Although Israel is not dependent on natural gas imports, the price of natural gas in Israel was affected by the linkage components of the supply contracts, such that indirectly, the global energy crisis led, in Israel too, to a certain increase in the natural gas prices in the various agreements, albeit in a significantly more moderate manner compared to the increase recorded globally.

Along with the sharp rise in natural gas prices in the world market, and as a result of the global economic recovery after the Covid Crisis, in 2021, sharp rises were also recorded in coal prices, whose main consumers are China and India, after a low that was recorded in May 2020. At the same time, oil prices also rose in 2021, however at a more moderate rate than natural gas and coal.

In 2022, the prices of LNG were high and led to an almost complete discontinuation of LNG imports to Israel, Egypt and Jordan, to an increase in the quantities of LNG exports by Egypt, and to an increase in the demand for (non-liquid) natural gas in the regional market in general, and in Israel in particular.

Moreover, on February 24, 2022, the Russian army invaded Ukraine as part of an initiated campaign which included mobilizing ground forces, alongside air and artillery assaults. As a result, the United States and the member states of the European Union imposed a series of economic punitive measures against Russia, which included, among others, sanctions on trade with Russia and Russian seniors, a decision to suspend the completion of the Nord Stream 2 project, which is intended to double the volume of gas exported from Russia to Germany, discontinuation of some collaboration with Russian entities by international companies, including significant companies in the fields of natural gas and oil production, and more. Further thereto, the sale of natural gas from Russia to the European market was significantly reduced, and a significant shortage of natural gas occurred among countries consuming significant quantities of natural gas from Russia. In addition, a steep decrease was recorded in the volume of oil sales from Russia to western countries.

The said Ukraine war led to a steep and unusual increase in global prices of oil and natural gas, and in June 2022, the Brent oil price peaked at over $120 per barrel, which price is significantly higher than the prices to which the world has grown accustomed in recent years.

The decline in the supply of natural gas via pipeline from Russia to Europe forced European countries to import more LNG in 2022 than in 2021. The import of LNG to Europe increased from approx. 90 BCM in 2021 to approx. 150 BCM in 2022, an increase of approx. 70%. The said leap in European demand for LNG resulted in extreme price competition in Asia's LNG markets, Asia being the world's primary consumer of LNG. At the same time, China, Japan, South Korea and Taiwan comprised 50-60% of the global import of LNG in 2021.

In H2/2022, along with a concentrated effort to find alternatives to secure regular supply of natural gas, most European countries acted to lower electricity consumption and concurrently increased the use of renewable energy sources and also began to put nuclear power plants (which constitute an alternative to electricity production through natural gas) into use. Moreover, in this period there began a trend of decline in the prices of energy products in the global markets, which continued also in Q1/2023. As of the report approval date, the Brent barrel price is approx. $75, which price is lower than the price range in the same period last year.

Below is a graph presenting the Brent price in $, commencing from 2020:

Concurrently, a similar decline was also recorded in the natural gas price in the global markets. In the Partnership's estimation, the continued decline in the energy prices in the global markets from mid-2022 may be attributed to signs of slowdown in the global economy and a concern of escalation of the recession, *inter alia* against the backdrop of a swift rise in the inflation rate, which has led to an increase in the base interest rates, as specified below, and to the effect of the weather, which was relatively mild in the winter months in Europe.

Against this backdrop, recently, many European countries are seeking to diversify their natural gas resources, aiming to decrease dependence on natural gas from Russia, which has led to a significant increase in demand for natural gas, especially in areas to which pipelines for transmission of natural gas to Europe can be connected, and to an increase in demand for LNG.

The global LNG market has characteristics of a commodity market, as distinct from the markets for natural gas that is supplied via pipelines, which are dependent on the trends of supply and demand in each and every region. As of the report approval date, it is estimated that approx. 14% of the global demand for gas is in the form of LNG. This market share is expected to grow to approx. 22% by 2045 as a result of a decrease in domestic gas production in certain regions, which will require the import of LNG in order to meet the demand for natural gas.

In 2022, the global LNG market reached an annual consumption rate of approx. 535 BCM and according to estimates, demand is expected to grow at an average annual rate of approx. 2.5% per year and reach approx. 940 BCM in 2045.

At present, Australia, Qatar and the United States are the world's largest LNG exporters, and in 2022 they provided approx. 60% of the global LNG supply.

On June 20, 2022, the Knesset's Research and Information Center published an economic review on the effect of the global energy crisis on the Israeli energy market and on the Israeli Citizens' Fund (in this section: the "**Review**"),[20] whose main parts are as follows:

(a) Effect on the Israeli electricity market – the global increase in coal prices as a result of the global increase in demand and shortage in supply of various fuels, among others, as a result of the Ukraine war, affects the Israeli electricity market which partially relies on coal to produce gas. Accordingly, the Electricity Authority advertised that the cost of coal-based electricity production has risen by approx. 83% in February-June 2022. According to the Review, the economic costs of continued operation of the coal plants in view of the energy crisis, which are estimated at approx. ILS 1 billion for 2022, are high compared to natural-gas based electricity production and are also expected to increase the electricity price for consumers.

(b) Effect on the revenues of the Israeli Citizens' Fund – the price of the natural gas sold to IPPs is expected to increase as a result of the increase in the electricity prices such that the revenues of the levy

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[20] https://fs.knesset.gov.il/globaldocs/MMM/14077da5-3edb-ec11-814d-005056aa4246/2_14077da5-3edb-ec11-814d-005056aa4246_11_19541.pdf.

fund will be impacted. In addition, the global increase in oil prices affects the price of exported natural gas, as the same is partially linked to the global oil barrel price, and the export of natural gas from Israel through Egypt to Europe, according to the MOU, and is also expected to lead to an increase in the gas quantities that are sold.

According to the macro-economic forecast of the Bank of Israel's Research Department dated January 2023 (the "**Bank of Israel 2023 Forecast**"), [21] the end of the war in the forecast period may moderate the energy and commodity prices, accelerate the activity, and moderate the inflation rate and, on the other hand, possible escalation in the fighting may have an adverse effect on the prices of energy, commodities and economic activity, mainly in Europe.

Moreover, the inflation rate in Israel in 2022 was approx. 5.3%,[22] compared to inflation of approx. 2.8% in 2021.[23] The inflation rate in 2022 as aforesaid crossed the upper limit of the target set by the Bank of Israel but was low compared with the inflation rate in most developed economies. According to the Bank of Israel 2023 Forecast, the increase in prices in Israel in the past two years derived from a combination of supply factors, the most significant of which is the Ukraine war, which led to a significant increase in the energy and commodity prices and the continuing interruptions in the supply chains, and factors of domestic demand, against the background of the economy returning to employment rates that are higher than the pre-Covid Crisis rates.

With the aim of curbing inflation, the central banks began to increase the interest rates and in such context, also the Bank of Israel which raised the base interest rate incrementally, from 0.1% in April 2022 to 4.25% as of the report approval date.

In the context of the Bank of Israel 2023 Forecast, the authors estimate that: (a) the GDP in Israel in 2023 and 2024 will grow at the rates of 2.8% and 3.5%, respectively; (b) the inflation rate in Israel in 2023 and 2024 will be 3.0% and 2.0%, respectively; and (c) the monetary interest in Israel is expected to average 4.0% in Q4/2023. The moderation of the expected inflation rate in the forecast period is affected by the moderation in the demand due to the influence of the restraining monetary policy in Israel

[21] https://www.boi.org.il/50476.
[22] https://www.cbs.gov.il/he/mediarelease/Madad/DocLib/2023/021/10_23_021b.pdf.
[23] https://www.cbs.gov.il/he/mediarelease/Madad/DocLib/2022/023/10_22_023b.pdf.

and worldwide, but also from the continued moderation of supply-side pressures.

The price increases in 2022 as aforesaid, and in particular the increase in commodity prices, impacted the Partnership’s business, which primarily led to an increase in revenues from the sale of natural gas and condensate deriving from the increase in Brent barrel prices to which the agreements for the export of gas to Egypt and Jordan are partially linked. The prices of the energy products and the inflation rate also affect the operating costs of the gas production, as well as the development costs in the Partnership’s projects, including the drilling of development, appraisal and exploration wells.

For further details regarding the global energy crisis, the war in Ukraine, the global interest rate increases and the rise in the inflation rate, and the impact of these events on the price of and the demand for natural gas and other energy products, see Sections 3G and 3H of Part One of the Board of Directors’ Report (Chapter B of this report). The Partnership, together with its partners in the Leviathan and Aphrodite projects, is examining the effect of the said factors on the additional possibilities for development and/or the expansion of its assets.

Caution concerning forward-looking information – The Partnership's estimates regarding the possible ramifications of the Ukraine war, the inflation and increase in interest constitute forward-looking information, as defined in Section 32A of the Securities Law. This information is based, *inter alia*, on the Partnership's estimations and assessments as of the report approval date, and on public reports in Israel and worldwide on this issue and on directives of the relevant authorities, the materialization of which is uncertain, in whole or in part, and beyond the Partnership's control.

7.1.5. Material technological changes

The last decades saw technological changes in the field of oil and natural gas exploration, development, production and transportation, both in the area of monitoring, 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 to operate 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 it is a partner strive to use the best available technologies in all of the operation segments. Thus, for example, until 2022 significant resources were invested in the reprocessing and reanalyzing 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, and update the development plans. In addition, reprocessing was used to define new deep prospects. Furthermore, technologies defined as the best available technologies are used, to the extent possible, in 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 liquefaction (FLNG) facility, or into CNG and into liquid (GTL) may facilitate more efficient transportation and commercialization of natural gas. In this context it is noted that the Partnership is working on the construction of an offshore liquefaction (FLNG) facility for converting natural gas into LNG as aforesaid as part of implementation of Phase 1B, as specified in Section 7.2.5(f) below.

7.1.6. <u>Critical success factors in the field of business</u>

(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 and/or oil 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.

7.1.7. Changes in suppliers and raw materials

For details, see Section 7.16 below.

7.1.8. 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 at the Ministry of Energy (the "**Petroleum Commissioner**") (and, in Cyprus – directives and criteria prescribed by legislation and arrangements under the PSC, as specified in Section 7.3.3(l) below), the ability to transfer and/or purchase interests in petroleum and natural gas 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 PSC 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.

7.1.9. 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 such as diesel oil, fuel oil, coal, LPG and 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, etc. The switch from using one type of energy to using another type of energy usually involves large investments. The principal advantages of the 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 carbon dioxide, 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 resolutions of the Israeli government on the promotion of use of renewable energy and setting targets for reducing greenhouse gas emissions, see Section 7.22.10 below, respectively. It is noted that technologies that are under development and/or in initial stages of implementation (such as hydrogen, waste-to-energy and nuclear fusion) may change the global energy market in the coming decades.

7.1.10. Structure of competition in the field of business

For details, see Section 7.13 below.

Below are details regarding the Partnership's petroleum assets:

7.2. **Leviathan project**

7.2.1. General details

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.

General Details with respect to the Petroleum Asset	
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:	Chevron
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%). ▪ Chevron (39.66%). ▪ Ratio Energies – Limited Partnership ("**Ratio**") (15%). To the best of the Partnership's knowledge, the general partner of Ratio, Ratio Energies 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, owned by Deborah Landau (1/2), Yigal Landau (1/6), Shlomit Landau (1/6), and Yuval Landau (1/6). Aizenberg is a private company controlled by Eitan Aizenberg[24].
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	Approx. $1,374,819 thousand[25].

[24] To the best of the Partnership's knowledge, as of the report approval date, the rate of holdings of all of the interested parties in Ratio (apart from the holdings of institutional bodies, mutual funds and provident funds) is approx. 22.8%.

[25] The costs in the table do not include costs in respect of Leviathan's Participation (as specified in Section 7.24.6(d) below), the Combined Section (as specified in Sections 7.11.2(e)3(e), 7.11.2(e)3(f) and 7.11.2(e)3(g) below), the EMG transaction (as specified in Section 7.24.6 below), and the construction of the Israeli transmission system up to the border between Israel and Jordan (as specified in Section 7.10.3(b) below).

General Details with respect to the Petroleum Asset	
an asset in the financial statements):	

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, 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.

2. The export of natural 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**"). An Export Approval will be given in accordance with the government resolution on the export and subject to the conditions specified therein, and subject to any law; and provided that no export will be allowed in practice unless, following the execution of the development program, a quantity of 540 BCM will be available to the domestic market in accordance with the provisions of the government resolution.[26] 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).
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) Construction of facilities and adjustment of the capacity to the needs of the local economy

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

[26] For details regarding the government resolutions on export, see Section 7.22.9 below.

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 (a) 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) <u>Change of conditions in the lease deeds</u>

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) <u>Revocation or restriction of the lease</u>

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[27]

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

[27] 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.

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 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 thereto by the Petroleum 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 5 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, 2020 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)**[28]	**Amount of Actual Participation in the Budget by the Holders of the Equity Interests of the Partnership (Dollars in thousands)**
2020[29]	• Costs in connection with completion of Phase 1A of the Leviathan project development plan ("**Phase 1A**"), including promotion of the running-in of the systems on the platform (including the turbo expanders) and completion of construction of the onshore condensate system, including completion of the Hagit site. • Continued production from the Leviathan reservoir, ongoing operation and maintenance.	Approx. 94,872	Approx. 43,015
	• 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. • Performance of monitoring activities in the vicinity of the Leviathan 2 well, with	Approx. 2,052	Approx. 930

[28] The amounts for 2020-2022 are amounts actually expended and audited in the framework of the financial statements.

[29] The costs, budgets and operations specified in 2020 forth do not include costs and budgets for the adding of the Additional Compressor (as defined in Section 7.10.3(c) below) in the sum of approx. $39.9 million (100%, the Partnership's share approx. $27.6 million), the construction of the Combined Section (as defined in Section 7.11.2(e) below) in the sum of approx. $140 million (100%, the Partnership's share approx. $43.8 million), the flow of gas to Egypt via Jordan (as specified in Section 7.11.2(e) below), and costs of abandonment of the reservoir and the G&A and insurance costs.

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)[28]**	**Amount of Actual Participation in the Budget by the Holders of the Equity Interests of the Partnership (Dollars in thousands)**
	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. 15 Approx. 99	Approx. 7 Approx. 45
2021[30]	• Continued production from the Leviathan reservoir, ongoing operation and maintenance, including changes and upgrades for optimization of the production. • Costs in connection with the completion of Phase 1A, including acts related to Asset Integrity and the production and safety systems. In addition, the activation of the on-shore condensate system, including the activation of the Hagit site in full. • Planning and preliminary procurement of equipment for the "Leviathan-8" drilling in the I/14 Leviathan South lease area ("**Leviathan-8**")[31]. • Planning maintenance work and improvements in the subsea electrical and control systems. • Formulation of a deep target prospect in the Leviathan Leases. The Partnership is exploring the possibility of bringing in a strategic partner with relevant experience and knowledge in	Approx. 35,546 Approx. 19,092 Approx. 6,480	Approx. 16,117 Approx. 8,656 Approx. 2,938

[30] See Footnote 29 above.

[31] On July 12, 2021, the Leviathan Partners adopted a resolution regarding the drilling development and production of Leviathan-8 on the area of lease I/15 Leviathan North. The approved budget was approx. $248 million (100%, including completion and connection to the Leviathan reservoir production system). The aforesaid drilling ended in June 2022, in accordance with the timetables and below the planned budget.

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)[28]**	**Amount of Actual Participation in the Budget by the Holders of the Equity Interests of the Partnership (Dollars in thousands)**
	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. • (a) Examination of the development of Phase 1B and/or additional development alternatives, insofar as required; (b) Examination of additional alternatives for the transmission of condensate, as part of the preparation for Phase 1B; and (c) 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.	Approx. 69 Approx. 8,072 Approx. 142	Approx. 31 Approx. 3,660 Approx. 64
2022[32]	• Continued production from the Leviathan reservoir, ongoing operation and maintenance. • Performance of surveys, tests and actions to maintain the asset integrity of the production systems on the platform and the subsea systems. • Continued improvement of the systems and production processes, *inter alia*, by the performance of the necessary actions to reduce the pressure drops in the process, as well as improvement of the monitoring and detection systems in environmental and safety aspects, in accordance with operational and regulatory requirements;	Approx. 23,185	Approx. 10,512

[32] See Footnote 29 above.

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)[28]**	**Amount of Actual Participation in the Budget by the Holders of the Equity Interests of the Partnership (Dollars in thousands)**
	• Completion of engineering acts related to the development of Phase 1A.	Approx. 11,056	Approx. 5,014
	• Performance of maintenance work and improvements in the subsea electrical and control systems	Approx. 6,482	Approx. 2,939
	• Performance of drilling, development and production "Leviathan 8" and performance of subsea work as preparation for connection of the well to the production system	Approx. 121,026	Approx. 54,873
	• Examination of the possibility of characterization, drilling and development of the deep 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. 102	Approx. 46
	• Performance of monitoring activities in the vicinity of the Leviathan 2 well, with the aim of ensuring the continued rehabilitation of the environment.	Approx. 4	Approx. 2
	• Continued examination of development of Phase 1B and/or other development alternatives, insofar as required, including an alternative to exporting natural gas through subsea pipeline and/or liquefaction (including FLNG), *inter alia*, through preparation for performance of FEED, detailed technical design, and preparations for performance.	Approx. 13,472	Approx. 6,108
	• Continued development of additional alternatives for the transmission of condensate as part of the preparation for Phase 1B, preparation for the performance of FEED, detailed technical design, preparation for procurement and performance.		
	• Examination of possibilities for increasing volumes of natural gas exports to Egypt through onshore transmission systems. For additional details, see Section	Approx. 2,667	Approx. 1,209

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)[28]**	**Amount of Actual Participation in the Budget by the Holders of the Equity Interests of the Partnership (Dollars in thousands)**
	7.11.2(b) below.		
2023 forth[33]	• Continued production from the Leviathan reservoir, ongoing operation and maintenance. • Performance of surveys, tests and actions to maintain the asset integrity of the production systems, including the subsea systems. • Continued improvement of the production processes on the Leviathan platform, and improvement of environmental systems, according to operational and regulatory requirements;	Approx. 17,920	Approx. 8,125
	• Continued performance of maintenance work and improvements in the subsea electrical and control systems	Approx. 10, 080	Approx. 4,569
	• Completion of drilling Leviathan-8 and its connection to the existing production system. • Examination of the possibility of characterization, drilling and development of the deep exploration targets in the area of the leases.	Approx. 59,675	Approx. 27,055
	• Performance of pre-FEED in a competitive process between international groups specializing in planning and construction of FLNG facilities, in the context of promotion of the alternatives for development of phase 1B.	Approx. 51,500	Approx. 23,350
	• Performance of pre-FEED for expansion of the production system of the Leviathan reservoir, including construction of subsea facilities and performance of the necessary changes on the platform, in the context of promotion of the alternatives for the development of phase 1B. • Commencement of piping of condensate through PEI's pipeline. For additional details, see Section 7.10.4(c) below.	Approx. 44,900	Approx. 20,260

[33] The costs, budgets and work detailed in 2023 forth do not include costs and budgets for the construction of the Combined Section (as defined in Section 7.11.2(e) below) in the sum of approx. $140 million (100%, the Partnership's share is approx. $43.8 million), piping of the gas to Egypt via Jordan (as specified in Section 7.11.2(e) below), costs of abandonment of the reservoir and insurance and G&A costs, and participation fees in respect of the Nitzana Line, as specified in Section 7.11.2(b) below.

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)[28]**	**Amount of Actual Participation in the Budget by the Holders of the Equity Interests of the Partnership (Dollars in thousands)**
	• Performance of surveys, planning and procurement for the Third Pipeline (as defined in Section 7.2.5(e) below), including changes and adjustments on the platform. • Installation of a marine discharge detection system on the platform. • Continued performance of acts to reduce system pressure drops.	Approx. 26,610 Approx. 208,000 Approx. 1,060 Approx. 6,500	Approx. 12,065 Approx. 94,310 approx. 480 approx. 2,950

7.2.5. Plan for development of the Leviathan reservoir

(a) 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, and data that shall be received during the production from the field, the recoverable quantity assessment 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*, data of the Leviathan wells, the results of the reprocessing of seismic surveys, products of mapping and analysis of the scope of the reservoir and its characteristics based on the seismic inversion method, models of the reservoir and production data. It is further noted that the resource assessment in the said opinion materially differs from the resource assessment of the Operator and the resource assessment provided to the Leviathan Partners by NSAI. 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 updating the assessment of the resources in the Leviathan reservoir. Nevertheless, it is emphasized that export licenses have been granted in respect of all of the quantities stated in the current export 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 project expansion plan and engagement in additional export agreements, as specified in this section below.

(b) On February 23, 2017, the Leviathan Partners adopted a final investment decision (FID) for the development of Phase 1A, at a capacity of approx. 12 BCM per year, with a budget of approx. $3.75 billion (100%). During the development period, the Phase 1A development budget, as estimated when approved, decreased by approx. $217 million in total (100%). Total cost invested in the development of Phase 1A, as of December 31, 2022, is approx. $3.8 billion (100%). After a preliminary 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 from the Leviathan reservoir to Jordan commenced under the NEPCO agreement (as specified in Section 7.10.3(b)1 below). On January 15, 2020, the piping of natural gas from the Leviathan reservoir to Egypt commenced under the agreement with Blue Ocean (as specified in Section 7.10.3(c) below).

(c) 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 of a total volume of approx. 21 BCM per year, 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. A production system that includes up to 8 first wells that will be connected by a subsea pipeline to a permanent platform (in this section: the "**Platform**"), which is located in the territorial waters of Israel in accordance with the provisions of NOP 37/H and on which all gas and condensate treatment systems will be installed. Gas will flow 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 will be piped to the shore via a separate pipeline parallel to the gas pipeline, and connected to an existing fuel pipeline of Europe Asia Pipeline Co. ("**EAPC**") that leads to the tank farm of Energy Infrastructure Ltd. ("**PEI**") and from there to the Oil Refineries Ltd. ("**ORL**"). Furthermore, a site will be constructed for storage and unloading of condensate, for the purpose of providing backup in the event

that piping condensate to ORL is impossible[34]. For further details regarding the approval of NOP 37/H and the provisions thereof as aforesaid, see Section 7.22.11 below and for details with respect to the production system of the Leviathan project, see Section 7.15.1 below.

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

   (a) Phase 1A – the current stage, in which 4 first subsea production wells were drilled, a subsea production system was established, which connects the production wells and the platform, and a system for transmission to the shore and related onshore facilities were established. At this point, the gas production capacity is approx. 12 BCM per year. As aforesaid, on December 31, 2019, natural gas and condensate piping in the context of the development of Phase 1A has commenced. In the context of Phase 1A, the Leviathan partners decided to drill a fifth well in the reservoir, Leviathan-8, as specified in Section 7.2.5(d) below.

   (b) Phase 1B – expected to include, *inter alia*, 3 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). For details on the various possibilities for the development of Phase 1B, see Section 7.2.5(f) below.

(d) It is noted that additional production wells will be required during the life of the project to enable production of the required volume and in accordance with the level of redundancy of the production system and the wells in the field which is defined, from time to time, by the Leviathan partners. Accordingly, on July 12, 2021, the Leviathan partners adopted a resolution regarding the development and production of Leviathan-8 well in the area of lease I/14 Leviathan South, with a total budget of approx. $248 million (100%, including completion and connection to the existing production system of the Leviathan reservoir). The aforesaid drilling ended in June 2022, in accordance with the timetables and below the planned budget. As of the report approval date, the completion work at the well has been completed according to the work plan, and it is expected to be

[34] 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).

connected to the Leviathan project's existing subsea production system in Q2/2023.

(e) 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. In order to increase this capacity to approx. 1.4 BCF per day, the Leviathan partners are promoting a project in which a third subsea transmission pipeline will be laid from the field to the platform (the "**Third Pipeline**"). The investments in the laying of the Third Pipeline, together with the investments in the platform's related systems, are estimated at approx. $562 million (100%), to be made over a period starting from Q1/2023 until the expected operation of the Third Pipeline in mid-2025. Accordingly, the Leviathan partners gave the project operator approval for an initial expenditure of approx. $45 million (100%) for engineering design and booking supply dates, by way of initial engagements with suppliers, in order to enable the project to be performed according to accelerated timetables and to have it ready for adoption of a final investment decision as part of the total budget. In addition, in the context of approval of the 2023 budget, the Leviathan partners authorized approx. $163 million more (100%) to budget the Third Pipeline project. The total amount of the budgets approved by the report approval date is approx. $208 million (100%) out of a budget of approx. $562 million, as aforesaid. It is clarified that no final investment decision (FID) has yet been adopted in the Third Pipeline project. In the Partnership’s estimation, such a decision is expected to be adopted by the Leviathan partners during Q2/2023, after completion of the preliminary work mentioned above.

(f) Phase 1B of the Leviathan project Development Plan

As of the report approval date, the Leviathan partners are considering promoting various possibilities for the development of Phase 1B and increase of the production rate to a total volume of approx. 21 BCM per year, in order to make a final investment decision (FID). The aforesaid development possibilities may include development and expansion of natural gas flow infrastructures from the Leviathan reservoir to additional consumers in the target markets, primarily to the Egyptian market, supply to existing liquefaction facilities in Egypt, and promotion of the possibility of liquefying natural gas via a FLNG facility for its marketing to the global markets. Hence, the Phase 1B Development Plan, as approved as aforesaid in June 2016 by the Petroleum Commissioner, may be updated in accordance with the selected development possibility, in which case, an additional regulatory approval may be required for a change to the plan. For the purpose of examining the various expansion alternatives, on February 20, 2023, the Leviathan partners approved budgets for 2023, in accordance with the joint operating agreement (JOA) that applies to the Leviathan reservoir, in the sum total of approx. $96.4 million (100%), for the performance of Front End Engineering and Design (Pre-FEED) for Phase 1B (in this section below: the "**Budgets**"). In the context of the aforesaid design, and further to previous analyses, the Leviathan partners are promoting the future construction of a FLNG facility owned thereby, with an annual production capacity of approx. 4.6 million tons of liquefied natural gas (LNG) for purposes of sale thereof to global markets, thus also enabling the increase of the quantities supplied to the domestic market. The Budgets include the sum of $44.9 million (100%, the Partnership's share is $20.4 million), *inter alia* for the performance of Pre-FEED and commencement of FEED, for expansion of the Leviathan reservoir's production system, including the design of subsea infrastructures and of necessary changes on the production platform, as well as the sum of $51.5 million (100%, the Partnership's share is $23.3 million), *inter alia* for the performance of Pre-FEED for the FLNG facility, as aforesaid, in a competitive process between two international groups specializing in the design and construction of FLNG facilities.

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, including with respect to the FID adoption date, costs of laying the Third Pipeline and the expected start-up date of the Third Pipeline, constitute forward-looking information within the meaning thereof in Section 32A of the Securities Law. Such information is based on assessments and estimates by the Partnership and the Operator in the Leviathan reservoir, based on a range of factors, including the plan formulated thereby for laying the Third Pipeline, in respect of the costs, timetables and the mere performance of the aforesaid plan, the Development Plan and the timetables for implementation thereof, receipt of regulatory approvals, estimated data of availability of equipment, services and costs, past experience and geological, geophysical, technical-engineering and other information accumulated, *inter alia*, from the scope of production from the Leviathan reservoir and from the seismic survey conducted in the area of the Leviathan leases. In addition, the Partnership's estimation in respect of the FID adoption date is based on information received from the other Leviathan partners and depends, *inter alia*, on the Leviathan partners making the suitable decisions. The estimates in this report may

not materialize or may materialize in a materially different manner due to factors beyond the Partnership's control, *inter alia*, if changes and/or delays occur in the range of factors as specified above, and if the estimates and assessments received change, *inter alia*, as a result of geological conditions and/or operational and technical conditions and/or regulatory changes 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 and/or due to materialization of one or more of the risk factors entailed by the Partnership's operations, including as specified in Section 7.28 below.

7.2.6. <u>The actual participation rate in the expenses and revenues under the Leviathan Leases</u>

<u>Participation Rate</u>	<u>Percentage Pre Investment-Recovery</u>	<u>Percentage Post Investment-Recovery</u>	<u>Rate grossed-up to 100% Pre Investment-Recovery</u>	<u>Rate grossed-up to 100% Post Investment-Recovery</u>	<u>Explanations</u>
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 7.22.8(c) 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 rate 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[35].

[35] 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
			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 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 7.24.9 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%-104%	
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	45.79%-47.15%	

Item	Percentage	Summary explanation of how the royalties or payments are calculated
level)		
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 asset.	45.79%-47.15%	

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 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 2020	Approx. 101,468	-	Approx. 964
Budget actually invested in 2021	Approx. 114,614	-	Approx. 867
Budget actually invested in 2022	Approx. 179,458	-	Approx. 1,273

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

(a) For details regarding 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, 2022, see current reserves, contingent resources and DCF figures report for the Leviathan Leases attached as **Annex B** to this chapter. Attached as **Annex C** to this report 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.

(b) For details regarding prospective resources in the area of the Leviathan Leases (with regard to the Leviathan Deep prospect) as of December

31, 2019, see Section 7.2.10 of the Partnership's 2019 periodic report (the "**2019 Periodic Report**"), as released on March 30, 2020 (Ref. no.: 2020-01-032010), the information appearing therein is hereby included by reference. As of December 31, 2022, no change has occurred in the said details. Attached as **Annex C** to this chapter 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.

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 Leviathan Project, constitute forward-looking information within the meaning thereof in Section 32A of the Securities Law, which is based on the estimations 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 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 Leviathan 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 Interests in Cyprus

7.3.1 Background

On February 11, 2013 the authorities in Cyprus approved transfer to the Partnership of 30% of the rights of Chevron 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 PSC and the Government of Cyprus signed an amendment to the PSC (the "**First Amendment to the PSC**"), and at the same time, the right holders were given a production and exploitation license (in this section: the "**License**" or the "**Production License**" or the "**Block 12 License**"), and a production and development plan for the reservoir was approved (in Section 7.3: the "**Development Plan**"), as specified in Section 7.3.11 below.

In addition, on November 9, 2022, another amendment to the PSC was signed (the "**Additional Amendment to the PSC**"), deferring the date of the commitment of the Aphrodite reservoir partners to drill another appraisal/development well A-3 (Aphrodite 3) (the "**A-3 Well**") and to complete it by August 2023.

The PSC and the amendments to the PSC as aforesaid shall hereinafter be referred to jointly as the: "**PSC**".

Note that Cyprus and Turkey disagree in relation to the interests in the EEZ of Cyprus which may affect the Partnership's activity in the license. However, it is noted that according to its official reports, the Turkish government does not claim ownership of the Block 12 areas. For additional details in this regard, see Section 7.28.36 below.

7.3.2 General details

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[36].
Area	Approx. 386 square km.
Type of petroleum asset and description of actions permitted according to this type:	Exploitation license granted subject to the PSC.
Original grant date of the petroleum asset:	November 7, 2019.

[36] 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 further noted that the partners in the Aphrodite reservoir were contacted by both the partners in the Yishai License and the Ministry of Energy of the State of Israel 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. Moreover, further to dialog 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. As the parties failed to reach agreements and the date determined by the then Minister of Energy of the State of Israel for signing an agreement elapsed, the governments of Israel and Cyprus began negotiations for distribution of the profits between the parties and between the countries. On April 11, 2022, the Israeli Ministry of Energy announced that the ministers of energy of Israel and Cyprus agreed on the appointment of an external expert who will examine the quantity of natural gas in the reservoir. See at: https://www.gov.il/he/departments/news/press_110422.

General details about the petroleum asset	
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:	Chevron 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:	▪ Chevron 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[37]. ▪ 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 7.3.8 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 year (whether recognized as an expense or as an asset in the financial statements):	Approx. $17,993 thousand.

7.3.3 Following are further details regarding the license in Block 12 and the PSC

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

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

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, i.e., by November 2021. In accordance with the Additional Amendment to the PSC, the partners' commitment to perform the drilling was deferred as aforesaid until August 2023.

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., by November 2023).

   The PSC 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 PSC is a cause for revocation of the PSC, unless resulting from a "*force majeure*" (as defined in the PSC).

(b) It is noted that additional changes and revisions were made as part of the First Amendment to the PSC, *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, etc.

(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 (100%).

2. 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.

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[38]:

Average daily production (in barrels)[39]	**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 from 50,001 to 100,000 (inclusive)	63%	67%	72%
For the share in the average daily production from 100,001 to 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. Prior to the First Amendment to the PSC, the PSC 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, as released on March 24, 2019 (Ref. No.: 2019-01-023982), the information appearing therein is hereby included by reference.

2. Subsequent to the First Amendment to the PSC, a new mechanism for the distribution of the natural gas output was determined, which is based on a factor of the R-Factor

[38] It is noted that the oil sharing mechanism was not amended in the amendments to the PSC.
[39] The calculation is made progressively according to the brackets specified in the table.

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 PSC (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 PSC pertains, which were actually expended during the Calculation Period.

For details regarding 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 7.3.8 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**")[40] at a rate of up to 55% of the total

[40] 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 PSC.

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 7.3.3(c) 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.

(j) <u>Termination of the PSC</u>

1. The Republic of Cyprus may terminate the PSC by giving an advance notice of 3 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 (c) of Regulation 22 of Chapter D of this report.

7.3.4 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
Chevron 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 and preparation for drilling of an appraisal well[41].	-

[41] On October 2, 2013, Aphrodite A-2 appraisal well, which was started on June 7, 2013, was completed.

7.3.5 Compliance with the binding Block 12 Work Plan

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

7.3.6 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, 2020 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)[42]**	**Scope of actual participation of the holders of the equity interests of the Partnership in the budget (in Dollars in thousands)**
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 an appraisal well which will be converted, insofar as necessary, into a production well.	Approx. 3,372	Approx. 1,012
	• 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.		
	• Performance of FEED in preparation for adoption of a FID.	Approx. 2,131	Approx. 639
	• Continued examination of options for commercialization of the natural gas from the Aphrodite reservoir.	Approx. 885	Approx. 266
2021	• 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.		
	• Planning and examination of the	Approx. 2,013	Approx. 604

[42] The amounts for 2020-2022 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)[42]**	**Scope of actual participation of the holders of the equity interests of the Partnership in the budget (in Dollars in thousands)**
	drilling of an appraisal well, insofar as will be required, that will be converted 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. • Continued examination of options for commercialization of the natural gas from the Aphrodite reservoir.	Approx. 7,156	Approx. 2,147
2022	• 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. • Preparations for drilling the A-3 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. 11,722	Approx. 3,517
	• Continued examination of alternatives for commercialization of the natural gas from the Aphrodite reservoir.	Approx. 195	Approx. 59
	• Exploring the possibility of adopting an investment decision for the development of the Aphrodite reservoir in the format specified in Section 7.3.11 below.	Approx. 7,076	Approx. 2,123
2023 forth[43]	• Drilling the A-3 Well. • Continued geological, geophysical and engineering analysis of database existing at the license, *inter alia*, while	Approx. 106,000	Approx. 32,277

[43] As of the report approval date, out of the said budgets, the partners in Block 12 approved a budget for 2023 in the sum of approx. $169 million (100%), which includes the cost of drilling the A-3 Well, costs of performance of surveys and design work, in respect of which, approval from the Cypriot government is yet to be received. For additional details, see Section 7.3.11 below.

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)[42]**	**Scope of actual participation of the holders of the equity interests of the Partnership in the budget (in Dollars in thousands)**
	integrating data from adjacent fields, and updating the geological model and the flow model. • 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. • Continued examination of alternatives for commercialization of the natural gas from the Aphrodite reservoir, marine surveys, performance of pre-FEED and preparation for FEED. • Promotion of the selected development alternative, update of the development plan accordingly and approval thereof by the Cypriot government, performance of FEED, front-end engineering design and preparations for performance of the development plan, and adoption of an investment decision for the development of the Aphrodite reservoir, as specified in Section 7.3.11 below.	Approx. 53,800	approx. 16,382

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 Partnership 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.

7.3.7 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 7.3.2 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 7.3.8 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	30.3%-31.2%	30.3%-31.2%	101%-104%	101%-104%	For details see Section 7.3.9 below.

7.3.8 Participation rate of holders of the equity interests of the Partnership in the revenues from Block 12

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 is 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 that have been taken into account. Note that the figures provided below are based on various assumptions in relation to the development plan approved as of the report approval date, as specified in Section 7.3.11 below, and insofar as another development plan is approved by the Aphrodite reservoir partners and the Cypriot government, the effective participation rate of the holders of equity interests in the gas asset may change.

	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%	
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 7.24.9 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

	R-factor 1	R-factor 1.5	R-factor 2	R-factor 2.5	Notes
					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.

7.3.9 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:		

Item	Percentage	Summary explanation of how the royalties or payments are calculated
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 actions,[44] 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	30.3%-31.2%	

[44] It is noted that as of the report approval date, such rate in connection with the production actions, has not yet been agreed.

Item	Percentage	Summary explanation of how the royalties or payments are calculated
exploration, development or production activity at the petroleum asset.		

7.3.10 Fees and payments paid during exploration and development activity at Block 12 (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[45]	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 2020	Approx. 4,264	-	Approx. 57
Budget actually invested in 2021	Approx. 3,678	-	Approx. 55
Budget actually invested in 2022	Approx. 6,597	-	Approx. 100

7.3.11 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 deriving, *inter alia*, from technical, commercial and financial conditions. The approved plan includes the construction of a floating production and processing facility in the area of the License, with a maximum production capacity of approx. 800 MMCF per day, through 5 first production wells, and a subsea system for transmission to the Egyptian market. Formulating the development plan and adopting a final investment decision for development of the Aphrodite reservoir are subject, *inter alia*, to the update and approval of the development plan, completion of FEED, the making of commercial arrangements for the development of the export systems, signing of agreements for the supply of natural gas and fulfillment of the conditions precedent in these agreements, obtaining regulatory approvals and making of financing arrangements. Insofar as the aforesaid conditions

[45] Including costs in respect of which no payments are made to the Operator.

precedent are fulfilled, the supply of natural gas from the Aphrodite reservoir may occur in 2027 at the earliest.

In such context, the Aphrodite reservoir partners made a decision to engage with a drilling ship for the purpose of drilling the A-3 Well, which shall subsequently serve as a production well and on September 15, 2022, the partners in the Aphrodite reservoir made the decision to approve a budget for drilling the well as aforesaid, in the sum of $130 million (100%). Note that in the context of approval of the A-3 appraisal well budget, the partners approved an additional amount of approx. $62 million (100%) to perform pre-FEED work in order to promote the development of the reservoir. For additional details see the Partnership's immediate report dated September 18, 2022 (Ref. no. 2022-01-118267), the information appearing in which is included herein by reference. In addition, on September 21, 2022, the general meeting of the Unit holders approved refrainment from distribution of profits for the purpose of investment in Block 12. For additional details, see Section 4.5.3 above.

As of the report approval date, the partners in the Aphrodite reservoir are considering additional development alternatives, at lower costs than those in the development plan that is approved as aforesaid, which combine existing facilities and/or development plans for adjacent assets in Egypt. Some of these alternatives include 3 first production wells which will be connected through a subsea pipeline that is 260-390 km long, to an existing subsea infrastructure near the Egyptian coast, with maximum production of approx. 600 MMSCFD. These alternatives are regarding the connection of the subsea production system as aforesaid to one of the existing systems that are related to the infrastructures of the WDDM and Temsah assets which are not owned by the Block 12 partners, and are situated in the Mediterranean Sea, close to the Egyptian coastline. Note that the continued promotion of an alternative to the approved development plan is subject to approval by the Block 12 partners and by the Cypriot government.

In accordance with the current appraisal of the operator, which was delivered to the Partnership and to the Cypriot government, and before completion of the technical-economic feasibility tests, including performance of the FEED, the estimated cost of the approved Development Plan, including the cost of installation of the pipelines to the target markets, is estimated at approx. $3.6 billion (100%).

7.3.12 Contingent and prospective resources attributed to the Block 12 petroleum asset in Cyprus

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) (in this section: the "**Resource Report**"), as of December 31, 2020 part of the natural gas and condensate resources in the Aphrodite reservoir[46] 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 attributed to the petroleum asset, in fault blocks adjacent to the fault block where the said drilling was performed, were not proven and therefore remain classified as prospective resources. The Resource Report attributed to the Block 12 petroleum asset is included in the Partnership's periodic report for 2020, as released on March 17, 2021 (Ref. no. 2021-01-036588) (the "**2020 Periodic Report**"), the information appearing therein is included herein by reference. Attached as **Annex C** to this chapter, is NSAI's consent to the inclusion of such report herein, including by way of reference, and a letter of lack of material changes from NSAI in Block 12.

Caution concerning forward-looking information – The details presented above, with respect to the possible date for adoption of a final investment decision for the Aphrodite reservoir, 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 The Yam Tethys project

7.4.1 Background

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

[46] The resource report refers to resources located in the area of the EEZ of Cyprus only.

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 project's assets serve mainly for the provision of infrastructure services to the Tamar Reservoir, in accordance with an agreement signed on July 23, 2012 between the Partnership together with the other Yam Tethys partners and the Tamar partners. In the context of a usage agreement signed between the parties, the Yam Tethys partners gave the Tamar partners rights to use the project's facilities, in consideration for a total payment of $380 million (the "**Usage Agreement**"). 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; (b) giving of notice by the Tamar Partners of permanent discontinuation of commercial production of gas from the Tamar Project; and (c) the abandonment of the Tamar Project. The Usage Agreement provides various provisions in relation to the term of use and in relation to the end of the term of use, including a mechanism for the settlement of accounts in respect of upgrades made to the facilities. [47]

In the context of the sale of the Partnership's remaining interests in the Tamar I/12 and Dalit I/13 leases (the "**Tamar and Dalit Leases**"), the Partnership assigned to the buyers its rights in the Usage Agreement as a partner in the Tamar project. As of the report approval date, all the project wells have been plugged and abandoned, according to the directives of the Petroleum Commissioner.

In view of the aforesaid, the Partnership deems the Yam Tethys project a negligible petroleum asset.

The operator began the decommissioning and abandonment of the project's facilities, other than the platform, including the production wells and the subsea equipment, in accordance with a decommissioning plan and the directives of the Petroleum Commissioner, as updated from time to time. At the same time, there is a discussion on 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. The budget for abandonment of the drilling and subsea equipment which was approved by the Yam Tethys partners, as of the report approval date, is in the sum

[47] 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.

of approx. $276 million (100%). It is noted that this budget does not include a budget for abandonment of the Yam Tethys platform and the terminal, which is scheduled to take place at the end of the production period from the Tamar Project.

It is noted that on May 3, 2020, an agreement was signed between the Partnership, Chevron, 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 (Chevron, the Partnership and Delek Group) from the Leviathan Reservoir was regulated.

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

7.4.2 General details

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:	Chevron
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 (48.50%). ▪ Chevron (47.059%). ▪ Delek Group (4.441%).

7.4.3 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, 2020 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)**[48]	**Amount of Actual Participation in the Budget by the Holders of the Equity Interests of the Partnership (Dollars in thousands)**
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	• Ongoing operation and maintenance. • Examination of uses of existing infrastructures of the project. • Refurbishment of the platform for acts of abandonment of Marri-B wells and acts associated with dismantling of subsea equipment and pipeline of the Yam Tethys project, including the receipt of environmental permits, instillation of designated facilities, etc. • Commencement of plugging and abandonment of the project's production wells, of subsea facilities, in accordance with standards and the directives of the Petroleum Commissioner.	Approx. 141,465	Approx. 68,611
2022	• Continued plugging and abandonment of the project's production wells, and of subsea facilities, in accordance with standards and the directives of the Petroleum Commissioner. • Examination of uses of existing infrastructures of the project.	Approx. 106,924	Approx. 51,858
2023 forth	• Completion of plugging and abandonment of the project's production wells and of subsea facilities, in accordance with standards and the directives of the Petroleum Commissioner.	Approx. 20,249	Approx. 9,821

[48] The amounts for 2020-2022 are amounts actually expended and were audited in the framework of the financial statements.

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)[48]**	**Amount of Actual Participation in the Budget by the Holders of the Equity Interests of the Partnership (Dollars in thousands)**
	• Examination of uses of the project's existing infrastructures. • Decommissioning and abandonment of the platform at the end of use thereof, in accordance with standards and the directives of the Petroleum Commissioner.	Approx. 109,002	Approx. 52,866
	• Decommissioning and abandonment of the onshore terminal at the end of use thereof, in accordance with standards and the directives of the Petroleum Commissioner.	Approx. 9,712	Approx. 4,710

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 Partnership with respect to the components of the work plan, which are all based on estimations received by the Partnership 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.

7.5 **Right to overriding royalties from the Tanin and Karish Leases**

7.5.1 Background

As specified below, the Partnership has rights to receive overriding 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, a foreign public company whose shares are traded on the TASE and the London Stock Exchange, which is, to the best of the Partnership's knowledge, the controlling shareholder of Energean Israel. It is further clarified that the Partnership is unable to independently corroborate the veracity of the details presented in these reports.

7.5.2 General details

Following the Government's decision to ratify the Gas Framework, on August 16, 2016, an agreement was signed between the Partnership and

Avner, and Energean Israel, for the sale of all of the interests of the Partnership, Avner and Chevron in 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 Chevron 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 details regarding the aforesaid agreement, see Section 7.24.11 below.

As of December 31, 2022, the Partnership deems the overriding royalty from the Tanin Lease and the overriding royalty from the Karish Lease as petroleum assets that are negligible to the results of the Partnership's operations and its business, after quantitative examination was conducted by the Partnership, whereby it transpires, *inter alia*, that: (a) the Partnership's share in reserves and contingent resources in the Karish Lease and the Tanin Lease constitutes, respectively, less than 1% and 2% of the total reserves and contingent resources attributed to all of the Partnership's petroleum assets; and (b) the current value of cash flows attributed to the overriding royalty in the Tanin Lease and the overriding royalty in the Karish Lease constitutes, respectively, less than 1% and 5% of the total net current value attributed to all of the Partnership's petroleum assets including reserves or contingent resources.[49] 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 –

[49] For the purpose of calculating the net current value of the cash flows from the petroleum assets, the following cap rates (after tax) were taken into account: the Leviathan Project – 10%; Aphrodite Project – 10%; overriding royalty from the Tanin and Karish Leases – 10.5% (for details see Annex B to the Board of Directors' report (Chapter B of this report) and Note 8B to the financial statements (Chapter C of this report)).

General details about the Petroleum Asset	
	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:	Energean Israel (100%).

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 holding of the petroleum asset by the Partnership:	The Partnership is entitled to royalties in 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 (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):	-

7.5.3 The development plans of the Tanin and Karish Leases and the resources attributed thereto

To the best of the Partnership's knowledge, the original development plan for the Tanin and Karish leases that was submitted to the Petroleum Commissioner by Energean Israel, was approved by the Ministry of Energy in August 2017 (in this section: the "**Original Development Plan**"), which specifies that the Karish reservoir will be developed first and the Tanin reservoir will be developed further down the line.[50]

In 2018, Energean adopted a Final Investment Decision for development of the Karish reservoir through a floating production storage facility (FPSO). On October 26, 2022, Energean reported production of first gas from the Karish reservoir and on October 28, 2022 began to sell gas to its customers. Gas production is expected to be gradual, and Energean reported that it expects to reach commercial production capabilities at the rate of 6.5 BCM per year through the FPSO within 4-6 months from the date of production of the first gas as aforesaid.[51]

According to Energean's March 2023 reports, the sales forecast for 2023 is expected to be approx. 4.5 BCM to approx. 5.5 BCM.[52]

On April 15, 2019 Energean released a notice about a natural gas discovery at the Karish North reservoir.[53] According to Energean's reports, the plan for development of the Karish North reservoir filed thereby with the Petroleum Commissioner, which is based on the FPSO of the Karish reservoir, 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.[54] To the best of the Partnership's knowledge, based on Energean's March 2023 publications, the development of the Karish North reservoir is expected to be completed at the end of 2023 and, together with the upgrade of the production systems, will enable maximum annual production of approx. 8 BCM from the FPSO.

Furthermore, to the best of the Partnership's knowledge, the current data on the resources attributed to the Tanin, Karish and Karish North reservoirs (in this section: the "**Reservoirs**"), were reported by Energean in March 2023[55]. According to this report, the Reservoirs contain natural gas

[50] https://www.gov.il/he/Departments/news/spokesperson_development.
[51] Link to Energean's notice: https://mayafiles.tase.co.il/rpdf/1483001-1484000/P1483281-00.pdf
[52] Link to Energean's notice: https://www.energean.com/media/5400/dm-final-report-energean-israel- 2022ye.pdf
[53] Link to Energean's notice: https://maya.tase.co.il/reports/details/1224643
[54] Link to Energean's notice: https://www.energean.com/media/4647/20210113-karish-north-fid.pdf
[55] Link to Energean's notice: https://www.energean.com/media/5400/dm-final-report-energean-israel-2022ye.pdf

reserves (2P) of approx. 99.6 BCM and hydrocarbon liquids of approx. 95.6 million barrels.

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

7.5.4 <u>Disputes with Energean</u>

(a) In the agreement for the sale of the rights to Energean, it was agreed that the balance of the cash consideration in the amount of \$108.5 million (the "**Balance of the Consideration**") will be paid to the sellers in 10 equal annual installments plus interest in the mechanism and at the rate determined in the agreement. By the report approval date, Energean Israel paid the Partnership 5 of the 10 annual installments.

The agreement further stipulates that once Energean obtains financing ("**Financial Closing**") for the costs of the first phase of the approved Development Plan in the Karish and Tanin leases, plus the full (100%) monetary consideration for the sale as stipulated in the sale agreement (\$148.5 million), Energean will be required to immediately pay the Balance of the Consideration. For details on a legal proceeding instituted by the Partnership against Energean in connection with the Partnership's claim that Energean is obligated to immediately pay the Balance of the Consideration, see Section 7.25.13 below.

(b) Letters have been exchanged between Energean and the Partnership regarding claims raised by Energean with respect to the Partnership's right to receive royalties from the Tanin and Karish Leases. Energean claimed that: (a) The Partnership's overriding royalty does not apply to the Karish North reservoir (as opposed to the Karish reservoir); and (b) not all hydrocarbon liquids to be produced from the Karish Lease are deemed as Condensate according to the sale agreement which is subject to the duty to pay royalties. It is the Partnership's position, based on its legal counsel, that 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 reservoirs in the area of the leases constitute Condensate, as defined in the agreement, which is subject to royalties.

Caution concerning forward-looking information – The above description regarding the activities planned in the Karish lease, including the timetables for performance thereof, 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.

7.5.5 Below is a concise description of the main activities actually carried out in the Tanin and Karish Leases between January 1, 2020 and the report approval date, and a concise description of planned activities, according to Energean's reports and to the best of the Partnership's knowledge. Since the Partnership does not bear the development and production costs in the Tanin and Karish 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:

Tanin and Karish 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)**
2020	• Finalization of completion of 3 production wells in the Karish lease. • 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).		

Tanin and Karish 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)**
	• Submission and receipt of approval of the development plan for the Karish North reservoir.		
2021	• Adoption of a FID for the development of the Karish North reservoir and for the production and installation of second export razor, and second oil train system in liquids. • Continuation of work for installation of the gas and condensate production and processing systems on the FPSO hull in Singapore.		
2022	• Completion of installation and running-in of gas and condensate production and treatment systems on the FPSO body in Singapore. • Departure of the FPSO, including its systems, to Israel. • Completion of connection of the production systems and the running-in thereof. • Commencement of commercial production from the Karish lease, current operation and maintenance. • Drilling of appraisal and development well at the Karish lease and completion of Karish North 1 drilling.		
2023 forth	• Installation of a second export razor, and installation and running-in of a second oil train system in liquids. • Continued commercial production from the Karish lease, current operation and maintenance. • Connection of the production well in Karish North reservoir to the FPSO and commencement of commercial production from the Karish North reservoir. • Drilling of additional production wells in the Karish Lease and Karish North reservoir, insofar as required.		

Tanin and Karish 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)**
	• Development of the Tanin lease, 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 lease is expected, according to the publications of Energean, in 2030.		

7.6 The Boujdour Atlantique exploration license situated in the Atlantic Ocean off the Moroccan coast (the "Boujdour License")

7.6.1 Background

On December 6, 2022, the Partnership, jointly with Adarco Energy Limited[56] ("**Adarco**"), signed agreements concerning oil and natural gas exploration and production activities in the Boujdour Atlantique exploration license, which is situated in the Atlantic Ocean off the coast of Morocco (in this section: the "**Petroleum Asset**" or the "**License**"),[57] with the National Office of Hydrocarbons and Mines of Morocco (Office National des Hydrocarbures et des Mines, "**ONHYM**") (in this section: the "**Agreements**"). The Agreements confer, *inter alia*, on each of the Partnership and Adarco 37.5% of the interests in the License, with the remaining interests in the License, the rate of which is 25%, granted to ONHYM, in accordance with standard regulation in Morocco. On January 29, 2023, Delek Energy Limited, a wholly-owned subsidiary of the Partnership that was incorporated in England ("**NewMed Morocco**"), signed the Agreements in lieu of the Partnership and stepped into its shoes.

The Agreements further grant the Partnership, Adarco and ONHYM the right to search for hydrocarbons in the area of the License for a term of 8

[56] As the Partnership was informed by Adarco, Adarco is a private company all of whose shares are (indirectly) held for Mr. Yariv Elbaz (a Moroccan investor) and his family members.
[57] The license includes 17 different license areas.

years, subject to compliance with a work plan, which may be extended in the event of discovery.

The Partnership shall act as the operator of the License

During the exploration period, the Partnership and Adarco shall bear, in addition to their relative share of the costs, the costs in respect of ONHYM's share, in accordance with the regulation in Morocco. Furthermore, the agreements with ONHYM include additional provisions, *inter alia*, with respect to bonuses that are paid to ONHYM according to accomplishment of milestones of output from the License, royalties to the State of Morocco, fines in the event of noncompliance with obligations under the agreements, guarantees, stability in respect of economic terms, obligations of professional training in the domestic market, as well as provisions pertaining to the joint operation of the License.

On January 2, 2023, the general meeting of the Unit holders approved the Partnership's engagement in the Agreements, which is also contingent on receipt of approval from the Ministry of Energy and Sustainable Development and the Ministry of Finance of Morocco.

Note that the License is located off the coast of Western Sahara, an area whose sovereignty is in dispute. In December 2020, a normalization agreement was signed between Israel and Morocco, under which, *inter alia*, Israel and the United States recognized Morocco’s sovereignty over Western Sahara.

Assuming that the agreements are approved by Morocco’s Ministry of Energy and Ministry of Finance and take effect, the License will be a negligible petroleum asset relative to the Partnership’s total operations and assets, and therefore a limited description thereof is presented below. The following details with respect to the Petroleum Asset relate to the rate of the Partnership’s holdings in the Petroleum Asset through NewMed Morocco.

7.6.2 General Details

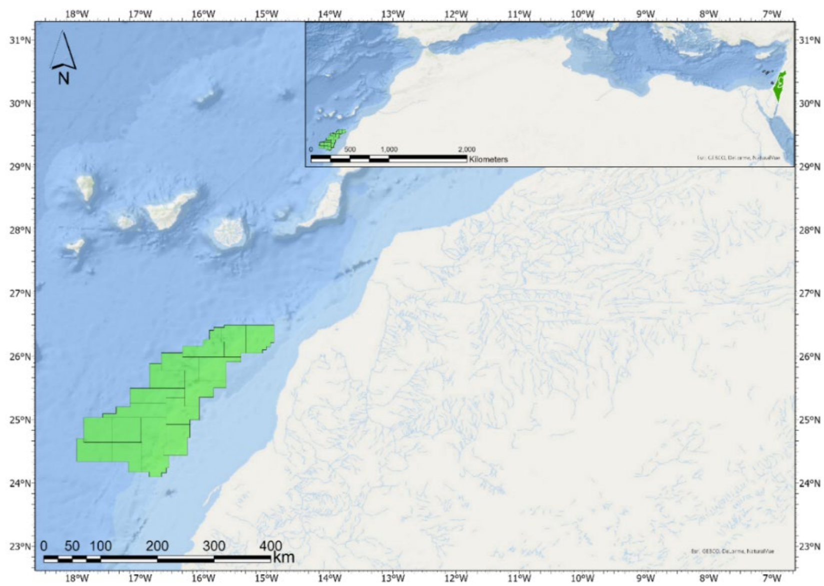
General Details with respect to the Petroleum Asset	
Name of the Petroleum Asset:	Boujdour Atlantique.
Location:	Offshore area in the south of the Moroccan exclusive economic zone (for a map of the Petroleum Asset, see below).
Area:	Approx. 33,812 km^2.

General Details with respect to the Petroleum Asset	
Type of the Petroleum Asset and description of the permitted activities according to such type:	Exploration and production license.
Original grant date of the Petroleum Asset:	According to the decision of the Ministry of Energy and Sustainable Development and the Ministry of Finance of Morocco.
Original expiration date of the Petroleum Asset:	According to the decision of the Ministry of Energy and Sustainable Development and the Ministry of Finance of Morocco.
Dates on which it was decided to extend the term of the Petroleum Asset:	-
Current expiration date of the Petroleum Asset:	The Agreements grant the right to conduct exploration for oil and/or natural gas in the area of the block for a term of 8 years in total – Initial term – 2.5 years; First extension (subject to the Partnership's decision and subject to commitment to the second term work plan) – 2 years; Second extension (subject to the Partnership's decision and subject to commitment to the third term work plan) – 3.5 years;
Note whether there is another possibility for extension of the term of the Petroleum Asset; if such possibility exists – note the possible term of extension:	Possibility of extension in a case where hydrocarbons are found and an examination of economic viability is required.
Note the name of the operator:	The Partnership.
Note the names of direct partners in the Petroleum Asset and their direct shares in the Petroleum Asset, and also, to the best of the Partnership's knowledge, the names of the control holders of such partners:	The Partnership – 37.5%. Adarco – 37.5%. ONHYM – 25%.

General Details with respect to the Partnership's Share in the Petroleum Asset	
For a holding in a petroleum asset that has been acquired – the acquisition date:	-
Description of the nature and manner of holding of the Petroleum Asset by the Partnership:	The Partnership, through NewMed Morocco, shall hold 37.5% of the interests in the License.
Note the actual share of the revenues from the Petroleum Asset attributed to the holders of the Partnership's equity interests:[58]	Pre investment recovery date – 34.5%. Post investment recovery date – 32.63%.

[58] The Partnership's interests in the petroleum asset are subject to royalties paid to the state. According to the local regulation in Morocco, the royalty amount depends on the water depth in the well and on the findings (gas or oil). Where the water depth in the well exceeds 200 meters, in the case of an oil discovery, royalties at the rate of 7% per annum will be paid. On the other hand, in the case of a **gas** discovery at the said depth or deeper, a royalty at the rate of 3.5% will be paid. The obligation to pay the royalty applies in relation to quantities exceeding 500,000 tons of oil or 0.5 BCM of natural gas. The figures in the table above were calculated assuming a gas discovery (i.e., a

General Details with respect to the Partnership's Share in the Petroleum Asset	
Total share of the holders of the Partnership's equity interests in the aggregate investment in the Petroleum Asset during the five years preceding the last day of the reporting year (regardless of whether recognized as an expense or as an asset in the financial statements):	-



7.6.3 Actual and Planned Work Plan for the Petroleum Asset

Following is a concise description of actual and planned activities, noting the estimated budget for the conduct of each activity and the share of the holders of the Partnership's equity interests in such budget:

royalty at the rate of 3.5%). It is further noted that according to Moroccan regulation, an exemption from corporate tax applies for a period of 10 years after commencement of production, after which corporate tax is paid at the rate of 31% (in both gas discoveries and oil discoveries).

Boujdour License			
Term	**Concise Description of Activities Actually Carried Out for the Term or of the Planned Work Plan**	**Estimated Total Budget for the Activity at the Petroleum Asset Level ($ in thousands)**	**Amount of Actual Participation in the Budget by the Holders of the Partnership's Equity Interests ($ in thousands)**
30 months from the License grant date	Geological and geophysical analysis of the License, including re-processing of seismic data and work pertaining to environment, social and government ("**ESG**") aspects.	Approx. 3,300	Approx. 3,300
First extension – 24 months from the lapse of the first term	Drilling of first exploration well.	Approx. 25,000	Approx. 12,500
Second extension – 42 months from the lapse of the second term	Drilling of exploration/appraisal well.	Approx. 25,000	Approx. 12,500

Caution regarding forward-looking information – The information about the planned activities in the License, including with respect to the costs, timetables and mere performance thereof, constitutes forward-looking information within the meaning thereof in the Securities Law, which is based on the information held by the Partnership on the report approval date, and includes assessments and estimations by the Partnership as of the report approval date. The actual execution of the work plan, including the timetables and the costs, may materially differ from the information specified above, and this is contingent, *inter alia*, on market conditions, regulation, numerous external circumstances, including technical needs, technical ability, new findings to be discovered and economic viability. The closing of the transaction is subject to approval from the Ministry of Energy and Sustainable Development and the Ministry of Finance of Morocco, as specified above.

7.7 Discontinued operations

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

7.7.1 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 which held approx. 22.67% of the interests in the license) 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 the 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. Groins, 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 (proportionately to their license holding rate). On April 11, 2019, a judgment was entered on the mediation arrangement agreed to by the parties, as aforesaid. Negotiations were held between the Tamar Partners and the State of Israel and the partners in the Eran License, regarding the regulation of the State's rights in additional related matters, but as of the report approval date, the parties have not yet reached agreements on how to implement the mediation arrangement, as specified above.

7.7.2 **Alon D license**

The Alon D license expired on June 21, 2020, after applications for the extension thereof have been denied by the Petroleum Commissioner.

See Section 7.25.10 below for details regarding a petition to the Supreme Court sitting as the High Court of Justice, in connection with the non-extension of the license.

Against the background of the expiration of the Alon D license, the Partnership and Chevron, which were the partners in the 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 Alon D license extended ("**Block 72**").

Following the aforesaid, 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.

As of the report approval date, the winner of the competitive process regarding Block 72 has not yet been declared and in view of Government Resolution no. 1906, as specified below, the Partnership estimates that this process may be terminated without a winner being declared in the context thereof. 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 knowledge, on the same day the Petroleum Commissioner delivered a request to the Concentration Committee to hold another consultation on the matter. In addition, to the best of the Partnership's knowledge, its offer (together with Chevron) is superior to other offers submitted in the process, considering the conditions that were determined therein in advance. Therefore, the Partnership believes that it has the full right to win the License.

On October 27, 2022, Government Resolution no. 1906, ratifying the agreement for regulation of the maritime border between Israel and Lebanon (the "**Maritime Agreement**"), was published. Simultaneously, the Maritime Agreement was signed by the Israeli Prime Minister and the President of Lebanon. The Maritime Agreement determines, *inter alia*, the maritime border between the countries, and that the status quo along the coast, including along the existing buoy line, shall be maintained as is. The Maritime Agreement further determines that if a natural gas reservoir is discovered which crosses the borderline as determined, the development thereof and production therefrom will be carried out by the holders of the interests in Block 9 in Lebanon which borders on Block 72.[59]

Further, on November 14, 2022, a memorandum of understandings was signed between the State of Israel, the French energy company Total Energies, and the Italian energy company ENI (the consortium holding the license to develop Block 9 in Lebanon, which borders Block 72). According to the announcement of the Ministry of Energy, the objective of the MOU is to ensure that the potential reserve between the countries will not be developed without protection of Israel's economic rights. The MOU does not determine the financial consideration that Israel will be entitled to receive from the reserve.[60] Further, the area of the potential reserve is partially included in the area of the Alon D license that was formerly held by the Partnership and Chevron, which filed a petition with the High Court of Justice in connection with the expiration of the interests therein, as specified in Section 7.25.10 below.

[59] https://www.gov.il/he/departments/policies/dec1906-2022

[60] https://www.gov.il/he/departments/news/press_151122

7.7.3 Tamar Project (Tamar Lease (I/12) and Dalit Lease (I/13))

On December 9, 2021, the transaction for the sale of the Partnership's remaining interests in the Tamar and Dalit Leases was closed. In accordance with the sale agreement, as specified in Section 7.24.13 below, and as of the report approval date, the sale consideration was transferred by the buyers in the sum of approx. $969 million. Following the closing of the transaction, liens that were created to secure the bonds of Tamar Bond were removed, and funds accumulated in pledged accounts in the amount of approx. $170 million were released.[61] The Partnership also received back various guarantees that it was required to provide as part of the Tamar project in the total amount of approx. ILS 60 million.

The sale proceeds together with the funds released as part of the closing of the transaction, served the Partnership, *inter alia*, for repayment of the bonds of Tamar Bond and Series A bonds of the Partnership. The Partnership also paid capital gain tax on the aforesaid sale in the amount of approx. NIS 478 million.

For further details regarding the closing of the transaction, see the Partnership's immediate reports dated December 6, 2021 and December 9, 2021 (Ref. no.: 2021-01-176682 and 2021-01-178137, respectively), the information in which is incorporated herein by reference. Also, see Notes 7C1 and 10E to the financial statements (Chapter C hereof).

7.7.4 New Ofek and New Yahel licenses

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 in central Israel, and in the onshore 406/New Yahel license (the "**New Yahel License**"), which is situated in the north of Israel (in this section: the "**Purchase Agreement**"). Upon fulfillment of the conditions precedent in the Purchase Agreement, on October 10, 2019 the aforesaid transaction for the purchase of the interests was closed and on November 5, 2019 the transfer of the interests as aforesaid was recorded in the Petroleum Register. For additional details with respect to the Purchase Agreement, see Section 7.24.10 below. The New Ofek and New Yahel licenses were classified by the Partnership as

[61] It is noted that the amount does not include (net) income of the Partnership in respect of sales from the Tamar project made in November 2021, for which payment was transferred to the Partnership after the closing of the transaction.

negligible petroleum assets compared with all of the Partnership's operations and assets.

For details on the activity performed in the context of the aforesaid licenses, see Sections 7.4 and 7.5 of the Partnership's 2021 periodic report (the "**2021 Periodic Report**"), as released on March 24, 2022 (Ref.: 2022-01-033988), the information in which is incorporated herein by reference.

On May 22, 2022, the Partnership notified the other holders of interests in the New Ofek License that it will no longer agree to bear any additional expenses in relation to the work in the Ofek-2 well, other than expenses connected to the plug and abandon of the well, and that it does not intend to support any proposal to extend the license period toward the license expiration date which was on June 20, 2022.

The New Ofek and New Yahel licenses expired on June 20, 2022, and the Partnership did not join the operator of the licenses in its application to the Petroleum Commissioner at the Ministry of Energy to extend them. To the best of the Partnership's knowledge, the Petroleum Commissioner's answer to the aforesaid extension application has not yet been received. Accordingly, the costs of investment in the New Ofek and New Yahel licenses were reduced in the Partnership's financial statements effective from Q1/2022. For further details, see Note 7C7 to the financial statements (Chapter C of this report).

On June 21, 2022, Globe Energy Resources (Y.C.D.), Limited Partnership, reported that the production tests ended and the operator in the New Ofek license began to perform acts for the permanent abandonment of the well.

To the best of the Partnership's knowledge, as it was informed by the operator, actions for abandonment of the well and the site in the New Ofek license are expected to be completed during Q2/2023.

7.8 **<u>Renewable energies</u>**

On March 13, 2023, the Partnership engaged with Enlight in a detailed agreement regarding exclusive collaboration for a fixed term regarding the identification, initiation, development, financing, construction and operation of renewable energy projects, including in the following areas: solar projects, wind projects, energy storage, and other renewable energy segments, if they will be relevant in several target countries, including Egypt, Jordan, Morocco, the UAE, Bahrain, Oman and Saudi Arabia (in this section: the "**Agreement**" and the "**Transaction**", respectively). As specified below, under the Transaction, Enlight will allocate a certain part of its interests in the Transaction to Mr. Yossi Abu, CEO of the General Partner (“**Mr. Abu**”). Accordingly, on March 13, 2023, an agreement was signed between Mr. Abu and Enlight (the "**Abu Agreement**").

Below is a concise description of the main parts of the Agreement:

(a) The parties will act together, on an exclusive basis for a fixed term, for the identification, initiation, development, financing, construction and operation of renewable energy projects in the aforementioned target countries (in this section: the “**Joint Venture**”). For the purpose of the Joint Venture, the parties will form corporations that will engage in the promotion of the joint operations (the “**Co-Owned Corporations**”). The rate of the Partnership’s holdings in the Co-Owned Corporations will be 33.33%, with the remaining interests in the Co-Owned Corporations (66.67%) held by a corporation that will be held by Enlight (70%) and Mr. Abu (30%) (the “**Enlight Corporation**”). According to the Abu Agreement, Mr. Abu’s share in the investments required in the Enlight Corporation will be provided for his benefit by Enlight by way of providing a non-recourse loan.

(b) As part of the Joint Venture, the Partnership will utilize its business connections in the aforementioned target countries to promote the Joint Venture, with Mr. Abu’s active personal involvement. The Enlight Corporation, via Enlight, will provide the joint operations with professional design, development and management services in the interest of promoting the Joint Venture.

(c) Control during the projects' construction and operation stages will be held by Enlight. The agreement stipulates provisions with respect to the parties’ rights to appoint board members of the Co-Owned Corporations based on their holding rates, and it also stipulates that Mr. Abu will serve as chairman of the board of the Co-Owned Corporations in the first 24 months.

(d) In the context of the Joint Venture, one of the Co-Owned Corporations will perform feasibility studies and due diligence for any project it deems suitable for the collaboration and thereafter, each party will notify the other party whether it wishes to participate and promote the proposed project in the context of the Joint Venture. If the Partnership does not approve its participation in a specific project or objects to its promotion, Enlight will be entitled to perform the project independently, without the Partnership, in which case the Partnership will be entitled to reimbursement of its expenses in the aforesaid project together with interest.

(e) In the Agreement it has been agreed that resolutions of the Co-Owned Corporations will be adopted by a majority vote, subject to the requirement of the Partnership's consent in certain resolutions, so long as the Partnership holds 15% or more of the capital of the Co-Owned Corporations. Provisions have also been specified with respect to the manner of financing of the operations of the Joint Venture and the investments in projects to be made thereunder, based on the relative share of each of the parties.

(f) The term of the parties' exclusive collaboration will be 3 years from the Agreement signing date, which, under certain circumstances, may be extended up to a term of five years from the Agreement signing date (the "**Term of Exclusivity**"). Following the expiration of the Term of Exclusivity, the collaboration will continue with respect to projects that shall have commenced prior to the expiration date, and Enlight may promote projects that are in advanced development stages without the Partnership's participation.

(g) The Agreement specifies additional provisions on other matters, as is standard in transactions of this type, *inter alia*, with respect to resolutions requiring the Partnership's consent, so long as the Partnership holds 15% or more of the equity of the Co-Owned Corporations, provisions on the restrictions that will apply to the transfer of interests in the Co-Owned Corporations to third parties, early termination of the Term of Exclusivity, provisions regarding the joining of third parties to the projects and provisions regarding the Co-Owned Corporations' profit distribution policy.

On September 21, 2022, the general meeting of the Unit holders gave approval to the Partnership to make investments in renewable energy projects, up to the aggregate investment amount (the Partnership's share only) of $100 million (by capital and/or by shareholder's loan including a capital note and/or by way of guarantee in respect of loans to be provided), as required by TASE Rules, and in such context, approved the outline of the Transaction with Enlight, while noting, *inter alia*, Mr. Abu's personal interest in the Transaction. For further details see the Partnership's immediate reports dated September 6, 2022 and September 21, 2022 (Ref. 2022-01-092520 and 2022-01-120358, respectively), the information appearing in which is included herein by reference.

As of the report approval date, the parties are working on identifying opportunities to make investments in renewable energy projects in the context of the collaboration.

7.9 **Products**

7.9.1 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 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.

LNG and CNG may be transported in large quantities over great distances by means of specifically-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 7.11.2 below.

7.9.2 Condensate

The process of production and treatment of natural gas also produces condensate, which is a product of condensation of various hydrocarbon components of natural gas. Condensation is caused as a result of temperature and pressure differences between the reservoir and the gas processing systems. The condensate produced from the Leviathan project requires minimal treatment, and mainly stabilization, to enable transportation thereof to the customers, where it mainly serves as feedstock for the production of refined oil products. The amount of condensate produced compared with the quantity of gas produced from the Leviathan project is relatively small, and is a few barrels per million cubic feet of natural gas (MMCF). For details regarding the engagements of the Partnership, together with its partners, in agreements in relation to the supply of condensate from the Leviathan project, see Section 7.10.4 below.

7.10 **Customers**

7.10.1 General

As of the report approval date, the Partnership, together with its partners in the Leviathan project, supplies natural gas produced from the Leviathan reservoir, to independent power producers, marketing companies and industrial customers in the domestic market, and exports natural gas to customers in Jordan and in Egypt. At the same time, the Partnership continues to conduct various stages of negotiations with other potential customers in the domestic market and in the export markets.

7.10.2 Key customers

In 2022, NEPCO in Jordan and Blue Ocean in Egypt were the largest customers of the Leviathan reservoir. The Partnership's revenues from the sale of gas from the Leviathan project in 2022 to NEPCO and Blue Ocean were approx. 28% and 47%, respectively, of the Partnership's total revenues from the Leviathan project. The agreements signed between the Leviathan Partners and NEPCO and Blue Ocean are long-term agreements and termination or non-performance of the agreements may materially affect the Partnership's business and future revenues. The Partnership's other revenues from the Leviathan reservoir in 2022 originated from independent power producers, industrial customers and natural gas marketing companies.

7.10.3 Engagements for the supply of natural gas from the Leviathan project

Below are concise details regarding the agreements for the supply of natural gas from the Leviathan project which were signed by the Partnership, together with the other Leviathan Partners, that are valid as of the report approval date[62].

[62] Note that the figures in the table do not include agreements for the supply of natural gas from the Leviathan project on an interruptible basis, and agreements whose closing conditions were not met as specified below. In such context, note that September 7, 2022 saw the expiration of an agreement for supply of natural gas from the Leviathan project to OR Power Energies (Dalia) Ltd. ("**OR Energies**"), signed between the Leviathan partners and OR Energies on November 30, 2016, with the parties' consent and in accordance with the terms and conditions of the aforesaid agreement, in view of non-fulfillment of the closing conditions in such agreement. In addition, November 14, 2022, saw the expiration of an agreement for supply of natural gas from the Leviathan project to Edeltech Ltd. ("**Edeltech**"), signed between the Leviathan partners and Edeltech on January 30, 2016, with the parties' consent and according to the terms and conditions of the agreement as aforesaid, in view of non-fulfillment of the closing

Customer	Supply commencement year	Agreement period[63]	Total maximum contract quantity for supply (100%) (BCM)	Quantity supplied until December 31, 2022 (100%) (BCM)	Main linkage basis of the gas price
Independent power producers	2020, or the date of commencement of the commercial operation of the purchasers' power plant (whichever is later).	The agreements are for a long term of 9 to 25 years. Some of the agreements grant each of the parties an option for extension of the agreement in the event that the total quantity determined in the agreement is not purchased.	Approx. 24	Approx. 6	In most of the agreements the linkage formula of the gas price is based on the Electricity Production Tariff and includes a "floor price". One of the agreements determines a fixed price without linkage.
Industrial customers	2020	The agreements are for a period of 2.5 to 15 years.[64] In most of the agreements the parties are not granted an option to extend the agreement period.	Approx. 5	Approx. 1.4	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. Several agreements determine a fixed price without linkage.
NEPCO export agreement (described in Subsection (d) below)	2020	15 years. The agreement stipulates that in the event that the purchaser does not buy the total contract quantity, the supply period will be extended by another two years.	Approx. 45	Approx. 7.3	The linkage formula is based on linkage to the Brent prices and includes a "floor price".
Blue Ocean export agreement (described in	2020	15 years. The agreement stipulates that in the	Approx. 60	Approx. 10.2	The linkage formula is based on linkage to the Brent prices, and includes a "floor price".

conditions in such agreement. It is further noted that the figures in the table include short-term bridging agreements, signed due to the delay in the date of commencement of production of gas from the Karish lease, which are expected to come to an end by the end of Q1/2023 (the "**Bridging Agreements for Energean's Customers**").

[63] In the majority of the agreements, the gas supply period may end on the date of supply to the customers of the maximum contract quantity set forth in the agreement.

[64] One of the agreements which expires at the end of March 2023, which includes a non-material quantity, is an agreement for a period of less than one year.

Customer	Supply commencement year	Agreement period[63]	Total maximum contract quantity for supply (100%) (BCM)	Quantity supplied until December 31, 2022 (100%) (BCM)	Main linkage basis of the gas price
Subsection (e) below)		event that the purchaser does not buy the total contract quantity, the period of the supply will be extended by another two years.			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. 133**	**Approx. 25**[65]	

Caution regarding forward-looking information – the information specified in the table above in relation to the overall financial scope of the supply agreements, natural gas quantities and supply periods, 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 and which may materialize in a materially different manner, due to different factors that are beyond the Partnership's control, including changes in the scope, rate and timing of consumption of natural gas by the gas consumers, exercise of options granted to customers in the supply agreements and the date of exercise thereof, and additional factors that are beyond the control of the Leviathan Partners.

<u>The following table includes a breakdown of the Partnership's revenues from the Leviathan reservoir in 2021-2022</u>:

	Year 2022		**Year 2021**	
Name of Customer	**Total Revenues ($ in million)**	**% of Total Revenues**	**Total Revenues ($ in million)**	**% of Total Revenues**
Independent Power Producers				
Other	Approx. 217	Approx. 19	Approx. 283	Approx. 32
Industrial Customers and Marketing Companies				
Other	Approx. 69	Approx. 6	Approx. 39	Approx. 4

[65] It is noted that the quantity supplied from the Leviathan project until December 31, 2022 (100%) (under the agreements specified in the table, under SPOT agreements and under agreements that have expired) totals approx. 29 BCM.

	Year 2022		Year 2021	
Name of Customer	**Total Revenues ($ in million)**	**% of Total Revenues**	**Total Revenues ($ in million)**	**% of Total Revenues**
Natural Gas Export				
NEPCO	Approx. 325	Approx. 28	Approx. 264	Approx. 30
Blue Ocean	Approx. 533	Approx. 47	Approx. 298	Approx. 34

(a) Further details regarding the agreements for the sale of natural gas from the Leviathan reservoir to independent power producers and industrial customers in the domestic market

1. In all of the agreements for sale of natural gas to independent power producers and industrial customers (in this section: the "**Agreements**"), the customers have undertaken to buy or pay for ("Take or Pay") a minimal annual quantity of natural gas at the scope and according to the mechanism determined in the supply agreement (the "**Minimum Quantity**"). It is noted that provisions and mechanisms have been established in the Agreements to allow each of such buyers, after it pays for natural gas not consumed thereby under the Agreement by operation of the aforesaid Minimum Quantity mechanism, to receive gas for no additional payment, up to the unconsumed quantity of gas for which it paid, in the years subsequent to the year in which the payment was made. The Agreements further establish a mechanism for accrual of a balance in respect of surplus quantities (over and above the "Take or Pay") consumed by the buyers in any given year and use thereof to reduce the buyers' obligation to purchase the Minimum Quantity as aforesaid for several years later.

2. The Agreements provide for additional provisions, *inter alia*, on the following issues: The right to terminate the Agreement in the case of breach of a material undertaking, the Leviathan Partners' right to supply gas to the said buyers from other natural gas sources, compensation mechanisms in the case of failure to supply 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 amongst themselves with respect to the supply of gas to the said buyers.

3. In accordance with the terms and conditions of the Gas Framework, each of the buyers under Agreements signed by June 13, 2017 for a term 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 option exercise notice, subject to adjustments as determined in the supply agreement. Upon reduction of the Minimum Quantity, the other quantities determined in the supply agreement will be reduced accordingly. Each of the said buyers may exercise such option by giving the sellers a notice during the 3-year period commencing 5 years after the date of commencement of the piping of the gas from the Leviathan project to the buyer. If the

buyer gives such option exercise notice, the quantity shall be reduced 12 months after the date of the giving of the notice.

(b) <u>Agreement for export of gas from the Leviathan reservoir to NEPCO in Jordan</u>

1. On September 26, 2016, an 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 to Jordan 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 to Jordan 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 to Jordan Agreement began on January 1, 2020.

   The gas delivery point according to the Export to Jordan Agreement is at the connection between the Israeli transmission system and the Jordanian transmission system at the border between Israel and Jordan. 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. $121 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 to Jordan 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. $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.

2. 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 to Jordan 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 to Jordan Agreement instead of the Marketing Company.

On April 14, 2020, an Offtake Intercreditor and Security Trust Deed was signed between the Marketing Company, the Leviathan Partners and HSBC Corporate 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 to Jordan Agreement.

Caution regarding forward-looking information – the information specified above regarding the total financial scope of the engagement for supply of natural gas to NEPCO and the quantity of natural gas that may be purchased under such engagement, 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 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.

(c) Agreement for export of gas from the Leviathan reservoir to Blue Ocean in Egypt

1. Further to previous engagements with Blue Ocean, on September 26, 2019, an agreement for supply of natural gas to Egypt was signed between the Leviathan Partners and Blue Ocean (the "**Export to Egypt Agreement**"), and at the same time, an agreement was signed between the Leviathan Partners and the Tamar Partners in connection with the allocation of the available capacity in the Israel to Egypt transmission system (for further details, see Section 7.24.6(d) below). The supply of natural gas to Egypt from the Leviathan reservoir according to the agreement began on January 15, 2020.

2. It is noted that in a tax decision 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 years after the date of

the signing of the tax decision, i.e. until December 9, 2022, to enter into agreements for the sale of natural gas at a price that shall be calculated according to the formula determined in Export to Egypt 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 determined in the Export to Egypt Agreement.

3. Below is a concise description of the main parts of the terms and conditions of the Export to Egypt Agreement:

   (a) The total contract gas quantity the Leviathan Partners undertook to supply the buyer, on a firm basis, is approx. 60 BCM (the "**Total Contract Quantity**").

   (b) The gas supply, which began on January 15, 2020, will continue until December 31, 2034 or until the supply of the full total contract quantity, whichever is earlier (the "**Supply Period**"). 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) The Leviathan Partners undertook to supply the Buyer with annual gas quantities as follows: (a) in the period that began January 15, 2020 and ended June 30, 2020 – approx. 2.1 BCM per year; (b) in the period that began July 1, 2020 and ended on June 30, 2022 – approx. 3.6 BCM per year, through a compressor that was installed at the EMG terminal in Ashkelon; and (c) in the period which commenced on July 1, 2022 and ending upon the conclusion of the Supply Period – approx. 4.7 BCM per year. It is noted that such increase of supply will be made by means of upgrading the systems at the EMG terminal in Ashkelon, including the installation of another compressor (the "**Additional Compressor**"), and by means of increasing the transmission capacity in the INGL system and/or piping natural gas from Israel to Egypt through Jordan, as specified in Section 7.11.2(e) below.

   (d) The buyer undertook to buy or pay for (Take or Pay, TOP) quarterly and annual quantities, in accordance with the mechanisms set forth in the Export to Egypt 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. Insofar as the contract quantity is reduced in case of failure to agree on the gas price update, as stated in Subsection (e) below, the buyer's aforesaid right to reduce the TOP quantity will be revoked. In this context, it is noted that following the steep drop in energy prices in H1/2020, the average daily Brent price (as defined in the agreement) at such time fell below $50 per barrel.[66] However, as of H2/2020, the average daily Brent price (as defined in the agreement) increased, and as of the report approval date, the Brent barrel price is approx. $75.

(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 Export to Egypt Agreement includes a mechanism for a price update of up to 10% (up or down) after the fifth year and after the tenth year of the agreement, upon fulfillment of certain conditions which were specified 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 Export to Egypt Agreement includes standard provisions pertaining to termination thereof, as well as provisions in case of termination of the export agreement signed between the Tamar Partners and Blue Ocean as a result of breach thereof, and the lack of consent of the Leviathan Partners to additionally supply the quantities under the aforesaid Tamar agreement, and also includes compensation mechanisms in such a case.

4. By December 31, 2022, the Leviathan Partners supplied the buyer approx. 10.2 BCM for the total monetary consideration of approx. $2,150 million. At the date of signing of the Export to Egypt Agreement, the Partnership estimated that the aggregate amount of the contract (with respect to all of the Leviathan Partners) may total approx. $12.5 billion. Such estimate is based, *inter alia*, on the assumption that the buyer would consume the Total Contract Quantity set forth in the agreement, as well as on various estimates regarding the prices of natural gas during the Supply Period. It is emphasized that

[66] For details regarding an action and a motion for certification thereof as a class action, filed against the Partnership in connection with the said clause, see Section 7.25.8 below, and for details regarding the administrative inquiry conducted by the Israel Securities Authority (ISA) in this matter, see Section 7.25.9 below.

the actual revenues will be derived from a gamut of factors, the majority of which are beyond the Partnership's control.

5. It is noted that, as part of the series of agreements, as specified in Section 7.11.2(e) below, the Leviathan Partners and Blue Ocean signed an amendment to the Egypt Export Agreement, in which agreements were reached, *inter alia*, on defining the delivery point in Aqaba, Jordan, as an additional point of delivery under the Egypt Export Agreement, and on adjustments to the price of the natural gas to be supplied at the additional point of delivery as aforesaid, in accordance with the additional costs entailed by the transmission of the gas from the additional point of delivery, to be borne by Blue Ocean.

   It was also agreed in the framework of said amendment that the calculation of the quantities made available by the Leviathan Partners to Blue Ocean shall be performed in 2022 on an annual average basis, such that at the end of the year the parties will review the average gas quantities supplied, including on a Spot basis, during the year, such that oversupplied quantities shall be offset against the quantities of gas nominated by Blue Ocean but not supplied thereto during such period.

Caution regarding forward-looking information – the above information regarding the amount of projected revenues under the Export to Egypt Agreement, and the natural gas quantities that may be sold to the Buyer, is based on various estimations, forecasts and assumptions made by the Partnership. These estimations 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 that are beyond the Partnership's control, 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 terms and conditions of the engagement and other factors that are not foreseeable on the report approval date and over which the Partnership has no control.

7.10.4 <u>Agreements for the supply of condensate from the Leviathan reservoir</u>

(a) <u>General</u>

As described in Section 7.9.2 above, condensate is a hydrocarbon liquid which is produced as a result of natural gas condensation. Since condensate is a byproduct of the production and processing of natural gas, the processes of production of the natural gas from the Leviathan reservoir require stabilization of the condensate and its transfer to shore.

(b) Agreement with ORL

On December 15, 2019, an agreement was signed whereby condensate produced from the Leviathan reservoir will be piped via EAPC's existing fuel pipeline to a container site of PEI in Kiryat Haim, and then piped from there to ORL's facilities, *inter alia*, according to regulatory directives.

The agreement signed with ORL is on an interruptible basis, for a term of 15 years from the date of commencement of condensate piping in commercial quantities, with each party having the right to terminate the agreement by giving notice, no less than 360 days in advance, to the other party. In addition, each party may terminate the 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 agreement.

The piping of condensate to ORL shall be made as aforesaid on an interruptible basis, up to a maximum quantity that was agreed by the parties. The parties may update the maximum quantity from time to time, subject to compliance with the terms determined by the authorities in this respect, including the Ministry of Energy and the Ministry of Environmental Protection.

Pursuant to the agreement, the Leviathan Partners are not entitled to consideration for the supply of condensate to ORL, and the Leviathan Partners are obligated to bear any and all expenses, including the tax exposures, with respect to the condensate supply.

As part of correspondence between the Leviathan Partners and ORL in Q1/2022, the Leviathan Partners communicated to ORL their claim that the absence of payment for the condensate supplied to ORL as noted above, constitutes prohibited abuse, in violation of the law, of ORL's power as a monopsony in the purchase of condensate. In such communication, the Leviathan Partners invited ORL to commence discussions for the purpose of remedying the aforesaid breach immediately and retroactively. ORL replied with a letter that rejected the claims of the Leviathan Partners, whereas the Leviathan Partners reiterated their position whereby ORL's failure to pay for the condensate supplied thereto, as noted, constitutes a violation of the law that inflicts material damage on the Leviathan Partners. As of the report approval date, the Leviathan Partners are considering legal action against ORL. Note that further to the signing of the agreement with PAR (as defined below), ORL sent a letter to the Leviathan partners whereby the engagement with PAR constitutes a breach of the agreement with ORL, an anticipated breach of the agreement and conduct in bad faith. The Partnership's position is that ORL's aforesaid claims are unfounded.

(c) Agreement with PEI

On September 1, 2022, Chevron and PEI signed an agreement designed to regulate an alternative mechanism for the piping of condensate from the Leviathan project through an existing 6” pipe of PEI and the systems related thereto (in this section: the "**Pipe**"). Below is a concise description of main parts of the agreement:

1. The agreement will take effect on the date of fulfillment of the closing conditions specified therein (the “**Effective Date**"), and the piping of the condensate through the Pipe will begin on the date of fulfillment of several additional conditions, as specified below (in this section: the "**Piping Commencement Date**"). The agreement will be valid for 20 years from the Piping Commencement Date. The Partnership estimates that the Piping Commencement Date is expected to fall in Q4/2023, subject to the fulfillment of the closing conditions in the Transmission Agreement.

2. PEI will be responsible for planning and carrying out the work for connection and adjustment of the Pipe for the purpose of transmission of the condensate as aforesaid (the “**Connection Work**"). PEI will be responsible for obtaining all the approvals for the piping of condensate through the Pipe and for the ongoing operation and maintenance of the Pipe.

3. In accordance with the agreement, Chevron (through the Leviathan partners, per their share in the Leviathan leases) will bear the costs associated with the Connection Work in accordance with the scope and mechanism stipulated in the Agreement, in amounts agreed upon by the parties in advance, and which are not material to the Partnership.

4. The agreement will take effect upon fulfillment of the following closing conditions: (a) receipt of the regulatory approvals specified in the agreement; (b) signing and taking effect of an agreement for the sale of condensate (which, as provided in Subsection (e), was signed with PAR on January 18, 2023); and (c) Chevron's approval of PEI's plan to implement the recommendations of a report prepared by an external professional consultant who examined the suitability of the

Pipe for the provision of the transmission services contemplated in the agreement.

5. The Piping Commencement Date will be upon completion of the Connection Work and receipt of the required approvals for the transmit of the condensate through the Pipe.

6. Each of the parties may terminate the agreement if the closing conditions are not met within 12 months from the signing date or if the Piping Commencement Date is not within 12 months from the Effective Date of the agreement.

7. During the piping period, PEI will make the Pipe available for Chevron's use (other than in emergencies defined in the agreement, in which the piping of condensate through the Pipe will be temporarily discontinued), and reserve an agreed capacity in the Pipe in exchange for fixed capacity fees stated in the agreement. In addition, PEI will transmit the condensate through the Pipe, in consideration for transmission fees agreed upon in the agreement.

8. The agreement includes provisions regarding the possibility of terminating it before the end of the period as specified above, in certain cases and under certain conditions.

Note that in November 2022, the Leviathan partners approved a budget of approx. $27 million (100%) for the implementation of the agreement as aforesaid.

Caution regarding forward-looking information – the above information, including the possibility that the preconditions will be fulfilled is forward-looking information within its meaning in the Securities Law. This information is based on the Partnership's estimations and assessments as of the report approval date. Fulfillment of the closing conditions to the agreement depends on various factors that are beyond the Partnership's control.

(d) <u>Agreement with Paz Ashdod Refinery Ltd. ("**PAR**")</u>

On January 18, 2023, the Leviathan partners, including the Partnership (in this section: the “**Sellers**”), engaged in an agreement with PAR for the sale of condensate to PAR (in this section: the “**Agreement**”). Below is a concise description of the main parts of the agreement:

1. According to the Agreement, the Sellers undertake to provide PAR with condensate produced from the Leviathan reservoir, to be piped through PEI's pipe.

2. The Agreement determines, inter alia, provisions regarding restrictions on the maximum (daily and monthly) quantities of the condensate to be supplied to PAR, fines in the event of breach of the provisions of the Agreement, and additional provisions as is customary in agreements of this kind.

3. Piping of the condensate to PAR will begin on the date of commencement of piping through PEI's pipe (in this section: the "**Piping Commencement Date**"), and will last for a period of four years. The Partnership estimates that the Piping Commencement Date is expected to fall in Q4/2023, subject to fulfillment of the closing conditions in the Transmission Agreement.

4. The price payable to the Sellers is determined according to the price of a Brent oil barrel, after deduction of a margin, in a phased manner, as specified in the Agreement.

5. The Sellers estimate that the total amount of revenues deriving for the Sellers from the Agreement may reach approx. 200-300 million dollars (100%, the Partnership's share approximately 90-135 million dollars), based on the Brent price level on the report approval date. It is clarified that there is no certainty in respect of the Piping Commencement Date, and the actual revenues will be according to a gamut of factors, including the condensate quantities actually produced and sold to PAR, and the Brent prices.

Caution regarding forward-looking information – the information provided above in relation to the agreement, including in respect of the Piping Commencement Date and the amount of the revenues expected to derive from the Agreement, constitutes forward-looking information within its meaning in the Securities Law, and there is no certainty that it will materialize, in whole or in part, or it may materialize in a materially different manner due to various factors that are beyond the Partnership's control, including an unusual delay in the completion of the work on PEI's pipe, changes in the volume and rate of production of the condensate (as a derivative of the rate of gas production from the Leviathan reservoir), and the condensate price to be determined according to the Brent prices.

7.11 Marketing and Distribution

7.11.1 Supply to the domestic market

The Partnership, together with its partners in the Leviathan project, supplies natural gas and condensate to its customers in Israel, in accordance with the engagements described in Section 7.10.3 above.

At the same time, the Leviathan Partners are conducting negotiations at various stages with other potential customers in the domestic market, including independent power producers and industrial consumers, subject, *inter alia*, to the supply capacity of the Leviathan project. Piping of natural gas to some of the potential 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, in accordance with an exemption from certain provisions of the Economic Competition Law, 5748-1988 (the "**Economic Competition Law**"), which as signed on December 17, 2015 by the former Prime Minister in his capacity as Minister of the Economy, and according to supply agreements that were signed between the customers and all of the Leviathan Partners.

7.11.2 Export

(a) General

The Partnership, together with the Leviathan Partners exports natural gas to customers in Jordan and Egypt, in accordance with the engagements described in Section 7.10.3 above. At the same time, the Leviathan Partners are acting to identify additional potential customers and markets outside of Israel 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, although, to the best of the Partnership's knowledge, there are also plans to build, on areas of the Palestinian Authority and in the Gaza Strip, power plants for the production of electricity), chiefly Egypt and Jordan, to which natural gas is exported via pipelines, and the more distant global markets to which it is possible to export natural gas via LNG and/or CNG. It is noted in this context that the Leviathan Partners are looking into the economic viability of potential projects for the export of natural gas via LNG (including liquefaction of natural gas via a FLNG facility) and CNG, as specified above and below.

(b) Export via pipelines

The Partnership is acting for the promotion of alternatives for the use of existing and/or new pipelines for export to regional markets, in addition to the export agreements into which it has entered, as specified in Sections 7.10.3(b) and 7.10.3(c) above. For details about the piping of natural gas pursuant to the Export to Egypt Agreement, through Jordan, see Section (e) below.

As of the report approval date, the Partnership is examining, together with Chevron, other possibilities for increasing the export amounts of natural gas through the Jordan Valley terminal (“**Jordan North**”) and the Jordanian transmission system, and through construction of a new onshore connection that will be built by INGL between the Israeli transmission system and the Egyptian transmission system at the Nitzana area (the "**Nitzana Line**"). In this context, it should be noted that on June 14, 2022, the Natural Gas Authority published a request for information regarding the ability and intention of the partners in the producing projects to export natural gas through Jordan North and via the Nitzana Line, in the context of which the aforementioned partners were asked to estimate the quantities of natural gas expected to be exported through these infrastructures. Further thereto, on July 25, 2022, Chevron replied to the Natural Gas Authority that the Leviathan Partners are interested in using the full transmission capacity within the aforementioned infrastructures and on November 9, 2022, the Natural Gas Authority notified the Leviathan Partners that in 2023, they will be allocated additional export capacity of 1 BCM for piping in Jordan North on an interruptible basis, over and above the quantities piped via Jordan North in the context of the Export to Jordan Agreement. In the Partnership's estimation, the said decision is not expected to affect the quantities piped to Egypt via Jordan, or the transmission tariffs.

(c) The natural gas market in Jordan[67]

To the best of the Partnership’s knowledge and based on information and analysis received from independent consulting firms, Jordan’s gas consumption for domestic use was approx. 3.5 BCM in 2022, slightly lower than in 2021, mainly as a result of a decrease in the economic activity as part of the effects of the Covid Crisis on the Jordanian economy. Natural gas is the main energy source for electricity production in Jordan, such that it is estimated that in 2022, approx. 80% of the electricity in Jordan was produced by using natural gas, and approx. 20% was produced by using renewable energies. In the Partnership’s estimation, natural gas consumption in Jordan is expected to slightly increase to approx. 3.8 BCM in 2023 and range between 3.8 and 4.2 BCM in the coming decade. The stability in the forecast for natural gas consumption in Jordan, despite the projected increase in the demand for energy in general and for electricity in particular, is related to the accelerated penetration of renewable energies into the electricity production sector in Jordan as a result of government policy, and due to the generation of electricity by a Jordanian power plant (Attarat Power

[67] The information regarding the natural gas market in Jordan and Egypt is based, *inter alia*, on reports published by external consulting companies.

Plant), which is fired by oil shale. As of the report approval date, the Leviathan reservoir is the primary source of the natural gas imported into Jordan for electricity generation purposes, along with import of approx. 0.7 BCM in 2022 from Egypt via the Arab Gas Pipeline in the context of past agreements between Jordan and Egypt. Furthermore, there is natural gas production in Jordan in negligible quantities.

To the best of the Partnership’s knowledge, Jordan has an operating LNG import facility in Aqaba and is able to import LNG, by seizing opportunities on LNG spot markets. Accordingly, in 2022, Jordan imported a negligible LNG quantity of approx. 0.09 BCM.

In this context it is noted that December 2019 saw the completion of the work that allows for connection of the Israeli and Jordanian transmission systems by: (a) laying down a pipeline parallel to the existing pipeline from the area of Tel Kashish to Dovrat; (b) construction of a new natural gas pipeline from Dovrat to the border with Jordan, including a station near the border whose goal is to measure the gas exported to Jordan; and (c) construction of a sequential pipeline on the Jordanian side that connects the Israeli transmission system to the existing transmission pipeline in Jordan (connection to the Arab Gas Pipeline that is operated by FAJR) (the “**Northern Pipeline**”). To the best of the Partnership’s knowledge, the Northern Pipeline’s capacity may enable the flow of natural gas to Jordan and transmission to Egypt through Jordan in an overall annual volume of up to approx. 10 BCM.

(d) <u>The natural gas market in Egypt</u>

Natural gas plays a key role in the Egyptian energy market, with consumption thereof mainly used for electricity production, but also for energy-intensive industry and households. Accordingly, in 2022, approx. 73% of the electricity in Egypt was produced by using natural gas while the remaining electricity was produced using fuel oil and renewable energies. In 2022, local production in Egypt was approx. 67 BCM, a decrease of approx. 4% compared with 2021, and domestic demand for natural gas in Egypt in 2022 was approx. 61 BCM, a decrease of approx. 3% compared with 2021. This decrease is attributed to the introduction of fuel oil as a raw material for electricity production in order to enable export of natural gas as LNG.

In addition, Egypt has two facilities for the liquefaction of natural gas for the purpose of export of LNG, with a total liquefaction capacity of approx. 12.2 million tons of liquefied natural gas per year, operation of which at full capacity requires approx. 19 BCM of natural gas per year, in addition to the domestic demand. As of the report approval date, natural gas production in Egypt is sufficient to fulfill the needs of the domestic market, but not sufficient for the operation of the two liquefaction facilities at full capacity, and therefore, one or both of the said facilities operate with partial output.

According to the reports of independent consulting firms, demand forecasts for the domestic Egyptian market (excluding the liquefaction facilities) for 2023, 2024 and 2025 are approx. 64 BCM, approx. 66 BCM and approx. 66 BCM, respectively, whereas domestic production from producing fields, either at development stages or with high probability of production commencement, is expected to remain at approx. 65 BCM per year in 2023-2024 and approx. 63 BCM in 2025. The difference between the forecasts of the domestic market's demand and projected domestic production is expected to even increase in the future. Accordingly, 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. At the same time, the Egyptian Government is encouraging natural gas exploration, development and production activities in Egypt. It is clarified that as a result of these activities, new discoveries may be found in Egypt and/or the development of existing fields will be accelerated, such that the aforesaid production forecasts change.

For details regarding the EMG Transaction, which allows for piping natural gas to Egypt, see Section 7.24.6 below, and for details about agreements for piping gas to Egypt through Jordan, see Section 7.11.2(e) below.

For details regarding an MOU signed between Israel, Egypt and the EU for export of natural gas to the EU from Egypt, Israel and other destinations through liquefaction facilities in Egypt, see Section 7.1.3 above.

Caution regarding forward-looking information – The forecasts and estimates regarding the natural gas market in Jordan and in Egypt 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 projections and assumptions 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 that are 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 influence the economic activity in these markets, including acceleration or deceleration in the economic activity, etc.

(e) <u>Engagement with INGL in transmission agreements in relation to the export to Egypt</u>

1. On May 28, 2019, an agreement was signed between Chevron 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**"). The payment pursuant to the 2019 Agreement will be made based on the gas quantity which will actually be piped in the transmission system, subject to Chevron's undertaking to pay for specific minimum quantities.

2. In July 2020, with the operation of a compressor at the entry to the ENG system in Ashkelon, the capacity of the EMG pipeline, under the limitations of INGL's existing transmission system infrastructure, increased to approx. 500 MMCF per day (approx. 5 BCM per year). Under the Export to Egypt Agreement, as described in Section 7.10.3(c) above, the Additional Compressor was installed in Ashkelon, such that, coupled with the construction of the Ashdod-Ashkelon combined section by INGL, the EMG's system piping capacity will be able to be increased to approx. 650 MMCF per day, and given certain conditions in the Israeli and Egyptian transmission systems, even more.

3. On January 18, 2021, Chevron engaged with INGL in an agreement for the provision of transmission services on a firm basis for the piping of natural gas from the Leviathan and Tamar reservoirs to the EMG terminal in Ashkelon and for the transmission thereof to Egypt, which took effect on February 14, 2021 (above and below: the "**Transmission Agreement**" or, in this section: the "**Agreement**"). Below is a concise description of the main principles of the Agreement:

   (a) In the Transmission Agreement, INGL undertook to provide transmission services for the natural gas that shall be supplied from the Leviathan and Tamar reservoirs, 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, Chevron 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.[68] 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, Chevron 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 Partnership's knowledge, the transmission system was planned to allow the transmission of the full contract quantity set forth in the export agreements.

(b) In the Transmission Agreement, Chevron 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.

(c) 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 (the "**Combined 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 Combined Section, as described in Section 7.22.5(d) below (in this section: the "**Council's Decision**"), in a manner which will allow the piping of the full quantities under the Transmission Agreement (in this section: the "**Piping Commencement Date**").

(d) The Transmission Agreement will end upon the earlier of: (a) the date on which the total quantity that is piped is 44 BCM; (b) 8 years after the Piping Commencement Date; or (c) 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

[68] As of the report approval date, the capacity fee and the throughput fee that INGL charges its customers amount to approx. ILS 0.65 and ILS 0.11 per MMBTU, respectively, according to Decision no. 02/2022 of the Natural Gas Sector Council dated October 3, 2022.

capacity and transmission rates of the transmission license holder at such time.

(e) In accordance with the principles determined in the Council's Decision, Chevron undertook to pay INGL the amount for the share of the partners in the Leviathan and Tamar projects (56.5%) out of the total cost of construction of the Ashdod-Ashkelon Combined Section, which was estimated upon the signing of the Transmission Agreement at ILS 738 million. On May 2, 2022, INGL updated the project budget to approx. ILS 796 million.

Chevron also undertook to pay ILS 27 million for the aforesaid share of the partners, out of the total cost of ILS 48 million for bringing forward the construction of doubling the Sorek-Nesher and Dor-Hagit sections.

(f) In accordance with the Council's Decision, the Leviathan Partners and the Tamar Partners provided a bank guarantee to secure INGL's share in the cost of construction of the foregoing infrastructure, and to cover Chevron's commitment to pay the capacity and transmission fees. Accordingly, in February 2021, the Partnership provided guarantees in respect of its rights in the Leviathan project, in the total sum, as of the report approval date, of approx. ILS 151 million, and also pledged in favor of the facility for the guarantees a deposit in the sum of approx. $11.5 million.

(g) The Leviathan Partners and the Tamar Partners will bear the costs stated in Subsection (e) above and provide the guarantees stated in Subsection (f) above at the rates of 69% and 31%, respectively.

(h) The Transmission Agreement stipulates that in case of cessation of the export of natural gas from the Tamar and Leviathan projects to Egypt, Chevron 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 Chevron 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.

(i) It was further determined that the transmission period under the 2019 Agreement will be extended until January 1, 2024 or until the Piping Commencement Date pursuant to the Transmission Agreement, whichever is earlier.

4. Concurrently with the signing of the Transmission Agreement, Chevron, 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 Tamar partners will be entitled to transmit natural gas (through Chevron) under the Transmission Agreement, and will be responsible for fulfillment of Chevron'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 Chevron'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 7.24.6 below. The Services Agreement further determined that the Base Capacity that is kept in the transmission system for Chevron will be allocated between the Leviathan Partners and the Tamar Partners according to the specified rates, and according to the order set forth in the Capacity Allocation Agreement. 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 unutilized capacity of the other party.

5. On February 26, 2023, Chevron received a letter from INGL, according to which, following a malfunction on a vessel carrying out infrastructure work for the laying of an offshore pipeline for INGL in the Combined Section, and further to a preliminary evaluation that INGL received from the construction contractor for the Combined Section, a delay of at least 6 months is expected in the date of its completion, such that the window of time in which the Piping Commencement Date may fall has been postponed to the period from October 1, 2023 until April 1, 2024. The said letter received from INGL was given as a notice of *force majeure* according to the Transmission Agreement, in which INGL stated that the full repercussions thereof are not yet known thereto at this stage. On March 9, 2023, Chevron responded on behalf of the Leviathan partners and Tamar to the said letter that it rejects the notice of *force majeure*.

The Partnership estimates that such delay does not have a material effect on the Partnership's business or on the results of its operations.

Caution regarding forward-looking information – The Partnership's estimation regarding the effect of a delay as aforesaid constitutes forward-looking information within the meaning thereof in the Securities Law, which is based, *inter alia*, on INGL's assumptions regarding the extent of the delay in completing the Combined Section, the availability of the systems for transmission to Egypt, including through Jordan,[69] assumptions regarding demand for natural gas in the domestic market and export markets, and assumptions regarding gas sale prices and quantities and production costs. There is no certainty that the aforesaid estimation will materialize, in whole or in part, and it may materialize in a materially different manner, due to various factors beyond the Partnership's control, including more delays in completing the Combined Section, non-availability of the systems for transmission to Egypt, including through Jordan, conditions of supply and demand in the domestic market and/or export markets of natural gas, etc.

(f) Export of natural gas to Egypt through Jordan

In view of the aforesaid, the Leviathan Partners have signed a set of agreements, aimed to allow for the piping of natural gas under the Export to Egypt Agreement, through Jordan, using the Israeli transmission system to Jordan and the Jordanian transmission system that is connected to the Egyptian transmission system in the Aqaba-Taba area (the Arab Gas Pipeline). Under such set of agreements, in March 2022, natural gas piping to Egypt through Jordan had commenced, which allows for maximizing the sale of the natural gas produced from the Leviathan reservoir and transmitting natural gas surpluses that are not consumed in Israel and Jordan and/or piped to Egypt via the EMG pipeline, to the Egyptian market, via the Jordanian transmission system, mainly until the Combined Section is completed by INGL as aforesaid. As of the report approval date, and as the Partnership was informed by the operator in the Leviathan project, using the existing transmission infrastructure and current operating conditions, natural gas can be flowed to Egypt, via Jordan, in an average daily amount of up to approx. 350 MMCF (approx. 3.5 BCM per year). It is noted in this context that the Ministry of Energy has granted the Leviathan Partners its approval for the addition of a delivery point

[69] For details on piping of natural gas pursuant to the Export to Egypt Agreement, through Jordan, mainly until completion of the Combined Section, see Section 7.10.3(c) above and Section 7.11.2(f) below.

of natural gas to Egypt, which is expected to be located in Aqaba, Jordan.

The aforesaid set of agreements includes the agreements specified below:

1. Agreement between Chevron and FAJR, the Jordanian transmission company, for supply of interruptible transmission services in relation to piping of natural gas from the Leviathan and Tamar reservoirs through the transmission system in Jordan, from the point of entry at the border between Israel and Jordan to the delivery point at the border between Jordan and Egypt, near Aqaba (the "**FAJR Agreement**"). The payment pursuant to the FAJR Agreement will be made based on the gas quantity actually piped in The FAJR transmission system.

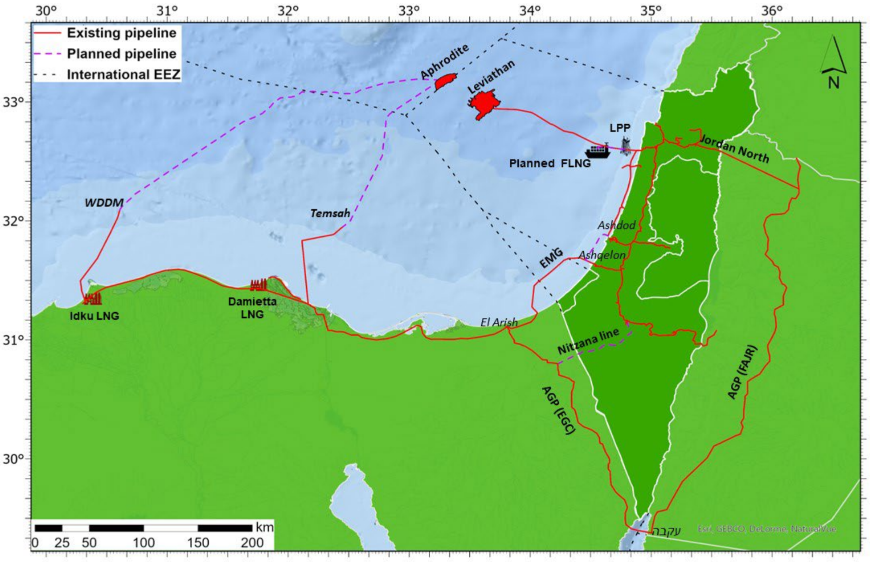
2. Concurrently with the signing of the FAJR Agreement, Chevron and the other Leviathan and Tamar partners engaged in a back-to-back services agreement, in the context of which the holders of interests to the Leviathan and Tamar reservoirs will be entitled to transmit gas (through Chevron) in the FAJR Agreement, and according to which, *inter alia*, the use of the FAJR transmission system for the purpose of export of natural gas to Egypt from the Leviathan and Tamar reservoirs will be made in accordance with the mechanism, terms and conditions, and order of priority specified in the aforesaid agreement.

3. Agreement between Chevron and INGL for supply of interruptible transmission services in relation to the piping of natural gas from the Leviathan reservoir to the point of connection to the FAJR transmission system at the border between Israel and Jordan (the "**INGL Agreement**"). The payment pursuant to the INGL Agreement will be made based on the gas quantity actually piped through the INGL transmission system, subject to Chevron's undertaking to pay for a minimum quantity as specified in the INGL Agreement. It is noted that the term of the INGL Agreement was extended until January 1, 2024, unless it expires prior thereto pursuant to the provisions thereof or if the parties consensually extend it, subject to the decisions of the Natural Gas Authority at such time. Concurrently with the signing of the INGL Agreement, Chevron and the other Leviathan partners engaged in a back-to-back services agreement in connection with the INGL Agreement.

4. The Leviathan and Blue Ocean partners signed an amendment to the Export to Egypt Agreement as specified in Section 7.10.3(c)5 above.

Since the aforesaid transmission agreements are for provision of interruptible transmission services, on the report approval date it is uncertain whether piping the full additional quantities which the Leviathan partners undertook to supply to Blue Ocean, through Jordan, will be possible, as specified in Section 7.10.3(c) above. However, effective from July 1, 2022, and as of the report approval date, the Leviathan partners piped, through Jordan, the full additional quantities they undertook to provide to Blue Ocean.

Caution regarding forward-looking information – The above estimations 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 Piping Commencement Date, the quantities that it will be possible to pipe under the Transmission Agreement, the estimate regarding the possibility of extending the Transmission Agreement, and the quantities that may be flowed to Egypt through Jordan, constitute forward-looking information, within the meaning thereof in the Securities Law, 5728-1968, which is partly based on estimations the Partnership received from INGL through Chevron, 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.



(g) The natural gas market in Judea and Samaria (the West Bank) and the Gaza Strip

Israel is the main source of electricity for the West Bank and the Gaza Strip. In recent years, the Palestinian Authority has been developing the ability to independently generate electricity, *inter* *alia*, by promoting the construction of a new power plant for the generation of electricity in Jenin.

In the Partnership's estimation, the demand for natural gas for operation of the future power plant in Jenin will be approx. 0.2 BCM per year, and the demand for natural gas for operation of Gaza's existing power plant will be approx. 0.25 BCM per year.

As of the report approval date, the Partnership, together with its partners in the various projects, is conducting negotiations, *inter alia*, in relation to the possibility of supplying natural gas to the aforesaid power plants.

(h) The natural gas market in Cyprus

As of the report approval date, 90% of electricity production in Cyprus which is based on the use of imported petroleum-based products, such as diesel oil. In addition, Cyprus has difficulties in connecting to the energy infrastructures in Europe due to its geographical location and its being an island. However, to the best of the Partnership's knowledge, the Government of Cyprus and the Cypriot electricity company are acting to replace the petroleum-based products used for electricity generation with natural gas and renewable energies. 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 7.13.6(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 connection to existing infrastructures in the Mediterranean Basin and negotiations for the supply of natural gas to be processed and liquefied at one of the existing liquefaction facilities in 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, the materialization of which, in whole or in part, is completely

uncertain, either in the manner specified or otherwise, and which may materialize in a manner that materially differs from the aforesaid description, and in particular there is no certainty that such discussions and/or negotiations will result in binding gas sale agreements and that the conditions required by any law for such agreements, if signed, to take effect, will be fulfilled.

(i) <u>Natural gas market in Morocco</u>

According to various reports, natural gas production in Morocco presently totals approx. 0.1 BCM per year. In general, Morocco has gas resources of approx. 1.2 TCF, which originate from 3 different onshore and offshore ventures and are operated by international oil and gas companies. Electricity production in Morocco is currently mostly based on coal (approx. 68%), with only approx. 9% based on natural gas. However, Morocco strives to reduce greenhouse gas emissions, *inter alia*, by replacing coal with natural gas. As of the report approval date, domestic demand for natural gas in Morocco is approx. 1 BCM per year, most of which (approx. 90%) has until recently been supplied by the import of gas from Algeria via the GME pipeline. On November 1, 2021, gas transmission through the GME pipeline came to a stop following the expiration of the supply agreement between the countries, and to the best of the Partnership's knowledge, given the increasing political tensions between Morocco and Algeria, entry into a new agreement is not expected. Consequently, Morocco began to import natural gas through Spain. The gas arrives in Spain as LNG, it is regasified there and piped through the GME pipeline to Morocco. According to media reports, Morocco is expected to import LNG in this manner, in volumes of approx. 1.1 BCM, 1.7. BCM and 3.1 BCM in 2025, 2030 and 2040, respectively. It is noted that, as of the report approval date, there are no LNG regasification or production facilities in Morocco. In addition, to the best of the Partnership's knowledge, there are currently about 4 power plants in Morocco with the ability to produce electricity based on natural gas, which may create demands amounting up to approx. 150 MMCFD, and there is a plan to build additional power plants that are expected to enable an increase in the natural gas-based electricity generation capacity.

It is clarified that to date, exploration in Morocco has not yielded significant oil or gas discoveries, despite substantial activity by various companies such as Eni, Shell, BP, Chevron, Total, Kosmos and Repsol, which held offshore and onshore licenses. In Morocco there is presently onshore and offshore exploration activity of insignificant scope. Meanwhile, the Anchois project, situated in the north of Morocco's EEZ in the Atlantic Ocean, is currently the main natural gas project in Morocco. In July 2022, the operator in the

Anchois project, Chariot Limited ("**Chariot**"), reported that there are 637 BCF of contingent resources and 754 BCF of prospective resources in the project. Chariot further reported that the field will be developed by connection to an onshore processing facility, and that the adoption of an FID for the field's development is expected in H1/2023. Moreover, Chariot announced that it will expand the exploration activity in the area of the licenses surrounding the Anchois project, and that the prospective resources in the licenses that it holds total approx. 4.5 TCF.

(j) In December 2020, a normalization agreement was signed between Israel and Morocco, under which, *inter alia*, Israel and the United States recognized Morocco's sovereignty over Western Sahara. For details on agreements signed by the Partnership with regard to oil and/or natural gas exploration and production activity in the Boujdour license in Morocco, see Section 7.6 above. As of the report approval date and to the best of the Partnership's knowledge, on September 24, 2021, Ratio Petroleum Energy – Limited Partnership signed the Dakhla Atlantique reconnaissance license agreement.

(k) Liquefied Natural Gas (LNG)

The Partnership is examining the possibility of liquefying natural gas and transporting it in a liquefied state (LNG) in designated tankers to various countries. 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, regulatory and commercial challenges that are entailed by such a project.

As of the report approval date, the Partnership, together with its partners in the Leviathan reservoir, is promoting the construction of an FLNG facility owned thereby, which will be stationed in the sea and used for the production and storage of LNG. Such a facility, insofar as constructed, will receive processed gas from the Leviathan platform, and produce LNG that will be offloaded onto designated vessels which will transport it to consumers. For further details see Section 7.2.5(f) above.

It is noted, in this context, that in March 2020, the Ministry of Energy released a request for public comment regarding the alternatives proposed by the Ministry of Energy for construction of an FLNG facility in Israel's EEZ[70]. The Association of Oil and Gas

[70] For further details, see the Ministry of Energy's announcement at: https://www.gov.il/he/departments/publications/Call_for_bids/flng_public.

Exploration Industries in Israel, of which the Partnership is a member, submitted its comments on the said document on May 17, 2020.

(l) Compressed Natural Gas (CNG)

The Partnership is examining the possibility of exporting natural gas to countries in the Mediterranean Basin, through its compression (CNG) and transportation thereof in designated vessels or using portable designated containers, thus allowing access to new and additional export markets, including Greece, the Mediterranean Islands, Italy and other countries. In this context, 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 currently no existing projects in the world for the supply of CNG through maritime transportation at large scopes.

7.12 **Order backlog**

7.12.1 Following are data regarding the Partnership's order backlog calculated on the basis of the minimum gas quantities (according to the Take or Pay 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 from the Leviathan project, which the customers have undertaken to consume or pay for, including quantities actually consumed in January-February 2023 under supply agreements on a SPOT and on an interruptible basis, and in the context of the Bridging Agreements for Energean's Customers. The calculation of the order backlog was performed based on the following main assumptions: (a) all of the options conferred on the customers in Israel to reduce the contract quantity, as specified in Section 7.10 above shall be exercised; (b) the possible reduction of the take or pay quantities due to the exercise of carry forward, was not taken into account; (c) the gas prices are based on the assumptions taken into account for the purpose of the discounted cash flows in the Leviathan project which were included in the resources report attached as **Annex B** to this chapter; and (d) no change shall occur in the minimal annual quantities in the export to Egypt agreement, as specified in Section 7.10 above:

Period	**Order Backlog (dollars in millions) as of Dec. 31, 2022**[71]
Q1/2023*	Approx. 217

[71] As of the report approval date, no material change has occurred in the order backlog, even though the order backlog does not include quantities included in agreements signed between January 1, 2023 and the report approval date.

Period	Order Backlog (dollars in millions) as of Dec. 31, 2022[71]
Q2/2023*	Approx. 193
Q3/2023*	Approx. 193
Q4/2023*	Approx. 197
2024	Approx. 766
2025	Approx. 755
2026	Approx. 716
2027	Approx. 708
2028	Approx. 704
2029	Approx. 700
2030	Approx. 701
2031	Approx. 677
2032	Approx. 688

* The division between the quarters was made 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 regarding the timing and amount of the revenues expected from the order backlog constitute forward-looking information within the meaning thereof in Section 32A of the Securities Law, which are based on the minimum gas quantities specified in the binding agreements for natural gas supply from the Leviathan project, and based on various assumptions regarding the natural gas quantities and prices, the materialization of which is completely uncertain, *inter alia*, due to the possible effect of the risk factors entailed by the Partnership's operations, as detailed in Section 7.28 below.

7.12.2 The order backlog from the Leviathan project for 2022, as included in the 2021 Periodic Report, was approx. $764 million. The Partnership's actual revenues from the Leviathan project in 2022 amounted to approx. $1.14 billion. The difference between the figures of the order backlog for 2022 and the actual revenues in this period primarily derived from the fact that the actual gas quantities supplied to customers exceeded the minimum gas quantities determined in the supply agreements.

7.13 **Competition**

7.13.1 Natural gas discoveries in Israel

The supply of natural gas from the Leviathan project is currently performed via pipeline and is designated for the domestic market, and markets in adjacent countries. As of the report approval date, the Partnership’s main competition in the domestic natural gas market is with the partners in the Tamar project and with Energean, the owner of the Tanin and Karish reservoirs, and with owners of natural gas and oil assets that operate in neighboring countries and LNG importers.

As of the report approval date, the vast majority of the natural gas currently supplied to the Israeli market originates from the Leviathan, Tamar and Karish reservoirs.

According to the provisions of the Gas Framework, the Tanin and Karish reservoirs owned by Energean are intended solely for supply of gas to the domestic market. Based on Energean’s reports, production from the Karish reservoir began in October 2022. In addition, Energean performed a drilling campaign in Israel’s EEZ, using the Stena Icemax drilling ship, which included 6 wells in licenses no. 12, 23, 31 and in the Karish lease. According to Energean's reports, in the context of this drilling campaign, 4 natural gas discoveries were made, whose total volume is estimated at approx. 1.1 TCF in the 2P category and another approx. 0.2 TCF in the 2C category.

According to reports of the Tamar partners, in December 2022, the said partners adopted a final investment decision (FID) for a development project for expansion of the production capacity from the Tamar reservoir to approx. 12 BCM from 2025. In addition, in January 2023, the Tamar partners reported that they were exploring the adoption of an investment decision for another development project which may increase the production capacity to approx. 16 BCM. Completion of the said expansion work may affect competition, in both the domestic and the export markets.

The Tamar Partners signed an agreement designed to enable separate marketing of natural gas, which agreement took effect in May 2021. To the Partnership’s best knowledge, as of the report approval date, no separate gas sale agreements were signed by any of the Tamar Partners. It is noted that the implementation of this agreement by the Tamar Partners may increase competition. In addition, as of the report approval date, the gas produced from the Leviathan reservoir is marketed jointly by the Leviathan Partners, and no arrangements have been determined for separate marketing of the gas. According to the joint operating agreement in the Leviathan project, each partner is entitled, under certain conditions, to take its share of the gas and market it separately. Should arrangements be determined for separate marketing of the gas produced in the Leviathan project, competition may increase.

For details regarding a fourth competitive process for gas and oil exploration in the EEZ of the State of Israel which was announced by the Ministry of Energy, see Section 7.13.2 below.

7.13.2 Oil and gas exploration in Israel in recent years

On November 15, 2016, the Ministry of Energy announced the opening of Israel's EEZ for oil and natural gas exploration, in a competitive process. In the framework of the first competitive process, on January 15, 2018, the Ministry of Energy gave 5 licenses for exploration in Israel's EEZ to the Greek company, Energean, and on April 9, 2018, gave a license for oil exploration in Block 1 to a consortium of Indian companies. The aforementioned consortium waived its rights to continue exploration in the license area and on November 10, 2020, Energean announced the waiver of its rights to continue exploration in the area of one of the licenses granted thereto.

On November 4, 2018, the Ministry of Energy announced a second competitive process, in whose context 12 petroleum licenses were granted, which were returned to the State upon expiration of the first license period (approx. 3.5 years), without being drilled.

It is noted that the Partnership and Chevron were barred from participation in the first two competitive processes.

On June 23, 2020, the Ministry of Energy announced a third competitive process, offering a single license, Block 72, which covers extensive parts of the Alon D license and which until expiry thereof, had been owned by Chevron and the Partnership. For details about this process, see Section 7.7.2 above). As of the report approval date, no answer has been received from the Ministry of Energy on the winning of the third competitive process, and in the Partnership's estimation, it is doubtful whether a winner will be declared in this process. Note that Block 72 is adjacent to the maritime border between Israel and Lebanon. Note further that Lebanon gave TotalEnergies and ENI an exploration license in Block 9 which partially overlaps Block 72. In this context, on October 27, 2022, a Maritime Agreement was signed determining, *inter alia*, the maritime border between the countries, as specified in Section 7.7.2 above.

On December 13, 2022, the Ministry of Energy announced the launch of a fourth competitive process for gas and oil exploration in the EEZ of the State of Israel.[72] According to this announcement, the purpose of the fourth competitive process is to increase the certainty of supply of natural gas to the Israeli market and to increase the competition

[72] https://www.gov.il/he/departments/news/press_131222.

between the natural gas providers and in its context, 4 clusters of exploration licenses will be offered. Accordingly, the terms and conditions of the competitive process encourage and prioritize companies that are not currently active in Israel to participate in the competitive process over companies that hold producing reservoirs. The Partnership intends to take part in the fourth competitive process as aforesaid, while strictly complying with the terms and conditions determined in respect of participation by companies holding existing reservoirs.

It is further noted that insofar as wells that shall be drilled in the areas of existing and/or new licenses lead to significant natural gas discoveries, and insofar as these discoveries, if any, will be developed, these reservoirs shall also constitute competition with the Partnership's field of business.

7.13.3 LNG import

From January 2013 until December 2022, LNG was imported into the domestic market using the import buoy and the regasification vessel for import of LNG off the shores of Hadera, which connected to an LNG tanker, that converts LNG into gas via the regasification vessel, in the volume of up to approx. 0.5 BCF per day. As of the report approval date, the import buoy is inactive and the State of Israel does not import LNG.

7.13.4 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 about the Israeli Government Resolutions regarding the reduction of coal use, see Section 7.22.10(a) 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.

Moreover, it is expected that hydrogen will gradually enter the mix of energy sources, which may be used in electricity production, transportation and heavy industry (such as concrete, steel, chemicals, etc.). Hydrogen may be produced through various methods, some of which are polluting, such as cracking from natural gas (gray hydrogen), and some of which are "clean", such as blue hydrogen and green hydrogen. In the context of the growing trend in the global energy market to reduce, insofar as possible, greenhouse gas emissions in general, and carbon dioxide emissions in particular, hydrogen itself does not leave a carbon footprint and use thereof for the production of energy does not produce greenhouse gas emissions, a clear advantage. To the best of the Partnership's knowledge, as of the report approval date, the main hydrogen producer in Israel is ORL, which produces gray hydrogen. However, several companies in Israel, including energy and technology companies, are examining hydrogen production using different methods, and some are even in advanced development stages. Thus, for example, according to media reports, the first hydrogen fueling station in Israel was built in 2022, in a collaboration between Sonol Israel and the ORL group.

7.13.5 Renewable energy sources

(a) According to a review report of November 2021 published by the Ministry of Energy[73], the dramatic changes in the global energy market that transpired in 2021 derived, *inter alia*, from an increase in the relative weight of renewable energies over the past decade, from approx. 8% to approx. 12% of the entire primary energy consumed globally, which is mainly the result of two simultaneous processes: (a) the declared policies of governments, mainly in developed markets, on dealing the climate crisis; and (b) technological improvements in the field of renewable energies, storage and demand management. According to the International Energy Agency (IEA), the projected demand for all types of fossil-based fuels is declining, given that production goals for renewable energy undertaken by governments shall be met. Against this background, investments made by the business sector in fossil fuels and related technologies have decreased because there is a significant concern regarding long-term demand for fossil fuels. However, in 2022, coal prices peaked, *inter alia*, because of the global energy crisis and the Ukraine war.[74] In addition, despite the soaring of the prices of natural gas in Europe in 2021, natural gas prices in Israel continued to decrease in that year, due to the

[73] For further details, see a review report of November 2021: https://www.gov.il/BlobFolder/reports/energy_101121/he/energy_101121.pdf.
[74] For further details, see the electricity sector status report for 2021 of July 27, 2022: https://www.gov.il/BlobFolder/reports/doch_meshek_hachashmal_2021/he/Files_Hadashot_press_doch_2021_n.pdf.

increase in supply of natural gas and the enhancement of competition in the natural gas sector subsequent to the connection of the Leviathan reservoir in 2020.[75]

(b) Like other developed countries, the Israeli Government has adopted a policy that promotes the transition to a low-carbon economy, and in such context, 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. For additional details on the Government's targets in this regard, see Section 7.22.10 below. To the best of the Partnership's knowledge, at the end of 2022, the installed capacity of renewable energy was approx. 4,795 megawatts and accordingly, its rate out of the total market capacity was approx. 21.2%. in recent years there has been a significant increase in the installed capacity, such that the growth rate increased from approx. 16% per year on average in 2015-2017 to approx. 37% per year on average in 2018-2022. In addition, to the best of the Partnership's knowledge, in 2022 actual rate of consumption of renewable energy sources was approx. 10% of all energy consumed in Israel in that year.[76] Note that this means that the renewable energy targets set for 2020 were achieved. In addition, according to the Government's targets, as specified in Section 7.22.10(c) below, the rate of electricity generation from renewable energy sources is intended to reach approx. 30% of all electricity generated in 2030, *inter alia*, by means of regulatory support, tax incentives to renewable energy-fired power plants, the formulation of various action plans and the removal of barriers. It is noted that the generation of electricity from renewable energy sources holds advantages in the environmental aspect; however, the generation of electricity from renewable energy sources in Israel chiefly refers to solar energy, which employs a technology that is partly and limitedly available, is still considered 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.

7.13.6 <u>Natural gas discoveries and exploration activity in neighboring countries</u>

[75] For further details, see the review of the developments in the natural gas market of April 24, 2022: https://www.gov.il/BlobFolder/reports/ng_2021/he/ng_2021.pdf.

[76] For further details, see the status report on renewable energies in the electricity sector for 2022: https://www.gov.il/BlobFolder/reports/yehadeie/he/Files_General_doch_mithadshot_meshek_energy_2022_12022023.pdf.

Natural gas discoveries in neighboring countries, if developed, and exploration activity resulting in discoveries of new reservoirs, if developed, may also compete with the Leviathan reservoir. The Partnership is following up on activity and trends of exploration, development and production in the countries of the region, including Egypt, Cyprus, Lebanon and Jordan. Below are details regarding discoveries and exploration activity in Israel's neighboring countries[77].

(a) Egypt

1. Resources: Approx. 36 TCF in reserves and approx. 21 TCF in contingent resources.

2. Current gas production capacity: Approx. 70 BCM.

3. Domestic demand: Domestic demand in 2022 totaled approx. 61 BCM, compared with approx. 64 BCM in 2021. For details about the amount of domestic demand in 2021 and 2022 and forecasts of the domestic demand in Egypt in the coming years, see Section 7.11.2(d) above.

4. Key facilities: Egypt has two LNG facilities: (a) ELNG in Idku, which is primarily owned by Shell with a production capacity of approx. 7.2 million tons of LNG per year; and (b) SEGAS in Damietta, which is primarily owned by Eni, with a production capacity of approx. 5 million tons of LNG per year. In the past decade, 2022 was the best year in terms of the amount of LNG exported by Egypt, which is estimated at approx. 7.14 million tons in that year, reflecting an increase of approx. 7% in respect of the scope of export in 2021. For further details about the LNG market in Egypt, see Section 7.11.2(d) above.

5. Production: In 2022 gas production in Egypt amounted to approx. 67 BCM, of which approx. 70% was produced from the reservoirs in the Mediterranean. At the same time, the most prominent reservoir is Zohr, the production from which represents approx. 45% of the total domestic gas production in Egypt. in 2022, production from the Zohr reservoir was approx. 27 BCM, representing approx. 80% of the maximum production capacity of the field. To the best of the Partnership's knowledge, based on media reports, since late 2021, maximum production from the Zohr reservoir is approx. 2.6 BCFD.

6. Exploration activity: In recent years, Egypt has offered exploration licenses of vast scope, *inter alia*, in tenders. Most of

[77] The reader of the report should take into account that the information in this section, which originates from public releases of information providers and data obtained from external consulting firms, in whole or in part, is information which the Partnership has no ability to independently check or verify.

the licenses in the Mediterranean area have been granted to the major companies in the industry, including Shell, Chevron, BP, Eni, ExxonMobil and TotalEnergies, and according to media reports, these companies plan various exploration activities in the Mediterranean Basin. On January 15, 2023, Chevron announced that it found a significant quantity of gas in the Nargis-1 well which, according to media reports, contains approx. 3.5 TCF. In addition, according to media reports, in November 2022 Eni began to drill the Thuraya-1 well, in the proximity of the Egypt-Israel maritime border.

7. Import/export balance: Since commencement of production from the Zohr reservoir in 2017, the total gas quantities produced from the reservoir usually exceeds the total domestic demand. However, according to forecasts, the domestic demand is expected to be greater than the projected domestic production capacity, *inter alia* as a result of the expected population growth and a waning of the production rates in Egypt. Moreover, in order to feed the liquefaction facilities through which Egypt aspires to export natural gas, an additional amount of natural gas of up to approx. 19 BCM is required. In addition, the fact that the export of natural gas in Egypt exceeds the import of natural gas to Egypt by 6 BCM, renders Egypt an exporter of natural gas, which is facilitated, *inter alia*, by the production of electricity through fuel oil in order to enable the diversion of gas for export.

(b) Cyprus

1. Resources: Other than the Aphrodite reservoir, two significant discoveries were announced in 2018 and 2019 in Cyprus's EEZ ("Glaucus" and "Calypso"), which each contain, as reported by the operating companies, approx. 5-8 TCF in place.[78] In order to confirm the said resource estimates, confirmation wells will be required in both discoveries. As of the report approval date, the results of an appraisal well drilled by ExxonMobil in the Glaucus discovery have not been reported yet, and the appraisal well in the Calypso discovery is yet to be drilled. In August 2022, Eni announced a significant gas discovery in Block 6 in the EEZ of Cyprus in the Cronos-1 well which is estimated at approx. 2.5 TCF in place, and in December 2022, Eni announced another gas discovery in Block 6 in the Zeus-1 well which is estimated at approx. 2-3 TCF in place. To the best of the Partnership's knowledge, the development of these discoveries may be

[78] "In place" means the quantity of gas in the reservoir. It is clarified that the quantity that can actually be produced is significantly lower.

based on export to Egypt, which may impact the Partnership's activity in Cyprus and/or in Egypt.

2. Current gas production capacity: None.

3. Domestic demand: As of the report approval date, Cyprus does not consume natural gas. For further details about the Cypriot market, see Section 7.11.2(h) above.

4. Key facilities: None. January 2023 saw the commencement of the construction work of a floating regasification facility (FSRU) for LNG import in Vasilikos in the south of Cyprus, by a consortium led by China Petroleum Pipeline Engineering Co. Ltd. Consequently, the forecast for completion of the construction of the facility is until early in 2024.

5. Production: None.

6. Exploration activity: Cyprus has granted licenses for most of its offshore territory to the major companies in the industry, including Eni, TotalEnergies, and ExxonMobil. In 2022, these three companies performed exploration activity which included seismic surveys and exploration and appraisal drillings, which trend is expected to continue in 2023. The dispute between Cyprus and Turkey in relation to the rights in the EEZ of Cyprus is causing delays in the work plans in the licenses situated within the disputed areas. In addition, according to reports in the foreign media, in the past the national Turkish oil company performed exploration activity, including drilling in the EEZ of Cyprus. For further details regarding the dispute, see Section 7.28.36 below.

7. Import/export balance: As of the report approval date, the construction of an FSRU facility for LNG import has commenced. In December 2020, the Government of Cyprus apprised that a tender issued thereby had generated 25 different bids for the import of gas, with the aim of signing future agreements. As pertains to future export, in the absence of relevant regulation of natural gas export facilities in Cyprus, it cannot be estimated what effect, if any, additional discoveries, if any, may have on the manner of export of natural gas from Cyprus and on the competition, to the extent it develops, as pertains to the domestic market and to access to export infrastructures.

(c) Lebanon

1. Resources: Not discovered yet.

2. Current gas production capacity: None.

3. Domestic demand: As of the report approval date, the existing electricity generation infrastructure in Lebanon totals approx. 2 GW (less than one tenth that of Israel), of which approx. 25% MW can be produced by means of natural gas in the power plant in Dir Ammar in the north of the country.

4. Key facilities: None.

5. Production: None.

6. Exploration activity: Lebanon has granted two licenses only to a consortium headed by TotalEnergies that includes ENI and QatarEnergies, in which exploration activity may be performed in the coming years, including exploration drillings. In addition, according to media reports, a well in Block 9 bordering on Israel's EEZ may be drilled in 2023. The rest of the areas in Lebanon's EEZ are offered under a tender which is expected to be closed in mid-2023. For details on the Maritime Agreement signed between the governments of Israel and Lebanon, see Section 7.7.2 above.

7. Import/export balance: As of the report approval date, Lebanon relies exclusively on import of fuels and is experiencing an energy crisis following the absence of an active agreement for gas import. According to media reports, Lebanon has agreed with Egypt on the import of gas to the Dir Ammar power plant in the estimated volume of approx. 60 MMCFD.

(d) Jordan

1. Resources: All of Jordan's gas resources amount to approx. 70 BCF in the Risha field. In addition, there is an accumulation of oil shale that is developed in the context of the Attarat power plant project.

2. Current gas production capacity: The Risha filed produces approx. 0.1 BCM per year.

3. Domestic demand: Domestic demand in Jordan totals approx. 3.8-4.2 BCM per year and is affected by the extent of the demand for electricity and from the generation of electricity by means of gas substitutes, which include renewable energy sources and refined oil products. Natural gas represents approx. 80% of all electricity generation sources of NEPCO, the Jordanian electricity company.

4. Key facilities: As of the report approval date, there is an LNG import facility in the Gulf of Aqaba in Jordan, Golar Eskimo FSRU, which is leased until 2025. In 2020, Jordan imported 0.8 million tons of LNG and in 2021 it imported no LNG whatsoever.

5. Production: The Risha gas field is the only producing gas field. Furthermore, drilling is planned for increasing the rate of production from this field to approx. 0.2 BCM over the next 4 years.

6. Exploration activity: In April 2021, Jordan announced an exploration tender under which some 9 different blocks were offered. Although the names of the winners in the tender have not yet been released, NPC, the Jordanian oil company, has reported about exploration wells that it is expected to drill in one of these blocks. Note that to the best of the Partnership's knowledge, there is no material exploration activity in Jordan.

7. Import/export balance: Jordan relies on the import of natural gas and energy, mostly from Israel and a little from Egypt. For further details about the Jordanian natural gas market, see Section 7.11.2(c) above.

7.14 **Seasonality**

7.14.1 In Israel, Egypt and Jordan, the consumption of natural gas for electricity production is affected, *inter alia*, by seasonal fluctuations in the demand for electricity and by the maintenance plans of the electricity producers. Accordingly, generally, in the first and third quarters of the year (the winter and summer months) electricity consumption will be highest. In addition, the gas consumption in Egypt is significantly affected by the demand for electricity and for energy for cooling purposes, and therefore the summer months are the peak months in demand for natural gas.

7.14.2 Following is data on the breakdown of natural gas sales (100%) from the Leviathan project in the past two years:[79]

Period	Q1 (in BCM)	Q2 (in BCM)	Q3 (in BCM)	Q4 (in BCM)
2021	2.7	2.8	2.8	2.4
2022	2.7	2.8	3.0	2.9

7.15 **Facilities and production capacity in the Leviathan project**

7.15.1 Phase 1A of the Leviathan project development plan

The production system of Phase 1A comprises 5 main segments, as follows:

(a) Production wells: 4 subsea production wells, each with a production capacity of up to approx. 400 MMCF per day. Natural gas from the Leviathan reservoir, which is at a depth of approx. 3 km below the seabed, is piped from such production wells to the subsea production system. In addition, another production well is expected to be connected to the production system in Q2/2023.

(b) 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 each well to the subsea manifold; two pipes, 18 inch in diameter and approx. 120 km long, come out of the manifold, transmitting gas, condensate and other liquids to the production platform. In addition, the subsea system includes two pipes, 6 inch in diameter and approx. 120 km long, for the transmission of MEG from the production platform to the wells.

[79] The data relate to the total sales of natural gas produced from the Leviathan reservoir and are rounded off to one tenth of a BCM.

Furthermore, a command and control (umbilical) cable, approx. 120 km long connects the production platform to the wells and manifold and enables the control and command of the production of the natural gas system at the seabed.

(c) Processing and production platform: The Leviathan platform is situated approx. 10 km from the shore. The entire gas and liquid treatment process is performed on the platform. The platform is attached to the seabed at a water depth of approx. 86 meters via a jacket. On the upper part of the topsides, which protrudes above sea level, the decks of the platform are assembled, which are divided at this stage into 2 main modules: (a) the domestic supply module (DSM) 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, auxiliary facilities and services, etc.; (b) the liquids supply module (LSM) which stores condensate and MEG. The platform processes approx. 1,200 MMCF of gas per day and approx. 5,400 barrels of condensate per day. It is noted that under certain operating conditions, production capacity can slightly exceed such quantity.

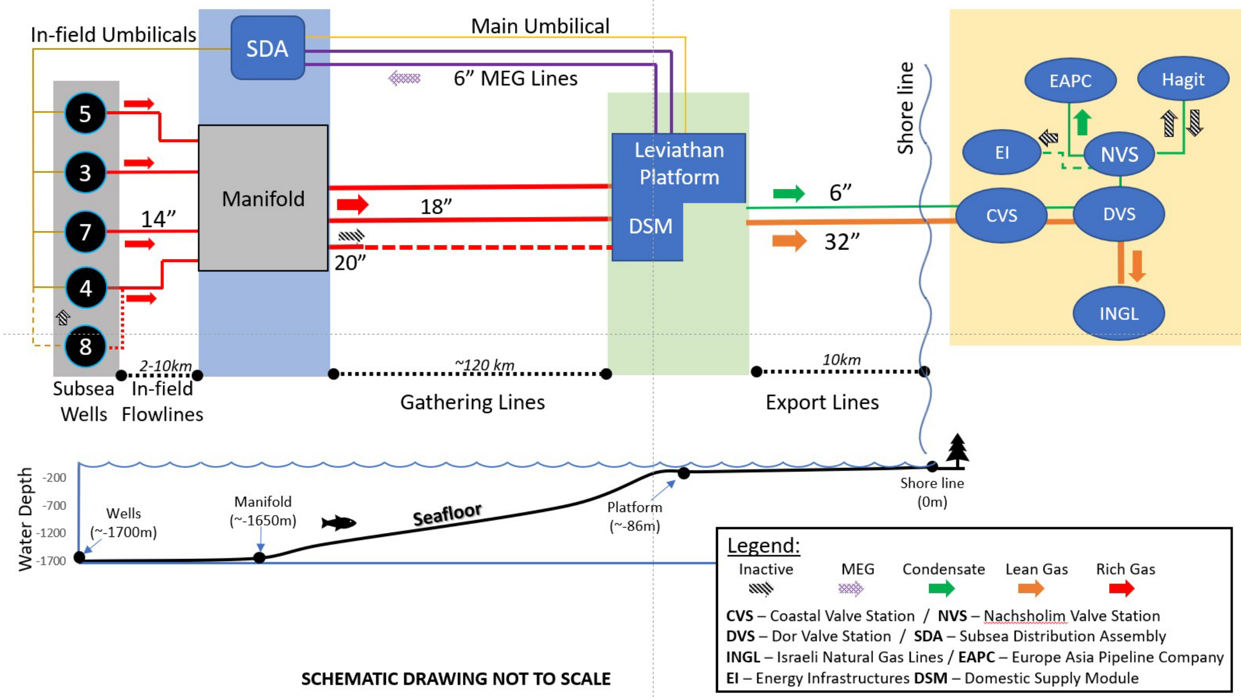
(d) Transmission system to the shore: The pipeline that comes out of the Leviathan platform to the shore comprises a 32-inch pipe for the transmission of natural gas[80] and a 6-inch pipe for the transmission of condensate. These pipes run under the shoreline, reach the coastal valve station and from 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 Nahsholim Valve Station.

(e) 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 and/or PAR (after commencement of transportation), the condensate will be transported and temporarily stored at the Hagit site, and transported to ORL and/or PAR when made possible, or insofar as necessary, will be removed therefrom

[80] For details regarding a license for the construction and operation of a transmission system, see Section 7.22.12 below.

using tankers, to the customers. For details regarding the agreements with ORL and PAR for the establishment of an alternative mechanism for transporting condensate from the Leviathan project, see Sections 7.10.4(c) and 7.10.4(d) above.

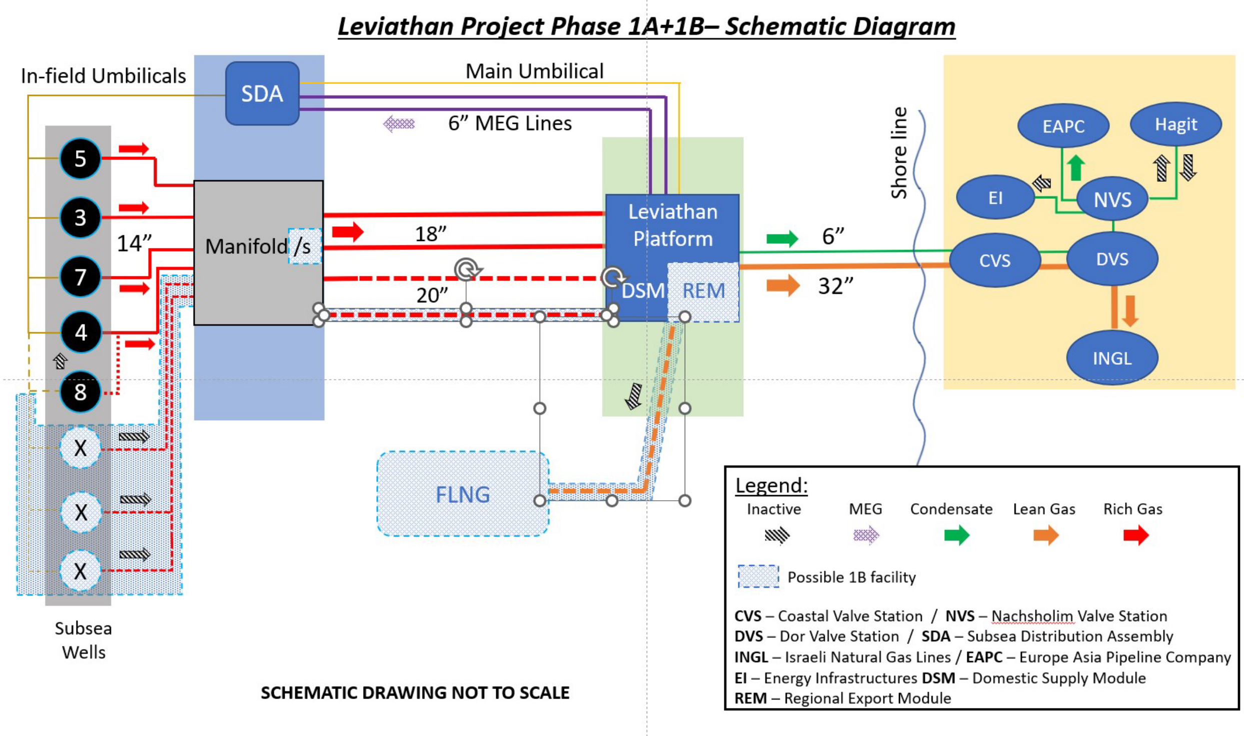
<u>Leviathan Project Phase 1A– Schematic Diagram</u>



7.15.2 <u>Phase 1B of the Leviathan project development plan</u>

Phase 1B of the approved development plan is planned to increase the daily production capacity of the Leviathan project to approx. 2.1 BCF. The facilities planned in this context (as an addition to Phase 1A) include, *inter alia*, 3 additional production wells, each with a production capacity of approx. 0.4 BCF per day, which shall be connected to the platform via a subsea pipeline and equipment which partially serves the existing production system. According to the plan, a processing system called 'Regional Export Module' (REM) will be added to the platform, which includes facilities for absorbing and processing an additional daily quantity of approx. 0.9 BCF, and compressions for the transfer of the gas to a FLNG facility or regional export pipeline. It is noted that there may be updates to the details of Phase 1B of the approved development plan, as stated above, which may require regulatory approval.

7.15.3 For details about the possibilities for increasing the daily production capacity in the Leviathan project and the various alternatives explored by the Leviathan Partners in relation thereto, see Section 7.2.5 above.



7.16 Raw materials and suppliers

In general, engagements with suppliers or professional contractors, are made by the operator of the various projects. It is noted that, in Israel, there are currently no companies that can perform the main acts performed in the projects, such as the drilling of wells at deep sea, production and laying of subsea infrastructures, production and establishment of marine facilities such as processing and production platforms, etc. Therefore, a significant portion of the infrastructure and development work in the various projects in which the Partnership is a partner is performed through international suppliers, with whom the operator engages directly, on behalf of the partners in the project. However, it is noted that the international suppliers are instructed to integrate into their activity, insofar as possible, local services and consultants. It is emphasized that this situation, in which services are imported from various countries for the establishment and operation of the projects, is customary in the oil and gas industry, also when the project is located in a country with high capabilities in the field, such as the United States or England. In this context, designated tools and materials, such as drilling vessels and crane platforms as well as pipes and cement, are leased or purchased, and brought in from all over the world in accordance with their availability, the work type and the project requirements. Accordingly, the costs of each tool and material depends on global supply chains, and are sensitive, *inter alia*, to volatility in the prices of raw petroleum and to current and projected demand for natural gas.

7.17 Human capital

7.17.1 In accordance with the provisions of the Partnerships Ordinance and the Partnership Agreement, the Partnership is managed by the board of directors of the General Partner. In general, the Partnership's workers are employed under personal employment agreements, and the officers and senior executives of the Partnership are employed according to terms and conditions that are agreed with each one of them in accordance with the Partnership's compensation policy. For further details see Regulations 21, 26 and 26A of Chapter D of this report.

7.17.2 On September 21, 2022, the general meeting of the unit holders approved an arrangement regarding the Partnership's management expenses. Accordingly, from January 1, 2022, the Partnership bears all of the management expenses which, according to the previous management arrangement, applied to the General Partner, including the cost of employment of several managers and employees employed until such date by the General Partner, including the CEO and the active chairman of the board of directors. For further details, see the Partnership's immediate reports of September 6, 2022 and September 21, 2022 (Ref.: 2022-01-092520 and 2022-01-120358, respectively), the information appearing in which is incorporated herein by reference.

7.17.3 As of December 31, 2021 and December 31, 2022, the Partnership employed employees as follows:

Department	Number of Employees as of December 31, 2021	Number of Employees as of December 31, 2022[81]
Management, HQ and Finance	7 (3of whom are officers)	17 (7 of whom are officers)
Professional departments	7 (2 of whom are officers)	7 (2 of whom are officers)
Total	**14**	**24**

7.17.4 In addition to the Partnerships' managers and 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, in the framework of operational agreements in various projects, the operator of the projects employs manpower for the purpose of management and operation of the projects.

[81] As of the report approval date, the number of employees in the departments of management, head office and finance is 16 (of whom 7 are officers), and the number of employees in the professional departments is 6 (of whom 2 are officers).

7.17.5 It is noted that the Partnership adopted an internal enforcement plan in the field of securities laws, in accordance with the criteria for an effective enforcement plan, released by the ISA on August 15, 2011. The Partnership updates the administrative enforcement plan from time to time, as needed.

7.18 **Working capital**

The Partnership's working capital comprises, on the assets side, primarily the cash balances, short-term investments and deposits, various receivables, and trade and other receivables deriving from the joint ventures, whereas, on the liabilities side, it primarily comprises payables deriving from the joint ventures, profits declared and not yet distributed, and short-term liabilities for retirement of oil and gas assets. For further details, see the statements of financial position in the financial statements (Chapter C of this report).

7.19 **Financing**

7.19.1 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 Leviathan project and from the issue of bonds to the institutional market in Israel and overseas.

7.19.2 Bonds of Leviathan Bond

On August 18, 2020, Leviathan Bond, a special-purpose subsidiary (SPC) 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 principal and interest of the Bonds are in dollars, with the interest on the Bonds of each series being paid twice a year, on June 30 and December 30. The Bonds were listed on TASE's "TACT-Institutional" system. For additional information on the Leviathan Bond Issuance see the Partnership's Immediate Report of August 5, 2020 (Ref. 2020-01-084006), the information appearing in which is included herein by reference.

The issue proceeds were provided as a loan to the Partnership by the subsidiary, as noted, under terms and conditions that are identical to the terms and conditions of the Bonds (back-to-back). The balance of the loan as of December 31, 2022 (net of capital raising costs) was approx. $2,230 million (approx. 2,155 net of buybacks, as specified below). It is noted that, upon completion of the Leviathan Bond Issuance on August 18, 2020, the loan that had been provided to the Partnership for financing its share in the balance of the investment in the development of the Leviathan project in the total amount of $1.67 billion, was fully repaid, as were the loans provided to the Partnership in the total amount of $300 million. For additional details, see Sections 7.21.1(a) and 7.21.1(b) of the 2019 Periodic Report, and Notes 10B and 10C to the financial statements (Chapter C of this report) and Part Five of the Board of Directors' Report (Chapter B of this report).

On May 22, 2022, the board of directors of the General Partner approved a plan to purchase the bonds, in an aggregate amount of up to $100 million, for a period of two years (the "**Purchase Plan**"). Until the date of approval of the report, the Partnership made buybacks in accordance with the Purchase Plan in the amount of approx. $100 million. Further thereto, on January 22, 2023, the board of directors of the General Partner approved the adoption of an additional plan for the purchase of the bonds, in an aggregate amount of up to $100 million, for a period of two years (the "**Additional Purchase Plan**"). Until the date of approval of the report, the Partnership made buybacks in accordance with the Additional Purchase Plan in the amount of approx. $9 million.

For further details, see the Partnership's immediate reports of May 23, 2022 and January 23, 2023 (Ref. 2022-01-062266 and 2023-01-010464, respectively), the information appearing in which is included herein by reference, as well as Section 3E to Part One of the Board of Directors' Report (Chapter B of this report).

7.19.3 <u>Credit facilities</u>

On February 5, 2023, the Partnership signed documents for bank credit facilities received from an Israeli bank, designated to serve the Partnership in its ongoing operations. According to the terms and conditions of the credit facilities, the Partnership may, for a period commencing on February 6, 2023 and ending on February 6, 2024, withdraw from time to time dollar loans up to a total amount of U.S. $150 million (divided into two loans, "**Facility A**" up to a total amount of U.S. $100 million and "**Facility B**" up to a total amount of U.S. $50 million). Facility A will be due by May 30, 2025 and Facility B will be due by December 31, 2024 (the "**Credit Facilities**"). For further details, see Note 10D to the financial statements (Chapter C of this report). As of the report approval date, the Partnership has not withdrawn any amount from the Credit Facilities.

7.19.4 Financial covenants

The Credit Facilities determine financial covenants which the Partnership is required to meet, the violation thereof gives the lender the right to acceleration, as specified below:

(a) The ratio between the value of the Partnership's assets and the net financial debt shall be no less than 1.5 on two consecutive review dates, with the covenant review being each quarter according to the Partnership's annual consolidated financial statements or according to the Partnership's quarterly consolidated financial statements, or each half-year insofar as the Partnership prepares only semi-annual reports.[82]

(b) The ratio between the excess sources and the amount in the credit facilities shall be no less than 1, whereby for the purpose of such calculation an amount equal to the balance of the credit facilities that have not yet been drawn down on such date shall be added to the sources, and shall be considered part of the “excess sources”.

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[82] For this purpose, the "**value of the Partnership's assets**" – the total capitalized cash flow (at a rate of 10%), after deduction of taxes of probable and/or contingent reserves (2P and/or 2C) of the Partnership's share in all of the projects, on the basis of the latest discounted cash flow (DCF) announced to the Partnership public, plus the value of additional assets of the Partnership (which are not included in the definition of projects) on the basis of an independent external valuation by a valuator whose identity is acceptable to the Bank.
"**Projects**" – Gas and oil projects that are held by the Partnership and for which a DCF report was released to the public.
“**Financial debt**” – Duties and obligations of the Partnership to banks and other financial institutions and/or which derive from bonds of any type, including straight bonds and convertible bonds and/or which derive from loans which were received by the Partnership from affiliated companies or from any third parties (other than loans for which letter of subordination were signed vis-a-vis bank by the Partnership and the loan provider). For the avoidance of doubt, the term “financial debt” does not include guarantee facilities and bank guaranties issued thereunder at the Partnership’s request.
“**Net financial debt**” – Financial debt net of: (1) cash and cash equivalents; and (2) deposits in banks and financial institutions; (3) fund and safety cushions which were given in order to secure a financial debt (insofar as such were not included in subsection (1) or (2)), and provided that none of the assets specified above is encumbered with a fixed charge and/or is the subject of an undertaking of non-withdrawal in favor of any entity which is not the bank other than due to the debt or liability included in the definition of the financial debt.

A review of the coverage ratio shall be conducted every half-year in accordance with the sources and uses report.[83] For further details, see Note 10D to the financial statements (Chapter C of this report).

7.20 Taxation

7.20.1 General

On August 3, 2021 the Finance Committee of the Knesset approved an amendment to 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 (the "**Income Tax Regulations**"), whereby the tax regime that applies to the Partnership changed from the tax year 2022, such that it is taxed as a company. As a result of this change, from the tax year 2022, the holders of the Partnership's Participation Units are subject to a tax regime for profit distributions made by the Partnership, similarly to the tax regime applicable to shareholders of a company in respect of dividend distributions (i.e., according to the two-stage method).[84] For additional details in this regard, see Note 20A to the financial statements (Chapter C of this report).

7.20.2 Section 19 of the Taxation of Profits from Natural Resources Law

For details regarding a legal proceeding held by the Partnership with respect to Section 19 of the Taxation of Profits from Natural Resources Law, see Note 20C to the financial statements (Chapter C of this report).

7.20.3 Oil and gas profit levy

(a) The Taxation of Profits from Natural Resources Law (in this section: the "**Law**"), enacted by the Knesset in April 2011, determined, *inter alia*, provisions which apply to the Partnership regarding a duty to pay an oil and gas profit levy pursuant to an R-Factor mechanism (in this section: "**Oil Profit Levy**" or the "**Levy**"). For details regarding the Levy and its calculation mechanism, as well as regarding the legal proceedings conducted in connection with the Levy for the Leviathan and Tamar reservoirs, see Note 20C to the financial statements (Chapter C of this report), respectively.

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[83] For this purpose, "**excess sources**" – the total sources accumulated by June 30, 2025 (as specified in the sources and uses report in an agreed version which will be prepared for the period until June 30, 2025) net of the total uses accumulated (as defined in the sources and uses report) until June 30, 2025.

[84] See link to the Tax Regulations as published in the Official Gazette on September 14, 2021: https://www.nevo.co.il/law_word/law06/tak-9627.pdf.

(b) 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**")[85] by virtue of Sections 10(b) and 51 of the Law, which were designed to regulate the payment of the advances for the Oil Profit Levy 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. Below is the essence of the main provisions included in the Regulations:

1. 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.

2. 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 (in the case of joint marketing), or the current revenues of the Holder of a Petroleum Interest (in the case of separate oil sale). Additionally, it was determined that in the first 3 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%.

3. 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, and 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, and therefore, the Regulations determine that a Holder of a Petroleum Interest is entitled to offset against its advance payments a sum withheld thereby from the recipient of a derivative payment, pursuant to the provisions of Section 9(b)(1) of

[85] https://www.gov.il/BlobFolder/legalinfo/law8957/he/LegalInformation_kesher_8957.pdf

the Law, provided that all of the following are satisfied: (a) 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; (b) The transferred withheld amount was not previously offset; and (c) 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.

4. 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.

(c) On November 10, 2021 the Knesset approved Amendment No. 3 to the Law, 5782-2021 which includes, *inter alia*, an amendment whereby according to the decision of an assessing officer, payment of 75% of the balance of the contested Levy which was appealed may be charged (even before the dispute is heard), and other amendments designed to confer powers on the assessing office to streamline the Levy collection. For further details, see Note 20C to the financial statements (Chapter C of this report).

7.20.4 <u>The 2015-2016 tax years</u>

(a) On December 3, 2017, the Partnership released an immediate report, attached to which were temporary tax certificates for Entitled Holders in respect of holding participation units of the Partnership and of the Avner Partnership (in this section: "**Entitled Holders**") for the 2015 and 2016 tax years (Ref. 2017-01-116190).

(b) On October 20, 2021 the Partnership issued an immediate report, attached to which were final tax certificates for Entitled Holders for the 2015 tax year (Ref. 2021-1-158139), the information included in which is incorporated herein by reference.

(c) In view of the disputes between the Partnership and the Tax Authority 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, 5721-1961 (the "**Income Tax Ordinance**" and, in this section: the "**Tax Assessment**"), whereby the taxable income from a business of the Partnership and the Avner Partnership for 2016 is approx. $136.9 million and approx. $124.0

million, respectively (rather than approx. $113.4 million and approx. $100.6 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. $49.3 million and approx. $65.6 million, respectively (rather than approx. $6.7 million and approx. $15.6 million, respectively, as included in the Partnerships' tax reports which were filed with the Tax Authority). It is noted that the said amounts were translated from ILS to $ according to the dollar exchange rate known as of December 31, 2022.

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 Income Tax Ordinance (the “**Orders**”), which primarily pertain, 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 Tanin and Karish 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. $45.9 million.

On September 15, 2020, the Partnership filed an appeal from the Orders with the Tel Aviv District Court. The grounds for the assessment in the appeal were submitted by the assessing officer on December 21, 2020, and according to the Court’s decision, the notice of the grounds for the appeal on behalf of the Partnership was filed on May 3, 2021. A pretrial hearing on the appeal was held on November 25, 2021, and another pretrial hearing has been scheduled for April 17, 2023.

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) Upon determination of the taxable income of an Entitled Holder for tax year 2016, a final certificate will be issued for purposes of calculating the taxable income of an Entitled Holder for tax year 2016, according to the Income Tax Regulations.

7.20.5 <u>The 2017 tax year</u>

(a) On November 8, 2018, the Partnership released an immediate report, attached to which was a temporary tax certificate for an entitled holder due to the holding of participation units of the Partnership for the 2017 tax year (Ref. 2018-01-101494).

(b) Against the backdrop of the disputes that arose 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**").

The disputes mainly 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 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 interests in the Tamar and Dalit leases.

On December 10, 2020, the Partnership filed an administrative objection to the Tax Assessment, and, accordingly, several discussions have been held at the offices of the Assessing Officer with respect to the administrative objection.

On December 21, 2022, the Assessing Officer issued an order for tax assessment for the 2017 tax year.

In accordance with the foregoing order, the Partnership's taxable income from a business for 2017 is approx. $354.7 million (rather than approx. $211.8 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. $674.2 million (rather than approx. $528.4 million, as included in the Partnership's tax report that was filed with the Tax Authority). It is noted that the said amounts were translated from ILS to $ according to the dollar exchange rate known as of December 31, 2022.

It is further noted that on January 22, 2023, the Partnership filed an appeal on the matter with the Tel Aviv District Court.

As of the report approval date, according to the said order, and insofar as all of the claims of the Tax Authority are accepted, the Partnership will be required to pay additional tax (including linkage differentials and interest), at the expense of the participation unit holders of the Partnership in the sum of approx. $108.2 million.

It is noted 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.

In the Partnership's estimation, based on the opinion of its legal counsel, the probability of acceptance of the Partnership's key claims is higher than 50%, and the Partnership therefore intends to exhaust the administrative and legal proceedings available thereto.

(c) Upon determination of the taxable income of an Entitled Holder for the 2017 tax year, a final certificate will be issued for purposes of calculating the taxable income of an Entitled Holder for tax year 2017, according to the Income Tax Regulations.

7.20.6 <u>The 2018 tax year</u>

(a) On February 19, 2020, the Partnership released an immediate report, attached to which was a temporary tax certificate for an entitled holder due to the holding of a participation unit of the Partnership for the 2018 tax year (Ref. 2020-01-017376), the information appearing in which is incorporated herein by reference.

(b) Against the backdrop of the disputes which arose between the Partnership and the Tax Authority and disagreements regarding the amount of the taxable income of the Partnership for 2018, on March 24, 2021, a tax assessment other than in agreement 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 2018 is approx. $185.0 million (rather than approx. $142.0 million, as included in the Partnership's tax report that was filed with the Tax

Authority) and the Partnership's capital gain for 2018 is approx. $16.4 million, as declared in the report filed thereby as aforesaid. It is noted that the said amounts were translated from ILS to $ according to the dollar exchange rate known as of December 31, 2022.

The disputes mainly pertain to the interpretation of the manner of recognition of financial expenses and additional expenses borne by the Partnership, similar to the disputes for which assessments to the best judgment were issued for 2016 and 2017, as specified in Sections 7.20.4(c) and 7.20.5(b) above, respectively.

As of the report approval date, 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. $13.8 million.

On June 10, 2021, the Partnership filed a reasoned administrative objection to all of the Assessing Officer's determinations in the Tax Assessment. As of the report approval date, several discussions on the objection have been held at the offices of the Assessing Officer, and several further discussions are expected to be held.

It is noted 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 tax year 2018 may be delayed pending the completion of the proceedings which will be required for the determination of the final assessment.

In the Partnership's estimation, based on the opinion of its legal counsel, the probability of acceptance of the Partnership's key claims is higher than 50%, and the Partnership therefore intends to exhaust the administrative and legal proceedings available thereto.

(c) Upon determination of the taxable income of an Entitled Holder for the 2018 tax year, a final certificate will be issued for purposes of calculating the taxable income of an Entitled Holder for tax year 2018, according to the Income Tax Regulations.

7.20.7 <u>The 2019 tax year</u>

(a) On July 14, 2021, the Partnership released an immediate report, attached to which was a temporary tax certificate for an entitled holder due to the holding of a participation unit of the Partnership for the 2019 tax year (Ref. 2021-01-116862), the information included in which is incorporated herein by reference.

(b) Upon determination of the taxable income of an Entitled Holder for tax year 2019, a final certificate will be issued for purposes of calculating the taxable income of an Entitled Holder for the 2019 tax year, according to the Income Tax Regulations.

7.20.8 The 2020 tax year

(a) On April 12, 2022, the Partnership released an immediate report, attached to which was a temporary tax certificate for an Entitled Holder and seller of participation units due to the holding of a participation unit for the 2020 tax year (Ref. 2022-01-047374), the information appearing in which is incorporated herein by reference.

(b) Upon determination of the taxable income of an Entitled Holder for 2020 tax year, a final certificate will be issued for purposes of calculating the taxable income of an Entitled Holder for the 2020 tax year, according to the Income Tax Regulations.

7.20.9 The 2021 tax year

(a) According to the tax report submitted by the Partnership for 2021, which is subject to the audit of the Tax Authority, the Partnership's taxable income is approx. ILS 919.0 million, and the capital gain, mainly in respect of the sale of the rest of the Partnership's interests in the Tamar and Dalit Leases, is approx. ILS 1,868 million, and deferred capital gain for the sale of the Partnership's holdings in Tamar Petroleum Ltd. ("**Tamar Petroleum**") is approx. ILS 203.1 million.

(b) Upon determination of the taxable income of an Entitled Holder for the 2021 tax year, a final certificate will be issued for purposes of calculating the taxable income of an Entitled Holder for tax year 2021 tax year, according to the Income Tax Regulations.

7.20.10 Although under the amendment to the Income Tax Regulations, the Partnership is taxed as a company (i.e., according to the two-stage method) as of 2022, as noted in Section 7.20.1 above, according to a clarification received from the Tax Authority, the payments made in January 2022 (after the tax regulations had taken effect) will not be taxed as a dividend distribution by a company according to the regulations.

7.20.11 It is clarified that for each of the tax years from 2016 forth, for which the Tax Authority's audit of the Partnership's tax reports is as yet uncompleted, it may transpire after the completion of the Tax Authority's 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 participation unit holders, the balance of the tax deriving from the assessment differences, according to the tax calculation under Section 19 of the Natural Resources Law . It is noted that according to the judgment of June 28, 2021, as specified in Note 20B to the financial statements (Chapter C of this report), balancing payments due to such assessment differences (if any) will not be made. 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.

7.20.12 It is further clarified that part of the unique tax issues 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.

7.20.13 For further details see Note 20B to the financial statements (Chapter C of this report).

Every participation unit 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 <u>Environmental risks and management thereof</u>

7.21.1 By nature, the activity of exploration, development, production and abandonment of oil and natural gas projects 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.

7.21.2 <u>The Partnership is subject to the provisions of the law and/or instructions of competent authorities on environmental issues.</u>

(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 is 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 (the "**Hazardous Substances Law**") 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; 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; Business Licensing Law, 5728-1968 ("**Business Licensing Law**"), the regulations and the orders promulgated thereunder.

(c) There has recently been a wide public debate on climate changes and mankind's influence over these changes, which may lead to regulatory changes with a material effect on the Partnership's business sector. In this context, on June 1, 2022, the Climate Bill, 5782-2022[86] was presented to the Knesset for a preliminary hearing. The bill determines that, starting in 2030, the targets for reducing carbon emissions will be in accordance with Government Resolution No. 171 of July 25, 2021, and from 2050 onwards they shall be zero emissions (hereinafter in this section: the "**Bill**"). On June 28, 2022, during the tenure of the previous Knesset, the Bill was passed in the first reading at the plenum, and as

[86] https://main.knesset.gov.il/Activity/Legislation/Laws/Pages/LawBill.aspx?t=lawsuggestionssearch&lawitemid=2193180

of the report approval date, there is uncertainty with respect to the date of completion of the legislation proceedings, if any.

(d) February 2022 saw the release of the Enhanced Efficiency of Environmental Licensing Proceedings Legislative Memorandum (Legislative Amendments), 5782-2022, the purpose of which is to optimize and enhance the efficiency of the existing licensing schemes from both a regulatory perspective and an environmental perspective, by means of a comprehensive reform that is based on conformity to the standards generally accepted in the European Union. Under the proposed law, the licensing arrangements in the existing environmental legislation will be amended so that licensing proceedings will be consolidated, to the extent possible, based on the regulation principles in the European Union, such that a uniform environmental permit will be issued for operations with the potential to cause considerable environmental impact. The memorandum was closed for public comment on February 27, 2022.

(e) In April 2022, the Ministry of Environmental Protection released a legislative memorandum for the Law for Preparedness for and Response to Incidents of Oil Pollution of the Sea and the Coastal Environment, 5782-2022, which aims to implement the 1990 International Convention on Oil Pollution Preparedness, Response and Cooperation on the Israeli-local level, by promoting preparedness for incidents by all entities whose jurisdiction or area of responsibility includes a coastal strip or which operate at sea, i.e., local authorities, the Israel Nature and Parks Authority, ports, factories and defense facilities, and owners of facilities for the exploration and production of oil and natural gas. In this framework, the responsible bodies are required to draft plans to deal with incidents of oil pollution of the sea and the coastal environment. Prepare themselves according thereto and comply therewith if incidents occur. It is also proposed to regulate the handling of such incidents and their outcome. The methods of handling are on three levels, as follows: (1) Preparedness – preparation of emergency plans, equipping and drills; (2) Response to the incident – mitigation of damage in general and environmental damage in particular; and (3) Cleaning and restoration – cleaning what was contaminated, restore the situation to its original state, and removal of the waste that was created. The memorandum was closed for public comment on May 5, 2022, and as of the report approval date, the report was not presented to the Knesset as a bill.

(f) 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 (for details, see Section 7.22.8(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 this context, it is noted that 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.

(g) <u>Environmental directives for offshore exploration and production of oil and natural gas</u>

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 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. These directives include, *inter alia*, directives for the performance of seismic surveys, directives on the drilling of exploration and appraisal wells and directives post-discovery and on leases, and specify the various tests, approvals and permits which are required from the interest holders in each of the aforesaid stages.

(h) In addition to the instructions of the Ministry of Energy and the Ministry of Environmental Protection, in the context of 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.

7.21.3 In addition, the operating approval of the Leviathan platform determines the leaseholder's duty to act, on issues of environmental protection, pursuant to the law and instructions and permits that are given pursuant to law, and also determine provisions with respect to the discharge of emissions into the sea, emissions into the air, etc. The said operating approval 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.

7.21.4 Events in connection with the environment

According to information provided to the Partnership by the operator of the Leviathan project, in 2022 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 7.21.7 below.

7.21.5 Environmental risk management policy

(a) The operator in the Leviathan project operates according to a strategic 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 an environmental risk management system, including training suitable manpower, and including a work plan for the reduction of environmental damage, for the support in biodiversity, for the prevention of incidents and accidents and for the constant improvement of the organizational culture and activity on issues of safety, environment and hygiene. In this framework the operator has a designated team both for all stages of the activity, 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 its teams and the teams of the contractors that work on the facilities. Additionally, the operator is acting to obtain all of the environmental-regulation permits required for each one of the sites operated thereby, as applicable, including a business license under the Business Licensing Law, a toxic materials permit under the Hazardous Substances Law, a marine discharge permit under the Prevention of Sea Pollution Law and an emission permit under the Clean Air Law. The Partnership is acting to receive periodic and specific updates regarding the operator's activity regarding the aforesaid matters, as needed and in accordance with an internal procedure on the matter, adopted by the Partnership.

(b) In 2019, the operator in the Leviathan project received a preliminary business license, air discharge permit, marine discharge permit and toxic materials permit for the Leviathan platform, which are extended from time to time in accordance with the requirements of the law. As of the report approval date, the business license is valid until December 31, 2029, the air discharge permit is valid until November 5, 2026, the marine discharge permit is valid until March 31, 2024, and the toxic materials permit is valid until June 4, 2023. A business license and the toxic materials permit were also received for the Hagit site, and its validity is extended in a similar manner.

7.21.6 <u>Environmental costs and investments</u>

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.

7.21.7 <u>Material legal or administrative proceedings in connection with the environment</u>

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) <u>Financial penalties</u>

On May 20, 2020, Chevron 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 Leviathan project's air emission permit and the Clean Air Law, and the instruction of the Supervisor of Emission Permit in the Ministry of Environmental Protection (in this section: the "**Supervisor**"), given by virtue thereof in connection with the continuous monitoring systems in the Leviathan platform. Chevron 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, the requested information has not yet been received and therefore the count of days for responding to the aforesaid notice has not yet begun, such that 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.

(b) <u>Hearings</u>

On November 1, 2021, Chevron received a letter of notice and summons to a hearing before the Ministry of Environmental Protection due to noncompliance with the conditions of the sea discharge permit issued to the Leviathan platform and violation of the Prevention of Marine Pollution Law, in which letter it is claimed that Chevron has deviated from the specified criteria for marine discharge from the open system. The hearing took place on January 6, 2022, in which it was determined that Chevron is required to take all actions to prevent deviations from the marine discharge permit and that the Ministry of Environmental Protection is considering exercising its full powers by law, including a possible recommendation for a financial penalty under the law. On June 28, 2022, Chevron received a letter of request for the receipt of details about the annual sales turnover under Section 5(C)(b)(2) of the Prevention of Sea Pollution Law. The letter notes that the information needed to determine the administrative fine amount that the Ministry of Environmental Protection intends to impose on Chevron for violation of conditions in the permit for sea discharge of wastewater (gas production) number 24/2021, in connection with the discharge of wastewater that exceeds the standards for discharge into the sea. Chevron submitted the required documents to the Ministry for Environmental Protection.

It is not possible at this stage to assess the violations for which the administrative fine will be imposed and the administrative fine amount which will be imposed, if any.

(c) On December 15, 2020, a motion for class certification was filed with the Tel Aviv District Court against Chevron (below in this section: the "**Respondent**") by a resident of Dor Beach on behalf of "anyone who was exposed to the air, sea and coastal environment pollution, due to prohibited <u>emissions</u> 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 "**Certification Motion**", the "**Petitioner**" and the "**Class Members**"). In essence, the certification motion argues that the Respondent exposed the Class Members to air, sea and environmental pollution, due to prohibited emissions deriving from the Leviathan 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 Members for the damage they allegedly incurred which is estimated at approx. ILS 50 million. In addition, the Petitioner moved for a remedy of an order instructing the Respondent to immediately fulfill the obligations imposed thereon in the Clean Air Law and the Regulations thereunder. On May 16, 2022, a pretrial hearing was held, at the end of which the Court ordered Chevron to submit a response to the motion for discovery order, within 30 days. In its decision of June 26, 2022, the court rejected the bulk of the motion for discovery and granted part thereof, in its ruling that Chevron must disclose the decisions of the Ministry for Environmental Protection to impose the fines and minutes of hearings ahead of the imposition of the fines. Chevron filed the relevant documents for the court's inspection together with an argument seeking to redact various details. On August 7, 2022, the petitioner filed a response to the argument by Chevron, in which Chevron was asked, *inter alia*, to disclose the minutes of a hearing which took place in the Ministry of Environmental Protection. Furthermore, in accordance with the court's decision of August 8, 2022, Chevron filed a number of clarifications on the matter with the court. A trial hearing took place on February 5, 2023. On February 21, 2023 the court dismissed the motion of the petitioner to submit the regulator opinion which was filed in another case and which, according to the petitioner, has implications on the certification motion.

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 Certification Motion being granted are lower than 50%.

7.21.8 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.

7.21.9 It is noted that the EMG pipeline, which connects between the Israeli transmission system in the area of Ashkelon and the Egyptian transmission system in the area of el-'Arīsh, is subject to Israeli and Egyptian regulation.

7.21.10 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.

7.22 **Restrictions and supervision of the Partnership's activity**

7.22.1 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[87] 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[88] to the Partnership, Avner, Ratio and Chevron (in this section: the “**Parties**”) by the Prime 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**”). The 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**”.

Below is a concise description of the main parts of 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 Chevron; 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, 2030.[89]

[87] In the exemption pursuant to Section 52 of the Restrictive Trade Practices Law, which was attached as Annex A to the Framework, Tamar was defined 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”.

[88] 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”.

[89] In accordance with the authority of the Minister of Energy to extend the Exemption until January 1, 2030 upon the fulfillment of certain conditions as prescribed in the Exemption, the Exemption was actually extended until January 1, 2030.

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 Leviathan and Tamar reservoirs only, the Partnership, Avner and Chevron being the holders of a monopoly according to the Competition Commissioner's declarations.[90]

(b) The Exemption from the Restrictive Arrangements specified above was made contingent upon the specific conditions, including:

1. <u>Transfer of the Partnership's and Chevron's rights in the Tanin and Karish Leases</u>

   In accordance with the provisions of the Gas Framework, the rights in the Tanin and Karish leases were fully transferred to a third party in December 2016. For further details, see Section 7.5.2 above.

2. <u>Transfer of the Partnership's rights in the Tamar Project</u>

   According to the provisions of the Gas Framework, the Partnership transferred all of its rights in the Tamar project in the context of a sale to Tamar Petroleum, which transaction was closed in July 2017 (for further details see Section 7.24.12 below) and an additional sale to Tamar Investment 1 RSC Limited and Tamar Investment 2 RSC Limited, which transaction was closed in December 2021. For further details see Section 7.24.13 below. In addition, in May 2021, the Partnership sold its entire holdings in shares of Tamar Petroleum in an off-exchange transaction.

   To the Partnership's best knowledge, according to the Gas Framework, Chevron reduced its percentage holdings in the Tamar project to 25%, after performing in December 2016 and March 2018 two transactions for the sale of 3.5% and 7.5% of the rights in the project to Everest and Tamar Petroleum, respectively.

[90] See Footnote 88 above.

(c) Specific restrictions to apply to new agreements for the supply of natural gas

The Gas Framework sets out specific restrictions that will apply to new agreements for the supply of gas from the Leviathan reservoir, that shall be signed with consumers from the date of the Government Resolution. Most of the restrictions are no longer relevant, other than:

a. The consumer shall be subject to no restriction with respect to the purchase of natural gas from any other natural gas supplier.

b. 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.

c. The parties shall not apply any restriction to the sale price at which the consumer shall sell the natural gas in a secondary sale.

d. The gas sales agreements shall not include a condition whereby the consumer's notification of shortening of the term of the agreement or reduction of the purchase amount will lead to any change in the terms of the agreement that is detrimental to the consumer. In this context, no change detrimental to the consumer shall be made to the price and terms of payment, the terms, dates and quantities of supply, the addition of restrictions on resale of the gas, etc.

(d) Restrictions regarding the price of natural gas in consumer supply contracts, which no longer apply as of the report approval date

The Gas Framework included provisions regarding the prices that the Partnership was required to offer to gas consumers from the date of the Government Resolution, on August 16, 2015 until the date of closing of the transfer of the rights of the Partnership, Avner and Chevron in the Tanin and Karish leases, or in the Tamar lease in accordance with the provisions of the Framework, whichever is later. Such period ended upon the closing of the sale of Partnership’s rights in the Tamar lease in December 2021.

7.22.2 Economic competition law

(a) The status of the Partnership as a monopoly

On November 13, 2012 the Partnership was declared a monopoly – together with its 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.

Even though in December 2021 the Partnership closed the sale of the balance of its interests in the Tamar and Dalit leases, as of the report approval date, the declaration of the monopoly in Tamar was not changed by the Competition Authority, and the Partnership still appears in the Register of Monopolists. In addition, since as of the report approval date, the Partnership is engaged in the joint marketing of the gas produced from the Leviathan project, it may also be considered a monopoly insofar as the Leviathan partners are considered a monopoly in the natural gas supply in Israel.

A monopoly is subject to Chapter D of the Economic Competition Law, including a prohibition to unreasonably refuse to supply the asset or service in the monopoly and a prohibition on abuse of its position in the market in a manner that might reduce competition in business or harm the public.

(b) Natural gas price control

The Products and Services Price Control Order (Application of the Law to Natural Gas and Determination of Level of Control), 5773-2013 (the "**Products and Services Price Control Order**"), imposes control on the gas market at the level of profitability and price reporting. Such duty to report applies separately with respect to each project. Over and above the duty to report prices and profitability, as of the report approval date, no control was imposed on the prices of gas marketed in Israel. For details regarding a risk factor pertaining to the possible impact of imposing control on natural gas prices in Israel, see Section 7.28.18 below.

(c) The consent of the Competition Commissioner to the merger in connection with the acquisition of EMG shares

In order to enable the export of gas from the Leviathan reservoir to Egypt, EMED acquired 39% of the share capital of EMG, according to an agreement signed in September 2018, specified in Section 7.24.6 below. The acquisition of EMG shares was subject, *inter alia*, to the receipt of approval for the merger, in accordance with Section 20(b) of the Economic Competition Law. On July 31, 2019, the decision of the Competition Commissioner approving the merger was given[91], under the conditions whose summary is described below:

[91] https://www.gov.il/BlobFolder/legalinfo/decisions037056/he/decisions_037056.pdf.

1. The Partnership, Chevron, EMG and EMED and any party related thereto as defined in the Resolution (in this section jointly: the "**Parties**") shall not refuse a request for gas swap and shall supply natural gas to a customer in Israel who signed a natural gas supply contract with a natural gas supplier in Egypt, in the same quantity and at quality no lower than the quality undertaken by the natural gas supplier in Egypt to the customer in Israel (the "**Gas Swap Arrangement**"). In this context, they shall make every reasonable effort including by exercising their rights in the Leviathan and Tamar projects, in order to comply with such request.

2. The duty of the parties as stated in subsection (1) above is up to the quantities of gas 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 transmission agreements in the EMG pipeline.

3. In respect of natural gas to be swapped as part of the Gas Swap Arrangement, EMG shall not charge from an Egyptian supplier an amount that exceeds one half of the pipeline transmission fee.

4. The Parties shall not refuse to provide pipeline transmission services to another party wishing to receive pipeline transmission services up to the scope of available capacity.

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 granted thereto to extend the capacity and operation agreement by an additional 10 years (as specified in Section 7.24.6 below) without the receipt of a prior permit from the Competition Commissioner.

For further details regarding the appeal filed against the decision of the Competition Commissioner to approve the merger and judgment which was issued in the appeal by the Competition Court, see Section 7.25.7 below.

7.22.3 The Promotion of Competition and Reduction of Concentration Law, 5774-2013 (the "**Anti-Concentration Law**")

According to the Anti-Concentration Law, regulators have powers to make industry competitiveness considerations and economy-wide concentration considerations, as part of the allocation of public assets by the State, in order to ensure increased industry competitiveness and decentralization of economy-wide concentration. Accordingly, 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 Anti- 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 Anti-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.

According to the provisions of the Anti-Concentration Law, the Committee for the Reduction of Concentration publishes and updates from time to time the list of the concentration entities in the economy, the list of significant financial entities and the list of significant non-financial corporations. The Partnership appears in the list of concentration entities and in the list of significant non-financial corporations. On December 28, 2021, the Partnership contacted the chairman of the Concentration Committee in a request to remove it from the list of concentration entities. To the best of the Partnership's knowledge, as of report approval date, the Partnership has not yet been removed from the said lists and it still appears therein.

7.22.4 The Petroleum Law and the regulations promulgated thereunder

(a) The Petroleum Law

The exploration, development and production of oil and/or natural gas (in this section: "**Petroleum**") in Israel is regulated mainly under the Petroleum Law, including the amendments incorporated therein, and the regulations promulgated thereunder (in this section: the "**Law**") the principles of which are as follows:

1. The Law provides 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 leaseholder 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 (which shall not exceed 250 square kilometers), 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. The Minister of Energy may expropriate the lease, if the license holder has not produced petroleum in commercial quantities during the first three years of receipt of the license. Furthermore, 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 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. The Law provides that the Petroleum 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 Petroleum 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 12 licenses, and that it will not have licenses for a total area exceeding 4 million thousand sqm, except upon prior approval of the Petroleum Council.

10. The Minister of Energy, after consulting with the Petroleum Council, may require the lease holders to first supply, at market price, from the petroleum that is produced in Israel and also from the petroleum products which were produced therefrom, the same amount of petroleum and petroleum products which are required, in the opinion of the Minister of Energy, for domestic consumption. However, note that a lease holder shall not be required (a) to produce from a well more than its maximum effective rate of output; (b) to supply a percentage of its output which is greater than the percentage of output required of another lease holder, unless the Minister of Energy sees fit to deviate from the rule, if so required in his opinion, for reasons of State security or prevention of waste or unfairness towards another lease holder.

11. Section 54 of the Petroleum Law stipulates that if a petroleum interest holder has not paid fees or royalties on time and it has been notified thereof in writing, and after 30 days it has not been paid thereby, the Minister may impose an attachment the entire petroleum inventory, facilities, and the other rights which belong to the petroleum right holder, and it may seize all of the attached property until payment is received in full.

12. Section 76 of the Petroleum Law determines that 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 Petroleum Commissioner's permission, and the Petroleum Commissioner will not permit the pledge or transfer of a license or of a lease other than after consulting with the Petroleum Council.

13. 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 Petroleum Commissioner. An oil pipeline will be constructed according to detailed drawings in accordance with the law, which will first require the approval of the Petroleum Commissioner,

which shall not be unreasonably withheld. The Petroleum Commissioner may, after consulting with the Petroleum Council, require a pipeline owner who is approved as aforesaid to transport the petroleum of a certain person, in the event that the owner of the pipe does not need it to transport its own petroleum and under acceptable conditions which the Petroleum Commissioner shall determine.

(b) <u>The Petroleum Regulations (Principles for Offshore Petroleum Exploration and Production), 5777-2017 (the "**Offshore Regulations**")</u>

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.

Below is a description of the principles of the Offshore Regulations:

1. The Petroleum Commissioner will not certify an applicant as operator unless the following principal conditions are fulfilled:

    (a) The operator will be the lease holder with at least 25% of the rights in the Petroleum asset.

    (b) The operator or control holder therein (subject to the conditions in the Offshore Regulations) will have at least 5 years of experience in the 10 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; and (d) experience in activities for preservation of health, safety, and environmental protection relating to activities in petroleum interests.

    (c) Furthermore, the Petroleum Commissioner will not certify a corporation as operator, unless it directly employs employees that have qualification and at least 5 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.

(d) 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.

(e) 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.

(f) The Petroleum 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.

2. The applicant for a petroleum interest must prove appropriate financial capacity by fulfillment of both of the following:

(a) 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.

(b) 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, 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.

3. 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.

4. 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 immaterial and the Petroleum Commissioner was convinced that there are special grounds which justify so doing.

5. 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.

7.22.5 The Natural Gas Sector Law and the regulations promulgated thereunder

(a) 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:

   (a) The construction and operation of a transmission system or part thereof.

   (b) The construction and operation of a distribution network or part thereof.

(c) The construction and operation of an LNG facility.

(d) The construction and operation of a storage facility.

(e) 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.

The Gas Sector Law establishes additional provisions that include, *inter alia*, conditions for granting licenses, granting powers to the Minister, the Natural Gas Sector Authority (appointed under Section 63 of the Natural Gas Sector Law) and the Director of the Authority regarding the granting of licenses and determining various conditions and restrictions that will apply with respect to the licenses or license holder, and grants them powers to determine provisions with respect to natural gas suppliers; provisions regarding revocation of licenses, guarantees required from a license holder, etc.

It is noted that in accordance with the provisions of the Natural Gas Sector Law, a transmission license was granted to Leviathan Transmission System, for the gas flow from the production platform of the Leviathan project to the northern entry point of the national transmission system of INGL.

Within the framework of the Economic Plan Law (Legislative Amendments for Implementation of Economic Policy for 2021 and 2022 Budget Years), 5782-2021, which was approved by the Knesset on November 4, 2021, the definition of the term "Rates" in the Natural Gas Sector Law was expanded such that it includes not only payments paid by consumers for services they receive, but rather any payment that will be imposed on any one of the players in the natural gas sector, including natural gas suppliers, for the benefit of another license holder and for any purpose, including purposes of gas sector development, backup and redundancies. The aforesaid applies whether or not such player on whom the Rate is imposed, receives any service from the license holder. This amendment may allow for the imposition of charges on natural gas suppliers by virtue of the Law. It is noted that the aforesaid law was approved by the Knesset after the petition mentioned in Section 7.25.12 below, has been filed with the Supreme Court.

(b) Natural Gas Sector Regulations (Management of the Natural Gas Sector in a State of Emergency), 5777-2017 (the "**Emergency Regulations**")

The Emergency Regulations were promulgated 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.

In the event that the Minister of Energy announces a state of emergency in the natural gas sector, the Emergency Regulations determine that if the demand at any time exceeds the maximum quantity that a natural gas supplier can supply from the field for which the declaration was given (the "**Defaulting Gas Supplier**"), then the gas supplier and the transmission license holder are obligated to make allocations of natural gas and LNG to consumers in accordance with the provisions specified in the Regulations. The Regulations authorize the Minister of Energy, under certain conditions, to deviate from the provisions of the Regulations and order a different allocation of the quantities of gas and LNG, provided that the deviation does not exceed what is required.

The Regulations determine that they do not derogate from the remedies and relief available to anyone that signed an agreement with the Defaulting Gas Supplier and in accordance with the said agreement.

(c) The Natural Gas Sector Regulations (Duty to Provide Information of a Natural Gas Seller and Marketer), 5782-2022 (in this section: the "**Regulations**")

On April 6, 2022, the Regulations took effect, according to which all those engaged in the sale or marketing of natural gas will be required to submit to the Director of the Natural Gas Authority quarterly reports that include details on the quantities of natural gas sold or marketed each month, the prices agreed upon in each natural gas supply agreement, the total income of the seller or marketer from natural gas sales to consumers in the Israeli market, copies of signed agreements and other details.

(d) <u>Regulation of criteria and rates regarding the operation of the transmission system in a flow control regime</u>

1. 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)[92] (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 took effect on April 1, 2021.

   After the release of the Decision, INGL contacted Chevron with a demand to apply the Decision retroactively from the beginning of 2020 with respect to the Leviathan project, and also forwarded for the inspection of Chevron, a notice in this spirit which it provided to its customers. Further to the above notice, Chevron 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.

   On April 7, 2021, the Partnership together with the other Leviathan Partners and Tamar Partners against the Natural Gas Council and the Ministry of Energy in which it is requested to order the nullification of the decision on February 9, 2023, the petitioners decided to withdraw their petition with the recommendation of the court. For further details, see Section 7.25.12 below.

2. On October 6, 2022, the Natural Gas Commission released decision no. 2/2022 which stipulates an annual update of the transmission

[92] 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.

tariffs, commencing in November 2022. In the context of the said update to the fees, it was stipulated that the capacity tariff shall be ILS 0.6453 per MMBTU, which reflects a decrease of approx. 17.6% in the rate compared with the rate last year. The transportation tariff shall be ILS 0.1109 per MMBTU, which reflects a decrease of approx. 18%, and the transportation tariff in the transmission system to consumers connected to the distribution network shall be ILS 0.7902 per MMBTU, which reflects a decrease of approx. 17.7%.[93]

3. On December 18, 2022, the Natural Gas Commission released decision no. 3/20252 regarding an amendment of decision no. 2/2019. The decision amends the current tariff, such that the annual load factor (an average factor of Israeli consumers) shall be 0.64, and therefore the commitment to transfer or payment for transfer shall be reduced from 0.5 BCM to 0.25 BCM per year.[94]

4. On December 20, 2022, the Natural Gas Commission released decisions no. 4/2022 and no. 5/2022, in which it is stipulated, inter alia, that the system tariff for 2023 will be ILS 0.0294 per MMBTU unit. The system tariff is intended to finance projects for purposes of infrastructure, development, backup, redundancy of systemic needs of the natural gas sector, or acts which the license holder must perform in accordance with the Natural Gas Sector Law.[95][96]

5. For details regarding the expansion of the definition of the term "Rates" in the Natural Gas Sector Law, which allows the imposition of charges on natural gas suppliers by virtue of the Natural Gas Sector Law, see this section above.

(e) Decisions of the Natural Gas Authority Council regarding the financing of export projects via the national transmission system (in this section: the "**Decision**")

The Natural Gas Authority Council made several decisions regarding the transmission rates that will apply to the export of natural gas via the national transmission system, and regarding the financing of the construction of those segments of the transmission system designated for purposes of export of natural gas as aforesaid, by the gas exporters.

[93] https://www.gov.il/BlobFolder/generalpage/ng_council_decisions/he/board_decision_2_2022.pdf.
[94] https://www.gov.il/BlobFolder/generalpage/ng_council_decisions/he/BoardDecision3_22.pdf.
[95] https://www.gov.il/BlobFolder/generalpage/ng_council_decisions/he/BoardDecision4_22.pdf.
[96] https://www.gov.il/BlobFolder/generalpage/ng_council_decisions/he/BoardDecision5_22.pdf.

According to the decisions of the Council, on June 23, 2020 the Director General of the Natural Gas Authority announced his determination that the cost of the combined section designated for the piping of natural gas from the Leviathan and Tamar reservoirs to EMG's terminal in Ashkelon for purposes of piping gas to Egypt according to the export agreements is estimated (as of the date of signing of the Transmission Agreement) at a sum total of ILS 738 million which will be updated according to an update and accounting mechanism between the parties as set forth in the Transmission Agreement with INGL. On May 2, 2022, INGL updated the project's budget to approx. ILS 796 million.

According to the announcement of the Director General of the Gas Authority, 43.5% of the section's cost, as shall be determined in accordance with the aforesaid, will be financed by the holder of the transmission license (INGL) and 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. In addition thereto, the exporter shall pay the holder of the transmission license ILS 27 million for its share in the cost deriving from the bringing forward of the doubling of the Dor-Hagit and Sorek-Nesher sections (which is estimated at approx. ILS 48 million) and that 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 above (the share of the holder of the transmission license in the cost of construction of the Combined Section plus ten percent), and in the sum of ILS 21 million, which will decrease in accordance with the provisions of the addendum to the Decision.

The announcement of the Director General of the Authority further determines that 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 and that 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 the section plus ILS 48 million (the cost derives from the bringing forward of the doubling of the Dor-Hagit and Sorek-Nesher sections), 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 the aforesaid.

For details on a transmission agreement signed between Chevron and INGL in connection with the export of natural gas to Egypt, see Section 7.11.2(e) above.

7.22.6 <u>Regulation of Security in Public Entities Law, 5758-1998 (in this section: the "**Law**")</u>

(a) The Law imposes various duties on a "public entity" (as defined in the Law), including: (a) Appointment of a security officer who will report directly to the 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; and (c) Appointment of a security guard in accordance with the requirements of an authorized officer.

(b) According to the Sixth Schedule to the Law, a license holder under the Gas Sector Law that owns an offshore facility or operates an offshore facility is deemed a public entity for the purpose of imposition of the duties listed in the Law, including the performance of maritime security 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 thereto. The definition of an offshore facility in the Law includes, *inter alia*, any facility or vessel 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 and therefore apply to the offshore production facilities of the Leviathan project. Accordingly, the provisions of the Sixth Schedule to the Law apply to Leviathan Transmission System, which holds the license for transmission from the Leviathan project.

(c) Other than offshore facilities the provisions of the Law also apply to 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 and therefore the provisions of the Law apply to the facilities of the Hagit site. An operator of an onshore facility as aforesaid is obligated to perform physical security activities and information security activities.

(d) In accordance with the Law, the Partnership and the other Leviathan Partners are responsible, *inter alia*, for the security of vital automated systems that exist in the facilities of 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 reservoir, it is the one that actually implements the instructions of the INCD on the matter. As the Partnership has been informed, and to the best of its knowledge, in June 2021, the operator received renewal of confirmation from the INCD with respect to the Leviathan reservoir's full compliance with the security requirements. It is noted that such confirmation is valid until May 2023, and to the best of the Partnership's knowledge, the operator is acting to renew the confirmation.

(e) As of the report approval date, and as the Partnership was informed by the operator in December 2022, in connection with operation of the Leviathan reservoir, the operator meets the provisions of the Regulation of Security in Public Entities Law and the sections concerning regulation of security in the lease deed, including the directives on security matters issued thereto by the professional functions in the navy pursuant to law.

7.22.7 <u>The Gas Legislative Memorandum (Safety and Licensing) (Amendment No. …) (Various Amendments), 5781-2021</u>

On August 18, 2021, the Gas Legislative Memorandum (Safety and Licensing) (Amendment No. …) (Various Amendments), 5781-2021 (the "**Safety and Licensing Legislative Memorandum**")[97] was released for public comment, proposing amendments to the existing safety regulation in the natural gas sector, through the amendment of both the Gas Law (Safety and Licensing), 5749-1989, which regulates safety matters in the gas sector and establishes authority to promulgate safety rules and regulations for gas facilities and entities engaged in the natural gas sector, and of the Natural Gas Sector Law.

7.22.8 <u>Directives of the Petroleum Commissioner</u>

(a) <u>Provision of collateral in connection with petroleum interests</u>

In accordance with Section 57 of the Petroleum Law, the Petroleum Commissioner published directives for the provision of collateral in connection with petroleum interests, which are updated from time to time (in this section: the "**Directives**"). The Directives determine, *inter alia*, provisions regarding guarantees required to be provided by new license applicants when submitting the application and prior to drilling wells, and confer vast discretion on the Petroleum Commissioner in relation thereto. The Directives also determine that the guarantees will be in force even after the right for which they were given terminates,

[97] https://www.tazkirim.gov.il/s/law-item/a093Y00001XNIJ9QAP.

until the Commissioner advises otherwise, but no more than 7 years after expiration of the right for which they had been provided.

The Directives further set forth that the Petroleum Commissioner may order forfeiture of all or part of the guarantees if he deems that a petroleum interest holder did not act with 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 according to the instructions of the Petroleum Commissioner, during the period of the right.

Moreover, the Directives obligate a petroleum interest holder to take out at its expense and maintain 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 and to give instructions in connection therewith.

In the event of non-compliance with the Directives, the Petroleum Commissioner may deem the same as non-compliance with the work plan and with the provisions of the interest and act in accordance with the provisions of the Petroleum Law.

As of the report approval date, in accordance with the Directives and the terms and conditions of the Partnership's petroleum assets, the Partnership, together with its partners in the various projects, deposited autonomous bank guarantees for the Ashkelon, Noa, Leviathan North, Leviathan South leases, the Alon D license and the New Ofek and New Yahel licenses.[98] The Partnership’s total share in the said guarantees totals approx. $54.7 million.

(b) Directives regarding the report of safety events in offshore facilities

On January 1, 2023, the Petroleum Commissioner released, for public comments, the draft directives regarding report of safety events in offshore facilities (in this section: the "**Directives**"). The draft Directives refers to irregular events that derive from exploration and production

[98] For details regarding additional guarantees that the Partnership provided, together with its partners in the Leviathan project in accordance with the terms of the lease, see Section 7.2.2(n) above. For details regarding guaranties that the Partnership provided for the customs in connection with the Leviathan project and Yam Tethys project, see Notes 12K5 and 12K6 to the financial statements (Chapter C of this report).

of oil at sea. As of the report approval date, the Directives have not yet been published.[99]

(c) Directives on the method of calculation of the royalty value at the wellhead

1. On May 14, 2020, the Director of Natural Resources at the Ministry of Energy released directives on the method of calculation of the royalty value at the wellhead according to Section 32(b) of the Petroleum Law (in this section: the "**Directives**").

   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 Petroleum Commissioner deems them essential for the sale of the petroleum: (a) the following capital expenses (capex): (1) costs for the treatment and processing of the petroleum; and (2) costs of pipeline transportation of the petroleum up to the first point of connection to the national transmission system; and (b) operating expenses (opex) arising directly from the types of capital expenses.

   The Petroleum 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.

   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 July 24, 2022, the specific directives of the Petroleum Commissioner at the Ministry of Energy were received, with respect to the method of calculation of the royalties to the State

[99] See in the link: https://www.gov.il/he/departments/publications/Call_for_bids/reporting-jan-2023.

from the Leviathan reservoir, and on September 1, 2022, the Leviathan Partners' response to the said specific directives. For further details, see Note 12P4 to the financial statements (Chapter C of this report).

3. For details on the specific directives of the Petroleum Commissioner in the Ministry of Energy with respect to the method of calculation of the royalties to the State from the Tamar Reservoir, as well as on the draft audit reports for the 2013-2018 royalties which were received from the Ministry of Energy in connection with the Tamar reservoir and about the response of the Tamar Partners to the such reports, see Note 15B4 to the financial statements (Chapter C of this report), respectively.

4. For details on a dispute which erupted between the Tamar Partners and the Ministry of Energy regarding the method of calculation of the royalty value at the wellhead, see Section 7.24.9(b) below.

(d) <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 an updated version of directives for purposes of Section 76 of the Petroleum Law, which determine instructions 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 (in this section: the "**Directives**"). These conditions are dependent, inter alia, on the question of whether commercial production has begun and the type of petroleum interest which is being transferred.

According to the Directives, the transfer and pledge of a petroleum interest is subject to receiving prior approval from the Petroleum Commissioner.

According to the Directives, the requirement to obtain the approval of the Petroleum Commissioner for a transfer and pledge of a petroleum interest and a benefit applies in certain cases also to a transfer or allocation of means of control in a corporation (as such terms are defined in the Directives).

The Directives specify conditions for the provision of the Petroleum Commissioner's approval for a transfer of interests, while distinguishing between a transfer of interests in a license and lease and other actions, including conditions regarding the financial capacity of the applicant and regarding the fulfillment of conditions required of an operator in accordance with the Petroleum Law and the Petroleum Commissioner's directives. The Directives further determine specific conditions pertaining to a transfer of royalty interests, a pledge of petroleum interests and other particular cases.

With respect to the pledge of petroleum rights the Directives clarify that 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. Furthermore, 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.

The Petroleum Commissioner may not approve a transfer, even if all the conditions for providing the approval which are detailed in the 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.

(e) Export permit applications

Directives published by the Petroleum Commissioner concerning the receipt of a permit to export natural gas specify, *inter alia*, the date and the manner for submission of the application. As of the report approval date, export permits have been received for the export agreements that were signed by the Partnership, which are specified in Section 7.10.3 above.

(f) In April 2022, the Petroleum Commission notified Chevron that commencing on June 1, 2022, and until September 15, 2022, the Leviathan Partners must ensure the supply of natural gas to the domestic market in a greater quantity than the daily quantity which the Leviathan Partners committed to supply to the domestic market under the gas supply agreements in which they engaged. It is clarified that the notification did not impact the 2022 business results of the Partnership.

7.22.9 Government resolutions regarding natural gas export

(a) Further to the conclusions of the committee for examination of the Government's policy on the natural gas sector in Israel headed by Mr. Shaul Tzemach, adopted by the Israeli Government in June 2013 (the "**Tzemach Committee**"), on January 6, 2019, the Israeli Government adopted the principal recommendations of the interministerial professional team headed by the Director General of the Ministry of Energy, Mr. Udi Adiri, which reexamined the matter of natural gas supply and demand as of 2018 (in this section: the "**Government Resolution**").

(b) According to the Government Resolution, the quantity of natural gas required to be secured for the domestic market shall be 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 to the Government Resolution. In this context, the "natural gas quantity" means 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.

(c) The duty to supply the Minimum Quantity for the Domestic Market in respect of discoveries recognized prior to the Government Resolution 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
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 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.[100] 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.

(d) The export of natural gas will require approval from the Petroleum Commissioner, 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, and subject to ensuring the minimum amount for the domestic market, as aforesaid.

(e) The Government Resolution further determines instructions regarding an obligation to connect reservoirs to the domestic market according to the size of the reservoir, instructions 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, instructions regarding regulation of secondary trade in natural gas, which may be directed toward export, etc.

(f) On June 21, 2021, the Ministry of Energy published for public comment the interim report of the professional team established for the periodic review of Government policies regarding the Israeli natural gas sector (the "**Interim Report**")[101] in which the professional team noted, *inter alia*, that the export policy should be reexamined, especially in relation to the restrictions on quantities reserved for the domestic market (the total and minimum mandatory supply volumes). The professional team stressed that should no changes be made to this policy, there is a substantial chance that Israel's natural gas resources will not be

[100] It is noted that the permitted export quota from the Tanin and Karish leases 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 the Tanin and Karish leases. For details, see Section 7.22.1(b)1 above.

[101] https://www.gov.il/he/departments/publications/Call_for_bids/ng_210621.

utilized in full. This is expected to lead to significant loss of revenue for the State. The Interim Report also stated that Israel's regulation of export is stricter than other countries, and that the working assumption should be that the sale of natural gas has a "window of opportunity" of approx. 2-2.5 decades. It is thus necessary to fully exhaust the existing potential for finding additional discoveries.

The Ministry of Environmental Protection objected to the proposed framework. This objection is due to its position that the proposed framework would undermine Israel's ability to wean itself off polluting fuels and transition to a competitive, low-carbon economy in line with other OECD countries.

On December 15, 2021, the former Minister of Energy announced that she does not intend to bring the recommendations of the Interim Report to the government for approval. As of the report approval date, the Partnership estimates that the conclusions of the Interim Report will be reexamined and that during 2023 the government will appoint a professional team to perform the periodic examination in accordance with the conclusions of the Tzemach Committee.

On December 13, 2022, the Ministry of Energy opened a fourth competitive process for the exploration of gas and oil in the Israeli EEZ. For further details see Section 7.13.2 above.

7.22.10 Resolutions and plans of the Israeli government and governmental authorities with respect to the reduction of greenhouse gas emissions and the promotion of renewable energies

(a) Cessation of use of coal for power production

On June 3, 2018, the Government, by Resolution 3859, approved a reform in the electricity sector and in IEC, under which IEC would reduce its power production operations by selling 5 production sites with an aggregate maximum capacity of approx. 4,000 MW, representing about one half of its power production capacity, and IEC would build two modern natural gas-fired production units in Orot Rabin, as part of the direction of reducing the use of coal in the power production process. according to the Minister of Energy's decision of November 13, 2019, conversion of the coal-fired power plants in Hadera and Ashkelon to natural gas will be completed by 2025, meaning that in that year the era of coal use for electricity production in Israel is in fact expected to come to an end.

Further thereto, in 2020 and in February 2021, the Government issued directives to IEC to reduce and limit the use of coal such that it does not exceed 22.5% of total power production in 2021. To the best of the Partnership's knowledge, the closure of the coal-fired units 1-4 at the Orot Rabin station, which was designated to be performed by June 30, 2022 was deferred, and it is doubtful whether it will be fully implemented by the end of 2023. Concurrently, and in accordance with government policy, the IEC is promoting a move to convert the remaining coal-fired units at the Orot Rabin and Rutenberg stations, such that they will operate on natural gas on a regular basis. To the best of the Partnership's knowledge, such conversion process is expected to begin and be completed by the end of 2025.[102]

(b) 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'.[103] The plan set goals for 2030, specifying concrete steps and determining timetables in 5 main sectors, as follows:

1. 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.

2. 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 (CNG)-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 issues, from time to time, tenders for the establishment of electric car charging stations nationwide.

3. 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

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[102] Website of the Special Committee for Oversight of the Israeli Citizens' Fund of May 10, 2022: https://main.knesset.gov.il/Activity/committees/GasFund/News/Pages/10052022.aspx
[103] https://www.gov.il/BlobFolder/rfp/target2030/he/energy_2030_final.pdf.

fuels and supplying CNG. Accordingly, in 2019 the Ministry of Energy issued grants to the distributing companies for purposes of accelerating deployment of the distribution network.[104]

4. 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.

5. Ensuring energy security in the market through ensuring redundancy in natural gas supply to the market, in the transportation, industry and electricity sectors.

(c) Government Resolution no. 465 on promotion of renewable energy in the electricity sector

On October 25, 2020, government resolution no. 465 was adopted pertaining to the promotion of renewable energy in the electricity sector ("**Resolution 465**") and it, *inter alia*, embraced 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. In addition, the policy regarding the promotion of conventional power generation facilities was modified. Resolution 465 included a series of decisions aimed at the promotion of use of renewable energies.

(d) On May 4, 2021, the National Planning and Building Council advised the Government to approve the Comprehensive National Outline Plan for Electricity Sector Infrastructures ("**NOP 41**"), the principal purposes of which are to delineate designated areas that will serve as sites for power production from renewable energies and to create a uniform planning framework for the production and storage of electricity from diverse sources and by various technologies[105]. It is noted that NOP 41, is an overall and comprehensive plan for infrastructures and meeting the needs of the national market in 2030 and 2050, while addressing

[104] https://www.gov.il/he/departments/news/electric_car_110619.

[105] https://www.gov.il/he/Departments/General/tama_41; https://mavat.iplan.gov.il/SV4/1/99006595.

the blend of energy sources, the range of production measures, and assurance of redundancy and reliability of capacity and integration of energy storage in significant amounts. The plan brings together the national outline plans that concern electricity, natural gas and fuels, and designates areas for renewable energy-fired power production, electricity transmission pathways and energy infrastructures. It is further noted that the plan implements Resolution 465 on the promotion of renewable energies in the electricity sector, and outlines the principles for planning energy infrastructures, it also being aimed at efficiency in the energy sector and reduction, to the greatest extent possible, of the effects of energy facilities on the environment and public health.

(e) Energy sector targets for 2050

1. On April 18, 2021, the Ministry of Energy published a plan for compliance with targets of emission reduction in the energy sector in 2050, as part of the attempts made by the State of Israel and other countries to cope with the climate crisis106, which plan determined a target of 80% reduction in the emissions of greenhouse gases in the sector by 2050, as well as several sub-targets that include a commitment to close down coal-fired plants by 2025, reduce greenhouse gas emissions in the electricity sector at a rate ranging between 75% and 85% by 2050, annual improvement of 1.3% in the Energy Intensity Indicator (energy consumption per output unit) as well as performance of another review of the export policy in the natural gas sector and performance of a full transition to natural gas in the industry sector.[107]

2. On July 25, 2021, the Israeli Government, by Resolution No. 171, approved the plan for reduction of approx. 85% of greenhouse gas emissions by 2050 and an interim target for reduction of approx. 27% of the greenhouse gas emissions by 2030 ("**Resolution 171**"). Resolution 171 also sets sectorial targets for the reduction of greenhouse gas emissions and for improved efficiency in the energy consumption in the market, as well as the appointment of an interministerial committee to formulate a national plan for accomplishment of the objectives[108].

[106] https://www.gov.il/he/departments/news/press_180421.
[107] https://www.gov.il/he/departments/publications/Call_for_bids/energy_2050_public.
[108] https://www.gov.il/he/departments/policies/dec171_2021.

3. On October 12, 2021, the Ministry of Energy published a long-term strategic plan for compliance with emission reduction targets by the energy sector in 2050[109]. The plan outlines principal courses of action and policy measures derived from such targets, and addresses the electricity, transportation, industry and natural gas sectors, as well as infrastructure planning and regional collaborations. Further thereto, on October 29, 2021, the Office of the Spokesperson of the Prime Minister's Office released an announcement, whereby the Prime Minister and the Minister of Energy had agreed to increase the carbon emission reduction target, such that by 2050 Israel would nullify emissions[110].

4. On May 29, 2022, the Electricity Authority released for public comment a multi-year plan for meeting of renewable energy consumption targets by 2025. On July 19, 2022, the Electricity Authority released a call for public comments on a review of the renewable energy targets for 2050. For further details, see Sections 7.22.10(k) and 7.22.10(l) below.

(f) Further to Resolution 171, several Government Resolutions were adopted on October 24, 2021 as follows:

1. Government Resolution 541, which approved an update to the national plan for energetic efficiency and reduction of greenhouse gas emissions, the principles of which are: (a) To adopt an interim target in terms of energy intensity of 131.7 MWh per ILS 1 million GDP in 2026; (b) To appoint an interministerial task force headed by the Ministry of Energy to monitor and control the implementation of the national plan for energetic efficiency; (c) Task all Government Ministries with a duty to report to the Ministry of Energy of measures taken by them in the interest of energetic efficiency and renewable energies; (d) Task the Minister of Energy, the Minister of Environmental Protection and the Minister of Economy and Industry to implement programs for grants and promotion of pioneering projects for energetic efficiency and reduction of greenhouse gas emissions and reduction of the negative effect on competition and the Israeli industry; and (e) Task the Minister of Energy with promoting the preparation and

109 https://www.gov.il/he/departments/publications/reports/energy_121021?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+%28253%29.

110 https://www.gov.il/he/departments/news/carbon_emissions291021

implementation of sustainable energy programs by local authorities.

2. Government Resolution 542, the principles of which are as follows: (a) Setting a new target, whereby as of 2035, at least 50% of vehicles exceeding 3.5 tons which are imported into Israel are clean or use fuels that reduce 80% of greenhouse gas emissions as compared with diesel oil; (b) Appointment of an interministerial steering task force to monitor compliance with the targets specified in the Resolution, act to remove barriers to implementation and recommend changes for promotion of the implementation of the targets specified in the Resolution; (c) Details of the actions to be taken with the purpose of complying with the targets specified in the Resolution.

3. Resolution 543, which concerns the acceleration of infrastructures in the context of countering climate changes, under which it was decided to appoint an interministerial task force headed by the Director General of the Prime Minister's Office, in order to accelerate infrastructure projects of national importance for the reduction of greenhouse gases and for compliance with the targets of the transition to a low-carbon economy.

(g) <u>Government Resolution no. 286 on "pricing of greenhouse gas emissions"</u>

August 1, 2021 saw the adoption of Government Resolution No. 286 ("**Resolution 286**"), the key points of which are as follows: (a) To task the Minister of Finance with the amendment of the Fuel Excise Order, the Customs Tariff and Exemptions Order and the purchase tax on goods, in order to lead to the gradual internalization of the environmental externalities of carbon emissions; (b) To task a team headed by the Budget Department of the Ministry of Finance and the Ministry of Energy, in consultation with the Bank of Israel and the National Insurance Institute, with advising the Director General of the Ministry of Energy on mechanisms for encouraging energy efficiency and facilitating the transition to clear energy for low-income demographics resulting from the imposition of such tax, without negatively affecting the incentives for emission reduction that underpin the tax, within 6 months of the date of issuance of Resolution 286; (c) To present to the Government, within 60 days of the date of Resolution 286, a national multiannual plan for energetic efficiency of the business sector, with an emphasis on industry; and (d) In the event of technological developments that allow for the reduction of carbon emissions from source fuels, the Ministry of Energy, Ministry of Finance and Ministry of Environmental Protection shall examine the implications of such technological developments.

In accordance with Resolution 286, on October 13, 2021, the Minister of Finance released orders as aforesaid in paragraph(a) above, which expired after two months, after the Knesset's Financial Committee did not approve them as required by law. As of the report approval date, it is doubtful whether Resolution 286 will be implemented in the future and in what way, if any. In the Partnership's estimation, even if Resolution 286 is implemented, such resolution is not expected to have a material effect on the volume of natural gas consumption in Israel, *inter alia*, in view of the economic implications of the Resolution and the provisions of the orders regarding the cost of natural gas compared with other fuels and considering the energy consumption forecasts in Israel in the coming years.

Caution concerning forward-looking information - The Partnership's estimation regarding the effect of Resolution 286 on the volume of natural gas consumption in Israel, constitutes Forward-Looking Information, as defined in the Securities Law and may not materialize or may materialize in a different manner than what is expected, due to factors that are beyond the Partnership's control.

(h) National plan for prevention and reduction of air pollution in Israel

Further to its publications of December 23, 2021[111], the Ministry of Environmental Protection presented for the Government's approval, during March 2022, a multiannual national plan for prevention and reduction of air pollution. The plan will, *inter alia*, address the transition to the use of green energy and the promotion of low-carbon economy, greenhouse gas pricing and the promotion of clean transportation and targets for the reduction of air pollution in Israel[112]. According to a preliminary estimation, the total benefits arising from the plan are approx. ILS 4.7 billion from the reduction of local air pollutants, and approx. ILS 12.8 billion from the reduction of greenhouse gases for 2030.

On March 14, 2022, Government Resolution No. 1282 was adopted, which presents an implementation plan to prevent and reduce air

[111] https://www.gov.il/he/departments/news/multi-year_plan
[112] https://www.gov.il/he/departments/news/a_national_plan_to_reduce_greenhouse_gas_emissions.

pollution and greenhouse gas emissions in Israel.[113] The resolution stipulated that the plan will constitute a part of the State of Israel's response to the climate crisis and it is intended, inter alia, to fulfill some of the commitments of the State of Israel under the Paris Agreement and the Glasgow Climate Change Conference, including the promotion of the meeting of the Government's targets to reduce greenhouse gas emissions by 2030.

(i) The Paris Agreement and the Powering Past Coal Alliance (PPCA)

In 2016, Israel joined the Paris Agreement, which was agreed in the course of the 2015 United Nations Climate Change Conference, and concerns reducing greenhouse gas emissions and coping with greenhouse gas emissions by the countries of the world. The principal undertaking of every country that signed the Paris Agreement is to submit a plan every 5 years which specifies the measures it will take to cope with climate changes.

Moreover, in December 2018, Israel joined the PPCA, the purpose of which is to encourage the reduction and discontinuation of use of coal. The parties to this initiative undertake to gradually reduce coal-fired power production and to support clean energy in government and corporate policies. The countries and the organizations that joined PPCA support the reduction of coal use in OECD countries by 2030 and worldwide by 2050.

(j) On April 12, 2022, the Ministry of Energy released a call for public comments on a review of the possible uses for hydrogen as an energy source in industry, whether with pure hydrogen or by using natural gas mixed with hydrogen in various proportions.[114]

(k) On May 29, 2022, the Electricity Authority released for public comments a multi-year plan for meeting the renewable energies consumption targets (hereinafter in this Section, the "**Plan**"),[115] which includes main steps that the Electricity Authority plans to take in order to meet the targets by 2025. In this context, the Plan specified the required installed capacity by 2025 in the context of the existing regulations for the establishment of renewable energy facilities, and the existing challenges in developing in operation the power grid.

[113] https://www.gov.il/he/departments/policies/dec1282_2022.

[114] For further details, see: https://www.gov.il/he/departments/publications/Call_for_bids/ng_120422.

[115] https://www.gov.il/BlobFolder/rfp/shim_rav_shenati_ne_05_2022/he/Files_Shimuah_tochnit2025_nn.pdf

(l) On July 19, 2022, the Electricity Authority released a call for public comments on a review of the renewable energy targets for 2025.[116] In this context, the Electricity Authority is interested in exploring the public's recommendations for ways to reach a low-carbon economy, and the tools required therefor, barriers to achieving a zero emissions economy by 2050, and proposals for incentives, steps, and mechanisms to achieve such targets.

(m) On September 28, 2022, the Ministry of Environment Protection released a technical-economic action plan to shift to clean industry based on renewable energies and zero dependence on fossil fuels, in the context of which ILS 100 million was allocated for a grant program for reducing greenhouse gases in industry. The plan includes a number of steps, including updating the state guarantee program for loans for reducing greenhouse gases, as stipulated in Government Resolution No. 542 of October 24, 2021, and a recommendation to formulate a grant program for the production of green and yellow hydrogen close to the consumer in industrial areas far from the gas infrastructure.[117]

(n) On November 10, 2022, the Ministry of Energy released that Israel and Germany had signed a collaboration agreement to promote projects in energy security, renewable energy, hydrogen, and natural gas. According to the said agreement, the countries will establish joint working groups which will discuss, inter alia, energy security and renewable energy, with an emphasis on the power grid, agrovoltaic, natural gas, and streamlining energy in the urban space.[118]

(o) The Economic Plan Bill (Legislative Amendments for Implementation of the Economic Policy for the Budget Years 2023 and 2024), 5783-2023, which was published on March 23, 2023, includes, *inter alia*, proposals designed to meet the Government's targets for the production of electricity using renewable energies. In this context, it was proposed to approve various provisions intended to facilitate the establishment of photo-voltaic facilities, and it was also proposed that the Government establish targets for approval of plans to produce electricity using renewable energies.

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[116] https://www.gov.il/he/departments/publications/Call_for_bids/kol_kore_2050.

[117] https://www.gov.il/he/departments/news/moep_technical_economic_action_plan_transition_clean_innovative_industry

[118] https://www.gov.il/he/departments/news/press_111122

7.22.11 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. It is noted that 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.

7.22.12 Permits and licenses for the facilities of the Yam Tethys project and the Leviathan project

(a) In the framework of the development of the Yam Tethys project, the Yam Tethys Partners received an 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 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 .

(b) In Phase 1A, 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, 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 (a company owned by the Leviathan Partners, as specified in Section 1.7.2 above) 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, and all subject to the conditions of the license.

7.22.13 Applicability of Cypriot legislation to the Partnership's activity

The Partnership's gas and oil exploration activity in Cyprus is subject to legislation and regulation that applies to the operating sector in the Republic of Cyprus, including instructions regarding the obligation to obtain permits and licenses for performance of acts, undertakings to execute work plans, provisions in relation to safety and environmental protection etc. It is noted that the Republic of Cyprus is a full member of the European Union and is therefore subject to 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 which regulates the exploratory activity and the production of hydrocarbons onshore and within the EEZ of the Republic of Cyprus.

For details on the petroleum asset, Block 12 in Cyprus, and the agreements signed with the Cypriot government in relation thereto, see Section 7.3 above.

7.23 **Pledges**

For details regarding pledges the Partnership has given on its assets, see Notes 10 and 12K to the financial statements (Chapter C of this report).

7.24 **Material Agreements**

The Partnership has entered into material agreements that were in effect during the period from January 1, 2021 until the report approval date, as specified below:

7.24.1 The main agreements for the sale of natural gas from the Leviathan project to the domestic market and for export as specified in Section 7.10.3 above.

7.24.2 Financing documents of the bonds issued by Leviathan Bond, as specified in Section 7.19.2 above.

7.24.3 Production Sharing Contract in respect of Block 12 (as specified in Section 7.3.3 above).

7.24.4 Agreements with respect to natural gas and oil exploration and production activity in the Boujdour license in Morocco, as specified in Section 7.6 above.

7.24.5 Agreements with respect to entry into the renewable energy sector, in collaboration with Enlight and the CEO of the Partnership, as specified in Section 7.8 above.

7.24.6 <u>Series of agreements for the purchase of EMG shares and regulation of the terms for export of gas to Egypt</u>

(a) <u>General</u>

With the aim of enabling the consummation of the agreement for export of gas to Egypt that is described in Section 7.10.3(c) above, EMED purchased 39% of the share capital of EMG, a private company registered in Egypt which owns a submarine pipeline of a diameter of 26 inches and approx. 90 km long, which connects 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**", and the "**EMG Transaction**", respectively).

The EMG Transaction was closed on November 6, 2019, and natural gas flow from the Leviathan reservoir to Egypt through the EMG Pipeline began on January 15, 2020, after additional related arrangements and agreements had been made, as specified below.

(b) <u>The agreements for the acquisition of EMG shares</u>

On September 26, 2018, EMED signed 4 separate, mainly similar, agreements with 4 shareholders of EMG (in this section: the "**Sellers**") for acquisition of 37% of EMG's share capital held by the Sellers, and, at the same time, EMED signed an agreement with another shareholder ("**MGPC**"), which transferred to EMED, without consideration, 2% of the EMG shares held thereby, in the context of the resolution of disputes that had arisen between the Sellers and MGPC. Following the closing of the transaction, EMG's shareholders are as specified in Section 1.7.5 above.

In the context of the transaction, the Sellers, the shareholders of the Sellers and the companies affiliated with the Sellers have agreed to 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 arbitration proceedings which were held between the parties in relation to discontinuation of piping of the gas from Egypt to Israel.

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, EMED paid the Sellers the sum total of approx. $527 million (in this section: the "**Consideration**"), out of which each one of the Partnership and Chevron paid a sum of approx. $188.5 million, and the balance was paid by the Egyptian Partner.

(c) Capacity Lease & Operatorship Agreement (CLOA)

In the CLOA signed on June 30, 2019 between EMED and EMG, EMG gave EMED the exclusive right to lease and operate the EMG Pipeline for the period expiring at the end of 2030, with an option to extend the agreement for 10 more years.

According to the agreement, 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 Blue Ocean shall pay for use of the pipeline (in this section: the "**Transmission Fees**"), net of the Operation Costs. As of December 31, 2022, Chevron and the Partnership as well as the other Leviathan and Tamar partners, have invested in the refurbishment of the EMG Pipeline, through EMED, approx. $158 million, most of which will be repaid to Chevron and the Partnership and the other Leviathan and Tamar partners, through EMG's revenues from transmission of the gas through the pipeline.

(d) Agreement for allocation of capacity in the transmission to Egypt system

Concurrently with the signing of the Export to Egypt Agreement, on September 26, 2019 an agreement was signed between the Partnership and Chevron and the Leviathan Partners and the Tamar Partners in connection with allocation of the capacity (in this section: the "**Capacity Allocation Agreement**") in the transmission from Israel to Egypt system. The capacity division in the transmission from Israel to Egypt system (the EMG Pipeline and the transmission in Israel pipeline) 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 up to 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.

Pursuant to the Capacity Allocation Agreement, on the date of the closing the EMG Transaction, the Leviathan Partners and the Tamar Partners paid the Partnership and Chevron the sum of $250 million (80% by the Leviathan Partners and 20% by the Tamar Partners), as participation fees, in consideration for the undertaking to allow the piping of natural gas from the Leviathan and Tamar reservoirs and guaranteeing capacity in the EMG Pipeline. Pursuant to the agreement, the amount of the aforesaid payments will be updated according to the formula determined in the agreement and the dates set therein, based on the actual use of the EMG Pipeline. In view thereof, for the period between January 1, 2022 and June 30, 2022, the payment division between the Leviathan partners and the Tamar Partners was approx. 83% and approx. 17%, respectively. The Capacity Allocation Agreement determines further arrangements for bearing the additional costs and investments that will be required for refurbishment of the EMG Pipeline and maximum utilization of the pipeline capacity, which shall be paid by both the Leviathan Partners and the Tamar Partners. In this context it is noted that on June 30, 2022, the parties updated the payment division between the Leviathan Partners and the Tamar Partners, and accordingly an accounting was performed in non-material amounts for purposes of adjusting the rates borne by the parties in the costs of the actual usage of the EMG pipeline's capacity in the said period.

The Capacity Allocation Agreement further determines that 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 Blue Ocean, 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 Agreement, 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; or 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 7.22.1 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.

(e) EMED's shareholders' agreement

In proximity to the date of the signing of the agreements for the purchase of the shares of EMG, 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.

(f) Term sheet for use of additional infrastructures

Concurrently with the signing of the agreements for the purchase of the shares of EMG, as specified above, a term sheet was signed between the Partnership and Chevron and the Egyptian Partner (which holds the Arab Gas Pipeline in the segment between el Arish and Aqaba, and an affiliate of Blue Ocean, whereby the parties agreed that the Partnership and Chevron 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, for the purpose of implementation of the Export to Egypt 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. For further details see Section 7.11.2(e) above.

(g) Agreement between EMG and EAPC and Eilat-Ashkelon Infrastructure Services Ltd.

On July 1, 2019, an agreement was signed between EMG and EAPC and Eilat-Ashkelon Infrastructure Services Ltd. (in this section: the "**EAPC Companies**" and "**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 until June 10, 2030, 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. 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 was required to provide a bank guaranty (renewable over the term of the Agreement) in the sum of $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 $2 million each, which were provided by the Partnership and Chevron (in this section: the "**Bank Guaranties**"). The guaranty provided by EMED shall expire and be null and void in the events 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 Leviathan and Tamar 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 Leviathan and Tamar Partners.

(h) For details regarding agreements signed between Chevron and INGL pertaining to transmission of natural gas to the EMG Pipeline through the INGL system, see Section 7.11.2(e)3 above.

7.24.7 The Joint Operating Agreement in respect of the Leviathan Leases[119]

(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 this section: the "**Agreement**" or "**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 Leviathan Leases (in this section: the "**Petroleum Asset**").

According to the aforesaid operating agreements, Chevron 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,[120] and all the credits to the joint account,[121] 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. It is noted that payment dates are of the essence of the JOA and 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, Chevron is entitled to be reimbursed for of all direct expenses paid in connection with it fulfilling its position as operator and to be

[119] 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.

[120] In accordance with the definitions in 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.

[121] In accordance with the definitions in 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.

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 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[122] 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); and 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.

[122] 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.

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.

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) <u>The operating committee</u>

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 two 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 JOA.

(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: (a) if it becomes insolvent, bankrupt or if it has made an arrangement with its creditors; (b) 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 insolvency laws; (c) if a receiver is appointed to a significant portion of its assets; or (d) 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) Sanctions applicable to the parties and the conditions for imposition thereof

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.

(i) Transfer of rights

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. It is noted that 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.

(j) <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; and (b) collateral with respect to the financial ability to comply with the obligations under the agreement. In addition, the party undergoing such change, is required to give notice of the change of control to the other parties (in this section, 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.

(k) Withdrawal from the JOA

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 (in this section: "**Withdrawal Notice**"). The Withdrawal 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.

(l) 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.

(m) 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).

7.24.8 Joint operating agreement in Block 12

The joint operating agreement in Block 12 covers the same issues as, and is in a format similar to the joint operating agreement in the Leviathan project, as specified in Section 7.24.7 above, with decisions 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. Chevron Cyprus serves as operator in Block 12.

7.24.9 Payment of royalties to the State and royalty payment undertakings 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 specified in Section 7.24.9(c)2 below, and undertakings originating from Avner’s Limited Partnership Agreement as specified in Section 7.24.9(c)3 below.

(b) Calculation of the market value of the royalties at the wellhead

1. General

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**").

2. The Effective Rate of the royalties in the Tamar project.

   Since the commencement of production in 2013, a dispute erupted between the Tamar Partners and the Ministry of Energy regarding the method of calculation of the Effective Rate of the royalties. According to the Tamar Partners, the payments made thereby, at the State's request, are payments in excess that were unlawfully collected and therefore the Tamar Partners through Chevron are acting to resolve this dispute vis-à-vis the Ministry of Energy. 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 2013-2021 is approx. $17.7 million.

   It is noted in this context that, according to the terms and conditions of the transaction for the sale of the remaining interests of the Partnership in the Tamar and Dalit Leases, which was closed in December 2021, the Partnership is entitled to receive amounts for excess payments made to the State in respect of the Tamar project, if the arguments of the Tamar Partners on this issue are accepted.

3. The Effective Rate of the 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. 11.26%, in accordance with a letter of demand received from the Ministry of Energy in January 2020. Such effective rate is higher than the calculation performed by the Partnership and Chevron, such that in accordance with the 2020 royalties report submitted by Chevron to the Ministry of Energy, the State's rate of royalties in the Leviathan project ought to be approx. 9.58%. Accordingly, the rate of the royalties on which the Partnership's 2021 financial statements are based is approx. 10.7%, and approx. 10.9% on the 2022 financial statements.[123] The difference between the royalties actually paid by the Partnership to the State in the Leviathan project and the effective rate of royalties on which the Partnership's financial statements in 2019 to 2022 are based is approx. $12.8 million. For further details see Note 15 to the financial statements (Chapter C of this report).

[123] 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 11.26%.

It is noted that the method of calculation of the market value at the wellhead of the royalties in respect of the Leviathan project, which the Partnership is paying to the royalty interest owners is in accordance with the effective rate of the royalties paid by the Partnership to the State.

(c) Undertaking to pay royalties to the royalty interest owners [124]

1. General

In addition to the State royalties, the Partnership pays, as aforesaid, royalties to the royalty interest owners, which include related and third parties, in accordance with undertakings that the Partnership and Avner assumed in the past, as specified below.

2. Delek Group Royalties

(a) In the context of an interest transfer agreement of 1993 (the "**Interest Transfer Agreement**") signed between Delek Energy and Israeli Fuel Company Ltd.[125] ("**Delek Israel**" and jointly in this section: the "**Transferors**") and the General Partner, the Transferors transferred to the Partnership interests in several oil licenses, in consideration for the Partnership's undertaking to pay the Transferors (Delek Energy – 75% and Delek Israel – 25%) overriding 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 "**Delek Group Royalties**").

(b) The royalty rates of the Delek Group Royalties as 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),

[124] Note that following the merger of the partnerships, all of the undertakings to pay royalties to the royalty interest owners now apply with respect to all of the Partnership's (existing and future) petroleum assets, however, on the merger date, such royalty rate 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 of the partnerships to Delek Group and Delek Energy, and by 52.58% relative to the royalties that were paid by Avner prior to the merger of the partnerships.

[125] Following the reorganization that was carried out in the past, the royalty right as aforesaid of Delek Israel was transferred to Delek Group.

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.

(c) As of the report approval date, the holder of the right to the Delek Group Royalties in the Leviathan project is Delek Overriding Royalty Leviathan Ltd., a wholly owned subsidiary of Delek Energy (the "**Delek Overriding Royalty**").[126] Delek Group and Delek Energy are entitled to Delek Group Royalties with respect to all the remaining oil assets of the Partnership that exist on the report approval date, and with respect to the petroleum assets in which the Partnership will have interests in the future.

(d) Until the sale of the remainder of its interests in the Tamar and Dalit Leases in December 2021, the Partnership paid the Delek Group Royalties for the Tamar project to the parties entitled thereto.[127] On September 4, 2018, the Audit Committee and the Board of the General Partner approved a calculation whereby the Investment Recovery Date in the Tamar Project falls in January 2018 and therefore, from this date, the Partnership paid the increased royalties rate (6.5% in lieu of 1.5%) to the parties entitled to the Delek Group Royalties in the Tamar project. For details on a legal proceeding being conducted in connection with determination of the Investment Recovery Date in the Tamar Project, see Section 7.25.6 below.

3. <u>Avner Partnership Royalties</u>

In the context of the closing of the merger of the partnerships the Partnership assumed the undertakings of Avner Partnership to pay royalties, as the same are set forth in the Avner Partnership

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[126] To the best of the Partnership's knowledge and in accordance with the reports of Delek Group, in October 2020, Delek Group and Delek Energy transferred their right to receive Delek Group royalties from the Partnership's share (45.34%) in oil and/or gas and/or other valuable substances to be produced and utilized from the Leviathan Leases, to Delek Overriding Royalty.

[127] To the best of the Partnership's knowledge and in accordance with the reports of Delek Group, in June 2018, Delek Energy transferred its right to receive royalties from the Tamar Project to Tomer Energy Royalties (2012) Ltd., and in December 2019, Delek Group transferred its right to receive royalties from the Tamar Project to Advanced Study Funds for School and Kindergarten Teachers – Managing Company Ltd. and to Advanced Study Funds for High School and Seminar Teachers and Supervisors – Managing Company Ltd.

Agreement[128] (the " **Avner 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). As of the report approval date, all of the parties entitled to Avner Royalties are third parties.

4. <u>Terms and conditions of the royalties</u>

The following terms and conditions apply to all of the royalties paid by the Partnership (Delek Group Royalties and Avner Royalties) (in this section jointly: the "**Royalties**"):

(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 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

[128] The 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 (the "**Avner Partnership Agreement**").

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. In view of the dispute that has arisen between the Tamar Partners and the State regarding the method of calculation of the royalty value at the wellhead in the Tamar Project, as described in Section 7.24.9(b) above (in this section: the "**Tamar Dispute**"), and the dispute that has arisen regarding royalties paid to the State for gas that was marketed from the Tamar reservoir to customers of the Yam Tethys project as described in Section 7.25.2 below (in this section: the "**Yam Tethys 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 Tamar 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 underpayments 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 Dispute, it was agreed that the ruling in the claim conducted in such regard by the Partnership and Chevron 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, after a binding method of calculation is determined, 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.

7.24.10 <u>Agreement for the purchase of interests in the New Ofek and New Yahel licenses</u>

On March 19, 2019, the Partnership entered into an agreement with SOA for the purchase of a 25% interest (out of 100%) in each of the New Ofek and New Yahel Licenses, which are in the center and the north of the State of Israel, respectively. For further details regarding the said agreement, see Section 7.24.9 of the 2021 periodic report.

It is clarified that on June 20, 2022, the validity of the New Ofek and New Yahel licenses has expired and the Partnership did not join the application of the operator in the licenses to the Petroleum Commissioner at the Ministry of Energy, in a request to extend its validity.

7.24.11 <u>Agreement for the sale of the Partnership's interests in the Tanin and Karish Leases</u>

Following the Government decision to approve the Gas Framework, on August 16, 2016, an agreement was signed between the Partnership and Avner (in this section: the "**Sellers**") and Energean Israel (in this section: the "**Buyer**"), whereby the Buyer purchased all of the Sellers' and Chevron's interests in the Tanin and Karish leases.

For further details regarding the said agreement, see Section 7.24.10 of the 2021 periodic report. For details regarding the very material valuation regarding the Partnership's royalties from the sale of the leases, see Note 8B to the financial statements (Chapter C of this report) and Section 8B of Chapter D of this report. For details regarding disputes that arose between the Partnership and Energean, see Section 7.5.4 above.

7.24.12 <u>The agreement for the sale of 9.25% of the interests in the Tamar and Dalit Leases to Tamar Petroleum</u>

In accordance with the provisions of the Gas Framework, which, *inter alia*, obligated the Partnership to sell its full holdings in the Tamar and Dalit leases, on July 2, 2017, a sale agreement was signed between the Partnership as the seller of the first part and Tamar Petroleum as the buyer of the second part, according to which Tamar Petroleum purchased from the Partnership, 9.25% rights (out of 100%) in the Tamar and Dalit leases.

For further details regarding the agreement, see Section 7.24.11 of the 2021 periodic report.

7.24.13 <u>Agreement for the sale of the Partnership's remaining interests (22%) in the Tamar and Dalit leases</u>

In accordance with the provisions of the Gas Framework which, *inter alia*, obligated the Partnership to sell all of its holdings in the Tamar and Dalit leases, on September 2, 2021 the Partnership engaged in an agreement for the sale of the Partnership's remaining interests (22%) in the Tamar and Dalit Leases to Tamar Investment 1 RSC Limited and Tamar Investment 2 RSC Limited.[129]

For further details regarding the agreement, see Section 7.24.12 of the 2021 Periodic Report.

7.24.14 Further to the legal proceeding specified in Section 7.25.14 below, Further to the aforesaid, on September 29, 2022, the Partnership and the General Partner engaged with the British company Capricorn Energy PLC ("**Capricorn**") in a contingent agreement for the performance of a transaction for a business combination of the Partnership and of Capricorn, such that after the closing of the Transaction, all the holders of the Partnership's participation units (including the General Partner) are expected to hold approx. 89.7% of the share capital of the consolidated company, whose shares were intended to be listed on the London Stock

[129] To the best of the Partnership's knowledge, the buyers are SPCs that were established for the purpose of the transaction and are held (in a chain) by MDC Oil & Gas Holding Company LLC, a corporation from the Mubadala Investment Company PJDC group, which is owned by the Government of Abu Dhabi.

Exchange's premium listing segment and "cross-listed" on the Tel Aviv Stock Exchange (the "**Capricorn Transaction**"). However, on February 15, 2023, the Partnership and Capricorn agreed on the cancellation of the transaction with immediate effect, *inter alia* in view of developments in Capricorn in the period after the signing of the said agreement, including a fundamental change in the composition of Capricorn's board of directors and executive management. For further details regarding the Capricorn transaction, the approval proceedings and cancelation thereof, see the Partnership's immediate reports of September 29, 2022, January 15, 2023, January 24, 2023, February 1, 2023 and February 15, 2023 (Ref. 2022-01-122176, 2023-01-006930, 2023-01-010953, 2023-01-013680 and 2023-01-017664, respectively), the information appearing in which is included herein by reference.

7.25 **Legal proceedings**

7.25.1 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 (in this section: the "**Petitioner**" and the "**Certification Motion**", respectively), in connection with 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 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 (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 June 8, 2021, a judgment of the District Court was issued, denying the Certification Motion, both since the cause of action was not proved, not even ostensibly, in the sense that there is no evidence that the price of natural gas in the IEC contract is unfair, and since the Certification Motion does not meet the requirement of Section 8(A)(2) of the Class Actions Law, 5766-2006, in the sense that the class action is not the effective and fair way to decide the dispute under the circumstances. The aforesaid is in view of the deep involvement of the regulators who examined broad questions from the field of economics, economic competition, and Israel's foreign and security policy, which were reflected in the decision of the regulators and the government of Israel.

On September 30, 2021 the Petitioner filed an appeal from the judgment with the Supreme Court, in which the Supreme Court was moved to certify the class action and order the District Court to hear the class action. The Tamar Partners filed their response to the appeal on March 1, 2022, and the Attorney General filed her response to the appeal on May 4, 2022, in which she argued that the appeal must be dismissed because a class action is not the efficient and fair way to the resolve the dispute, mainly in view of the comprehensive regulation of the price of gas in the "Gas Framework". A hearing of the appeal was held on January 9, 2023, and upon its conclusion, at the recommendation of the Supreme Court, the petitioner rescinded the appeal and it was dismissed by the court.

7.25.2 On March 12, 2015, the Partnership and Chevron (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, which primarily includes a demand for the restitution of royalties paid by the Plaintiffs to the State in excess and under protest, for the Plaintiffs' revenues from gas supply agreements signed between consumers of natural gas and the Yam Tethys Partners, some of which was actually supplied from the Tamar Project, according to the accounting mechanism designed to maintain a balance of the gas quantities in the Tamar Project between the partners therein according to their share. The restitution remedy claimed from the State is, as of December 31, 2022, approx. $28 million, the Partnership's share being approx. $13 million.

Alternatively, the Plaintiffs' argument is that they are at least entitled to a partial restitution amount that is, as of December 31, 2022, approx. $19.4 million, the Partnership's share being approx. $9 million.

On November 14, 2022, a judgement was issued by the court dismissing the complaint, other than in connection with the Plaintiffs' position regarding the restitution of interest amounts which the defendant collected from the Plaintiffs in an insignificant amount. On February 6, 2023, the Plaintiffs filed an appeal from the judgement with the Supreme Court.

In the estimation of the Partnership, based on the opinion of the legal advisors, it is difficult to assess the chances of the Plaintiffs' claims being accepted in the appeal, further to the issuance of the judgment and since the defendant's response to the appeal has not yet been filed and no hearing has yet been conducted on the appeal.

Note that the decision on this matter, when it will be final and conclusive, shall also apply, *mutatis mutandis*, with respect to the overriding royalties that the Partnership has paid over the years for the Tamar Project, in accordance with the agreements described in Section 7.24.9(c)5 above. Accordingly, insofar as the court's said decision of November 14, 2022 stands, the Partnership shall bear an additional payment to the royalty holders for the amounts of gas which were supplied by the Partnership to the customers of the Yam Tethys Project, for which a provision was recorded in the financial statements in the sum of approx. $6.4 million (including interest and linkage).

In accordance with the terms and conditions of the Agreements for the sale of the Partnership's rights in the Tamar and Dalit Leases, also after the closing of the transaction, the Partnership is responsible and entitled, as the case may be, with respect to the amounts in dispute vis-à-vis the State and the Royalty Owners.

For further details, see Note 7C1 to the financial statements (Chapter C of this report).

7.25.3 On December 25, 2016, the participation unit holders in Avner prior to the merger of the partnerships (in this section: the "**Petitioners**"), filed a motion for class certification (in this section: the "**Certification Motion**") based on the argument that the Merger of the partnerships' 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 of the partnerships' 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**"). The motion claims, *inter alia*, that 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 Certification Motion will be amended by adding an argument of minority oppression by Delek Group, and on July 6, 2017, the court ordered to add the Partnership as a respondent in accordance with the Partnership's motion. According to the agreed stipulation between the parties, the petitioners filed their summations on August 16, 2021, and the Respondents filed their summations on June 29, 2022. On December 29, 2022, the responding summations on behalf of the Respondents have been filed.

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%.

7.25.4 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 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* the duty of care of the said officers and the Partnership's duties as shareholder and holder of control of Tamar Petroleum before the IPO.

The remedies sought in the Certification Motion mainly included 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, and 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 the context of which they sought to add to the Certification Motion an additional petitioner who participated in the IPO, unlike the current Petitioners who did not participate therein and they also sought to increase the amount of the alleged damage to $153 million. On April 6, 2021, the court granted the Petitioners' motion to amend the Certification Motion, and ruled that the Petitioners are entitled to file the amended Certification Motion in accordance with the language filed with the court subject to payment of expenses to the Respondents in the sum total of ILS 100,000. On January 23, 2022, an amended motion for class certification was filed, and on August 21, 2022 and September 4, 2022, the Respondents filed their response to such motion. On December 20, 2022, a pretrial hearing was conducted, and in accordance with the court's decision as part thereof, on January 17, 2023, the Petitioners filed an amended response to the Respondents' answers to the amended 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%.

7.25.5 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 Chevron 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 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 Chevron (in this section: the "**Amendment to the Tamar Agreement**").

The Petitioner's principal arguments are, 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 Chevron'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 Chevron under this agreement, while harming competition, amount to unjust enrichment.

The Petitioner alleges that such actions of the Partnership and Chevron 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 Certification Motion is a ruling by the court that the Partnership and Chevron are not entitled to prevent the other holders in the Tamar Project from signing the Amendment to the Tamar Agreement.

On December 22, 2020 the other holders of the Tamar project filed a motion for summary omission thereof, and on September 9, 2021 the Court approved their omission. Furthermore, on November 17, 2021, the court approved Ratio's stipulation to be omitted from the Certification Motion.

On December 9, 2021, the Partnership and Chevron filed their response to the Certification Motion as well as a motion to remove the legal opinion that was attached to the Certification Motion, and on February 27, 2022, the Court decided that this motion will be heard at the pretrial hearing set for April 24, 2022. On February 28, 2022, the Petitioner filed a response to the Respondents' response to the Certification Motion.

On April 24, 2022, in the context of a pretrial hearing, the court ordered as follows: (1) the legal opinion which was attached to the Certification Motion will be removed, and the Petitioner will bear the expenses of the respondents to the Motion on this matter; (2) the Petitioner shall be given an opportunity until May 24, 2022 to file a motion to amend the Certification Motion; (3) until then, the parties shall be given an opportunity to file a list of questions with the court which will be directed to the regulator relevant to the Certification Motion; and (4) on May 25, 2022, or soon thereafter, the court shall allow the respondents to respond to the motion to amend the Certification Motion, insofar as such motion is filed, or alternately shall deliver the pleadings, with the questions filed by the parties attached, for the regulator's comments.

On May 25, 2022, the partied filed a list of questions which will be directed to the regulator, and on May 31, 2022 the court ordered the delivery of the pleadings to the Office of the Tel Aviv District Attorney (Civil) in order to obtain the position of the regulator on the dispute which is the subject of the Certification Motion. On January 19, 2023, the position of the regulator (the Competition Authority, with the consent of the Ministry of

Finance and the Ministry of Energy and in coordination with the Attorney General) was filed. In summary, the position refrained from explicitly stating whether or not there is any truth in the claims made in the Certification Motion, but it reviewed the relevant factual and legal background in a way that is generally consistent with the claims of the Partnership and Chevron. On February 26, 2023, a pretrial hearing took place, at the end of which, the court determined dates for trial hearings in March-April 2024.

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%.

7.25.6 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 General Partner, Delek Group, Delek Energy and Tomer Energy Royalties (Delek Group, Delek Energy and Tomer Energy Royalties,[130] 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.

On April 4, 2019, the Royalty Interest Owners filed an answer and a counter-complaint against the Partnership, the General Partner 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

[130] On June 13, 2021, Delek Royalties (2012) Ltd. announced the change of its name to Tomer Energy Royalties (2012) Ltd. ("**Tomer Energy Royalties**").

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, 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 said calculation to the Royalty Interest Owners.

On October 2, 2019, the answers were filed on behalf of the Partnership and the General Partner, and in this context both an answer in relation to the Supervisors’ Claim and a counter-answer in relation to the Counterclaim which was filed by the Royalty Interest Owners, in which it was asserted that both of the claims should be simultaneously dismissed with prejudice.

On April 5, 2021, a pre-trial hearing took place, during which the parties were offered to refer to mediation, following which the parties agreed to apply to former Supreme Court Justice Yoram Danziger as a mediator. As of the report approval date, the mediation process has not yet been exhausted.

The Partnership estimates that any decision that is made with respect to the method of calculation of the Investment Recovery Date in respect of the Tamar Project shall also apply, *mutatis mutandis*, to the Partnership’s royalty obligations in the Leviathan Project (in view of the fact that the royalty arrangements in the Tamar Project are similar to the royalty arrangements in the Leviathan Project).

The Partnership estimates, based on the opinion of its legal counsel, that the chances of the Counterclaim being accepted are lower than 50%.

7.25.7 Following the decision of the Competition Commissioner (in this section: the “**Commissioner**”), pursuant to Section 20(b) of the Economic Competition Law, to approve, under specific conditions, a merger between EMG and EMED, in the framework of several agreements signed in order to allow the export of gas to Egypt , as specified in Section 7.24.6 above, on September 8, 2019, Lobby 99 Ltd. (CIC) and Hatzlacha – For Promotion of a Fair Society (R.A.) (in this section, the "**Appellants**"), filed an administrative appeal with the Jerusalem District Court (sitting as the Competition Court) against the Commissioner (as a respondent) and against EMG and EMED (in this section: the "**Respondents**"). In summary, the administrative appeal asserts that the Merger will enable the

Partnership and Chevron to block any possibility of importing or exporting natural gas from Egypt that will compete with the gas produced from the Leviathan and Tamar reservoirs (on the administrative appeal filing date, the Partnership has not yet sold its rights in the Tamar reservoir), 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 21, 2022, a judgement was given in the administrative appeal, in the context of which the court determined that the appellants failed to demonstrate that the merger raises a reasonable concern for significant reduction of competition, and it therefore denied the remedy which sought to revoke the approval given to the merger transaction. However, the court ordered the Commissioner to provide a supplementary decision on the conditions she imposed on the merger, in view of the difficulties that such conditions raised. The court also determined that each party shall bear its own costs. Since no appeal was filed from the judgement, on February 5, 2023 the judgement became final and conclusive.

7.25.8 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, Delek Group, Yitzhak Sharon (Tshuva), the directors of the General Partner (including the former chairman of the board) and the CEO of the General Partner (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 Blue Ocean (formerly 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 (the "**Reduction Clause**"). 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 that states, *inter alia*, 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, and 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. On January 2, 2022, the Attorney General, after being required to do so by the court, notified that at this stage, he did not deem it fit to take a position in the proceeding. Trial hearings were held in November 2022. In accordance with the decision of the court and the stipulation between the parties, the Petitioner and the Respondents must file closing statements and responding summations in 2023 by July 11, 2023.

In the Partnership's estimation, based on an opinion of its legal counsel, the chances of the motion being granted are lower than 50%.

7.25.9 On July 20, 2020, the Partnership received a letter from the ISA requesting provision of information and documents as part of an administrative inquiry being conducted by the ISA in connection with the Reduction Clause in the Export to Egypt Agreements, in relation to which the class certification motion was filed, as specified in Section 7.25.8 above. On November 10, 2020, the Partnership filed a response to the said letter of request and on April 12, 2022, the Partnership received notice from the ISA regarding the closing of such administrative inquiry case, according to the decision of the chairman of ISA not to open an administrative enforcement proceeding against the Partnership on this matter.

7.25.10 On June 18, 2020, the Partnership and Chevron which held the Alon D license, as provided in Section 7.7.2 above, filed a petition with the Supreme Court, sitting as the High Court of Justice (in this section: the "**Petitioners**" and the "**Petition**", respectively). 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 Petitioners granted a substitute license in its stead, and why the Petitioners 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, or 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 consequently the Alon D license expired on June 21, 2020.

Further to the aforesaid, 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 May 13, 2020, the State filed its preliminary response to the Petition, in which it argued, *inter alia*, that the Petition should be denied due to the failure to join Energean as a respondent. On May 19, 2021, a hearing took place on the Petition, in which the parties reached an agreement whereby Energean will be joined as a respondent in the proceeding, will file a response on its behalf within 60 days, and on such date, the parties will also update on the progress of the competitive process in Block 72, based on the assumption that by such date, a winner would be selected in the competitive process, which is expected to affect the claims in the Petition. The court approved the stipulation between the parties, such that on August 19, 2021, Energean filed its response to the Petition and on October 25, 2021 the Petitioners filed their answer to the response of Energean. Following the signing of the maritime agreement as specified in Section 7.7.2 above, on December 8, 2022, the State filed a notice of update whereby, in view of the signing of the maritime agreement, such developments obviate the Petition. On December 15, 2022, a hearing on the Petition was held, and in the end, the court suggested that the Petitioners withdraw the Petition, and also allowed them to file their position in writing with respect thereto. On December 25, 2022, the Petitioners filed a notice whereby they are not withdrawing the Petition. As of the report approval date, the parties are awaiting the court's decision.

In this context, as of the report approval date, no decision has yet been made on the competitive process for Block 72.

7.25.11 On May 3, 2021, Haifa Port Company Ltd. (in this section: "**Haifa Port**") filed a claim against Chevron, Coral Maritime Services Ltd. (in this section:

"**Coral**") and Gold-Line Shipping Ltd. (in this section: "**Gold-Line**"), in the amount of approx. ILS 77 million (in this section: the "**Primary Claim**"). According to Haifa Port's claim, the direct offloading of cargo onto the Leviathan platform, as done by Chevron, without first unloading such cargo in one of Israel's ports, is unlawful and was done to avoid making obligatory payments to the Port, thereby causing the Port a loss. As argued in the complaint, from July 2018 forward, Chevron engaged in such direct offloading, while declaring to the tax authorities that the Haifa Port was the "offloading port", although the offloaded cargoes did not actually go through the Haifa Port. The claim against the Coral and Gold-Line companies is that they acted, during the relevant times, as ship agents for Chevron, which, as argued by Haifa Port, gives rise to their duty to pay the handling fees on behalf of Chevron.

Chevron filed its answer on August 31, 2021, and on December 1, 2021, Haifa Port filed a reply. At the same time, Chevron filed a counter-complaint in the amount of ILS 4,405,842 against Haifa Port, seeking ILS 715,691 for handling fees and infrastructure fees actually charged by Haifa Port, in violation of the law, and seeking ILS 3,690,151 for mooring fees charged to Chevron without a 30%-reduction, in violation of the law, in cases of self-navigation by ships passing through the port area. Haifa Port filed a counter-answer on December 1, 2021.

On September 11, 2022, a pretrial hearing was held, in which it was determined that the parties will negotiate with the aim of reaching agreement on the completion of the preliminary proceeding, failing which they will file motions accordingly. Despite the attempt to reach agreements, the parties filed mutual motions regarding the preliminary proceedings. The parties are required to respond to the motions by April 9, 2023 and these shall be discussed in the pretrial hearing scheduled for April 20, 2023.

In the Partnership's estimation, based on an opinion of its legal counsel, it is more likely that the Primary Claim will be denied rather than accepted.

7.25.12 On April 7, 2021, the Partnership, together with the other Tamar Partners and Leviathan Partners, filed a petition against the Natural Gas Commission and the Ministry of Energy (in this section: the "**Respondents**"). The petition moves for annulment of the decision of the Natural Gas Commission (in this section: the "**Commission**"), decision no. 5/2020 of December 29, 2020 – Amendment to Commission decision 8/2019 - criteria and tariffs for operation of the transmission system in a flow control regime (Amendment no. 2), published on January 3, 2021, which is described in Section 7.22.5(c) above (in this section: the "**Decision**"). According to the Decision, the natural gas suppliers shall bear the cost of one half of the "Unaccounted For Gas Target (UFG-T)", which is defined in the Decision as a difference of up to 0.5% between the quantity of gas measured by the meter at the entrance to the national natural gas transmission system and the quantity measured by the meter at the exit therefrom. The petition argued that this Decision was issued without any lawful authority and is extremely unreasonable.

On October 26, 2021, Energean, which was joined as a respondent to the petition, filed its response according to which the petition is justified, and on October 27, 2021, INGL, which was also joined as a respondent to the petition, filed its response, in which it was argued that the petition is tainted with bad faith and unclean hands due to the concealment of material facts and failure to join entities which may be harmed by the petition, and that the Decision contemplated in the petition was adopted with authority and is reasonable. In addition, on November 5, 2021, the Respondents filed their responses to the petition, according to which the petition should be summarily dismissed with prejudice due to failure to join the gas consumers as respondents and the petition should also be dismissed on the merits because the Decision was adopted with authority and is reasonable on the merits. A hearing on the Petition took place on February 9, 2023, upon the conclusion of which the court recommended to the Petitioners to withdraw the Petition. The Petitioners did so and the Petition was dismissed with no order for costs.

7.25.13 On May 31, 2022, the Partnership filed a monetary claim against Energean, in a total amount of $65.1 million, plus differentials for legal linkage and agreed annual interest of 4.6% (hereinafter in this Section: the "**Claim**"). In the context of the Claim, the Partnership is claiming that, according to the provisions of the agreement for the sale of the interests in the Tanin and Karish Leases to Energean, in the event that Energean obtains the financial closing of the costs of the first stage of the development plan which is approved for Tanin and Karish Leases plus all (100%) of the monetary consideration for the object of sale as determined in the sale agreement ($148.5 million), Energean shall be obligated to immediately pay the balance of the consideration (as defined in Section 7.5.4 above). Therefore, in the opinion of the Partnership, Energean's notice of April 30, 2021 on the issue of bonds in a total sum of $2.5 billion and the release of the issue funds to its account, constitutes cause for immediate payment of the balance of the consideration. A pretrial hearing in the case has been scheduled for April 19, 2023.

7.25.14 On May 4, 2021, the General Partner and Limited Partner filed a motion with the Tel Aviv District Court pursuant to Sections 350 and 351 of the Companies Law for approval of the convening of a general meeting of the unit holders for approval of an arrangement which mainly concerns substitution of all of the issued participation units with ordinary shares of a new company incorporated in England, whose shares were intended to be listed for dual listing on the London Stock Exchange and on the Tel Aviv Stock Exchange. For details regarding the motion, the proceedings to approve the motion, the decision of the District Court on the motion and an appeal from the District Court's decision that was filed with the Supreme Court, see Section 7.26.4 of the 2021 Periodic Report and the Partnership's immediate reports of May 4, 2021, December 27, 2021, February 24, 2022, April 4, 2022, June 1, 2022, July 26, 2022, August 17, 2022, October 9, 2022, November 2, 2022, December 27, 2022 and February 10, 2023 (Ref. 2021-01-077190, 2021-01-185460, 2022-01-022645, 2022-01-035619, 2022-01-068698, 2022-01-095101, 2022-01-104887, 2022-01-125206, 2022-01-106695, 2022-01-156484 and 2023-01-005442, respectively), the information appearing in which is included herein by reference.

For details regarding the business combination agreement in which the Partnership engaged further to this legal proceeding, which was terminated, see Section 7.24.14 above.

7.26 **Goals and business strategy**

7.26.1 General

The Partnership's goals and accordingly also its business strategy, are exhaustion of the economic potential of the natural gas assets held thereby alongside examination of acquisition of additional natural gas assets, in and out of Israel, and examination of possibilities of using new technologies designed to streamline the activity of natural gas production and utilization. The said strategy is realized mainly through exhaustion of the production and sales potential of Phase 1A and promotion of the development of Phase 1B, as specified in Section 7.2.5 above, improvement of the production and operation of the Leviathan reservoir, promotion of the development of the Aphrodite reservoir, 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 as LNG.

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 through the pipelines and/or liquefaction and/or compression of the natural gas and the marketing thereof to the global markets and taking into account the Government's policy on the matter.

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. In this context, 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.

Furthermore, in view of the changes occurring in the energy industry, government policy in Israel and in the developed countries to encourage the transition to electricity production from alternative energies, and the desire to promote ESG aspects of the Partnership’s activity,[131] the Partnership is exploring possibilities for investment in the alternative energies sector, and in the context of which, engaged in an agreement with Enlight, as specified in Section 7.8 above, and is also exploring entry into the field of blue hydrogen in a manner which may constitute a low-carbon substitute for energy consumers, as specified in Section 7.1.3 above.

7.26.2 **Natural Gas**

The Partnership will continue to act to exhaust the economic potential of the natural gas assets held thereby alongside examination of acquisition of additional assets, including:

(a) Leviathan Project

1. Assurance of the supply of natural gas and condensate from the Leviathan reservoir, 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

[131] ESG report posted on the Partnership’s website. For details visit: http://newmedenergy.com/wp-content/uploads/2022/02/NewMed-Energy_ESG-Report-_2020-2021.pdf.

to various potential consumers in Israel and in counties in the region, chiefly Egypt, Jordan and the Palestinian Authority.

2. Promotion of the development of Phase 1B and increase the maximum scope of production to approx. 21 BCM per year, as specified in Section 7.2.5(c)2 above, with the purpose of making a final investment decision (FID).

3. Promotion of the consideration of forming an exploration prospect to oil targets in the Leviathan Leases, as specified in Section 7.2.4 above.

(b) Block 12 in Cyprus

Promotion of the development of the Aphrodite reservoir in Cyprus, as specified in Section 7.3.6 above.

(c) 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 construction and transmission costs and increasing the feasibility of advancing various projects. For instance, the Partnership is examining, together with its partners in the Aphrodite reservoir, the possibility of using existing infrastructure in Egypt, 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 7.11.2(d) above.

(d) Oil and gas explorations

Continued natural gas and oil exploration activity in the Partnership's assets and identification of business opportunities in new assets, mainly in and around the Mediterranean Basin countries. In this context, the Partnership signed agreements regarding exploration activity and production under a Boujdour license in Morocco. For further details, see Section 7.6 above.

(e) Increasing the demand for natural gas

The Partnership is working to increase demand for natural gas, *inter alia*, in the following methods:

1. 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 CNG, and to increase the use of natural gas for generating electricity for electric transportation, such as electric buses, trains and passenger cars in the Israeli transportation market. In the Partnership's estimation, the scope of conversion of the transportation is expected to grow by approx. 2.3 BCM by 2030.

2. Conversion of coal-fired power plants to use of natural gas: 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 the end of 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. 4.3 BCM per year.

3. Additional industries: To the best of the Partnership's knowledge, projects are being examined and promoted in the State of Israel by various entrepreneurs, both in industries in which natural gas is used as a raw material, such as the production of ammonia, hydrogen 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.

7.26.3 **Alternative energies**

(a) Renewable energies

The Partnership is exploring possibilities for investments in projects in the field of renewable energy as part of a collaboration with Enlight, as specified in Section 7.8 above.

(b) Production of hydrogen

The Partnership is examining a blue hydrogen venture, in which natural gas is split into hydrogen and carbon dioxide (CO_2), with the carbon dioxide being collected and stored in designated subsurface storage sites. Hydrogen is currently considered one of the main staples of a sustainable and prosperous low-carbon economy and constitutes a key strategy for dealing with the climate crisis.

7.26.4 The scope and range of the Partnership's operations require the investment of significant financial resources, *inter alia*, for the purpose of establishing and deepening the commercial, technical, financial, legal, regulatory and other capabilities and knowledge. Therefore, the Partnership intends to consider and make use of the variety of resources available thereto for purposes of raising money, by way of debt and/or equity, in addition to using the future surplus income from the Leviathan project, and the surplus cash in its possession.

It is clarified that the Partnership's goals and strategy as specified above constitute general intentions and goals and therefore there is no certainty that they will be realized, *inter alia*, due to changes in the market conditions, geopolitical changes, changes in regulation and in tax laws, changes in priorities resulting from the results of the activity in the Partnership's projects as well as other developments, unpredicted events, and the risk factors, as specified in Section 7.28 below. It is further clarified that realization of the goals and strategy specified above is subject to approvals by the Partnership's competent organs, which have not yet been obtained, including the general meeting of the unit holders, as well as third-party approvals.

7.27 **Insurance coverage**

From time to time, the Partnership takes out the insurance policies generally accepted 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 licenses and the leases, 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 and products thereof, and 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 (except for gradual pollution damage).

It is noted that the Partnership and Chevron 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.

Furthermore, 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 modification and/or 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 7.3.3(m) above. For further details, see Section (c) of Regulation 22 to Chapter D of this report. As a condition for granting the aforesaid guarantee, the Partnership was required to take out additional insurance to the Guarantor's satisfaction, 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 7.28.11 below.

7.28 <u>Risk factors</u>

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 Risks**"). 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 specified in this chapter, as well as risks which, as of the date of approval of the report, are not yet known to the Partnership.

7.28.1 The Covid pandemic

The Covid pandemic, which began in 2020, impacted the global energy sector in recent years, as specified in Section 7.1.4 above. In 2021 and 2022, countries around the world, including Israel, continued to tackle the Covid pandemic, and during 2022 there was a significant decline in the morbidity rates, and the economy began to recover. However, as of the report approval date, it is impossible to know whether other variants of the Covid virus will emerge, and therefore, it is difficult to estimate whether the Covid pandemic will again impact the global and domestic economy in the future, and its effect on the demand for and prices of natural gas and the other energy products. In these circumstances, the Covid pandemic may affect the financial markets, interest margins, currency exchange rates and the prices of commodities in the energy sector, and may adversely affect many sectors, including the energy sector in which the Partnership operates.

In addition, restrictions and actions that may be employed by the Israeli government and other countries for future tackling of the Covid pandemic may have a material negative impact on the Partnership's business and its work plans. As a consequence thereof, delays may be caused in the entry of foreign experts and in the supply of designated equipment into the State of Israel, due to restrictions which apply to the movement of citizens between sites and countries and due to restrictions on production or transportation which apply in the various countries, which may, *inter alia*, disrupt the regular production activity, the said work plans, and also impose additional unexpected costs. In view of the aforesaid, notwithstanding the precautions taken by the partners in the Leviathan project, the reservoir's operation may be adversely affected.

7.28.2 Fluctuations in the linkage components in the natural gas price formulas in the supply contracts

The gas price is determined in the natural gas supply agreements according to price formulas which include various linkage components, including mainly linkage to the Brent barrel price, to the Electricity Production Tariff, to the ILS/$ exchange rate, to the general TAOZ index published by the Electricity Authority and the refining margin index. All of the natural gas supply agreements in which the Partnership engaged, other than agreements that include a non-linked fixed price, also specify, along with the price formulas, price floors that limit, to a certain extent, the exposure to fluctuations in the linkage components. However, there is no certainty that the Partnership will also be able to determine such price floors in new agreements to be signed thereby in the future.

Moreover, a decrease in the Brent prices and/or a decrease in the Electricity Production Tariff 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), 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.

7.28.3 <u>Changes in demand and in the prices of the energy products</u>

The demand for natural gas from the Partnership's customers and the price thereof are affected, *inter alia*, by significant changes in the prices of oil, natural gas, including LNG, and the prices of other sources of energy, including coal, sources of renewable energy and other alternatives to the produced natural gas marketed by the Partnership, both in the domestic market and in the global markets. Thus, for example, low LNG prices in the global 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 Leviathan reservoir. In this context, it is noted that the prices of energy products in the global markets started declining from H2/2022, as specified in Section 7.1.4 above.

An increase in supply, a decrease in demand or a decrease in the prices of energy sources alternative to natural gas, including coal, sources of renewable energy and other products, in the domestic market or in the global markets, may reduce demand on the part of 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.

Moreover, reforms and decisions relating to the electricity sector and in the energy sector, 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 pandemics, such as the Covid pandemic, extensive military conflicts between countries 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.

7.28.4 Global macroeconomic factors

The Partnership's ability to sell the natural gas produced, as well as to sign new long-term agreements for the sale of natural gas, and to adopt investment decisions with respect to new projects for the production of natural gas 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 pandemics such as the Covid pandemic, extensive military conflicts between countries 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 significantly harm the global economy, increase uncertainty in the markets, damage the confidence of investors, the business community and consumers, result in a decline in global consumption of energy products, including oil and natural gas, and make it difficult to refinance.

Accordingly, in 2022, the Partnership’s operations and results were influenced by various factors, including by the global energy crisis, which derived, *inter alia*, from the Covid pandemic and the war in Ukraine, and the rise of global inflation, and the consequent rises of interest rates by central banks globally. For the impact of such events on the Partnership’s operations, see Section 7.1.4 above.

Naturally, the Partnership is unable to influence factors of this type, and it is difficult to assess and estimate how factors of this type may evolve and affect the Partnership's business.

7.28.5 Geopolitics

The general security, economic and political situation in the Middle East, and specifically in Israel, Egypt, Jordan and Cyprus, 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 agreements of export of gas to Egypt and to Jordan, i.e. to Blue Ocean 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.

7.28.6 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 or withdrawal of credit from the Credit Facilities as specified in Section 7.19.3 above, may be difficult, particularly against the background of the global economic crisis that is expressed in a reduction of the available credit sources, the tightening of requirements of the finance providers for provision of the financing, and the increase in the interest rates by the central banks in the world, which may affect the Partnership's financing expenses.

7.28.7 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 may lead to a drop in demand and in natural gas prices that will be determined in new supply agreements, which may lead to a material negative effect on the Partnership’s revenues and business.

In this context, 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. In Egypt and in Jordan, to which the Partnership exports natural gas under the Blue Ocean and NEPCO supply agreements, the Partnership is exposed to competition that may intensify in the future by reservoirs that have been discovered (In Israel and in the region, 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.

In addition, the Tamar reservoir and the partners therein are competitors of the Partnership in the domestic and regional market, and the Karish lease and its partners are competitors of the Partnership in the domestic market.

As of the report approval date, the gas from the Leviathan reservoir is jointly marketed by all of the Leviathan Partners. However, under the JOA each partner is entitled, subject to certain conditions, to take its share of the gas produced from the reservoir and market 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 the business sector, see Section 7.13 above.

7.28.8 Restrictions on export

The results of the Partnership's activity are dependent, to a great extent, on the possibility of exporting gas from the Leviathan reservoir, and selling it in the regional and international market. The Government Resolutions on Export, as specified in Section 7.22.9 above, limit the quantity of gas that may be exported. Therefore, 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.

It is noted that in the event of a decrease in the supply capacity of natural gas from the Tamar reservoir and/or the Karish lease, mainly in the peak months where demand for natural gas in the domestic and export markets exceeds the production capacity from the Leviathan, Tamar and Karish reservoirs, the Leviathan Partners may be required to supply the domestic demand at the expense of quantities designated for export. For details on the amendment to the Export to Egypt Agreement, see Section 7.10.3(c) above.

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, 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.

7.28.9 Dependence on the development and functioning of the gas transmission systems

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: 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 operation results.

In addition, a delay in implementation of the development and expansion plans for the gas transmission systems may impair the Partnership's ability to meet its undertakings to its customers and its forecasts in connection with natural gas sales.

7.28.10 Operational risks

Oil and natural gas exploration, development, production and abandonment of activity in deep water entails considerable risks, including, *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 systems. Performance below the expected or efficient level may also be caused, *inter alia*, as a consequence of the contractor or the operator errors, work disputes or disruptions, injuries, a delay or non-receipt of permits, approvals or licenses, a breach of requirements of the 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.

In addition, drilling and completion in deep water requires use of designated technologies and equipment, 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.

7.28.11 <u>Lack of sufficient insurance coverage</u>

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 are certain insurance policies which the Partnership may decide not to purchase at all for various reasons, such as lack of economic merit, nor is there any certainty that it will be possible to purchase suitable insurance policies in the future with reasonable commercial terms or at all.

In addition, the Partnership's activity in Jordan (as specified in Section 7.11.2(c) above) and in Egypt (as specified in Sections 7.11.2(d) and 7.24.6 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.

Therefore, 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 during infrastructuring crossing and 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 is 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 type of prospect in which the well is expected to be drilled, 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 and the project in the insurance market and the foreseeable risks.

7.28.12 Construction risks, dependence on contractors and on professional service and equipment suppliers

In Israel there are currently no contractors and suppliers who can perform the main actions performed in the Partnership's assets, such as drilling of wells in deep sea and production and laying of subsea infrastructure of natural gas, and therefore the Partnership engages through the operator with foreign contractors for such purpose. Moreover, the equipment required for the performance of the actions, such as drilling vessels or vessels for laying pipelines at sea or crane platforms for the construction of platforms, is limited and therefore there is no certainty that it will be available for performing the aforesaid actions on the dates scheduled therefor. As a result, various actions may entail costs that are higher than planned and/or significant delays may be caused to the timetables set for the performance of the work. In addition, following the limited availability of the designated equipment and manpower to operate the same, it is required to reserve the engagement therewith a considerable time in advance, which adds complexity to the project and may significantly increase the costs of the Partnership's activities, including the ability to engage with foreign contractors and the ability of such contractors to consummate the engagement therewith, may encounter difficulties also due to the political and security situation of the State of Israel. It is noted that the price of the services and the costs of exploration, development, production and abandonment activities is determined according to 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.

7.28.13 Risks of exploration activity and reliance on partial and estimated data, estimates and evaluations

Oil and gas exploration activity entails a high level of risk, mainly since the geological and geophysical means do not provide an exact projection of the location, form, characteristics or size of oil and gas reservoirs, and therefore exploration activities may end in findings that do not allow for commercial development and production.

The estimation of the quantity of resources in the assets of the Partnership in general, and in the Leviathan Project in particular, is examined on a continuous basis, and is updated from time to time, based, *inter alia*, on production data and additional information accrued, through the operator, an independent reserve evaluator and the Ministry of Energy. The process for estimating the quantities of resources is subjective and based on various assumptions and estimates and on partial information, and therefore the estimates regarding the same reservoirs that are carried out by different experts may sometimes be materially different.

In view of the aforesaid, 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 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 Leviathan project 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 Leviathan project cash flows, see the resources report attached hereto as **Annex B**.

7.28.14 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. In addition, 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. In addition, faults caused 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.

7.28.15 <u>Forfeiture of the Partnership's rights in its petroleum assets and the financial strength of the partners in the petroleum assets</u>

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, the financial strength of the partners in the petroleum assets held by the Partnership may have repercussions, *inter alia*, on its cash flow.

7.28.16 <u>Dependence on obtaining regulatory and other approvals</u>

Exploration, development, production and abandonment 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 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 new Approvals that shall be required in the future and the conditions to be determined therein, and therefore, there is no certainty that it will be possible to obtain them or comply with their conditions.

7.28.17 Regulatory changes

In general, the scope of regulation applying to the field of business of the Partnership is constantly growing. 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 regulations or policy, or if there is a delay in the receipt of regulatory approvals, 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.

For details regarding the main regulation that applies to the Partnership's operations as of the report approval date, see Sections 7.21.2 and 7.22 above.

7.28.18 Potential control of natural gas prices

The Partnership is subject to the Control of Prices of Commodities and Services Order, which imposes control on the gas sector in terms of profitability and price reporting, as specified in Section 7.22.2(b) above. According to the said order, it is necessary to report semiannually on the prices and on the profit margins of the sold natural gas. 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 have an adverse effect on the Partnership's business, the scope of which shall be derived from the maximum price to be determined.

7.28.19 Applicable environmental regulation

The Partnership's activity, performed mainly by the operator in the various petroleum assets, 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, etc.), 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 in the various petroleum assets, to obtain approvals for the activity of the operator 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, as well as the officers therein, 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 its activity.

In addition, 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.

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, as specified in Section 7.21.2(g) above. 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. In addition, 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 noted that the interpretation and enforcement of the environmental laws and regulation change from time to time and may be stricter in the future.

For details on the provisions of law and the instructions of competent authorities on environmental subjects which apply to the Partnership and about material administrative and legal proceedings in connection with environmental protection, see Sections 7.21.2 and 7.21.7 above, respectively.

7.28.20 Climate crisis

The climate crisis impacts the Partnership's operations both directly and indirectly. Directly, the increasing intensity and frequency of extreme climate events, whether occurring in the Partnership's assets or in areas through which the chain of supply to such assets runs, may, inter alia, disrupt and delay the operations in the assets and/or render them more expensive. Indirectly, in recent years, there has been increasing regulatory intervention whose purpose is to reduce the emission of greenhouse gases and promote the use of renewable energies, in the context of declared government policy for tackling the climate crisis, which is mainly prevalent among the developed countries. This intervention is expressed, *inter alia*, in the determination of targets for reduction of the use of fossil fuels and for increase of the use of clean and renewable energies, and it is implemented, *inter alia*, by giving positive incentives to producers and consumers of renewable energy sources and determining negative incentives for producers and consumers of fossil energy (such as the imposition of a 'carbon tax'). For details regarding decisions and plans published on this issue on behalf of the Israeli government and government authorities, see Section 7.22.10 above.

The regulatory intervention on this issue, which may be expressed, *inter alia*, in international agreements, legislation and other regulatory measures, may have a material negative effect on the Partnership's business and on its financial results, and may cause, *inter alia*, a considerable increase in expenses that are required for compliance with the new requirements, a significant increase in competition on the part of suppliers of renewable energy sources, and a decrease in demand for the natural gas produced by the Partnership from the Leviathan reservoir, and even a decrease in the value of the Partnership's assets.

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.

In view of the aforesaid, the Partnership is exploring possibilities of investment in projects in the renewable energy sector, in the context of the collaboration with Enlight, as detailed in Section 7.8 above.

7.28.21 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.

Furthermore, 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.

For details regarding the impact of weather on demand and regarding the delays in the completion of the Combined Segment, see Sections 7.1.3 and 7.11.2(e) above, respectively.

7.28.22 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 Leviathan reservoir, 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, following the changes in the working market 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 and/or security exposures in IT systems, including in ICS, information systems, infrastructure and information security systems, may allow unauthorized access for the purpose of misuse of the Partnership's assets, and deliberate harm to such IT systems of the corporations. Unauthorized access may cause damage to the administration networks of the Partnership and/or the operator, the leak of information to unauthorized entities, disruption of the information in the systems, damage to the integrity of the information, and damage to processes in connection with ICS. 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 acts 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 in its organizational network, whereas the operator implements the directives of the National Cyber Directorate with respect to the operational aspect of the production platform of the Leviathan project, as a critical State infrastructure. The Partnership has established an information security and cyber protection policy (the "**Protection Policy**") which is approved once a year by the Partnership's board, defines its position with respect to aspects of information security and cyber protection, and is acting for implementation of this position while guiding all of the employees for adequate conduct vis-à-vis cyber risks.

The defense policy includes mapping the Partnership's defense goals, reviews are made to the Partnership's cyber risks, cyber defense controls are characterized and implemented and processes to review the effectiveness of such controls, are determined.
The Partnership also performs, from time to time, risk surveys to examine the information security gaps and check the effectiveness of the information security and cyber defense policies, and acts to implement the findings thereof.

In addition, the Partnership works on a routine basis to increase the level of the employees' awareness of aspects of information security and cyber protection, including phishing attempts, specific training, and remote work rules. 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.

Tal Levi, VP Budget and Control, who reports to the CEO of the Partnership, is responsible in the Partnership for the implementation of the defense policy, and the Partnership further outsources an IT company and information security manager, who act regularly towards constant strengthening and improvement of the Partnership's defenses. The Partnership's information security manager is responsible, *inter alia*, for: (a) the establishment of the defense policy and supporting procedures; (b) implementation of a regular work and control plan over the compliance with the requirements of regulations in the defense policy and procedures; (c) instructions in connection with the implementation of the cyber defense measures in the Partnership; and (d) instructing the Partnership and the said IT company with respect to the information security and cyber defense at the Partnership.

In addition, the Partnership is preparing to cope with a cyber event, and to this end has adopted a procedure for the management of a cyber event and conducted a cyber event management drill for the Partnership's management and information security manager. In this context it is noted that as part of the cyber insurance policy that was taken out for the Partnership, if a cyber event occurs, the insurance company will provide the Partnership with additional functions specializing in the management of cyber events from the professional and legal aspects as well as crisis management.

In 2022 the Partnership allocated a designated budget to cyber risk management.

It is further noted that the Partnership and all of its computer systems, have no 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.

7.28.23 <u>Changes in investment trends due to ESG-related considerations</u>

In recent years, there has been a growing awareness among investors in Israel and around the world and among other stakeholders, such as suppliers, consumers, employees, credit providers, etc., of the climatic and environmental impacts of various activities. As part of this trend, existing and potential investors, as well as other stakeholders, are considering ESG aspects as part of their investment and business policies, including with regard to the provision of credit.

Simultaneously, a similar trend is emerging among regulators in Israel and around the world. For example, in December 2020, the Supervisor of Banks issued a notice stating that banks are expected to take adequate operative measures to identify, monitor and manage environmental risks; In April 2021, the ISA released a proposed outline for reporting corporations regarding, *inter alia*, voluntary disclosure of annual reports on corporate governance and ESG risks; and in July 2022 a circular published by the Capital Market, Insurance and Savings Authority took effect, stating, *inter alia*, that institutional bodies will be obligated to address ESG aspects upon making investments. Similar approaches are also included in documents of other supervision and regulation bodies in the world and particularly in Europe.

The implications of these trends may be manifested in various ways, including public opposition to operations in the Partnership's oil and gas assets, diminishing of the Partnership's appeal to potential employees, pressure from financing banks and investors to adapt the Partnership's operations to the targets of the Paris Agreement of December 2015 which aims to reduce greenhouse gas emissions, and difficulty in access to capital, including in debt raising, for external investments and financing of projects. In addition, these trends may also adversely affect the business and financial condition of the Partnership, and may lead, inter alia, to a decrease in the value of its assets, an increase in the price of debt and an erosion of the price of the participation units.

In February 2022, the Partnership published its first corporate responsibility report reviewing the years 2020-2021, which set initial targets for areas defined as material by stakeholders, according to the materiality test and in accordance with GRI standards. The Partnership intends to release an updated ESG report for 2022 in Q2/2023.

7.28.24 Tax risks

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. In such context, note that in November 2021, an amendment to the Taxation of Profits from Natural Resources Law was approved, whereby, inter alia, according to the decision of an assessing officer, payment of 75% of the balance of a contested levy may be charged. For information regarding the amendment to the law as aforesaid and the disputes with the Tax Authority regarding levy assessments for the years 2016-2021, see Section 7.20 above.

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. However, in August 2021 an amendment to the Income Tax Regulations was approved. Pursuant to the amendment, the tax regime that applies to the Partnership took effect as of the 2022 tax year, such that it is taxed as a company. For further details see Section 7.20.1 above.

7.28.25 Financing-related undertakings

The terms of the bonds issued by Leviathan Bond define events of default and various undertakings, some of which are beyond the Partnership's control, a breach of which may give the bondholders grounds for acceleration of the debt and enforcement of the pledges on the Partnership's rights in the Leviathan project that were created to guarantee the repayment of the bonds, as specified in Section 7.19 above.

7.28.26 Dependence on customers

As of the report approval date, Blue Ocean and NEPCO are the key customers of the Leviathan project. Accordingly, the Partnership is exposed, in respect of these customers, to risks that are beyond its control, including changes in the economic and political conditions in Egypt and in Jordan which may affect these customers or their ability to meet their obligations under the gas supply agreements. For details regarding the Partnership's revenues from these customers, see Section 7.10.3 above.

It is noted that, in the agreement signed with Blue Ocean, dates were determined on which each party to the agreement may request adjustment of the price. In the event that Blue Ocean requests an adjustment of the price of the gas purchased thereby in accordance with the mechanism set forth in the agreement therewith, this may have a negative effect on the Partnership's business and on the results of its operations.

Furthermore, 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 agreements. Insofar as its customers in general and its key customers in particular fail to meet their obligations under the supply agreements, and if the Partnership shall be unable to sell the contract quantity determined in the supply agreement to other customers, this will have a material adverse effect on the Partnership's revenues and on its financial results.

7.28.27 Reliance on the operator

The Partnership relies to a great extent on the operator in its assets, Chevron in the Leviathan reservoir and Block 12 in Cyprus, 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 agreements, or any change in its status and/or rights, such that it ceases to be the operator of the project, 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 under the current terms and conditions or at all. The Partnership's failure to find a substitute operator may adversely affect the activity of the various projects, and in particular on the Partnerships' undertakings to supply gas in accordance with the existing gas sale agreements and consequently the Partnership's revenues may be impacted. Furthermore, in the event that the operators in the Partnership's assets fail to comply with their obligations as operators under the joint operating agreements or under agreements with third parties with which they engage as operators, the Partnership may then bear expenses and losses that may derive from the operators' acts (or omissions).

It is noted that according to the expired licenses New Ofek and New Yahel, the rights holders in the licenses are required by law to carry out plug and abandon activities, and although according to the joint operation agreements, such obligations apply, in practice, to the operator, SOA, this does not derogate from the obligations of the Partnership in this respect.

7.28.28 Risk in development and production in the case of a discovery

The process of making a decision to make an investment in the development of a field for the purpose of commercial production therefrom, 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. In this context, 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, as aforesaid, the development and production of assets in deep water, such as those of the Partnership's assets are located, are complex and high-risk activities.

7.28.29 <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 such terms, the petroleum interest may be revoked, subject to the Petroleum Law. Furthermore, non-compliance with the terms set forth in the Petroleum Law 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 drilling by August 2023, as specified in Section 7.3 above.

7.28.30 <u>Overflow of reservoirs</u>

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.

For details on the mediation arrangement in connection with the Eran License, see Section 7.8.1 above.

7.28.31 <u>Security risks</u>

INGL's gas transmission facilities, the EMG Pipeline and other infrastructures used for the supply of gas to Egypt are located partly offshore and relatively close to the border between Israel and the Gaza Strip at sea and on land, and to the gas terminal and distribution infrastructure in Egypt which is connected to the EMG Pipeline in the Sinai, in consequence of which they are exposed to security risks, including terrorist attacks and sabotage. Furthermore, the facilities of the Leviathan project, the pipeline, the infrastructures and the facilities used for the supply of gas to Jordan and Egypt are also exposed to the aforesaid security risks.[132]

Such security risks, if and insofar as they materialize, may, *inter alia*, disrupt the production of gas from the Leviathan reservoir 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 project, 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.

7.28.32 <u>Fluctuations in the dollar exchange rate</u>

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 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 Leviathan reservoir are determined by price formulas that include various linkage components, and, *inter alia*, linkage to the ILS/Dollar exchange rate and linkage to the electricity production 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; and (c) Since the Partnership reports its taxable income in ILS and pays the tax advances in

[132] It is noted that according to media publications of August 2022, the Lebanese terror organization Hezbollah launched 3 UAVs towards Energean's gas platform at the "Karish" lease, which were intercepted by the IDF. Furthermore, the head of the organization communicated several times, on different media channels, the organization's intention to harm the offshore platforms in Israel's exclusive economic zone, as part of a military conflict that may erupt.

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.

7.28.33 The Partnership's belonging to Delek Group and to the control holder thereof

The Partnership's belonging to Delek Group and to the controlling shareholder thereof, and the financial position thereof, may have an 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, and there are also 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 his approval.

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 7.3.3 above, a change of control of the 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.

7.28.34 The Partnership's status as a monopoly

As provided in Section 7.22.2(a) above, the Partnership was declared a monopoly together with the other partners in Tamar and separately, and although it has closed the sale of the remainder of its interests in the Tamar and Dalit Leases, it may be considered a monopoly in the field of supply of natural gas in Israel in view of its inclusion in the monopoly register and in view of its being a partner in the Leviathan project. It is noted that a monopolist may be subjected to restrictions and prohibitions under the Economic Competition Law, and is subject, *inter alia*, to the prohibition on unreasonable refusal to supply natural gas to customers and the prohibition on abuse of its status in the market 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).

7.28.35 “*Force majeure*” event clauses in the various agreements

As is standard, the various agreements signed by the Partnership include events of "force majeure" clauses. "Force majeure" events may exempt a party to the agreement from fulfilling its undertakings under the agreement. Therefore, the occurrence of a "force majeure" event to a party to any agreement signed by the Partnership, may have an impact on the various projects promoted by the Partnership, the expected timetables for completion thereof and the costs derived therefrom. Also, in some cases a "force majeure" event that lasts a long time may lead to grounds for cancellation of the agreements.

In addition, in all of the Partnership’s natural gas sale agreements (hereinafter in this Section: the “**Gas Agreements**”), the customers are obligated to pay for a minimum annual quantity of natural gas (Take or Pay) in accordance with the mechanisms set forth in the Gas 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 Gas Agreements. A “*force majeure*” event is defined as an event beyond the customer’s control, which prevents it from fulfilling its undertakings under the Gas Agreement, and which could not reasonably have been prevented in the circumstances. The Gas 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 Gas 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 Gas Agreement, 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.

7.28.36 Geopolitical conflicts in regions where the Partnership operates

In July 1974, Turkish military forces invaded Cyprus and occupied about one third of its territory (in this Section: the "**Occupied Territories**"). As of the report approval date, Turkey still maintains a large military force in the Occupied Territories.

The ceasefire line that was drawn in August 1974 turned into a buffer area supervised by the UN and named the "Green Line".

From 1975, attempted negotiations between the parties were facilitated by the UN, in order to settle the dispute. In this context, the UN Security Council adopted throughout the years a number of resolutions on the dispute over the Occupied Territories, and drafts of two agreements were forwarded in 1977 and 1979.

In 1983 the "Turkish Republic of Northern Cyprus" unilaterally declared its independence; however Turkey is the only country that acknowledged it and its rights to the Occupied Territories.

In view of the aforesaid, the relationship between Turkey and Cyprus may deteriorate, leading to political instability in the region or even a military conflict. Developments of this type may result in delays in the development of the Aphrodite Reservoir.

It is noted that following the declaration of independence of the Turkish Republic of Northern Cyprus, Turkey is performing natural gas exploration activities in vast regions in the East Mediterranean, including in the exclusive economic zones of Egypt and Cyprus. In this context, Turkey is performing various drilling and surveys in disputed offshore areas. Such acts may lead to regional instability or even a military conflict in the East Mediterranean, which may affect (directly or indirectly) the Partnership's operations, cause physical damage to the Partnership's facilities in Cyprus or lead to a reduction in the trade between Israel and Cyprus and their current trading partners. However, it is noted that in accordance with its official reports, the Government of Turkey is not claiming ownership on the areas in which Block 12 is located.

Furthermore, the dispute in respect of the sovereignty of Morocco over the Western Sahara areas may affect receipt of regulatory approvals in connection with the Partnership's activity in the Boujdour license, operation of the license and promotion of additional actions in this region.

* * *

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 Pandemic			X
Fluctuations in the Linkage Components in the Natural Gas Price Formulas in the Supply Contracts		X	
Changes in Demand and in the Energy Prices		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 Gas Transmission Systems	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	
Applicable Environmental Regulation	X		
Climate Crisis		X	
Dependence on Weather and Sea Conditions			X
Cyber and Information Security Risks		X	
Changes in investment trends due to ESG considerations		X	
Risks Specific to the Partnership			

	Degree of Risk Factor's Effect on Partnership's Business		
	Significant Effect	**Medium Effect**	**Small Effect**
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
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			X
"*Force majeure*" events clauses in the various agreements		X	
Geo-Political conflicts in regions where the Partnership operates			X

It is noted that 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.
Blue Hydrogen	A product of cracking natural gas in which the gas molecules are split by using steam into hydrogen and CO2. The hydrogen produced is taken for processing, transportation and marketing, while the CO2 is separated from the other products of the process and carried separately for processing, transportation and marketing or geological burial (a process known as carbon capture, utilization and storage (CCUS)).
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).
Green Hydrogen	A product of electrolysis in which the water molecules are split into hydrogen and oxygen using electricity from renewable energy, generally solar or wind energy. The hydrogen produced is taken for processing, transportation and marketing and the oxygen is emitted into the atmosphere.

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 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	(a) 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. (b) 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 the Tamar and Leviathan projects, 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 etc. 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 the edition 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 the Tamar and Leviathan projects, 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 the Tamar and Leviathan projects, the term refers to control and command cables through which the wells are operated, as well as conduits of liquids to the wells. In the Tamar and Leviathan projects, 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	Within the meaning thereof 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	Within the meaning thereof in the PRMS.

Units

BCF - Billion Cubic Feet

BCFD - Billion Cubic Feet per Day

BCM - Billion Cubic Meters

TCF - Trillion Cubic Feet

MMCF - Million Cubic Feet

MMCFD - Million Cubic Feet per Day

MMBBL - Million Barrels

MMBTU - Million British Thermal Units

Below are conversion coefficients used in this report:

BCM	BCF	MMCF
1	35.3147	**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

CCUS – Carbon Capture, Utilization and Storage

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

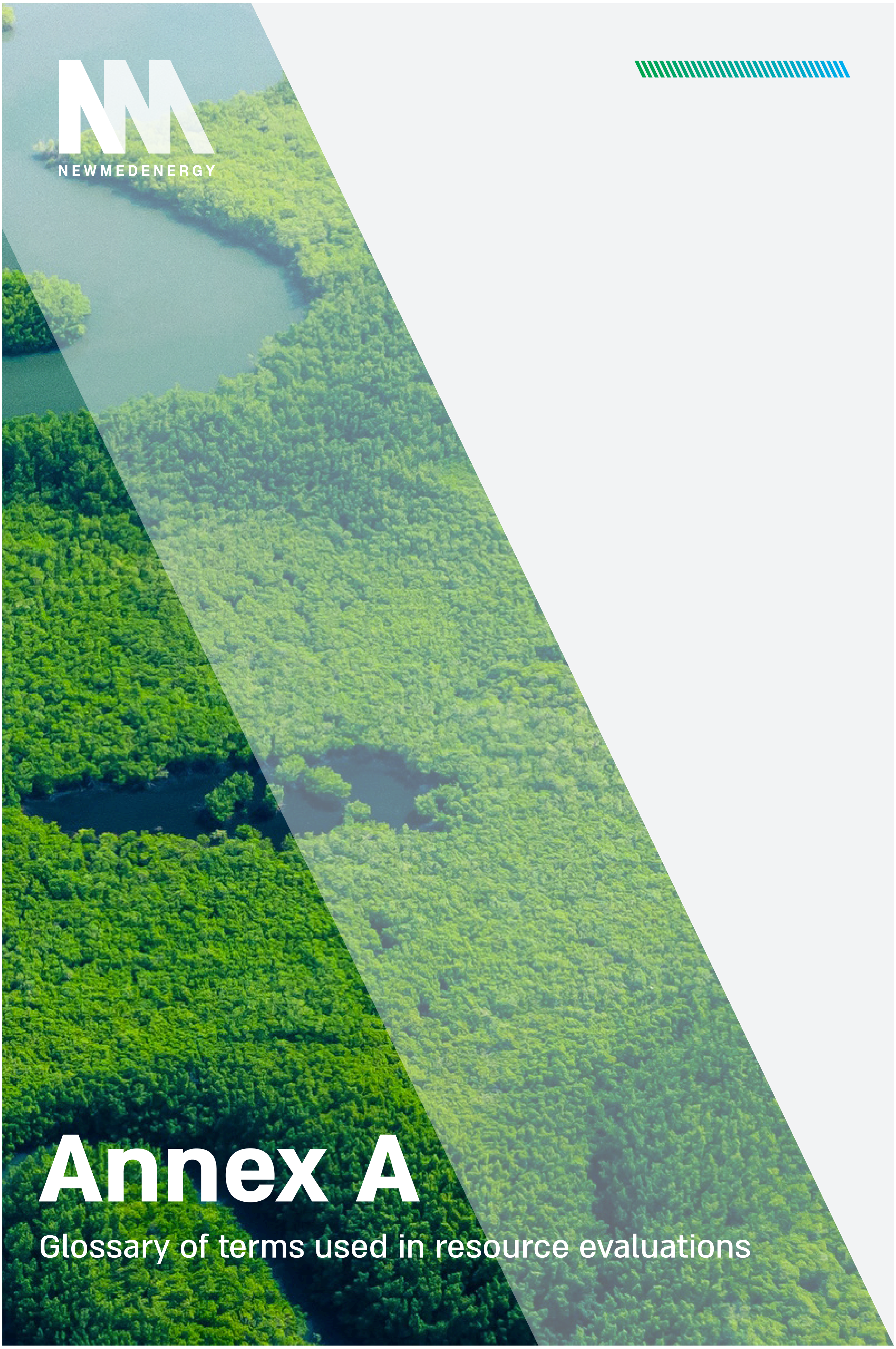
TCQ – Total Contract Quantity

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: 5.3 - 23.0
- Oligocene: 23.0 - 33.9
- Upper Cretaceous: 66.0 - 100.5
- Lower Cretaceous: 100.5 - 145.0
- Jurassic: 145.0 - 201.3
- Triassic: 201.3 - 251.9
- Permian: 251.9 - 298.9



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Annex A

Glossary of terms used in resource evaluations

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.

NEWMEDENERGY

Annex B

Current report on reserves, contingent resources, and DCF for the Leviathan leases

ESTIMATES
of
RESERVES AND FUTURE REVENUE AND CONTINGENT RESOURCES AND CASH FLOW
to the
NEWMED ENERGY LIMITED PARTNERSHIP INTEREST
in
CERTAIN GAS PROPERTIES
located in
LEVIATHAN FIELD, LEASES I/14 AND I/15 OFFSHORE ISRAEL
as of
DECEMBER 31, 2022

BASED ON PRICE AND COST PARAMETERS
specified by
NEWMED ENERGY LIMITED PARTNERSHIP

NETHERLAND, SEWELL & ASSOCIATES, INC.
WORLDWIDE PETROLEUM CONSULTANTS
ENGINEERING • GEOLOGY
GEOPHYSICS • PETROPHYSICS

March 19, 2023

NewMed Energy 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, 2022, to the NewMed Energy Limited Partnership (NewMed) interest in certain gas properties located in Leviathan Field, Leases I/14 and I/15, offshore Israel. Also as requested, we have estimated the contingent resources and cash flow, as of December 31, 2022, to the NewMed interest in these properties. It is our understanding that NewMed owns a direct working interest in these properties. We completed our evaluation on or about the date of this letter. For the reserves and the Phase I – First Stage contingent resources, this report has been prepared using price and cost parameters specified by NewMed, as discussed in subsequent paragraphs of this letter. Monetary values shown in this report are expressed in United States dollars ($) or millions of United States dollars (MM$). For reference, the March 16, 2023, exchange rate was 3.67 New Israeli Shekels per United States dollar.

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 NewMed'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.

RESERVES

Reserves are those quantities of petroleum anticipated to be commercially recoverable from known accumulations by application of development projects from a given date forward under defined conditions. Reserves must be discovered, recoverable, commercial, and remaining as of the evaluation date based on the planned development projects to be applied. 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 probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.

We estimate the gross (100 percent) reserves and the NewMed working interest reserves for these properties, as of December 31, 2022, to be:

Category	Gas Reserves (BCF) Gross (100%)	Gas Reserves (BCF) Working Interest	Condensate Reserves (MMBBL) Gross (100%)	Condensate Reserves (MMBBL) Working Interest
Proved (1P)	13,813.0	6,262.8	30.4	13.8
Probable	1,756.2	796.3	3.9	1.8
Proved + Probable (2P)	15,569.2	7,059.1	34.3	15.5
Possible	704.5	319.4	1.5	0.7
Proved + Probable + Possible (3P)	16,273.7	7,378.5	35.8	16.2

Totals may not add because of rounding.

We estimate the future net revenue after levy and corporate income taxes, discounted at 0, 5, 10, 15, and 20 percent, to the NewMed interest in these properties, as of December 31, 2022, 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)	13,128.8	6,906.0	4,533.7	3,372.1	2,694.7
Probable	1,603.9	641.9	386.6	290.1	240.1
Proved + Probable (2P)	14,732.7	7,547.9	4,920.3	3,662.2	2,934.8
Possible	691.6	227.3	110.2	72.7	57.8
Proved + Probable + Possible (3P)	15,424.2	7,775.1	5,030.5	3,734.9	2,992.7

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.

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, 2022, 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.

Working interest revenue for the reserves shown in this report is NewMed's share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for NewMed's share of royalties, capital costs, abandonment costs, operating expenses, and NewMed'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 NewMed's historical production and operating expense data.

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the NewMed 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 NewMed receiving its net revenue interest share of estimated future gross production.

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 approval of additional drilling, project approval for additional future developments, demonstration of a market for future gas sales, and commitment to develop the resources. For the purposes of this report, the contingent resources have been divided into two development phases: Phase I – First Stage and Future Development. The Phase I – First Stage contingent resources can be recovered through drilling during this development phase without significant upgrades to the production system. The Future Development contingent resources may require upgrades to the production system and additional drilling beyond the Phase I – First Stage. If the 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. 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 gross (100 percent) contingent resources by development phase for these properties, as of December 31, 2022, to be:

	Gross (100%) Contingent Resources					
	Gas (BCF)			Condensate (MMBBL)		
Development Phase	Low Estimate (1C)	Best Estimate (2C)	High Estimate (3C)	Low Estimate (1C)	Best Estimate (2C)	High Estimate (3C)
Phase I – First Stage	2,101.2	2,707.9	2,828.4	4.6	6.0	6.2
Future Development	0.0	3,588.9	7,692.5	0.0	7.9	16.9
Total	2,101.2	6,296.8	10,520.9	4.6	13.9	23.1

We estimate the NewMed working interest contingent resources by development phase for these properties, as of December 31, 2022, to be:

	Working Interest Contingent Resources					
	Gas (BCF)			Condensate (MMBBL)		
Development Phase	Low Estimate (1C)	Best Estimate (2C)	High Estimate (3C)	Low Estimate (1C)	Best Estimate (2C)	High Estimate (3C)
Phase I – First Stage	952.7	1,227.8	1,282.4	2.1	2.7	2.8
Future Development	0.0	1,627.2	3,487.8	0.0	3.6	7.7
Total	952.7	2,855.0	4,770.2	2.1	6.3	10.5

As requested, economic analysis was only performed on the Phase I – First Stage contingent resources. We estimate the net contingent cash flow after levy and corporate income taxes, discounted at 0, 5, 10, 15, and 20 percent, to the NewMed interest in these properties, as of December 31, 2022, to be:

Category	Net Contingent Cash Flow After Levy and Corporate Income Taxes (MM$) Discounted at 0%	Discounted at 5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
Low Estimate (1C)	1,338.1	609.5	301.1	169.8	108.2
Best Estimate (2C)	1,985.1	579.2	197.0	76.0	32.3
High Estimate (3C)	2,101.0	540.0	165.4	58.3	22.6

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.

Working interest contingent revenue shown in this report is NewMed's share of the gross (100 percent) revenue from the properties prior to any deductions. Net contingent cash flow is after deductions for NewMed's share of royalties, capital costs, abandonment costs, operating expenses, and NewMed's estimates of its oil and gas profits levy and corporate income taxes. The net contingent cash flow has been discounted at annual rates of 0, 5, 10, 15, and 20 percent to indicate the effect of time on the value of money; the contingent cash flow, whether discounted or undiscounted, should not be construed as being the fair market value of the properties. Tables VII through IX present cash flow, costs, and taxes by resources category for the Phase I – First Stage contingent resources. As requested, we have included an appendix to this report that presents tables of cash flow, costs, and taxes resulting from aggregating our estimates of reserves and the Phase I – First Stage contingent resources.

ECONOMIC PARAMETERS

As requested, this report has been prepared using gas and condensate prices specified by NewMed. Gas prices are based on NewMed's estimates of expected approved and future sales contracts. These contract prices are derived from various formulae that include indexation mainly to the Power Generation Tariffs published by The Electricity Authority or to an average of long-term forecasts for Brent Crude prices provided by various institutions. Condensate prices are based on Brent Crude prices.

Operating costs used in this report are based on operating expense records of NewMed. Operating costs include direct project-level costs, insurance costs, workover costs, transportation costs, and NewMed's estimate of the portion of the operator's headquarters general and administrative overhead expenses that can be directly attributed to this project; Chevron Mediterranean Limited is the operator of the properties. Based on our understanding of future development plans, 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 NewMed and are based on authorizations for expenditure and actual costs from recent activity. Capital costs are included as required for gas and condensate export facility upgrades, a third gathering line, new development wells and flowlines, and production equipment. Based on our understanding of future development plans, 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 NewMed'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.

GENERAL INFORMATION

This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves and contingent resources have been estimated. 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 or resources quantities estimated in this report or the commerciality of such estimates. Therefore, our estimates do not include any costs due to such possible liability.

The reserves and contingent 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. 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 current development plans as provided to us by NewMed, 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 volumes, and that our projections of future production will prove consistent with actual performance. If these volumes 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, and costs incurred may vary from assumptions made while preparing this report. 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 and contingent resources 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 volumes in accordance with the 2018 PRMS definitions and guidelines. The contingent resources and a portion of the reserves shown in this report are for undeveloped locations; such volumes are based on estimates of reservoir volumes and recovery efficiencies along with analogy to properties with similar geologic and reservoir characteristics. Certain parameters used in our volumetric analysis are summarized in Table X. 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, 2022, by Mr. Yossi Abu, Chief Executive Officer of NewMed, to perform this assessment. The data used in our estimates were obtained from NewMed, Chevron Mediterranean Limited, 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 NewMed.

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. John R. Cliver and Mr. Zachary R. Long. Mr. Cliver and Mr. Long are Vice Presidents in the firm's Houston office at 1301 McKinney Street, Suite 3200, Houston, Texas 77010, USA. Mr. Cliver is a Licensed Professional Engineer (Texas Registration No. 107216). He has been practicing consulting petroleum engineering at NSAI since 2009 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.
Executive Chairman

By:
John R. Cliver P.E. 107216
Vice President

STATE OF TEXAS
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LICENSED
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Date Signed: March 19, 2023

By:
Zachary R. Long, P.G. 11792
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STATE OF TEXAS
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Date Signed: March 19, 2023

JRC:MDK

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the 2018 Petroleum Resources Management System (PRMS), version 1.03
Approved by the Society of Petroleum Engineers (SPE) Board of Directors

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 Resources.

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.

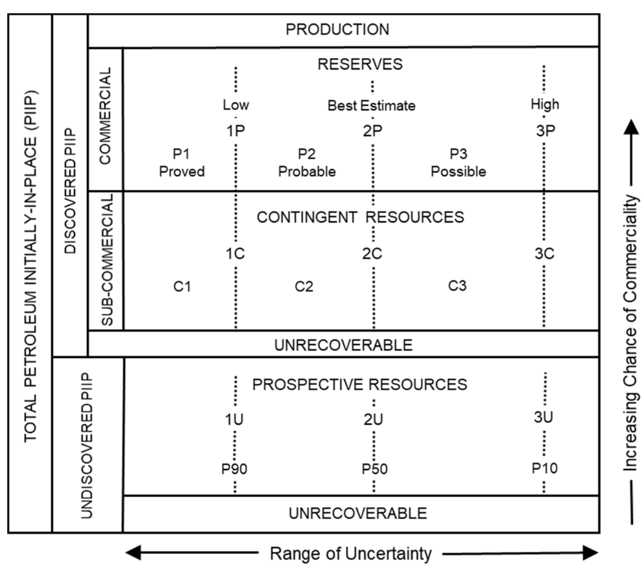

Figure 1.1—Resources classification framework

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

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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).

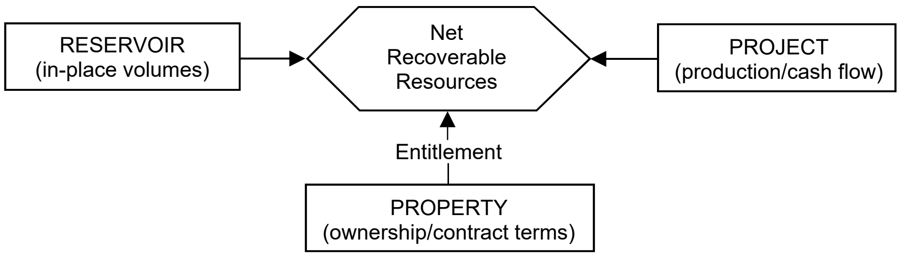

Figure 1.2—Resources evaluation

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, CO_2) 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) reserves; 1C, 2C, 3C, C1, C2, and C3 contingent resources; or 1U, 2U, and 3U prospective resources categories. The chance of commerciality 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.

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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.
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 2018 Petroleum Resources Management System (PRMS), version 1.03
Approved by the Society of Petroleum Engineers (SPE) Board of Directors

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

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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 commercial 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

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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

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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.

REVENUE, COSTS, AND TAXES
PROVED (1P) RESERVES
NEWMED ENERGY LIMITED PARTNERSHIP INTEREST
LEVIATHAN FIELD, LEASES I/14 AND I/15, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2022

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$)
12-31-2023	1,051.4	118.4	14.2	28.4	161.0	211.5	0.0	156.7	522.2
12-31-2024	1,115.3	125.6	15.1	30.1	170.8	159.6	0.0	132.5	652.4
12-31-2025	1,142.3	128.6	29.0	30.9	188.4	27.5	0.0	131.1	795.3
12-31-2026	1,196.5	134.7	70.1	32.3	237.1	0.0	0.0	122.5	836.9
12-31-2027	1,192.7	134.3	69.8	32.2	236.4	0.0	0.0	137.0	819.4
12-31-2028	1,214.8	136.8	71.1	32.8	240.7	0.0	0.0	137.6	836.4
12-31-2029	1,228.0	138.3	71.9	33.2	243.4	0.0	0.0	158.7	826.0
12-31-2030	1,246.7	140.4	73.0	33.7	247.1	0.0	0.0	138.7	861.0
12-31-2031	1,294.6	145.8	75.8	35.0	256.6	0.0	0.0	132.7	905.4
12-31-2032	1,319.1	148.5	77.2	35.6	261.4	0.0	0.0	133.3	924.4
12-31-2033	1,319.0	148.5	77.2	35.6	261.4	0.0	0.0	133.3	924.3
12-31-2034	1,319.5	148.6	77.3	35.7	261.5	0.0	0.0	153.9	904.1
12-31-2035	1,253.8	141.2	73.4	33.9	248.5	0.0	0.0	110.0	895.3
12-31-2036	1,253.8	141.2	73.4	33.9	248.5	0.0	0.0	110.1	895.2
12-31-2037	1,253.8	141.2	73.4	33.9	248.5	0.0	0.0	110.1	895.2
Subtotal	18,401.4	2,072.0	941.9	497.3	3,511.2	398.5	0.0	1,998.1	12,493.5
Remaining	22,933.2	2,582.3	1,342.8	619.7	4,544.8	0.0	95.1	2,952.3	15,341.0
Total	41,334.6	4,654.3	2,284.7	1,117.0	8,056.0	398.5	95.1	4,950.4	27,834.5

Period Ending	Levy Rate[2] (%)	Levy[2] (MM$)	Future Net Revenue After Levy and Before Corporate Income Taxes Discounted at 0% (MM$)	Corporate Income Tax Rate[3] (%)	Corporate Income Taxes[3] (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$)	Discounted at 20% (MM$)
12-31-2023	0.0	0.0	522.2	23.0	120.8	401.4	391.7	382.7	374.3	366.4
12-31-2024	0.0	0.0	652.4	23.0	133.4	519.0	482.4	449.8	420.8	394.8
12-31-2025	0.0	0.0	795.3	23.0	134.0	661.3	585.3	521.1	466.3	419.2
12-31-2026	0.0	0.0	836.9	23.0	136.0	701.0	590.9	502.1	429.8	370.3
12-31-2027	15.4	125.8	693.6	23.0	103.1	590.5	474.1	384.5	314.8	259.9
12-31-2028	30.1	251.7	584.8	23.0	78.7	506.1	386.9	299.6	234.6	185.7
12-31-2029	37.1	306.7	519.2	23.0	63.6	455.6	331.8	245.2	183.7	139.3
12-31-2030	43.2	372.0	489.0	23.0	96.3	392.7	272.4	192.2	137.7	100.1
12-31-2031	46.8	423.4	482.0	23.0	96.8	385.2	254.5	171.3	117.4	81.8
12-31-2032	46.8	432.6	491.8	23.0	99.0	392.8	247.1	158.8	104.1	69.5
12-31-2033	46.8	432.6	491.7	23.0	102.0	389.8	233.5	143.3	89.8	57.5
12-31-2034	46.8	423.1	481.0	23.0	104.7	376.2	214.7	125.7	75.4	46.2
12-31-2035	46.8	419.0	476.3	23.0	108.1	368.2	200.1	111.9	64.2	37.7
12-31-2036	46.8	419.0	476.3	23.0	109.5	366.7	189.8	101.3	55.6	31.3
12-31-2037	46.8	419.0	476.3	23.0	109.6	366.7	180.7	92.1	48.3	26.1
Subtotal		4,024.8	8,468.7		1,595.6	6,873.1	5,035.9	3,881.7	3,116.9	2,585.7
Remaining		7,206.1	8,134.9		1,879.2	6,255.7	1,870.1	652.0	255.3	109.0
Total		11,230.9	16,603.6		3,474.8	13,128.8	6,906.0	4,533.7	3,372.1	2,694.7

Notes: Remaining represents estimates after December 31, 2037, through the end of the lease term in 2064.
Totals may not add because of rounding.

(1) Operating costs include direct project-level costs, insurance costs, workover costs, transportation costs, and NewMed's estimate of the portion of the operator's headquarters general and administrative overhead expenses that can be directly attributed to this project.

(2) Oil and gas profits levy rates and estimates are provided by NewMed.

(3) Corporate income tax rates and estimates of corporate income taxes are provided by NewMed and are its expected corporate income taxes per year.

REVENUE, COSTS, AND TAXES
PROBABLE RESERVES
NEWMED ENERGY LIMITED PARTNERSHIP INTEREST
LEVIATHAN FIELD, LEASES I/14 AND I/15, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2022

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$)
12-31-2023	98.3	11.1	1.3	2.7	15.0	0.0	0.0	6.0	77.3
12-31-2024	102.2	11.5	1.4	2.8	15.6	0.0	0.0	5.9	80.7
12-31-2025	125.7	14.2	19.6	3.4	37.2	0.0	0.0	5.9	82.6
12-31-2026	157.8	17.8	9.2	4.3	31.3	0.0	0.0	6.1	120.5
12-31-2027	157.4	17.7	9.2	4.3	31.2	0.0	0.0	6.1	120.2
12-31-2028	160.9	18.1	9.4	4.3	31.9	0.0	0.0	6.1	122.9
12-31-2029	162.9	18.3	9.5	4.4	32.3	0.0	0.0	6.1	124.6
12-31-2030	163.2	18.4	9.6	4.4	32.3	0.0	0.0	6.1	124.8
12-31-2031	150.2	16.9	8.8	4.1	29.8	0.0	0.0	5.1	115.3
12-31-2032	128.9	14.5	7.5	3.5	25.5	0.0	0.0	5.0	98.3
12-31-2033	104.6	11.8	6.1	2.8	20.7	0.0	0.0	4.9	79.0
12-31-2034	81.4	9.2	4.8	2.2	16.1	0.0	0.0	4.8	60.4
12-31-2035	55.0	6.2	3.2	1.5	10.9	0.0	0.0	2.1	42.0
12-31-2036	32.8	3.7	1.9	0.9	6.5	0.0	0.0	2.0	24.2
12-31-2037	10.5	1.2	0.6	0.3	2.1	0.0	0.0	1.9	6.5
Subtotal	1,691.9	190.5	102.3	45.7	338.5	0.0	0.0	74.1	1,279.2
Remaining	3,392.0	381.9	198.6	91.7	672.2	0.0	0.0	65.4	2,654.3
Total	5,083.8	572.4	300.9	137.4	1,010.7	0.0	0.0	139.6	3,933.5

Period Ending	Levy Rate[2] (%)	Levy[2] (MM$)	Future Net Revenue After Levy and Before Corporate Income Taxes Discounted at 0% (MM$)	Corporate Income Tax Rate[3] (%)	Corporate Income Taxes[3] (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$)	Discounted at 20% (MM$)
12-31-2023	0.0	0.0	77.3	23.0	17.8	59.5	58.1	56.7	55.5	54.3
12-31-2024	0.0	0.0	80.7	23.0	18.6	62.1	57.7	53.8	50.4	47.3
12-31-2025	0.0	0.0	82.6	23.0	19.0	63.6	56.3	50.1	44.8	40.3
12-31-2026	1.7	16.5	104.0	23.0	23.9	80.1	67.5	57.4	49.1	42.3
12-31-2027	26.4	122.6	-2.4	23.0	-0.6	-1.9	-1.5	-1.2	-1.0	-0.8
12-31-2028	35.6	89.7	33.2	23.0	7.6	25.6	19.6	15.2	11.9	9.4
12-31-2029	42.8	100.1	24.5	23.0	5.6	18.9	13.7	10.1	7.6	5.8
12-31-2030	46.8	89.0	35.8	23.0	8.2	27.6	19.1	13.5	9.7	7.0
12-31-2031	46.8	54.3	61.0	23.0	14.0	47.0	31.0	20.9	14.3	10.0
12-31-2032	46.8	46.0	52.3	23.0	12.0	40.3	25.3	16.3	10.7	7.1
12-31-2033	46.8	37.0	42.0	23.0	9.7	32.3	19.4	11.9	7.5	4.8
12-31-2034	46.8	28.3	32.1	23.0	7.4	24.8	14.1	8.3	5.0	3.0
12-31-2035	46.8	19.6	22.3	23.0	5.1	17.2	9.3	5.2	3.0	1.8
12-31-2036	46.8	11.3	12.9	23.0	3.0	9.9	5.1	2.7	1.5	0.8
12-31-2037	46.8	3.0	3.5	23.0	0.8	2.7	1.3	0.7	0.4	0.2
Subtotal		617.5	661.7		152.2	509.5	396.1	321.6	270.2	233.2
Remaining		1,233.1	1,421.3		326.9	1,094.4	245.7	65.1	19.9	6.9
Total		1,850.6	2,083.0		479.1	1,603.9	641.9	386.6	290.1	240.1

Notes: Remaining represents estimates after December 31, 2037, through the end of the lease term in 2064.
Totals may not add because of rounding.

(1) Operating costs include direct project-level costs, insurance costs, workover costs, transportation costs, and NewMed's estimate of the portion of the operator's headquarters general and administrative overhead expenses that can be directly attributed to this project.
(2) Oil and gas profits levy rates and estimates are provided by NewMed.
(3) Corporate income tax rates and estimates of corporate income taxes are provided by NewMed and are its expected corporate income taxes per year.

REVENUE, COSTS, AND TAXES
PROVED + PROBABLE (2P) RESERVES
NEWMED ENERGY LIMITED PARTNERSHIP INTEREST
LEVIATHAN FIELD, LEASES I/14 AND I/15, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2022

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$)
12-31-2023	1,149.6	129.4	15.5	31.1	176.0	211.5	0.0	162.6	599.4
12-31-2024	1,217.5	137.1	16.5	32.9	186.4	159.6	0.0	138.4	733.1
12-31-2025	1,268.0	142.8	48.6	34.3	225.6	27.5	0.0	137.0	877.9
12-31-2026	1,354.4	152.5	79.3	36.6	268.4	0.0	0.0	128.5	957.4
12-31-2027	1,350.2	152.0	79.1	36.5	267.6	0.0	0.0	143.0	939.6
12-31-2028	1,375.7	154.9	80.6	37.2	272.6	0.0	0.0	143.7	959.4
12-31-2029	1,391.0	156.6	81.4	37.6	275.7	0.0	0.0	164.8	950.5
12-31-2030	1,409.9	158.8	82.6	38.1	279.4	0.0	0.0	144.7	985.8
12-31-2031	1,444.8	162.7	84.6	39.0	286.3	0.0	0.0	137.8	1,020.7
12-31-2032	1,448.0	163.1	84.8	39.1	287.0	0.0	0.0	138.4	1,022.7
12-31-2033	1,423.6	160.3	83.4	38.5	282.1	0.0	0.0	138.2	1,003.3
12-31-2034	1,400.9	157.7	82.0	37.9	277.6	0.0	0.0	158.7	964.5
12-31-2035	1,308.8	147.4	76.6	35.4	259.4	0.0	0.0	112.2	937.3
12-31-2036	1,286.6	144.9	75.3	34.8	255.0	0.0	0.0	112.1	919.5
12-31-2037	1,264.3	142.4	74.0	34.2	250.6	0.0	0.0	112.0	901.7
Subtotal	20,093.3	2,262.5	1,044.2	543.0	3,849.7	398.5	0.0	2,072.3	13,772.7
Remaining	26,325.2	2,964.2	1,541.4	711.4	5,217.0	0.0	95.1	3,017.7	17,995.3
Total	46,418.4	5,226.7	2,585.6	1,254.4	9,066.7	398.5	95.1	5,090.0	31,768.1

Period Ending	Levy Rate[2] (%)	Levy[2] (MM$)	Future Net Revenue After Levy and Before Corporate Income Taxes Discounted at 0% (MM$)	Corporate Income Tax Rate[3] (%)	Corporate Income Taxes[3] (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$)	Discounted at 20% (MM$)
12-31-2023	0.0	0.0	599.4	23.0	138.5	460.9	449.8	439.5	429.8	420.8
12-31-2024	0.0	0.0	733.1	23.0	152.0	581.1	540.1	503.7	471.2	442.1
12-31-2025	0.0	0.0	877.9	23.0	153.0	724.8	641.6	571.2	511.1	459.5
12-31-2026	1.7	16.5	940.9	23.0	159.9	781.0	658.4	559.5	478.9	412.6
12-31-2027	26.4	248.5	691.1	23.0	102.5	588.6	472.6	383.3	313.8	259.1
12-31-2028	35.6	341.4	618.0	23.0	86.4	531.7	406.5	314.8	246.5	195.0
12-31-2029	42.8	406.8	543.7	23.0	69.3	474.4	345.5	255.3	191.3	145.0
12-31-2030	46.8	461.0	524.8	23.0	104.5	420.3	291.5	205.6	147.3	107.1
12-31-2031	46.8	477.7	543.0	23.0	110.8	432.2	285.5	192.2	131.7	91.8
12-31-2032	46.8	478.6	544.1	23.0	111.0	433.1	272.4	175.1	114.8	76.6
12-31-2033	46.8	469.5	533.7	23.0	111.6	422.1	252.9	155.2	97.3	62.2
12-31-2034	46.8	451.4	513.1	23.0	112.1	401.0	228.8	134.0	80.4	49.3
12-31-2035	46.8	438.6	498.6	23.0	113.2	385.4	209.4	117.1	67.2	39.5
12-31-2036	46.8	430.3	489.2	23.0	112.5	376.7	194.9	104.0	57.1	32.1
12-31-2037	46.8	422.0	479.7	23.0	110.4	369.3	182.0	92.7	48.7	26.3
Subtotal		4,642.3	9,130.4		1,747.8	7,382.6	5,432.0	4,203.2	3,387.0	2,818.9
Remaining		8,439.2	9,556.2		2,206.1	7,350.1	2,115.8	717.1	275.2	115.9
Total		13,081.5	18,686.6		3,953.9	14,732.7	7,547.9	4,920.3	3,662.2	2,934.8

Notes: Remaining represents estimates after December 31, 2037, through the end of the lease term in 2064.
Totals may not add because of rounding.

[1] Operating costs include direct project-level costs, insurance costs, workover costs, transportation costs, and NewMed's estimate of the portion of the operator's headquarters general and administrative overhead expenses that can be directly attributed to this project.

[2] Oil and gas profits levy rates and estimates are provided by NewMed.

[3] Corporate income tax rates and estimates of corporate income taxes are provided by NewMed and are its expected corporate income taxes per year.

NETHERLAND, SEWELL & ASSOCIATES, INC.

REVENUE, COSTS, AND TAXES
POSSIBLE RESERVES
NEWMED ENERGY LIMITED PARTNERSHIP INTEREST
LEVIATHAN FIELD, LEASES I/14 AND I/15, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2022

		Royalties							Future Net Revenue Before Levy and Corporate Income Taxes
Period Ending	Working Interest Revenue (MM$)	State (MM$)	Interested Party (MM$)	Third Party (MM$)	Total (MM$)	Net Capital Costs (MM$)	Net Abandonment Costs (MM$)	Net Operating Expenses[1] (MM$)	Discounted at 0% (MM$)
12-31-2023	62.5	7.0	0.8	1.7	9.6	0.0	0.0	5.1	47.8
12-31-2024	25.2	2.8	0.3	0.7	3.9	0.0	0.0	4.6	16.8
12-31-2025	36.6	4.1	6.8	1.0	11.9	0.0	0.0	4.6	20.1
12-31-2026	21.5	2.4	1.3	0.6	4.3	0.0	0.0	4.5	12.8
12-31-2027	21.2	2.4	1.2	0.6	4.2	0.0	0.0	4.5	12.5
12-31-2028	20.3	2.3	1.2	0.5	4.0	0.0	0.0	4.5	11.8
12-31-2029	19.9	2.2	1.2	0.5	3.9	0.0	0.0	4.5	11.5
12-31-2030	22.0	2.5	1.3	0.6	4.4	0.0	0.0	4.5	13.1
12-31-2031	19.3	2.2	1.1	0.5	3.8	0.0	0.0	1.3	14.2
12-31-2032	22.2	2.5	1.3	0.6	4.4	0.0	0.0	1.3	16.5
12-31-2033	26.3	3.0	1.5	0.7	5.2	0.0	0.0	1.3	19.8
12-31-2034	29.3	3.3	1.7	0.8	5.8	0.0	0.0	1.3	22.2
12-31-2035	30.7	3.5	1.8	0.8	6.1	0.0	0.0	1.7	23.0
12-31-2036	33.8	3.8	2.0	0.9	6.7	0.0	0.0	1.7	25.4
12-31-2037	36.8	4.1	2.2	1.0	7.3	0.0	0.0	1.7	27.8
Subtotal	427.7	48.2	25.7	11.6	85.5	0.0	0.0	46.9	295.3
Remaining	1,819.2	204.8	106.5	49.2	360.5	0.0	0.0	49.0	1,409.7
Total	2,246.9	253.0	132.3	60.7	446.0	0.0	0.0	95.9	1,705.0

						Future Net Revenue After Levy and Corporate Income Taxes				
Period Ending	Levy Rate[2] (%)	Levy[2] (MM$)	Future Net Revenue After Levy and Before Corporate Income Taxes Discounted at 0% (MM$)	Corporate Income Tax Rate[3] (%)	Corporate Income Taxes[3] (MM$)	Discounted at 0% (MM$)	Discounted at 5% (MM$)	Discounted at 10% (MM$)	Discounted at 15% (MM$)	Discounted at 20% (MM$)
12-31-2023	0.0	0.0	47.8	23.0	11.0	36.8	35.9	35.1	34.3	33.6
12-31-2024	0.0	0.0	16.8	23.0	3.9	12.9	12.0	11.2	10.5	9.8
12-31-2025	0.0	0.0	20.1	23.0	4.6	15.5	13.7	12.2	10.9	9.8
12-31-2026	5.2	34.4	-21.6	23.0	-5.0	-16.6	-14.0	-11.9	-10.2	-8.8
12-31-2027	27.5	13.4	-0.9	23.0	-0.2	-0.7	-0.6	-0.4	-0.4	-0.3
12-31-2028	36.5	13.2	-1.5	23.0	-0.3	-1.1	-0.9	-0.7	-0.5	-0.4
12-31-2029	43.7	13.7	-2.2	23.0	-0.5	-1.7	-1.2	-0.9	-0.7	-0.5
12-31-2030	46.8	6.5	6.6	23.0	1.5	5.1	3.5	2.5	1.8	1.3
12-31-2031	46.8	6.7	7.6	23.0	1.7	5.8	3.8	2.6	1.8	1.2
12-31-2032	46.8	7.7	8.8	23.0	2.0	6.8	4.3	2.7	1.8	1.2
12-31-2033	46.8	9.3	10.5	23.0	2.4	8.1	4.9	3.0	1.9	1.2
12-31-2034	46.8	10.4	11.8	23.0	2.7	9.1	5.2	3.0	1.8	1.1
12-31-2035	46.8	10.7	12.2	23.0	2.8	9.4	5.1	2.9	1.6	1.0
12-31-2036	46.8	11.9	13.5	23.0	3.1	10.4	5.4	2.9	1.6	0.9
12-31-2037	46.8	13.0	14.8	23.0	3.4	11.4	5.6	2.9	1.5	0.8
Subtotal		150.9	144.4		33.2	111.2	82.8	67.0	57.8	52.0
Remaining		656.0	753.7		173.3	580.3	144.5	43.1	15.0	5.8
Total		806.9	898.1		206.6	691.6	227.3	110.2	72.7	57.8

Notes: Remaining represents estimates after December 31, 2037, through the end of the lease term in 2064.
Totals may not add because of rounding.

(1) Operating costs include direct project-level costs, insurance costs, workover costs, transportation costs, and NewMed's estimate of the portion of the operator's headquarters general and administrative overhead expenses that can be directly attributed to this project.
(2) Oil and gas profits levy rates and estimates are provided by NewMed.
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REVENUE, COSTS, AND TAXES
PROVED + PROBABLE + POSSIBLE (3P) RESERVES
NEWMED ENERGY LIMITED PARTNERSHIP INTEREST
LEVIATHAN FIELD, LEASES I/14 AND I/15, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2022

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$)
12-31-2023	1,212.2	136.5	16.4	32.8	185.6	211.5	0.0	167.8	647.3
12-31-2024	1,242.7	139.9	16.8	33.6	190.3	159.6	0.0	142.9	749.9
12-31-2025	1,304.5	146.9	55.4	35.3	237.5	27.5	0.0	141.6	897.9
12-31-2026	1,375.9	154.9	80.6	37.2	272.7	0.0	0.0	133.0	970.2
12-31-2027	1,371.4	154.4	80.3	37.1	271.8	0.0	0.0	147.5	952.1
12-31-2028	1,396.0	157.2	81.7	37.7	276.7	0.0	0.0	148.2	971.2
12-31-2029	1,410.9	158.9	82.6	38.1	279.6	0.0	0.0	169.2	962.0
12-31-2030	1,431.9	161.2	83.8	38.7	283.8	0.0	0.0	149.2	998.9
12-31-2031	1,464.1	164.9	85.7	39.6	290.2	0.0	0.0	139.0	1,034.9
12-31-2032	1,470.3	165.6	86.1	39.7	291.4	0.0	0.0	139.7	1,039.2
12-31-2033	1,449.9	163.3	84.9	39.2	287.3	0.0	0.0	139.5	1,023.1
12-31-2034	1,430.2	161.0	83.7	38.7	283.4	0.0	0.0	160.1	986.8
12-31-2035	1,339.6	150.8	78.4	36.2	265.5	0.0	0.0	113.9	960.2
12-31-2036	1,320.3	148.7	77.3	35.7	261.7	0.0	0.0	113.8	944.9
12-31-2037	1,301.1	146.5	76.2	35.2	257.8	0.0	0.0	113.8	929.5
Subtotal	20,520.9	2,310.7	1,070.0	554.6	3,935.2	398.5	0.0	2,119.1	14,068.1
Remaining	28,144.4	3,169.1	1,647.9	760.6	5,577.5	0.0	95.1	3,066.8	19,405.0
Total	48,665.3	5,479.7	2,717.9	1,315.1	9,512.7	398.5	95.1	5,185.9	33,473.1

Period Ending	Levy Rate(2) (%)	Levy(2) (MM$)	Future Net Revenue After Levy and Before Corporate Income Taxes Discounted at 0% (MM$)	Corporate Income Tax Rate(3) (%)	Corporate Income Taxes(3) (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$)	Discounted at 20% (MM$)
12-31-2023	0.0	0.0	647.3	23.0	149.5	497.7	485.7	474.6	464.1	454.4
12-31-2024	0.0	0.0	749.9	23.0	155.8	594.0	552.1	514.9	481.7	451.9
12-31-2025	0.0	0.0	897.9	23.0	157.6	740.3	655.3	583.3	522.0	469.3
12-31-2026	5.2	50.9	919.3	23.0	154.9	764.4	644.4	547.6	468.7	403.8
12-31-2027	27.5	261.9	690.2	23.0	102.3	587.9	472.0	382.8	313.4	258.8
12-31-2028	36.5	354.6	616.6	23.0	86.0	530.5	405.7	314.1	246.0	194.6
12-31-2029	43.7	420.5	541.5	23.0	68.8	472.8	344.3	254.4	190.6	144.5
12-31-2030	46.8	467.5	531.4	23.0	106.0	425.4	295.0	208.1	149.1	108.4
12-31-2031	46.8	484.3	550.6	23.0	112.6	438.0	289.3	194.8	133.5	93.0
12-31-2032	46.8	486.4	552.9	23.0	113.0	439.8	276.7	177.8	116.6	77.8
12-31-2033	46.8	478.8	544.3	23.0	114.0	430.2	257.8	158.2	99.2	63.4
12-31-2034	46.8	461.8	525.0	23.0	114.9	410.1	234.0	137.0	82.2	50.4
12-31-2035	46.8	449.4	510.8	23.0	116.0	394.8	214.5	119.9	68.8	40.4
12-31-2036	46.8	442.2	502.7	23.0	115.6	387.0	200.3	106.9	58.7	33.0
12-31-2037	46.8	435.0	494.5	23.0	113.8	380.7	187.7	95.6	50.2	27.1
Subtotal		4,793.2	9,274.9		1,781.0	7,493.8	5,514.8	4,270.2	3,444.8	2,870.9
Remaining		9,095.2	10,309.8		2,379.4	7,930.4	2,260.3	760.3	290.2	121.8
Total		13,888.4	19,584.7		4,160.5	15,424.2	7,775.1	5,030.5	3,734.9	2,992.7

Notes: Remaining represents estimates after December 31, 2037, through the end of the lease term in 2064.
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(1) Operating costs include direct project-level costs, insurance costs, workover costs, transportation costs, and NewMed's estimate of the portion of the operator's headquarters general and administrative overhead expenses that can be directly attributed to this project.
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HISTORICAL PRODUCTION AND OPERATING EXPENSE DATA
NEWMED ENERGY LIMITED PARTNERSHIP INTEREST
LEVIATHAN FIELD, LEASES I/14 AND I/15, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2022

Year	NewMed Working Interest Production (BCF)	Average Per Production Unit ($/MCF)				Reserves Depletion Rate[1] (%)
		Price Received	Royalties Paid	Production Costs	Net Revenue	
2022[2]	182.2	6.28	0.94	0.73	4.61	3.0
2021	171.5	5.14	0.75	0.68	3.71	2.8
2020	116.2	5.06	0.74	0.76	3.56	1.9

Note: Values in this table have been provided by NewMed; these values are based on historical data since January 2020.

[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 2022 data are representative of unaudited financial data.

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.

CASH FLOW, COSTS, AND TAXES
PHASE I – FIRST STAGE LOW ESTIMATE (1C) CONTINGENT RESOURCES
NEWMED ENERGY LIMITED PARTNERSHIP INTEREST
LEVIATHAN FIELD, LEASES I/14 AND I/15, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2022

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 Cash Flow Before Levy and Corporate Income Taxes Discounted at 0% (MM$)
12-31-2023	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2024	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2025	23.5	2.6	1.7	0.6	4.9	0.0	0.0	0.1	18.4
12-31-2026	91.0	10.3	5.3	2.5	18.0	0.0	0.0	0.4	72.5
12-31-2027	113.2	12.7	6.6	3.1	22.4	88.6	0.0	0.6	1.5
12-31-2028	116.8	13.2	6.8	3.2	23.2	0.0	0.0	0.6	93.1
12-31-2029	118.9	13.4	7.0	3.2	23.6	0.0	0.0	0.6	94.8
12-31-2030	121.7	13.7	7.1	3.3	24.1	0.0	0.0	0.6	97.0
12-31-2031	139.8	15.7	8.2	3.8	27.7	0.0	0.0	0.6	111.5
12-31-2032	144.7	16.3	8.5	3.9	28.7	0.0	0.0	0.6	115.4
12-31-2033	144.7	16.3	8.5	3.9	28.7	0.0	0.0	0.6	115.4
12-31-2034	144.7	16.3	8.5	3.9	28.7	200.7	0.0	0.6	-85.4
12-31-2035	144.7	16.3	8.5	3.9	28.7	0.0	0.0	0.6	115.4
12-31-2036	144.7	16.3	8.5	3.9	28.7	0.0	0.0	0.6	115.4
12-31-2037	144.7	16.3	8.5	3.9	28.7	0.0	0.0	0.6	115.4
Subtotal	1,593.0	179.4	93.6	43.0	316.0	289.4	0.0	7.3	980.3
Remaining	4,256.3	479.3	249.2	115.0	843.5	903.3	78.9	9.0	2,421.6
Total	5,849.3	658.6	342.8	158.1	1,159.5	1,192.7	78.9	16.4	3,401.9

Period Ending	Levy Rate[2] (%)	Levy[2] (MM$)	Future Net Cash Flow After Levy and Before Corporate Income Taxes Discounted at 0% (MM$)	Corporate Income Tax Rate[3] (%)	Corporate Income Taxes[3] (MM$)	Future Net Cash Flow After Levy and Corporate Income Taxes: Discounted at 0% (MM$)	Discounted at 5% (MM$)	Discounted at 10% (MM$)	Discounted at 15% (MM$)	Discounted at 20% (MM$)
12-31-2023	0.0	0.0	0.0	23.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2024	0.0	0.0	0.0	23.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2025	0.0	0.0	18.4	23.0	4.2	14.2	12.6	11.2	10.0	9.0
12-31-2026	0.0	0.0	72.5	23.0	16.7	55.9	47.1	40.0	34.3	29.5
12-31-2027	17.8	20.6	-19.0	23.0	15.0	-34.0	-27.3	-22.2	-18.1	-15.0
12-31-2028	31.7	42.8	50.3	23.0	9.5	40.7	31.2	24.1	18.9	14.9
12-31-2029	39.4	55.9	38.8	23.0	6.9	31.9	23.3	17.2	12.9	9.8
12-31-2030	45.5	64.1	32.9	23.0	5.5	27.3	19.0	13.4	9.6	7.0
12-31-2031	46.8	52.5	59.0	23.0	11.5	47.5	31.4	21.1	14.5	10.1
12-31-2032	46.8	54.0	61.4	23.0	12.1	49.3	31.0	19.9	13.1	8.7
12-31-2033	46.8	54.0	61.4	23.0	12.1	49.3	29.5	18.1	11.4	7.3
12-31-2034	46.8	-40.0	-45.4	23.0	31.4	-76.8	-43.8	-25.7	-15.4	-9.4
12-31-2035	46.8	54.0	61.4	23.0	7.5	53.9	29.3	16.4	9.4	5.5
12-31-2036	46.8	54.0	61.4	23.0	7.5	53.9	27.9	14.9	8.2	4.6
12-31-2037	46.8	54.0	61.4	23.0	8.5	52.9	26.1	13.3	7.0	3.8
Subtotal		466.0	514.4		148.3	366.0	237.1	161.8	115.5	85.7
Remaining		1,185.9	1,235.7		263.7	972.0	372.4	139.3	54.3	22.4
Total		1,651.9	1,750.0		412.0	1,338.1	609.5	301.1	169.8	108.2

Notes: Remaining represents estimates after December 31, 2037, through the end of the lease term in 2064.
Totals may not add because of rounding.

[1] Operating costs include direct project-level costs, insurance costs, workover costs, transportation costs, and NewMed's estimate of the portion of the operator's headquarters general and administrative overhead expenses that can be directly attributed to this project.

[2] Oil and gas profits levy rates and estimates are provided by NewMed.

[3] Corporate income tax rates and estimates of corporate income taxes are provided by NewMed and are its expected corporate income taxes per year.

Table VII

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.

CASH FLOW, COSTS, AND TAXES
PHASE I – FIRST STAGE BEST ESTIMATE (2C) CONTINGENT RESOURCES
NEWMED ENERGY LIMITED PARTNERSHIP INTEREST
LEVIATHAN FIELD, LEASES I/14 AND I/15, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2022

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 Cash Flow Before Levy and Corporate Income Taxes Discounted at 0% (MM$)
12-31-2023	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2024	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2025	14.6	1.6	0.9	0.4	3.0	0.0	0.0	0.1	11.5
12-31-2026	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2027	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2028	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2029	0.0	0.0	0.0	0.0	0.0	88.6	0.0	0.0	-88.6
12-31-2030	2.6	0.3	0.1	0.1	0.5	0.0	0.0	0.0	2.0
12-31-2031	24.4	2.8	1.4	0.7	4.8	0.0	0.0	0.1	19.5
12-31-2032	49.6	5.6	2.9	1.3	9.8	0.0	0.0	0.2	39.5
12-31-2033	73.9	8.3	4.3	2.0	14.6	0.0	0.0	0.3	58.9
12-31-2034	97.1	10.9	5.7	2.6	19.2	0.0	0.0	0.4	77.4
12-31-2035	120.4	13.6	7.0	3.3	23.9	0.0	0.0	0.5	96.0
12-31-2036	142.7	16.1	8.4	3.9	28.3	112.1	0.0	0.6	1.7
12-31-2037	164.9	18.6	9.7	4.5	32.7	0.0	0.0	0.7	131.5
Subtotal	690.1	77.7	40.5	18.6	136.9	200.7	0.0	3.1	349.4
Remaining	7,062.6	795.2	413.5	190.9	1,399.6	991.9	78.9	33.5	4,558.7
Total	7,752.7	873.0	454.0	209.5	1,536.5	1,192.7	78.9	36.6	4,908.1

Period Ending	Levy Rate[2] (%)	Levy[2] (MM$)	Future Net Cash Flow After Levy and Before Corporate Income Taxes Discounted at 0% (MM$)	Corporate Income Tax Rate[3] (%)	Corporate Income Taxes[3] (MM$)	Future Net Cash Flow After Levy and Corporate Income Taxes: Discounted at 0% (MM$)	Discounted at 5% (MM$)	Discounted at 10% (MM$)	Discounted at 15% (MM$)	Discounted at 20% (MM$)
12-31-2023	0.0	0.0	0.0	23.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2024	0.0	0.0	0.0	23.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2025	0.0	0.0	11.5	23.0	2.6	8.9	7.9	7.0	6.3	5.6
12-31-2026	1.7	0.1	-0.1	23.0	0.0	-0.1	-0.1	-0.1	-0.1	0.0
12-31-2027	26.6	1.3	-1.3	23.0	-0.3	-1.0	-0.8	-0.6	-0.5	-0.4
12-31-2028	35.7	1.2	-1.2	23.0	-0.3	-0.9	-0.7	-0.6	-0.4	-0.3
12-31-2029	42.4	-41.0	-47.6	23.0	8.4	-56.0	-40.8	-30.2	-22.6	-17.1
12-31-2030	46.6	-0.2	2.3	23.0	-1.5	3.8	2.6	1.9	1.3	1.0
12-31-2031	46.8	9.1	10.4	23.0	0.3	10.0	6.6	4.5	3.1	2.1
12-31-2032	46.8	18.5	21.0	23.0	2.8	18.2	11.5	7.4	4.8	3.2
12-31-2033	46.8	27.6	31.3	23.0	5.2	26.2	15.7	9.6	6.0	3.9
12-31-2034	46.8	36.2	41.2	23.0	7.4	33.8	19.3	11.3	6.8	4.1
12-31-2035	46.8	44.9	51.1	23.0	9.7	41.4	22.5	12.6	7.2	4.2
12-31-2036	46.8	0.8	0.9	23.0	22.7	-21.8	-11.3	-6.0	-3.3	-1.9
12-31-2037	46.8	61.5	70.0	23.0	11.5	58.5	28.8	14.7	7.7	4.2
Subtotal		160.0	189.4		68.5	120.9	61.2	31.4	16.3	8.5
Remaining		2,170.1	2,388.6		524.4	1,864.2	518.0	165.6	59.7	23.8
Total		2,330.1	2,578.0		592.9	1,985.1	579.2	197.0	76.0	32.3

Notes: Remaining represents estimates after December 31, 2037, through the end of the lease term in 2064.
Totals may not add because of rounding.

(1) Operating costs include direct project-level costs, insurance costs, workover costs, transportation costs, and NewMed's estimate of the portion of the operator's headquarters general and administrative overhead expenses that can be directly attributed to this project.

(2) Oil and gas profits levy rates and estimates are provided by NewMed.

(3) Corporate income tax rates and estimates of corporate income taxes are provided by NewMed and are its expected corporate income taxes per year.

Table VIII

NETHERLAND, SEWELL & ASSOCIATES, INC.

CASH FLOW, COSTS, AND TAXES
PHASE I – FIRST STAGE HIGH ESTIMATE (3C) CONTINGENT RESOURCES
NEWMED ENERGY LIMITED PARTNERSHIP INTEREST
LEVIATHAN FIELD, LEASES I/14 AND I/15, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2022

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 Cash Flow Before Levy and Corporate Income Taxes Discounted at 0% (MM$)
12-31-2023	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2024	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2025	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2026	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2027	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2028	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2029	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2030	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2031	10.8	1.2	0.6	0.3	2.1	88.6	0.0	0.0	-80.1
12-31-2032	31.4	3.5	1.8	0.8	6.2	0.0	0.0	0.1	25.0
12-31-2033	51.6	5.8	3.0	1.4	10.2	0.0	0.0	0.2	41.1
12-31-2034	71.8	8.1	4.2	1.9	14.2	0.0	0.0	0.3	57.3
12-31-2035	91.1	10.3	5.3	2.5	18.0	0.0	0.0	0.4	72.6
12-31-2036	110.3	12.4	6.5	3.0	21.9	0.0	0.0	0.5	87.9
12-31-2037	129.5	14.6	7.6	3.5	25.7	112.1	0.0	0.6	-8.8
Subtotal	496.4	55.9	29.1	13.4	98.4	200.7	0.0	2.2	195.1
Remaining	7,605.9	856.4	445.3	205.5	1,507.3	991.9	78.9	37.2	4,990.6
Total	8,102.3	912.3	474.4	219.0	1,605.7	1,192.7	78.9	39.4	5,185.7

Period Ending	Levy Rate[2] (%)	Levy[2] (MM$)	Future Net Cash Flow After Levy and Before Corporate Income Taxes Discounted at 0% (MM$)	Corporate Income Tax Rate[3] (%)	Corporate Income Taxes[3] (MM$)	Future Net Cash Flow After Levy and Corporate Income Taxes: Discounted at 0% (MM$)	Discounted at 5% (MM$)	Discounted at 10% (MM$)	Discounted at 15% (MM$)	Discounted at 20% (MM$)
12-31-2023	0.0	0.0	0.0	23.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2024	0.0	0.0	0.0	23.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2025	0.0	0.0	0.0	23.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2026	5.2	0.0	0.0	23.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2027	27.5	0.0	0.0	23.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2028	36.5	0.0	0.0	23.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2029	43.7	0.0	0.0	23.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2030	46.8	0.0	0.0	23.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2031	46.8	-37.5	-42.6	23.0	9.6	-52.2	-34.5	-23.2	-15.9	-11.1
12-31-2032	46.8	11.7	13.3	23.0	1.0	12.3	7.7	5.0	3.3	2.2
12-31-2033	46.8	19.3	21.9	23.0	3.0	18.9	11.3	6.9	4.4	2.8
12-31-2034	46.8	26.8	30.5	23.0	5.0	25.5	14.6	8.5	5.1	3.1
12-31-2035	46.8	34.0	38.6	23.0	6.8	31.8	17.3	9.7	5.5	3.3
12-31-2036	46.8	41.2	46.8	23.0	8.7	38.1	19.7	10.5	5.8	3.2
12-31-2037	46.8	-4.1	-4.7	23.0	21.4	-26.1	-12.8	-6.5	-3.4	-1.9
Subtotal		91.3	103.8		55.5	48.3	23.3	10.9	4.7	1.7
Remaining		2,365.8	2,624.8		572.1	2,052.7	516.7	154.5	53.6	21.0
Total		2,457.0	2,728.6		627.6	2,101.0	540.0	165.4	58.3	22.6

Notes: Remaining represents estimates after December 31, 2037, through the end of the lease term in 2064.
Totals may not add because of rounding.

[1] Operating costs include direct project-level costs, insurance costs, workover costs, transportation costs, and NewMed's estimate of the portion of the operator's headquarters general and administrative overhead expenses that can be directly attributed to this project.
[2] Oil and gas profits levy rates and estimates are provided by NewMed.
[3] Corporate income tax rates and estimates of corporate income taxes are provided by NewMed and are its expected corporate income taxes per year.

Table IX

VOLUMETRIC INPUT SUMMARY
LEVIATHAN FIELD, LEASES I/14 AND I/15, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2022

	Gross Rock Volume (acre-feet)			Area (acres)			Average Gross Thickness[1][2] (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	10,739,300	11,378,816	11,448,680	82,537	83,800	84,167	130	136	136	0.71	0.81	0.87
B Sand	4,656,174	5,192,194	5,268,631	41,177	48,371	49,071	113	107	107	0.30	0.34	0.39
C Sand	1,915,488	2,315,922	2,451,782	19,413	24,373	25,789	99	95	95	0.66	0.73	0.74

	Porosity[3] (decimal)			Gas Saturation (decimal)			Gas Formation Volume Factor (SCF/RCF)[4]			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	0.23	0.23	0.23	0.73	0.75	0.79	374	374	374	0.60	0.65	0.70
B Sand	0.24	0.23	0.22	0.69	0.70	0.72	374	374	374	0.60	0.65	0.70
C Sand	0.23	0.22	0.22	0.74	0.76	0.81	374	374	374	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, 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 structural character of the B and C Sands results in a lower average gross thickness in the best and high estimate cases relative to the low estimate case.
[3] 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.
[4] The abbreviation SCF/RCF represents standard cubic feet per reservoir cubic foot.

APPENDIX

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.

CASH FLOW, COSTS, AND TAXES
PHASE I – FIRST STAGE LOW ESTIMATE (1C) CONTINGENT RESOURCES (INCLUDING 1P RESERVES)
NEWMED ENERGY LIMITED PARTNERSHIP INTEREST
LEVIATHAN FIELD, LEASES I/14 AND I/15, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2022

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 Cash Flow Before Levy and Corporate Income Taxes Discounted at 0% (MM$)
12-31-2023	1,051.4	118.4	14.2	28.4	161.0	211.5	0.0	156.7	522.2
12-31-2024	1,115.3	125.6	15.1	30.1	170.8	159.6	0.0	132.5	652.4
12-31-2025	1,165.8	131.3	30.6	31.5	193.4	27.5	0.0	131.2	813.7
12-31-2026	1,287.6	145.0	75.4	34.8	255.2	0.0	0.0	122.9	909.5
12-31-2027	1,305.9	147.0	76.5	35.3	258.8	88.6	0.0	137.5	820.9
12-31-2028	1,331.7	149.9	78.0	36.0	263.9	0.0	0.0	138.2	929.6
12-31-2029	1,346.9	151.7	78.9	36.4	266.9	0.0	0.0	159.3	920.7
12-31-2030	1,368.4	154.1	80.1	37.0	271.2	0.0	0.0	139.3	958.0
12-31-2031	1,434.5	161.5	84.0	38.8	284.3	0.0	0.0	133.3	1,016.9
12-31-2032	1,463.8	164.8	85.7	39.6	290.1	0.0	0.0	134.0	1,039.7
12-31-2033	1,463.7	164.8	85.7	39.6	290.1	0.0	0.0	133.9	1,039.7
12-31-2034	1,464.2	164.9	85.7	39.6	290.2	200.7	0.0	154.6	818.7
12-31-2035	1,398.5	157.5	81.9	37.8	277.1	0.0	0.0	110.7	1,010.6
12-31-2036	1,398.5	157.5	81.9	37.8	277.1	0.0	0.0	110.7	1,010.6
12-31-2037	1,398.5	157.5	81.9	37.8	277.1	0.0	0.0	110.8	1,010.6
Subtotal	19,994.4	2,251.4	1,035.5	540.3	3,827.2	687.9	0.0	2,005.5	13,473.9
Remaining	27,189.4	3,061.5	1,592.0	734.8	5,388.3	903.3	174.0	2,961.3	17,762.6
Total	47,183.8	5,312.9	2,627.5	1,275.1	9,215.5	1,591.2	174.0	4,966.8	31,236.4

Period Ending	Levy Rate[2] (%)	Levy[2] (MM$)	Future Net Cash Flow After Levy and Before Corporate Income Taxes Discounted at 0% (MM$)	Corporate Income Tax Rate[3] (%)	Corporate Income Taxes[3] (MM$)	Future Net Cash Flow After Levy and Corporate Income Taxes: Discounted at 0% (MM$)	Discounted at 5% (MM$)	Discounted at 10% (MM$)	Discounted at 15% (MM$)	Discounted at 20% (MM$)
12-31-2023	0.0	0.0	522.2	23.0	120.8	401.4	391.7	382.7	374.3	366.4
12-31-2024	0.0	0.0	652.4	23.0	133.4	519.0	482.4	449.8	420.8	394.8
12-31-2025	0.0	0.0	813.7	23.0	138.3	675.4	597.9	532.2	476.3	428.2
12-31-2026	0.0	0.0	909.5	23.0	152.7	756.8	638.0	542.2	464.0	399.8
12-31-2027	17.8	146.4	674.5	23.0	118.1	556.4	446.8	362.4	296.7	245.0
12-31-2028	31.7	294.5	635.0	23.0	88.2	546.8	418.1	323.7	253.5	200.6
12-31-2029	39.4	362.7	558.1	23.0	70.5	487.5	355.0	262.4	196.5	149.0
12-31-2030	45.5	436.1	521.9	23.0	101.8	420.1	291.3	205.5	147.3	107.0
12-31-2031	46.8	475.9	541.0	23.0	108.3	432.7	285.8	192.5	131.9	91.9
12-31-2032	46.8	486.6	553.1	23.0	111.1	442.1	278.1	178.8	117.2	78.2
12-31-2033	46.8	486.6	553.1	23.0	114.0	439.1	263.1	161.4	101.2	64.7
12-31-2034	46.8	383.2	435.6	23.0	136.1	299.4	170.9	100.1	60.0	36.8
12-31-2035	46.8	473.0	537.7	23.0	115.6	422.1	229.4	128.2	73.6	43.2
12-31-2036	46.8	473.0	537.6	23.0	117.0	420.6	217.7	116.2	63.8	35.9
12-31-2037	46.8	472.9	537.6	23.0	118.1	419.6	206.8	105.3	55.3	29.8
Subtotal		4,490.8	8,983.0		1,743.9	7,239.1	5,273.0	4,043.4	3,232.4	2,671.4
Remaining		8,392.0	9,370.6		2,142.9	7,227.7	2,242.6	791.3	309.6	131.5
Total		12,882.8	18,353.6		3,886.8	14,466.9	7,515.5	4,834.8	3,542.0	2,802.9

Notes: As requested, cash flows presented in this table include revenue and costs from proved (1P) reserves; the 1P reserves are inclusive of proved developed producing and proved undeveloped reserves. As presented in the 2018 PRMS, petroleum accumulations can be classified, in decreasing order of likelihood of commerciality, as reserves, contingent resrouces, or propsective resources. Different classifications of petroleum accumulations have varying degrees of technical and commercial risk that are difficult to qauantify; thus reserves, contingent resources, and prospective resources should not be aggregated without extensive consideration of these factors.
Remaining represents estimates after December 31, 2037, through the end of the lease term in 2064.
Totals may not add because of rounding.

(1) Operating costs include direct project-level costs, insurance costs, workover costs, transportation costs, and NewMed's estimate of the portion of the operator's headquarters general and administrative overhead expenses that can be directly attributed to this project.

(2) Oil and gas profits levy rates and estimates are provided by NewMed.

(3) Corporate income tax rates and estimates of corporate income taxes are provided by NewMed 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.

CASH FLOW, COSTS, AND TAXES
PHASE I – FIRST STAGE BEST ESTIMATE (2C) CONTINGENT RESOURCES (INCLUDING 2P RESERVES)
NEWMED ENERGY LIMITED PARTNERSHIP INTEREST
LEVIATHAN FIELD, LEASES I/14 AND I/15, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2022

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 Cash Flow Before Levy and Corporate Income Taxes Discounted at 0% (MM$)
12-31-2023	1,149.6	129.4	15.5	31.1	176.0	211.5	0.0	162.6	599.4
12-31-2024	1,217.5	137.1	16.5	32.9	186.4	159.6	0.0	138.4	733.1
12-31-2025	1,282.6	144.4	49.5	34.7	228.6	27.5	0.0	137.1	889.4
12-31-2026	1,354.4	152.5	79.3	36.6	268.4	0.0	0.0	128.5	957.4
12-31-2027	1,350.2	152.0	79.1	36.5	267.6	0.0	0.0	143.0	939.6
12-31-2028	1,375.7	154.9	80.6	37.2	272.6	0.0	0.0	143.7	959.4
12-31-2029	1,391.0	156.6	81.4	37.6	275.7	88.6	0.0	164.8	861.9
12-31-2030	1,412.5	159.0	82.7	38.2	279.9	0.0	0.0	144.7	987.8
12-31-2031	1,469.2	165.4	86.0	39.7	291.2	0.0	0.0	137.9	1,040.2
12-31-2032	1,497.6	168.6	87.7	40.5	296.8	0.0	0.0	138.6	1,062.2
12-31-2033	1,497.5	168.6	87.7	40.5	296.8	0.0	0.0	138.5	1,062.2
12-31-2034	1,498.0	168.7	87.7	40.5	296.9	0.0	0.0	159.2	1,042.0
12-31-2035	1,429.2	160.9	83.7	38.6	283.2	0.0	0.0	112.7	1,033.3
12-31-2036	1,429.2	160.9	83.7	38.6	283.2	112.1	0.0	112.8	921.1
12-31-2037	1,429.2	160.9	83.7	38.6	283.2	0.0	0.0	112.8	1,033.2
Subtotal	20,783.3	2,340.2	1,084.7	561.6	3,986.6	599.3	0.0	2,075.3	14,122.2
Remaining	33,387.8	3,759.5	1,954.9	902.3	6,616.7	991.9	174.0	3,051.2	22,554.0
Total	54,171.1	6,099.7	3,039.6	1,463.9	10,603.2	1,591.2	174.0	5,126.5	36,676.1

Period Ending	Levy Rate[2] (%)	Levy[2] (MM$)	Future Net Cash Flow After Levy and Before Corporate Income Taxes Discounted at 0% (MM$)	Corporate Income Tax Rate[3] (%)	Corporate Income Taxes[3] (MM$)	Future Net Cash Flow After Levy and Corporate Income Taxes: Discounted at 0% (MM$)	Discounted at 5% (MM$)	Discounted at 10% (MM$)	Discounted at 15% (MM$)	Discounted at 20% (MM$)
12-31-2023	0.0	0.0	599.4	23.0	138.5	460.9	449.8	439.5	429.8	420.8
12-31-2024	0.0	0.0	733.1	23.0	152.0	581.1	540.1	503.7	471.2	442.1
12-31-2025	0.0	0.0	889.4	23.0	155.7	733.7	649.5	578.1	517.3	465.1
12-31-2026	1.7	16.6	940.8	23.0	159.9	781.0	658.4	559.4	478.8	412.6
12-31-2027	26.6	249.7	689.8	23.0	102.3	587.6	471.8	382.7	313.3	258.7
12-31-2028	35.7	342.6	616.8	23.0	86.1	530.7	405.8	314.2	246.0	194.7
12-31-2029	42.4	365.8	496.1	23.0	77.7	418.4	304.7	225.2	168.7	127.9
12-31-2030	46.6	460.7	527.1	23.0	103.0	424.1	294.1	207.5	148.7	108.0
12-31-2031	46.8	486.8	553.4	23.0	111.2	442.2	292.1	196.7	134.8	93.9
12-31-2032	46.8	497.1	565.1	23.0	113.8	451.3	283.9	182.5	119.6	79.8
12-31-2033	46.8	497.1	565.1	23.0	116.8	448.3	268.6	164.8	103.3	66.1
12-31-2034	46.8	487.6	554.3	23.0	119.6	434.8	248.1	145.3	87.1	53.4
12-31-2035	46.8	483.6	549.7	23.0	122.9	426.8	231.9	129.6	74.4	43.7
12-31-2036	46.8	431.1	490.0	23.0	135.2	354.9	183.7	98.0	53.8	30.3
12-31-2037	46.8	483.5	549.7	23.0	121.8	427.8	210.9	107.4	56.4	30.4
Subtotal		4,802.3	9,319.8		1,816.3	7,503.5	5,493.2	4,234.6	3,403.3	2,827.5
Remaining		10,609.2	11,944.8		2,730.5	9,214.3	2,633.8	882.7	334.9	139.7
Total		15,411.6	21,264.6		4,546.8	16,717.7	8,127.0	5,117.3	3,738.2	2,967.2

Notes: As requested, cash flows presented in this table include revenue and costs from proved plus probable (2P) reserves. As presented in the 2018 PRMS, petroleum accumulations can be classified, in decreasing order of likelihood of commerciality, as reserves, contingent resrouces, or propsective resources. Different classifications of petroleum accumulations have varying degrees of technical and commercial risk that are difficult to qauantify; thus reserves, contingent resources, and prospective resources should not be aggregated without extensive consideration of these factors.
Remaining represents estimates after December 31, 2037, through the end of the lease term in 2064.
Totals may not add because of rounding.

[1] Operating costs include direct project-level costs, insurance costs, workover costs, transportation costs, and NewMed's estimate of the portion of the operator's headquarters general and administrative overhead expenses that can be directly attributed to this project.

[2] Oil and gas profits levy rates and estimates are provided by NewMed.

[3] Corporate income tax rates and estimates of corporate income taxes are provided by NewMed and are its expected corporate income taxes per year.

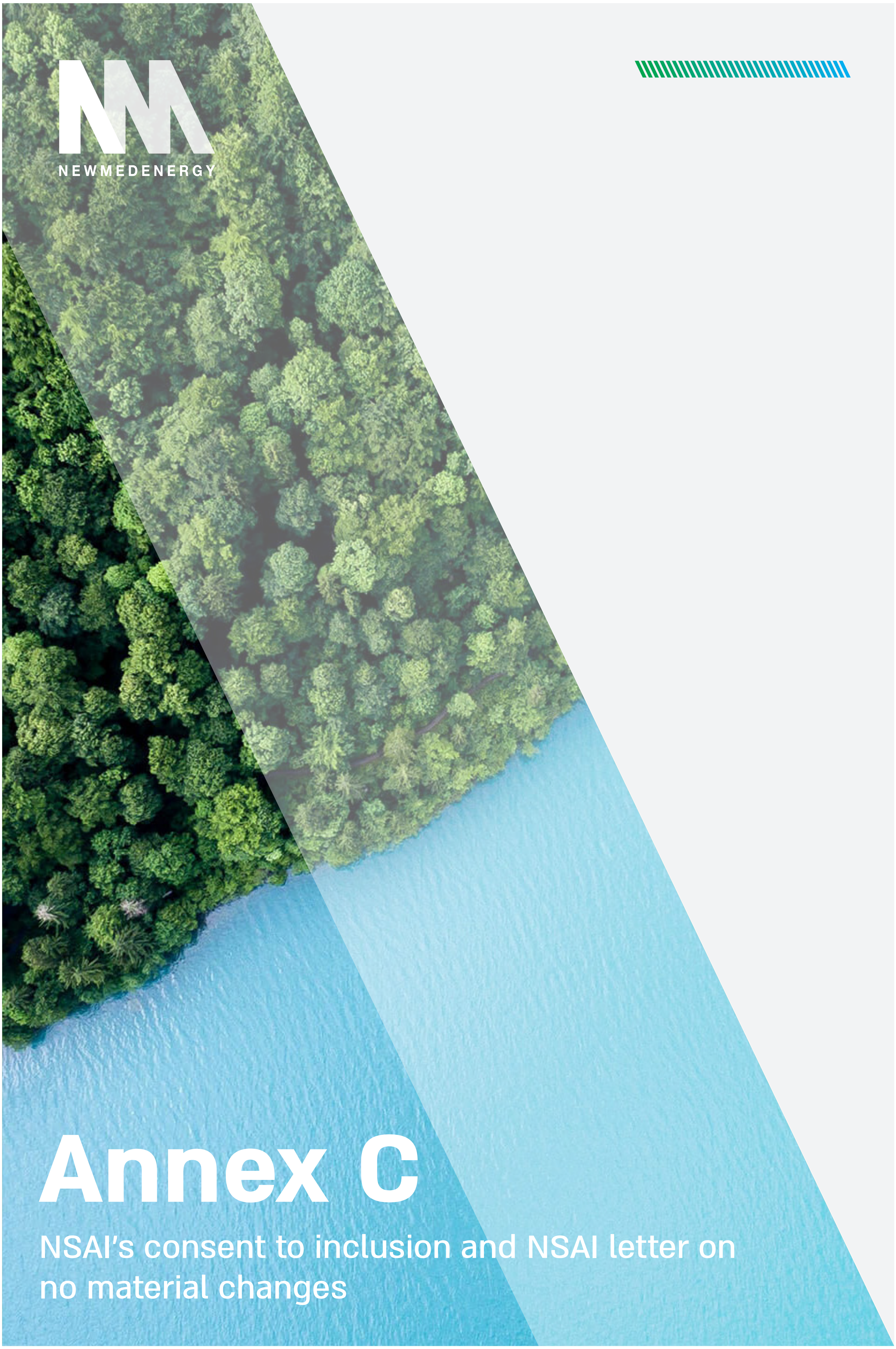
CASH FLOW, COSTS, AND TAXES
PHASE I – FIRST STAGE HIGH ESTIMATE (3C) CONTINGENT RESOURCES (INCLUDING 3P RESERVES)
NEWMED ENERGY LIMITED PARTNERSHIP INTEREST
LEVIATHAN FIELD, LEASES I/14 AND I/15, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2022

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 Cash Flow Before Levy and Corporate Income Taxes Discounted at 0% (MM$)
12-31-2023	1,212.2	136.5	16.4	32.8	185.6	211.5	0.0	167.8	647.3
12-31-2024	1,242.7	139.9	16.8	33.6	190.3	159.6	0.0	142.9	749.9
12-31-2025	1,304.5	146.9	55.4	35.3	237.5	27.5	0.0	141.6	897.9
12-31-2026	1,375.9	154.9	80.6	37.2	272.7	0.0	0.0	133.0	970.2
12-31-2027	1,371.4	154.4	80.3	37.1	271.8	0.0	0.0	147.5	952.1
12-31-2028	1,396.0	157.2	81.7	37.7	276.7	0.0	0.0	148.2	971.2
12-31-2029	1,410.9	158.9	82.6	38.1	279.6	0.0	0.0	169.2	962.0
12-31-2030	1,431.9	161.2	83.8	38.7	283.8	0.0	0.0	149.2	998.9
12-31-2031	1,474.9	166.1	86.4	39.9	292.3	88.6	0.0	139.1	954.8
12-31-2032	1,501.6	169.1	87.9	40.6	297.6	0.0	0.0	139.8	1,064.2
12-31-2033	1,501.5	169.1	87.9	40.6	297.6	0.0	0.0	139.7	1,064.2
12-31-2034	1,502.1	169.1	87.9	40.6	297.7	0.0	0.0	160.4	1,044.0
12-31-2035	1,430.6	161.1	83.8	38.7	283.5	0.0	0.0	114.3	1,032.8
12-31-2036	1,430.6	161.1	83.8	38.7	283.5	0.0	0.0	114.3	1,032.8
12-31-2037	1,430.6	161.1	83.8	38.7	283.5	112.1	0.0	114.3	920.7
Subtotal	21,017.3	2,366.5	1,099.0	568.0	4,033.6	599.3	0.0	2,121.3	14,263.1
Remaining	35,750.4	4,025.5	2,093.3	966.1	7,084.9	991.9	174.0	3,104.0	24,395.6
Total	56,767.7	6,392.0	3,192.3	1,534.1	11,118.4	1,591.2	174.0	5,225.3	38,658.7

Period Ending	Levy Rate[2] (%)	Levy[2] (MM$)	Future Net Cash Flow After Levy and Before Corporate Income Taxes Discounted at 0% (MM$)	Corporate Income Tax Rate[3] (%)	Corporate Income Taxes[3] (MM$)	Future Net Cash Flow After Levy and Corporate Income Taxes: Discounted at 0% (MM$)	Discounted at 5% (MM$)	Discounted at 10% (MM$)	Discounted at 15% (MM$)	Discounted at 20% (MM$)
12-31-2023	0.0	0.0	647.3	23.0	149.5	497.7	485.7	474.6	464.1	454.4
12-31-2024	0.0	0.0	749.9	23.0	155.8	594.0	552.1	514.9	481.7	451.9
12-31-2025	0.0	0.0	897.9	23.0	157.6	740.3	655.3	583.3	522.0	469.3
12-31-2026	5.2	50.9	919.3	23.0	154.9	764.4	644.4	547.6	468.7	403.8
12-31-2027	27.5	261.9	690.2	23.0	102.3	587.9	472.0	382.8	313.4	258.8
12-31-2028	36.5	354.6	616.6	23.0	86.0	530.5	405.7	314.1	246.0	194.6
12-31-2029	43.7	420.5	541.5	23.0	68.8	472.8	344.3	254.4	190.6	144.5
12-31-2030	46.8	467.5	531.4	23.0	106.0	425.4	295.0	208.1	149.1	108.4
12-31-2031	46.8	446.9	508.0	23.0	122.1	385.9	254.9	171.6	117.6	81.9
12-31-2032	46.8	498.1	566.2	23.0	114.1	452.1	284.4	182.8	119.8	80.0
12-31-2033	46.8	498.0	566.2	23.0	117.0	449.1	269.1	165.1	103.5	66.2
12-31-2034	46.8	488.6	555.4	23.0	119.8	435.6	248.5	145.6	87.3	53.5
12-31-2035	46.8	483.4	549.5	23.0	122.9	426.6	231.8	129.6	74.3	43.7
12-31-2036	46.8	483.3	549.4	23.0	124.3	425.1	220.0	117.4	64.4	36.3
12-31-2037	46.8	430.9	489.8	23.0	135.2	354.6	174.8	89.0	46.7	25.2
Subtotal		4,884.5	9,378.6		1,836.5	7,542.1	5,538.1	4,281.1	3,449.5	2,872.6
Remaining		11,460.9	12,934.7		2,951.5	9,983.2	2,777.0	914.8	343.8	142.7
Total		16,345.4	22,313.3		4,788.0	17,525.3	8,315.1	5,195.9	3,793.3	3,015.3

Notes: As requested, cash flows presented in this table include revenue and costs from proved plus probable plus possible (3P) reserves. As presented in the 2018 PRMS, petroleum accumulations can be classified, in decreasing order of likelihood of commerciality, as reserves, contingent resrouces, or propsective resources. Different classifications of petroleum accumulations have varying degrees of technical and commercial risk that are difficult to qauantify; thus reserves, contingent resources, and prospective resources should not be aggregated without extensive consideration of these factors.
Remaining represents estimates after December 31, 2037, through the end of the lease term in 2064.
Totals may not add because of rounding.

(1) Operating costs include direct project-level costs, insurance costs, workover costs, transportation costs, and NewMed's estimate of the portion of the operator's headquarters general and administrative overhead expenses that can be directly attributed to this project.
(2) Oil and gas profits levy rates and estimates are provided by NewMed.
(3) Corporate income tax rates and estimates of corporate income taxes are provided by NewMed and are its expected corporate income taxes per year.



Annex C

NSAI's consent to inclusion and NSAI letter on no material changes

NETHERLAND, SEWELL & ASSOCIATES, INC.
WORLDWIDE PETROLEUM CONSULTANTS
ENGINEERING • GEOLOGY • GEOPHYSICS • PETROPHYSICS

March 28, 2023

NewMed Energy Limited Partnership
19 Abba Eban Boulevard
Herzliya 4612001
Israel

Ladies and Gentlemen:

As independent consultants, Netherland, Sewell & Associates, Inc. (NSAI) hereby grant permission to NewMed Energy Limited Partnership (NewMed) to use the following NSAI reports issued to NewMed and Delek Drilling Limited Partnership (Delek) in the 2022 Annual Report of NewMed to be published in March 2023 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 19, 2023, which sets forth our estimates of the proved, probable, and possible reserves and future revenue, as of December 31, 2022, to the NewMed interest in certain gas properties located in Leviathan Field, Leases I/14 and I/15, offshore Israel. The March 19 report also sets forth our estimates of the contingent resources and cash flow, as of December 31, 2022, to the NewMed interest in these properties.

- 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 working interest in discoveries and prospects located in the Aphrodite Field Area, Block 12, offshore Cyprus.

- The report dated January 21, 2020, which sets forth our estimates of the unrisked prospective resources, as of December 31, 2019, to the Delek working interest in two Leviathan Deep prospects located in Leases I/14 and I/15, offshore Israel.

Since our March 19 report, we have received daily well production data for Leviathan Field through March 26, 2023. 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 19 report.

It is our understanding that Delek Drilling Limited Partnership changed its name to NewMed Energy Limited Partnership on February 21, 2022. As of the date hereof, nothing has come to our attention regarding the Aphrodite Field Area and Leviathan Deep prospects that could cause us to make any revisions in our March 14 and January 21 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 contingent and prospective resources referenced in our March 14 report and the unrisked prospective resources referenced in our January 21 report.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: Richard B. Talley, Jr.
Richard B. Talley, Jr., P.E.
Chief Executive Officer

RBT:MDK

NEWMEDENERGY

Part B

Board of Directors report

This report is a translation of NewMed Energy – 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 27, 2023

NewMed Energy – Limited Partnership

Report of the Board of Directors of the General Partner for the Year Ended December 31, 2022

The board of directors of NewMed Energy Management Ltd. (the "**General Partner**") hereby respectfully submits the board of directors' report for the year ended December 31, 2022 (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 of this report (Description of the Partnership's Business).

It is noted that on March 27, 2023, the General Partner received a non-binding indicative offer (the "**Offer**") from Abu Dhabi National Oil Company (ADNOC) P.J.S.C. and BP Exploration Operating Company, which are two international energy companies (jointly: the "**Consortium**"), regarding a possible transaction in which the Consortium will purchase for cash all of the participation units of the Partnership (the "**Units**") held by the public and some of the units held by Delek Group Ltd., the control holder of the Partnership ("**Delek Group**"), subject to specific conditions (the "**Transaction**").

Below is a summary description of the Offer:

a. As part of the Transaction, the Consortium will purchase all of the issued unit capital held by the public (approx. 45%) and purchase approx. 5% of the issued unit capital from Delek Group, such that after the closing of the Transaction, each of the Consortium and Delek Group will hold 50% of the equity and controlling interests in the Partnership , by way of approval of an arrangement under Section 350 of the Companies Law, 5759-1999.

b. The Offer of the Consortium, which, as aforesaid, is non-binding and subject to conditions, is payment of ILS 12.05 per unit purchased. Such price reflects a premium of approx. 72% relative to the closing price of the units on TASE on March 26, 2023 (ILS 6.996) or a premium of approx. 76% and approx. 60% relative to the average closing price of the units on TASE in the last 30 and 90 trading days prior to the Offer date, respectively.

c. The Offer included conditions which the Consortium wishes to arrange vis-à-vis Delek Group regarding the joint control of the Partnership after the closing of the Transaction, as well as additional conditions for the Transaction, including the completion of due diligence, obtaining detailed agreements with Delek Group on all relevant issues and obtaining all other required agreements and approvals.

d. The Consortium may withdraw and cancel the Offer at any time and for whatever reason.

For further details regarding the Transaction, see Section 1.8 of the Description of the Partnership's Business (Chapter A hereto).

Caution concerning forward-looking information – the information presented in this report concerning a possible transaction constitutes forward-looking information within the meaning thereof in the Securities Law, 5728-1968. It is emphasized that at this stage, there is no certainty regarding the closing and performance of the transaction, since this depends on conditions that are beyond the control of the Partnership.

2. Results of operations

A. General

As of the date of approval of the report, the Partnership operates in the energy sector and mainly engages in the exploration, development, production and marketing of natural gas, condensate and oil in Israel and in Cyprus, as well as in the promotion of various natural gas-based projects, with the aim of increasing the volume of sales of the natural gas produced by the Partnership. At the same time, the Partnership explores business opportunities in the area of the exploration, development, production, and marketing of natural gas, condensate and oil in additional countries, and also explores and promotes possibilities for investments in projects in the renewable energies sector, in the context of a collaboration with Enlight Renewable Energy Ltd. ("**Enlight**")[1] and possibilities of entering the field of hydrogen, including blue hydrogen which is produced from natural gas and may constitute a low-carbon substitute for energy consumers.

The Partnership's income from continuing operations before tax in the Report Year totaled approx. $595 million, compared with approx. $316 million in the same period last year. The increase in income was mainly due to an increase in net revenues from the sale of natural gas from the Leviathan reservoir and a decrease in net financial expenses, as specified below.

The Partnership's income from continuing operations before tax in Q4/2022 totaled approx. $150 million compared with approx. $31 million in the same quarter last year. The increase in income derived mainly from an increase in net revenues from the Leviathan reservoir, a decrease in depreciation, depletion and amortization expenses as well as a decrease in net financial

[1] For details regarding the Enlight transaction, see Section 7.8 of the description of the Partnership’s business chapter (Chapter A of this report).

expenses, as shall be specified below.

The Partnership’s net profit in the Report Year after recording income tax expenses (current taxes and updating deferred taxes) totaled approx. $470 million, compared with a total of approx. $405 million in the same period last year, which derived mainly from the increase in profit before tax from continuing operations and a decrease in deferred tax expenses due to registration for the first time of deferred tax liability in 2021, which was offset by a decrease in income from discontinued operations, as specified below.

The Partnership's net profit in Q4/2022 totaled approx. $142 million compared with approx. $218 million in the same period last year. The decrease in income derived mainly from the recording in 2021 of income from discontinued operations and income from the sale of oil and gas assets in the sum of approx. $179 million, following the sale of the Partnership’s interests in the Tamar and Dalit leases.

B. Analysis of statements of comprehensive income

Below are main figures with regards to the Partnership's statements of comprehensive income (dollars in millions):

	1-3/22	4-6/22	7-9/22	10-12/ 2022	2022	10-12/ 2021	2021
Revenues							
From natural gas and condensate sales	246.8	290.8	318.0	288.3	1,143.9	201.3	882.5
Net of royalties	(36.0)	(41.7)	(53.1)	(41.2)	(172.0)	(27.1)	(128.7)
Revenues, net	**210.8**	**249.1**	**264.9**	**247.1**	**971.9**	**174.2**	**753.8**
Expenses and costs:							
Cost of natural gas and condensate production	(33.6)	(36.9)	(29.1)	(34.5)	(134.1)	(35.0)	(118.4)
Depreciation, depletion and amortization expenses	(37.7)	(22.0)	(44.7)	(26.6)	(131.0)	(44.4)	(113.1)
Other direct expenses	(1.0)	(0.7)	(1.5)	(2.0)	(5.2)	(1.7)	(4.2)
G&A expenses	(3.1)	(4.8)	(4.0)	(7.8)	(19.7)	(5.3)	(17.3)
Total expenses and costs	**(75.4)**	**(64.4)**	**(79.3)**	**(70.9)**	**(290.0)**	**(86.4)**	**(253.0)**
The Partnership's share in the profits (losses) of a company accounted for at equity	(1.1)	(1.1)	(1.2)	0.3	(3.1)	(0.8)	(4.5)
Operating income	**134.3**	**183.6**	**184.4**	**176.5**	**678.8**	**87.0**	**496.4**
Financial expenses	(38.3)	(37.9)	(36.4)	(42.7)	(155.3)	(58.0)	(211.3)
Financial income	19.9	13.6	21.8	15.8	71.1	1.9	31.4
Financial expenses, net	(18.4)	(24.3)	(14.6)	(26.9)	(84.2)	(56.1)	(179.9)
Profit before taxes on the income	**115.9**	**159.3**	**169.8**	**149.6**	**594.6**	**30.9**	**316.4**
Taxes on the income	(31.6)	(35.3)	(43.4)	(5.7)	(116.0)	8.4	(207.8)
Income from continuing operations	**84.3**	**124.0**	**126.4**	**143.9**	**478.6**	**39.3**	**108.6**
Income (loss) from discontinued operations	-	(3.1)	(7.7)	(2.4)	(13.2)	34.2	151.7
Income from the sale of natural gas and oil assets	-	-	4.3	-	4.3	144.6	144.6
Total income (loss) from discontinued operations	-	(3.1)	(3.4)	(2.4)	**(8.9)**	**178.8**	**296.3**
Net profit	**84.3**	**120.9**	**123.0**	**141.5**	**469.7**	**218.1**	**404.9**
Other comprehensive income from discontinued operations:							
Amounts which will not be subsequently reclassified to profit or loss:							
Profit from investment in equity instruments designated for measurement at fair value through other comprehensive income	-	-	-	-	-	-	13.6
Total comprehensive income	**84.3**	**120.9**	**123.0**	**141.5**	**469.7**	**218.1**	**418.5**

Net revenues in the Report Year amounted to approx. $972 million, compared with approx. $754 million last year, up around 29%. The increase mainly derives from the increase in the natural gas quantities sold from the Leviathan reservoir, from a quantity of approx. 10.7 BCM (100%) last year to a quantity of approx. 11.4 BCM (100%) in the Report Year, as well as from the rise in the average price per unit of heat (MMBTU) from approx. $5.08 last year to approx. $6.17 in the Report Year, mostly in the quantities sold to the regional market, whose average price is high relative to the domestic market, and from the rise in the price of gas for export, which is partially linked to the Brent oil barrel prices.

Net revenues in Q4/2022 totaled approx. $247 million compared with approx. $174 million in the same period last year, up around 42%. The increase mainly derives from the increase in the natural gas quantities sold from the Leviathan reservoir, from a quantity of approx. 2.4 BCM in Q4/2021 to a quantity of approx. 2.9 BCM in Q4/2022, as well as from the rise in the average price per unit of heat (MMBTU) from approx. $5.16 in Q4/2021 to approx. $6.21 in Q4/2022.

In the Report Year, the quantities sold from the Leviathan reservoir totaled approx. 11.4 BCM, compared with approx. 10.65 BCM (in the framework of the 2P reserve flow) according to the Partnership's forecast for 2022, as included in the DCF in the reserve report for December 31, 2021, which was released on February 20, 2022 (Ref. 2022-01-020062). The gap derives from sales of natural gas to Egypt that were significantly higher than the forecast.

Below is a table specifying the gas quantities (100%) sold from the Leviathan reservoir in the Report Year and in 2021 according to the customers' geographic location:

2022 - (BCM)*					
	Israel	Jordan	Egypt	Total	Average Price**
Q1	0.9	0.7	1.1	2.7	**$5.78**
Q2	0.8	0.6	1.4	2.8	**$6.39**
Q3	1.2	0.7	1.1	3.0	**$6.44**
Q4	0.9	0.7	1.3	2.9	**$6.21**
Total/Average	**3.8**	**2.7**	**4.9**	**11.4**	**$6.17**

2021 - (BCM)*					
	Israel	Jordan	Egypt	Total	Average Price**
Q1	1.2	0.7	0.8	2.7	**$4.92**
Q2	1.4	0.6	0.8	2.8	**$4.94**
Q3	1.1	0.8	0.9	2.8	**$5.30**
Q4	0.9	0.6	0.9	2.4	**$5.16**
Total	**4.6**	**2.7**	**3.4**	**10.7**	**$5.08**

* The figures are rounded off to one-tenth of a BCM
** Price per MMBTU in dollars, rounded off to 2 digits after the decimal point.

Cost of natural gas and condensate production mainly includes expenses of management and operation of the Leviathan project which include, *inter alia*, expenses of haulage and transport, salaries, consulting, maintenance, environment, insurance and the cost of transmission of natural gas to Egypt. The cost of gas and condensate production in 2022 totaled approx. $134 million, compared with approx. $118 million, an increase of approx. 13%. The increase in the Report Year mainly derives mainly from an increase in transportation and shipping expenses and the costs of transmission of gas to Egypt that derive, *inter alia*, from the increase in the quantity of gas sold to Egypt, which was partially offset mainly by a decrease in the maintenance costs in the period.

The cost of gas and condensate production in Q4/2022 amounted to approx. $35 million, similar to the same quarter last year.

Depreciation, depletion and amortization expenses in the Report Year amounted to approx. $131 million, compared with approx. $113 million last year, an increase of around 16%. The increase mainly derives from depreciation of the "New Ofek" project to the Statement of Comprehensive Income and from an increase in the quantities of natural gas that were sold.

Depreciation and amortization expenses in Q4/2022 amounted to approx. $27 million, compared with approx. $44 million in the same quarter last year. The decrease mainly derives from an update of the Yam Tethys asset decommissioning obligations in the same quarter last year.

Other direct expenses in 2022 totaled approx. $5 million compared with approx. $4 million last year. The expenses include, *inter alia*, expenses of geologists, engineers and consulting as well as G&A expenses of various projects which are not at a production stage.

Other direct expenses in Q4/2022 amounted to approx. $2 million, similarly to the same period last year.

G&A expenses in the Report Year amounted to approx. $20 million, compared with approx. $17 million last year, and include, *inter alia,* salary expenses, professional services and D&O insurance. The increase derives, *inter alia*, from the Partnership's expenses for its activity in the context of the Capricorn transaction[2].

It is noted that in the parallel period last year, G&A expenses included expenses that were recorded against a capital reserve for transactions

[2] For details regarding the Capricorn transaction, see Section 7.24.14 of the description of the Partnership's business chapter (Chapter A of this report).

between a corporation and a controlling interest holder therein, which mainly derived from costs that were financed by the General Partner, according to the partnership agreement. On September 21, 2022, the Partnership's general meeting approved an amendment to the partnership agreement whereby the Partnership bears all of the management expenses of the Partnership from January 1, 2022, and hence expenses were recorded in the Report Year in respect of reimbursement of the General Partner for management expenses borne thereby in the Report Year. The increase in the Report Year essentially derived from an increase in salary and related expenses and an increase in the cost of share-based payment to the Partnership's CEO.

G&A expenses in Q4/2022 amounted to approx. $8 million, compared with approx. $5 million in the same quarter last year. The increase in Q4/2022 compared with the same quarter last year, derives mainly from the reasons stated above.

The Partnership's share in the profits (losses) of a company accounted for at equity in the Report Year totaled a loss of approx. $3 million, compared with a loss of approx. $4 million 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 Partnership's share in the profit (loss) of a company accounted for at equity in Q4/2022 amounted to a profit of approx. $0.3 million, compared with a loss of approx. $0.8 million in the same quarter last year.

Financial expenses in the Report Year totaled approx. $155 million, compared with approx. $211 million last year. The financial expenses in the Report year mainly derived from interest in respect of the Leviathan Bond bonds in the sum of approx. $146 million, compared with approx. $207 million last year, in respect of the Leviathan Bond, Tamar Bond and Series A bonds. The decrease in financial expenses in the period, compared with the same period last year, derived from full repayment in December 2021, of the bonds issued by Delek & Avner (Tamar Bond) Ltd., a wholly-owned subsidiary of the Partnership, following the sale of the Partnership's holdings in the Tamar project (see below "income (loss) from discontinued operations"), and from the final repayment of Series A bonds, also in December 2021.

Financial expenses in Q4/2022 amounted to approx. $43 million, compared with approx. $58 million in the same quarter last year. Most of the financial expenses in Q4/2022 derived from interest in respect of the Leviathan Bond bonds in the sum of approx. $36 million compared with approx. $56 million in respect of the Leviathan Bond, Tamar Bond and Series A bonds in the same quarter last year. The decrease in the financial expenses compared with the same quarter last year mainly derived from the reasons stated above.

Financial income in the Report Year amounted to approx. $71 million, compared with approx. $31 million last year. The increase in financial income mainly derives from revaluation of royalties and debt receivable for the Karish and Tanin leases in the sum of approx. $63 million, compared with revaluation of approx. $26 in the same period last year. For further details, see Note 8 to the financial statements attached below.

Financial income in Q4/2022 amounted to approx. $16 million and mainly derived from income due to the update of royalties receivable from the Karish and Tanin leases in the sum of approx. $10 million, compared with income in the sum of approx. $2 million last year. The increase in financial income compared with the same quarter last year, was mainly due to the aforesaid.

Taxes on income in the Report Year totaled approx. $116 million (deferred taxes in the sum of approx. $63 million as well as current taxes), compared with a sum of approx. $208 million (deferred taxes) last year. The decrease derives from the recognition for the first time of a deferred tax liability last year, following the amendment to the Income Tax Regulations "Rules for the Calculation of Tax due to the Holding and Sale of Participation Units in Oil Exploration Partnerships", whereunder from 2022, the tax regime that applies to the Partnership is the same as the tax regime that applies to companies.

Taxes on income in Q4/2022 totaled an expense of approx. $6 million compared with income of approx. $8 million in the same quarter last year. The income in the same quarter last year derived from the update of deferred taxes due to the decrease in the dollar/shekel exchange rate in the quarter, which was partly offset by an increase in temporary differences between the tax basis of the oil and gas assets and their book value. The tax expenses in Q4/2022 include current taxes offset by the update of deferred taxes, mainly as a result of a change in an estimate for the tax basis in respect of other long-term assets as a result of a change in the forecast for recovery of the value of a financial asset.

Income (loss) from discontinued operations in the Report Year totaled a loss of approx. $13 million, compared with income of approx. $152 million in the same period last year, which derived from the Partnership's holdings in the Tamar project which were sold in December 2021 (the "**Tamar Transaction**"). The loss in the Report Year derived mainly from the write-off of an asset for royalties receivable from the State and the recording of additional overriding royalties due to the dismissal of a claim that was filed with the District Court by the Partnership and Chevron (the "**Plaintiffs**") for reimbursement of royalties. For further details see Note 12L1 to the financial statements (Chapter C hereof) and Section 7.25.2 of the description of the Partnership's business chapter (Chapter A of this report).

Income (loss) from discontinued operations in Q4/2022, totaled a loss of approx. $2 million, compared with income of approx. $34 million in the same quarter last year. The loss in the quarter, compared with the income in the same quarter last year derive from the aforesaid reasons.

For further details, see Note 7C1 to the financial statements (Chapter C of this report).

Income from the sale of natural gas and oil assets amounted in the Report Year to approx. $4.3 million which derived from reconciliation for reimbursement of the Tamar levy expenses for 2021, compared with proceeds from the Tamar Transaction of approx. $145 million last year, which derived from proceeds in the amount of approx. $965 million net of the cost of the assets and liabilities transferred to the buyer and transaction costs at a sum total of approx. $820 million.

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, 2022, compared with the statement of financial position as of December 31, 2021, are specified below:

Total assets as of December 31, 2022 amounted to approx. $3,939 million, compared with approx. $3,850 million as of December 31, 2021.

Current assets as of December 31, 2022 amounted to approx. $771 million compared with approx. $581 million as of December 31, 2021. The change mainly derived from the following factors:

(1) Cash and cash equivalents as of December 31, 2022 totaled approx. $22 million, compared with approx. $220 million as of December 31, 2021. The decrease mainly derived from payments made in the Report Year for 2021, including payment of capital gains tax in connection with the Tamar Transaction in the sum of approx. $154 million, a balancing and tax payment to the participation unit holders in the sum of approx. $86 million, and payments in the Report Year, including a profit distribution to the participation unit holders in the sum of approx. $100 million, tax advances of approx. $74 million and investments and payments in respect of various projects. Conversely, the Partnership had revenues from the sale of natural gas from the Leviathan project, additional revenues from the Tamar transaction, repayment of a loan from Energean, and a tax refund in respect of previous years.

(2) Short-term investments and deposits as of December 31, 2022 totaled approx. $396 million, compared with approx. $121 million as of December 31, 2021, and primarily consist of deposits which serve as a safety cushion for the Leviathan Bond bonds in the sum of approx. $384 million. The increase mainly derived from the classification as current assets of a deposit which serves as a cushion for the bond series of Leviathan Bond maturing in 2023 (the "**2023 Series**") and the accumulation of an additional safety cushion of approx. $150 million (according to the terms and conditions of the Leviathan bond promissory note) intended for the redemption of 2023 Series.

(3) Trade receivables as of December 31, 2022 totaled approx. $199 million, compared with approx. $153 million as of December 31, 2021. The increase mainly derived from an increase in the Partnership's income from natural gas from the Leviathan project.

(4) Other receivables as of December 31, 2022 totaled approx. $134 million, compared with approx. $87 million as of December 31, 2021. The increase mainly derived from an increase in the debt balances of the operator in the context of the joint transactions, and from the classification to current assets of some of the royalty receivables from the sale of Karish and Tanin assets. For further details, see Note 8B to the financial statements (Chapter C hereof).

(5) Current taxes receivable as of December 31, 2022 totaled approx. $20 million. The balance comprises taxes receivable for 2021, following the filing of the Partnership's tax report, for details see Note 20B9 to the financial statements (Chapter C hereof), and from tax advances that were paid for 2022, net of a provision for current taxes in the Report Year.

Non-current assets as of December 31, 2022 totaled approx. $3,168 million, compared with approx. $3,269 million on December 31, 2021, as specified below:

(1) Investments in oil and gas assets as of December 31, 2022 totaled approx. $2,547 million, compared with approx. $2,570 million as of December 31, 2021. The change in the Report Year mainly derived from depreciation, depletion and amortization expenses in the Leviathan project in the sum of approx. $76 million, a decrease in the cost of retirement of Leviathan assets in the sum of approx. $25 million, and amortization of the New Ofek and New Yahel projects in the sum of approx. $13 million to the Statement of Comprehensive Income. Conversely, the Partnership mainly recorded investments in the Leviathan project in the sum of approx. $81 million. For further details, see Note 7 to the financial statements (Chapter C hereof).

(2) Investment in the company accounted for at equity as of December 31, 2022 totaled approx. $60 million compared with approx. $63 million as of December 31, 2021, and is due to 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 Year that derived mainly from depreciation of the excess purchase cost. For details see Note 6 to the financial statements (Chapter C of this report).

(3) Long-term bank deposits as of December 31, 2022 totaled approx. $1 million, compared with approx. $101 million as of December 31, 2021, the decrease derives from classification to current assets of a long-term deposit in the sum of approx. $100 million that serves as a safety cushion for the redemption of the 2023 Series.

(4) Other long-term assets as of December 31, 2022 totaled approx. $560 million, compared with approx. $535 million as of December 31, 2021. The increase derives from the revaluation of royalties and debt receivable in respect of the Karish and Tanin leases. For further details, see Note 8B to the financial statements (Chapter C to this report).

Current liabilities as of December 31, 2022 totaled approx. $582 million, compared with approx. $385 million as of December 31, 2021, as specified below:

(1) Bonds as of December 31, 2022 totaled approx. $425 million and include the 2023 Series, net of issue expenses, and net of bonds which were purchased in the context of a buyback plan (for further details, see Section F and Part Four below).

(2) Provision for balancing and tax payments – as of December 31, 2021 totaled approx. $86 million and included balancing and tax payments for 2021, that were paid in January 2022.

(3) Declared profits for distribution as of December 31, 2022 totaled approx. $50 million, and were distributed in January 2023.

(4) Trade and other payables as of December 31, 2022 totaled approx. $97 million, compared with approx. $271 million as of December 31, 2021. The decrease mainly derived from a payment of approx. $154 million for tax on capital gains from the Tamar Transaction, which were paid in January 2022, and from tax and balancing payments for 2015 and 2016 in the sum of approx. $13 million that were transferred to the trustee in September 2022.

(5) Other short-term liabilities as of December 31, 2022 totaled approx. $10 million compared with approx. $28 million as of December 31, 2021, and derive from the oil and gas asset retirement obligation in the Yam Tethys project. The decrease in the balance of the liability derived from the progress of the abandonment actions during 2022.

Non-current liabilities as of December 31, 2022 totaled approx. $2,070 million, compared with approx. $2,527 million as of December 31, 2021, as specified below:

(1) Bonds as of December 31, 2022 totaled approx. $1,731 million and include the Leviathan Bond bonds (net of issue expenses) (for details see Part Four below), compared with approx. $2,225 million as of December 31, 2021. The decrease mainly derived from classification of the 2023 Series as current liabilities.

(2) Deferred tax liability as of December 31, 2022 totaled approx. $270 million, compared with approx. $ 208 million as of December 31, 2021. Deferred tax liability derives mainly from differences between accounting depreciation and amortizations and depreciation and amortizations for tax purposes for oil and gas assets (including oil and gas asset retirement). The increase in this item derived mainly from an increase in the exchange rate and its impact on the temporary differences between the measurement base reported for tax purposes (ILS) and the measurement base reported in the financial statements (dollars) for oil and gas assets and other long-term assets. Conversely, a decrease was recorded in deferred taxes due to a change in a tax basis estimate as stated in the explanation for the taxes on income item above.

(3) **Other long-term liabilities** as of December 31, 2022 totaled approx. $69 million, compared with approx. $94 million as of December 31, 2021. The decrease mainly derives from an update of obligations to retire the assets of the Leviathan and Yam Tethys projects due to the rise in the interest to discount the obligations.

The capital of the limited partnership as of December 31, 2022 totaled approx. $1,287 million, compared with approx. $939 million as of December 31, 2021. The change in capital mainly derives from comprehensive income recorded in the Report Year in the sum of approx. $470 million, from an update of the tax liability of participation unit holders and balancing payments in the sum of approx. $29 million for 2021, which was offset by declared profits and distributed profits in the sum total of approx. $150 million.

B. **<u>Cash flow</u>**

(1) The cash flows generated by the Partnership from operating activities amounted in the Report Year to approx. $505 million, compared with approx. $454 million last year. The increase mainly derived from the increase in pre-tax profit for the period.

(2) The cash flows used for investment activities amounted in the Report Year to approx. $274 million, compared with cash flows derived from investment activities of approx. $982 million last year. In the Report Year, the Partnership invested in oil and gas assets, approx. $98 million (mainly in the Leviathan project), and approx. $28 million in other long-term assets (mainly in connection with expansion of infrastructures for transmission to Egypt) and it further recorded an increase in investments and short-term deposits, primarily in respect of the increase of the safety cushion for the redemption of the 2023 Series.

(3) The cash flows used for financing activities amounted in the Report Year to approx. $429 million, compared with approx. $1,286 million last year, a decrease deriving mainly from the redemption of the Tamar Bond and Series A bonds last year. The cash flows used for financing activities in the Report Year were used mainly for a profit distribution and for tax and balancing payments as well as for the buy-back of the Leviathan Bond debt, as stated in Section E below.

The balance of cash and cash equivalents as of December 31, 2022 amounted to approx. $22 million, compared with approx. $220 million as of December 31, 2021.

C. Financing

On February 5, 2023, the Partnership signed bank facility documents with an Israeli bank to be used by the Partnership in its operating activities. In accordance with the terms and conditions of the credit facilities, the Partnership may, during a period beginning on February 6, 2023 and ending on February 6, 2024, draw down, from time to time, U.S. dollar loans up to a total sum of $150 million (divided into two facilities: Facility A in the total sum of up to $100 million, and Facility B in the total sum of up to $50 million).
The undrawn balance of each of the credit facilities will bear a non-drawdown quarterly fee of 0.65% per year, until it is drawn down by the Partnership or until February 6, 2024, the earlier of the two.
Any and all loans drawn down from Facility A shall be payable until May 30, 2025 and bear SOFR interest plus a margin of 2.7% per annum.
Any and all loans drawn down from Facility B shall be payable in four equal quarterly payments in 2024 and bear SOFR interest plus a margin of 3% per annum.
As of the report release date, the Partnership did not draw down any amount from the said credit facilities. For further details, see Note 10D to the financial statements (Chapter C hereof).

D. Profit distributions, tax payments and balancing payments:

(1) On January 20, 2022, the Partnership made a payment which includes tax payments for individual eligible holders and balancing payments to non-individual eligible holders, of approx. ILS 268 million (ILS 0.2283281 per participation unit) (approx. $86 million), which was approved by the General Partner's board of directors on December 23, 2021.

(2) On March 23, 2022, the General Partner's board of directors approved a negligible distribution to the limited partner in the sum of ILS 1 million (approx. $0.3 million), which was designated 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 May 22, 2022, the General Partner's board of directors approved, after receiving the recommendation of the General Partner's Financial Statements Review Committee, a profit distribution in the sum total of $50 million ($0.0426 per participation unit), with the record date for the distribution being May 30, 2022. The said profit distribution was performed on June 16, 2022.

(4) On August 17, 2022, after receiving the recommendation of the Financial Statements Review Committee of the General Partner, the General

Partner's board of directors approved a profit distribution in the sum total of $50 million ($0.0426 per participation unit), with the record date for the distribution being August 25, 2022. The said profit distribution was performed on September 22, 2022.

(5) On November 23, 2022, after receiving the recommendation of the Financial Statements Review Committee of the General Partner, the General Partner's board of directors approved a profit distribution in the sum total of $50 million ($0.0426 per participation unit). The record date for the distribution is December 26, 2022 and the said profit distribution was made on January 19, 2023.

(6) On March 1, 2023, the board of directors of the General Partner approved a negligible distribution to the Limited Partner in the sum of NIS 1 million (approx. $0.3 million) which was designated to 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.

(7) On March 27, 2023, the board of directors of the General Partner approved, after receiving the recommendation of the Financial Statements Review Committee of the General Partner, a profit distribution in the sum total of $60 million ($0.05112 per participation unit). The record date for the distribution is April 9, 2023 and the said profit distribution will be made on April 20, 2023.

E. Buyback plan of bonds of Leviathan Bonds:

On May 22, 2022, the board of directors of the General Partner authorized the adoption of a plan for the purchase of the Leviathan Bond Bonds, which are listed on the TACT-Institutional system, according to which the Partnership and/or Levithan Bond will be able, from time to time, according to the discretion of the Partnership’s management and in accordance with the details of the purchase plan, to make purchases of the bonds in an aggregate amount of up to $100 million by way of an OTC purchase, a purchase on the TACT-Institutional system or by other methods (the “**Purchase Plan**”). The Purchase Plan took effect on May 24, 2022 for a period of two years and as of the date of approval of the Financial Statements, the Partnership made buybacks of approx. $100 million in accordance with the Purchase Plan.

Further thereto, on January 22, 2023, the board of directors of the General Partner of the Partnership, authorized to adopt an additional plan for the purchase of Bonds, whereby the Partnership and/or Leviathan Bond, may, from time to time, at the discretion of the Partnership's management, and in accordance with the details of the additional purchase plan, perform purchases of the Bonds, in an aggregate amount of up to $100 million, by way of an off-exchange, TACT-Institutional or any other purchase method (the "**Additional Purchase Plan**"). The Additional Purchase Plan took effect on January 23, 2023 and end after two years, i.e., on January 23, 2025.

It is noted that the financing sources for the making of the purchases according to the Purchase Plan will be the independent sources of the Partnership and of Leviathan Bond, and that in the Partnership's estimation, profit resulting from the purchase of the bonds may create a tax liability.

It is clarified that the above decisions regarding adoption of the Purchase Plan does not obligate the Partnership and/or Leviathan Bond to purchase the bonds, in whole or in part, and that the Partnership's management will be entitled to decide not to purchase bonds at all and/or to purchase bonds in a lower amount than approved.

The board of directors approved the buyback plans for the following main reasons:

1. In the current market situation, a buyback of the Partnership's bonds is a good business and economic opportunity for the Partnership.
2. The Plan will enable the reduction of the Partnership's debt.
3. The Plan is not expected to affect the cash flow forecast and the profit distribution capacity of the Partnership.
4. The Plan is not expected to adversely affect compliance with the financial covenants undertaken by the Partnership.
5. The Plan meets the provisions of the Partnership's indenture on the basis of which the Partnership's bonds of Leviathan Bond were issued, and approval of the Plan does not constitute a breach of the Partnership's undertakings to the Partnership's Leviathan Bond bondholders.
6. The Plan meets the conditions set forth in the buyback procedure adopted by the Partnership, as well as the Safe Harbor Directive.
7. 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.

As of the date of approval of the Financial Statements, the Partnership purchased $100 par value of Series 2023 Leviathan Bond Bonds as part of the Purchase Plan and approx. $9 million par value of Series 2023 Leviathan Bond Bonds as part of the Additional Purchase Plan.

For further details, see Part Five below.

F. <u>The Covid pandemic and its impact on the Partnership's business</u>:

During Q1/2020, Covid-19 began to spread throughout the world, including Israel, which was defined by the WHO as a global pandemic (the "**Covid Crisis**").

In 2021 and 2022, countries throughout the world, including Israel, continued to cope with the Covid Crisis. In 2022, the morbidity rates declined significantly, and the economy recovered, however, as of the date of approval of the report, it is unknown whether new Covid variants will emerge, and therefore it is difficult to estimate whether the Covid Crisis will continue to impact the global and the domestic economy, and what its effect will be on demand and the prices of natural gas and the other energy products.

G. **War between Russia and Ukraine and its possible impact on the Partnership's business:**

On February 24, 2022, the Russian army invaded Ukraine in an initiated campaign which included mobilization of ground forces, while also launching air and artillery assaults. As a result, the United States and the member states of the European Union imposed a series of economic punitive measures against Russia, which included, among others, sanctions on trade with Russia and with key Russian figures, a decision to suspend the completion of the "Nord Stream 2" project intended to double the volume of gas exported from Russia to Germany, the halt of some of the collaborations with Russian entities by international companies, including significant companies in the fields of natural gas and oil production, and more. Subsequently, the sale of natural gas from Russian to the EU was considerably reduced, causing a significant shortage of natural gas in countries that consumed considerable quantities of natural gas from Russia. Furthermore, a sharp decline was recorded in the scope of sales of oil from Russia to western countries.

In view of the aforesaid, the war in Ukraine caused an extreme and irregular rise in global prices of oil and natural gas; in the end of March 2022 the price of Brent oil barrels soared, up to approx. $120 per barrel, significantly exceeding the prices to which the world was accustomed in recent years.

The decline in the supply of natural gas via pipeline from Russia to Europe forced European countries to import more LNG in 2022 than in 2021. The import of LNG to Europe increased from approx. 90 BCM in 2021 to approx. 150 BCM in 2022, an increase of approx. 70%. The said leap in European demand for LNG resulted in extreme price competition in Asia's LNG markets, Asia being the world's primary consumer of LNG.

At the same time, China, Japan, South Korea and Taiwan comprised 50-60% of the global import of LNG in 2021.

During H2/2022, alongside a concentrated effort to identify alternatives that will secure the regular supply of natural gas, most European countries acted to reduce electricity consumption, while increasing the use of renewable energy sources, and further began utilizing nuclear power stations (which are an alternative to the generation of electricity by natural gas). In addition, in this period, a decline trend started in the global markets in the prices of the energy products, which continued also in Q1/2023. As of the date of approval of the report, the price of a barrel of Brent is approx. $75, lower than the price environment in the parallel period last year.

Concurrently, a similar decrease in the price of natural gas was also recorded in the global markets. In the assessment of the Partnership, the ongoing decline in energy prices in the global markets starting in mid-2022 can be attributed to signs of a slowdown in the global economy and to concern from the deepening of the recession, *inter alia*, against the background of a rapid increase in the rate of inflation, which led to the increase of the basic interest rate, as specified below, as well as to the effect of the weather, which was relatively mild in the winter months in Europe.

Against this background, many European countries are recently seeking to diversify their natural gas sources, with the aim of reducing the dependency on natural gas from Russia, which led to a significant increase in demand for natural gas, particularly in areas where pipeline can be connected for the transmission of natural gas to Europe, as well as an increase in demand for LNG. The Partnership, together with its partners in the Leviathan and Aphrodite projects, is examining the impact of such factors on the options for development and/or expansion of its assets.

H. <u>Inflation and the rise in the interest rate and their possible impact on the Partnership's business and the financial reporting and disclosure</u>:

As a result of global macro-economic developments, including the Covid Crisis and the war between Russia and Ukraine, as aforesaid, the inflation rates have risen in Israel, the U.S. and in other countries. As a result, and in order to curb the price increase, the central banks in Israel, the U.S. and other countries have started to increase the interest rates and declared plans for further interest rate raises in the future.

As of the date of approval of the Financial Statements, the Partnership is affected by such price increase, and particularly by the rise in commodity prices, which is primarily reflected in the rise in revenues from the sale of natural gas and condensate, which resulted from the rise in the Brent barrel prices to which the agreements for the export of gas to Egypt and Jordan are partly linked. In addition, such price increase is also affecting the cost of gas production and the cost of construction of projects and drilling of development, appraisal and exploration wells, but in an immaterial manner. In addition, the price increase may also affect the costs of future wells and projects in which the Partnership shall be a partner.

The impact of the interest rate rises as aforesaid on the financial position of the Partnership is evident mainly in the assets and liabilities in the Statement of Financial Position, which include capitalization components (see Part Two below for further details in connection with the sensitivity tests).

In this context it is noted that the Leviathan Bond Bonds bear fixed interest and therefore the interest expenses in respect thereof are not affected by the interest rate changes, but insofar as the Partnership shall need, in the future, to raise debt or, alternatively, shall use the credit facility as stated in Section C above and as specified in Note 10D to the financial statements (Chapter C hereof), this may also affect the Partnership's financial expenses.

Caution concerning forward-looking information – The Partnership's assessments regarding the possible consequences of Covid, the war between Russia and Ukraine and the inflation and the rise in the interest rate constitute forward-looking information, as defined in Section 32A of the Securities Law, 5728-1968. This information is based, *inter alia*, on the Partnership's assessments and estimates as of the date of approval of the Condensed Interim Financial Statements and relies on reports published in Israel and around the world on this issue and directives of the relevant authorities, the materialization of which is uncertain, in whole or in part, and beyond the Partnership's control.

I. <u>Capricorn transaction</u>:

On September 29, 2022, the Partnership and the General Partner engaged with the British company, Capricorn Energy Plc. ("**Capricorn**") in a contingent agreement for the performance of a transaction for a business combination of the Partnership and of Capricorn, such that upon the closing of the transaction, all of the holders of the Partnership's participation units (including the General Partner) were expected to hold approx. 89.7% of the share capital of the consolidated company, which were designated to be listed on the LSE's premium listing segment and also cross-listed on the Tel Aviv Stock Exchange. However, on February 15, 2023, the Partnership and Capricorn agreed on the cancellation of the transaction with immediate effect, *inter alia* in view of developments in Capricorn in the period after the signing of the Agreement, including a fundamental change in the composition of Capricorn's board of directors and executive management.

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 at the Partnership is VP Finance, Mr. Tzach Habusha.

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 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 part of the agreements for the sale of gas from the Leviathan reservoir are determined by price formulas that include various linkage components, and, *inter alia*, linkage to the ILS/Dollar exchange rate and linkage to the electricity production 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; and (c) Since the Partnership reports its taxable income in ILS and pays tax advances 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.

b. The natural gas and condensate price risk

The price of gas in agreements for natural gas supply, was determined according to price formulas that include various linkage components, including mostly linkage to the Brent barrel price, the electricity production tariff, the ILS/Dollar exchange rate, the general TAOZ (energy demand management) index published by the Electricity Authority and the Crack Spread. In all the agreements for natural gas supply in which the Partnership engaged, apart from agreements that include a fixed, unlinked price, floor prices were set alongside the price formulas, which to some extent limit the exposure to fluctuations in the linkage components. However, there is no certainty that the Partnership will be able to set floor prices as aforesaid also in new agreement to be signed thereby in the future.

In addition, a decrease in the Brent prices and/or a decrease in the electricity production tariff and/or an increase in the ILS/Dollar exchange rate (devaluation of the Shekel 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*, by significant changes in the prices of oil, natural gas, including LNG, and the prices of other sources of energy, including coal, sources of renewable energy and other alternatives to the produced natural gas marketed by the Partnership, 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 Leviathan reservoir.

An increase in supply, a decrease in demand or a decrease in the prices of alternative energy sources for natural gas, including coal, sources of renewable energy 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, 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, expansive military conflicts between countries 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 gas, as well as the making of decisions on investment in new natural gas projects and/or expansion of existing projects.

c. **The interest rate risk**

Further to Section 2C above regarding the Partnership's engagement with an Israeli bank for the provision of the credit facilities, it is noted that according to the terms of the credit facilities, the Partnership is exposed to possible changes in cash flows that may derive from changes in the SOFR interest, insofar as such facilities are used.

In addition, interest rate risk arises from the risk that the fair value or future cash flows of a financial instrument will change as a result of changes in market interest rates. Financial instruments that bear a variable interest rate expose the Partnership to cash flow and P&L risks due to a change in the interest rate.

Changes in interest rates may also affect the cost of financing of the Partnership's future investments in oil and gas assets, *inter alia* in the development of Phase 1B of the Leviathan project and the development of the Aphrodite reservoir.

Furthermore, the liquid financial assets of the Partnership are invested as of the date of approval of the financial statements in dollar deposits. It is noted that changes in interest rates may affect the current yield of the deposits.

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.

c. When the Partnership is aware of material payments in foreign currency or ILS it aspires to protect, insofar as possible and at its discretion, 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. The Partnership's policy in market risk management in SOFR interest

The Partnership periodically examines its exposure to changes in the SOFR interest rate insofar as the credit facilities are used, relative to other sources of financing, and it examines the possibility to buy hedges as needed.

5. 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 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 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, to 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 the date of approval of the report, are: Messrs. Efraim Sadka (Chairman of the Investment Committee, external director), Jacob Zack (external director) and 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.

6. 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 the parameters, assumptions and models

Parameters:

Parameter	Source/Manner of Treatment
ILS/Dollar exchange rate	Representative rate as of December 31, 2022
Dollar interest	Capitalization interest/SOFR interest

a. For details regarding an 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 22F2 to the financial statements (Chapter C of this report).

b. For details regarding an 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 22F4 to the financial statements (Chapter C of this report).

c. For details regarding an analysis of the sensitivity of financial instruments with variable interest see Note 22F2 to the financial statements (Chapter C of this report).

d. Tests of sensitivity to changes in the Dollar/ILS exchange rate ($ in millions):

Sensitive Instrument	Profit/(Loss) from Changes		Fair Value	Profit/(Loss) from Changes	
	10%	5%		-5%	-10%
	4.064	3.695	3.519	3.343	3.167
Cash and cash equivalents	(0.3)	(0.1)	2.6	0.1	0.3
Bank deposits	-	-	0.2	-	-
Trade and other payables	0.1	0.1	(1.7)	(0.1)	(0.1)
Total	**(0.2)**	-	**1.1**	-	**0.2**

7. Report on linkage bases in Dollars in thousands, as of December 31, 2022:

	Financial Balances		Non-financial balances	Total
	In dollars or dollar-linked	In non-linked ILS		
Assets				
Cash and cash equivalents	19.8	2.6	-	22.4
Short-term investments	395.7	0.2	-	395.9
Trade receivables	199.0	-	-	199.0
Other receivables	130.0	-	4.1	134.1
Current taxes receivable	-	-	19.9	19.9
Investments in oil and gas assets	-	-	2,547.2	2,547.2
Investment in company accounted for at equity	-	-	59.7	59.7
Long-term deposits	0.5	-	-	0.5
Other long-term assets	321.0	-	239.3	560.3
Total assets	**1,066.0**	**2.8**	**2,870.2**	**3,939.0**
Liabilities				
Declared profits for distribution	50.0	-	-	50.0
Other short-term liabilities	-	-	9.9	9.9
Trade and other payables	61.9	1.1	33.9	96.9
Bonds	2,155.8	-	-	2,155.8
Deferred tax	-	-	269.8	269.8
Other long-term liabilities	-	-	69.2	69.2
Total liabilities	**2,267.7**	**1.1**	**382.8**	**2,651.6**
Total net balance sheet balance	**(1,201.7)**	**1.7**	**2,487.4**	**1,287.4**

8. Report on linkage bases in Dollars in thousands, as of December 31, 2021:

	Financial Balances			
	In dollars or dollar-linked	In non-linked ILS	Non-financial balances	Total
Assets				
Cash and cash equivalents	214.1	6.1	-	220.2
Short-term investments	120.4	0.2	-	120.6
Trade receivables	152.5	-	-	152.5
Other receivables	73.4	-	14.0	87.4
Investments in oil and gas assets	-	-	2,570.5	2,570.5
Investment in company accounted for at equity	-	-	62.8	62.8
Long-term deposits	100.7	-	-	100.7
Other long-term assets	305.3	-	230.1	535.4
Total assets	**966.5**	**6.3**	**2,877.3**	**3,850.1**
Liabilities				
Trade and other payables	5.0	0.4	265.3	270.7
Other short-term liabilities	-	-	27.6	27.6
Provision for balancing and tax payments	-	-	86.2	86.2
Bonds	2,224.8	-	-	2,224.8
Deferred tax liability	-	-	207.8	207.8
Other long-term liabilities	-	-	94.4	94.4
Total liabilities	**2,229.8**	**0.4**	**681.3**	**2,911.6**
Total net balance sheet balance	**(1,263.4)**	**5.9**	**2,196.0**	**938.5**

Part Three – Corporate Governance Aspects

1. The Partnership's donation policy

In September 2022, the general meeting of the Partnership's participation unit holders approved an amendment to the partnership agreement regarding donations and assistance to the community. As of the date of approval of the report, the Partnership is formulating a plan for donations and assistance to the community, whereby the Partnership will be entitled to provide donations and financial assistance in a variety of fields, alongside individual or group voluntary activities of the managers and employees of the Partnership and the General Partner.

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, 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, as aforesaid, 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 minimum number as aforesaid 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 approval date, 3 directors with accounting and financial expertise serve on the General Partner's board of directors (Messrs. Efraim Sadka, Tamir Poliker and Jacob Zack). For details regarding the education, experience and qualifications of these directors, see Section 26 of Chapter D of this report (Additional Details regarding the Partnership).

3. Independent directors

The Partnership did not adopt a clause in the Trust and Partnership Agreements with regards to the number of independent directors, as they are defined by the Companies Law. As of the date of approval of the report, 3 external directors serve on the General Partner's board of directors. For details on the independence of the directors, see Section 26 of Chapter D of this report (Additional Details on the Partnership).

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.

   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), Certified in Data Privacy Solutions Engineer (CDPSE).

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 the control holder. 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, following its acceptance 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 audit performs audits on many issues in accordance with a carefully crafted plan, the results of which are discussed at the audit committee. The internal audit budget is approved by the audit committee. The work plan of the internal audit is prepared by the internal auditor in coordination with the General Partner's management, and is based on the risk survey for the determination of the audit targets performed by the internal auditor, from which the audit topics are derived. The plan is presented to the audit committee and the board of directors of the General Partner and is approved by the audit committee.

The work plan leaves the internal auditor discretion to deviate therefrom, subject to the 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 projects Leviathan and Block 12 in Cyprus, over the work of the operator in the projects as aforesaid. The Partnership's control and investment manager participates in the preparation, monitoring and supervision meetings of the audit as aforesaid and the internal auditor reports to the audit committee and the board of directors of the General Partner on its findings and results.

In 2022 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 (of the Leviathan project) for 2020-2021, with an approved budget of approx. 780 hours. In addition, an audit was conducted in 2022 by a joint team of the Partnership and Shell company in the books of the operators of the joint venture Block 12 in Cyprus for 2018-2021. . It is noted that the aforesaid audits were conducted in cooperation with all of the partners in the projects other than the operator, in accordance with the rules set forth in the joint operation agreements which govern the projects.

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. **Access to information**

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. **The internal auditor's report**

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: August 14, 2022 and March 15, 2023.

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 2022 the Partnership recorded a total annual expense of ILS 132 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 the joint ventures:

	Y2022		Y2021	
	For audit, audit-related and tax services	For other services*	For audit, audit-related and tax services	For other services*
	ILS in thousands			
Kost Forer Gabbay & Kasierer and Ziv Haft, co-auditors	1,805	1,271	2,009	2,435

*** Other services, mainly in connection with offerings and tax consultancy.**

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 Audit Committee examines the scope of the auditors' work and their fees (in the context of such examination considers the Financial Statements Review Committee's evaluation and the auditor's work) 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 was 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: insofar as each of the criteria that are relevant to the transaction (as specified in sub-sections 1-5 below) is at a rate of no more than 0.8% and the scope of the transaction does not exceed $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 the control holder, considering their proportionate share.

c. In cases where, according to the discretion of the audit committee, all of the criteria as aforesaid 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 the control 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 and code of ethics

a. The board of directors of the General Partner has determined that the audit committee will be in charge of the adoption of an internal enforcement program in respect of securities, for the management of the program and for the ongoing follow-up and supervision of the performance thereof. Accordingly, in July 2022, the audit committee approved an updated internal enforcement program in respect of securities (the "**Enforcement Program**"), according to the criteria published by the ISA and based on the results of a current compliance survey that was conducted at the Partnership prior to approval of the Enforcement Program. In this context, among other things, the procedures were updated according to the changes in the law from the adoption of the previous enforcement program and in accordance with the results of the said survey. The Partnership updates the Enforcement Program on a regular basis, according to developments in its business and to changes in the law (if any).

b. The Partnership adopted a monitoring and control procedure for the operator's environmental, health & safety activity (the "**EHS**

Procedure") which is designed to ensure that the operator acts in compliance with the provisions of the law in these matters. The audit committee approved the EHS Procedure and appointed an EHS officer at the Partnership.

c. The Partnership is acting to implement the provisions of the Privacy Protection Law, 5741-1981 and the Privacy Protection Regulations (Information Security), 5777-2017 and accordingly, registered databases. Furthermore, the Partnership established an information security and cyber protection policy and is acting to implement the same by assimilation of organizational procedures. The audit committee was authorized as the entity in charge of ongoing reporting, monitoring and supervision of these matters.

d. The Partnership has a code of ethics specifying the proper rules of conduct and principles for the purpose of guidance of the actions of all of the officers and employees at the Partnership, in accordance with the fundamental values according to which the Partnership operates.

The Partnership provides training for its officers and employees in accordance with the provisions of the enforcement plan and the procedures thereunder, the information security procedures and the code of ethics.

8. Corporate Social Responsibility at the Partnership ("ESG")

In view of the importance that the Partnership attributes to the corporate responsibility, in particular to environmental, social and governance issues **("ESG")**, the General Partner's board of directors decided in February 2022 to update the Partnership's targets and strategy in this area in view, *inter alia*, of the desire to promote and highlight aspects of environmental, social and governance responsibility in the Partnership's operations.

In view of the above, the General Partner's board of directors authorized the audit committee as the function responsible for the issue of corporate responsibility in the Partnership. Accordingly, the audit committee has appointed an officer who is responsible for corporate social responsibility at the Partnership, and in February 2022, a first corporate social responsibility report for 2020-2021 was posted on the Partnership's website, in which initial targets were set for fields defined by the Partnership, according to the materiality test and in accordance with GRI (Global Reporting Initiatives) standards. The Partnership intends to release an updated ESG report for 2022 in Q2/2023.

Part Four – Disclosure in connection with the Partnership's Financial Reporting

Subsequent events

See Note 23 to the financial statements (Chapter C of this report).

Part Five – Details of bonds issued by Leviathan Bond Ltd.

Leviathan Bond bond series	2023	2025	2027	2030
Par value on the issue date	500	600	600	550
Issue date	August 18, 2020	August 18, 2020	August 18, 2020	August 18, 2020
Par value as of December 31, 2022	500	600	600	550
Linked par value as of December 31, 2022	500	600	600	550
Value in the Partnership's books as of December 31, 2022[3]	424.8	596.2	593.6	541.2
TASE value as of December 31, 2022[4]	424.6	587.2	584.0	519.6
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[5]	None			
Conversion right	None			
Right to prepayment or mandatory conversion[6]	Right to prepayment			
Guarantee for payment of the liability	See Note 10B to the financial statements (Chapter C of this report).			
Name of the trustee	HSBC Bank USA, National Association			
Name of person in charge at the trust company	Asma Alghofailey			

[3] See Section 1E above in respect of a buy-back plan of the bonds which was adopted by the board of directors.
[4] The bonds are traded in Israel on the "TACT-institutional" system on TASE.
[5] The bonds' principal and interest are depicted in dollars.
[6] 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 the rights in the Leviathan project, in whole or in part.

Leviathan Bond bond series	2023	2025	2027	2030
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[7]	Fitch Rating: BB stable Moody's: Ba3 Stable S&P: BB- Stable Standard & Poor's Maalot: ilA+ stable			
Rating as of the report date[8]	Fitch Rating: BB stable Moody's: Ba3 Stable S&P: BB- Stable Standard & Poor's Maalot: ilA+ stable			
Has the Partnership fulfilled, by December 31, 2022 and during the Report Year, all of the conditions and obligations under the indenture	Yes			
Is the bond series material[9]	Yes			
Have any conditions establishing cause for acceleration of the bonds been fulfilled	No			
Pledges to secure the bonds	See Note 10B to the financial statements (Chapter C hereof).			

[7] For updated rating reports, see the Partnership's immediate reports of February 8, 2022, November 13, 2022, March 16, 2022 and March 16, 2022 (Ref. No. 2022-01-016279, 2022-01-135988, 2023-01-027774 and 2023-01-027771, respectively), the information included in which is incorporated herein by reference.

[8] For updated rating reports, see the Partnership's immediate reports of July 29, 2021, August 1, 2021 and August 10, 2021 (Ref. no.: 2021-01-125100, 2021-01-125451 and 2021-01-130161, respectively), the information appearing in which is included herein by way of reference.

[9] 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.

Additional information

The board of directors of the General Partner expresses its appreciation of the management 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,

Yossi Abu	**Gabi Last**
CEO	Chairman of the Board

NewMed Energy Management Ltd.

On behalf of: NewMed Energy – Limited Partnership

Annex A to the Board of Directors' Report

Figures regarding Leviathan Bond Ltd.

Further to Note 10B to the financial statements (Chapter C of this report) and to Part Five of the Board of Directors' Report, and following a tax ruling received by the Partnership immediately prior to the bond offering, below are financial figures which will be disclosed to the holders of the Leviathan Bond bonds.

Statements of Financial Position (Expressed in US$ Thousands)

	31.12.2022 Audited	31.12.2021 Audited
Assets:		
Current Assets:		
Short term Bank deposits	253,279	5
Loans to shareholders	499,603	-
Related parties	**	**
	752,882	5
Noncurrent Assets:		
Loans to shareholders	1,749,625	2,248,082
Long term bank deposits	-	100,160
	1,749,625	2,348,242
	2,502,507	2,348,247
Liabilities and Equity:		
Current Liabilities:		
Bonds	500,000	-
Related parties	153,279	165
	653,279	165
Noncurrent Liabilities:		
Bonds	1,750,000	2,250,000
Loans from shareholders	100,000	100,000
	1,850,000	2,350,000
Equity (Deficit)	(772)	(1,918)
	2,502,507	2,348,247

**** Less than $1,000**

Statements of Comprehensive Income (Expressed in US$ Thousands)

	For the year Ended 31.12.2022 Audited	For the year Ended 31.12.2021 Audited
Financial expenses	146,252	141,872
Financial income	(147,398)	(142,343)
Total comprehensive expenses (income)	(1,146)	(471)

SPONSOR FINANCIAL DATA REPORT[10]

	ITEM	YEAR ENDED 31.12.2022 QUANTITY/ACTUAL AMOUNT (IN USD$,000)
A.	Total Offtake (BCM)	11.4[11]
B.	Leviathan Revenues (100%)	2,524,741[12]
C.	Loss Proceeds, if any, paid to Revenue Account	-
D.	Sponsor Deposits, if any, into Revenue Account	-
E.	Gross Revenues (before Royalties)	1,103,503
F.	Overriding Royalties	
	(a) Statutory Royalties	(126,827)
	(b) Third Party Royalties	(50,304)
G.	Net Revenues	926,372
H.	Costs and Expenses:	
	(a) Fees Under the Financing Documents (Interest Income)	1,439
	(b) Taxes	-
	(c) Operation and Maintenance Expenses	(126,548)
	(d) Capital Expenditures	(122,573)
	(e) Insurance (income)	(9,149)
I.	Total Costs and Expenses (sum of Items H(a), (b), (c), (d) and (e))	(256,831)
J.	Total Cash Flows Available for Debt Service (Item G *minus* Item H)	669,541
K.	Total Cash Flow from operation (Item G minus Items H(c) and H(e)	790,675
L.	Total Debt Service	(217,025)[13]
M.	Total Distribution to the Sponsor	272,000

[10] 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.
[11] Gas sales from January 1, 2022 until December 31, 2022 for 100% of the Leviathan partners on an accrual basis.
[12] Gas sales from January 1, 2022 until December 31, 2022 for 100% of the Leviathan partners on an accrual basis.
[13] Including buyback of bonds by the sponsor of approx. $75 million.

Annex B to the Board of Directors' Report

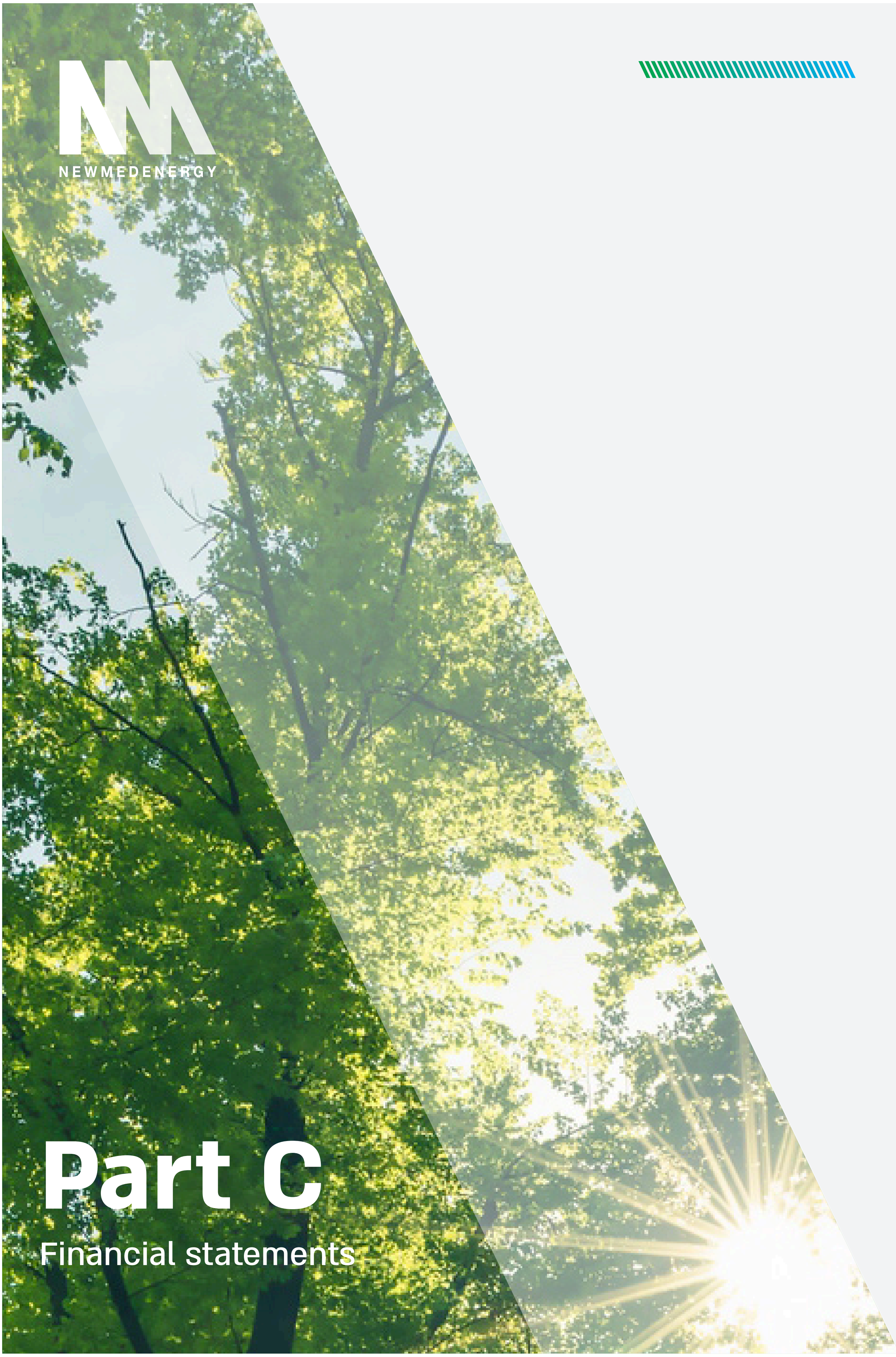
Summary of Data of a Valuation of Royalties from the Karish and Tanin Leases

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 financial statements (Chapter C of this report) 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, 2022
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. $320.8 million, which is included under other long-term assets of the Partnership and in the Partnership's short term receivables.
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:	Giza Singer Even 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 in the most prominent privatizations and the most important transactions in the Israeli market, which experience was gained thereby over the course of its 30 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 Gadi Beeri, Head of Economic Division and Corporate Finance and a senior executive at Giza Singer Even. Mr. Beeri has expertise and vast experience in corporate finance and financial consultancy. He holds a B.A. in Economics and an MBA from the Tel Aviv University. The Valuator has no personal interest in and/or dependence on the Partnership

Identification of the object of the valuation:	Royalties in respect of the sale of all of the interests in the Karish and Tanin leases.
	and/or NewMed Energy Management Ltd., the general partner of the Partnership (the "**General Partner**"), 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. Period of production from the Karish lease: October 1, 2022 to December 31, 2042; 2. Average annual rate of natural gas production from the Karish lease: approx. 3.68 BCM; average annual rate of condensate production from the Karish lease: approx. 4.56 million barrels; 3. Period of production of gas from the Tanin reservoir: January 1, 2030 to December 31, 2041; 4. Average annual rate of natural gas production from the Tanin lease: approx. 2.17 BCM; average annual rate of condensate production from the Tanin lease: approx. 0.37 million barrels;

Identification of the object of the valuation:	Royalties in respect of the sale of all of the interests in the Karish and Tanin leases.
	5. Royalty component cap rate: 10.5%; 6. Effective royalty rate to be paid to the State for the gas and the condensate: 11.25%; 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 the Partnership's forecast for Brent prices along the years of the forecast; 9. On March 23, 2022, Energean released an updated resource report of D&M (the "**Updated Report**"), a certified reserves and resources valuator, for the Karish and Tanin leases. According to the Updated Report, the gas quantity in the Karish reservoir is approx. 39.3 BCM and the quantity of the hydrocarbon liquids is approx. 54.2 MMBBL; the gas quantity in the Karish North reservoir is approx. 34.2 BCM and the quantity of the hydrocarbon liquids is approx. 36.9 MMBBL; and the gas quantity in the Tanin lease is approx. 26.1 BCM and the quantity of the hydrocarbon liquids is approx. 4.5 MMBBL. 10. Petroleum profit levy: According to the Petroleum Profit Taxation Law, 5771-2011; 11. Corporate tax rate: 23%.



Part C

Financial statements

March 27, 2023

To

The Board of Directors of the General Partner of NewMed Energy – Limited Partnership (the "Partnership")

19 Abba Eban, Herzliya

Dear Sir/Madam,

Re: Consent given simultaneously with the release of a periodic report in connection with the shelf prospectus of the Partnership (the "Offering Document")

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 27, 2023 on the Partnership's financial statements as of December 31, 2022 and 2021 and for each of the three years in the period ended December 31, 2022.

2. The Auditors' report of March 27, 2023 on the audit of components of internal control over financial reporting of the Partnership as of December 31, 2022.

Kost Forer Gabbay & Kasierer Certified Public Accountants	Ziv Haft Certified Public Accountants

NewMed Energy – Limited Partnership

Financial Statements as of December 31, 2022

in U.S. Dollars in Millions

This report is a translation of NewMed Energy - 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.

NewMed Energy – Limited Partnership

Financial Statements as of December 31, 2022

in U.S. Dollars in Millions

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Independent Auditors' Report to the Partners of NewMed Energy - 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 NewMed Energy – Limited Partnership **(**the "**Partnership**") as of December 31, 2022. These components of control were determined as explained in the paragraph below. The Board of Directors of the general partner and the Partnership's Management 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, 2022.

We have also audited, based on Generally Accepted Auditing Standards in Israel, the financial statements of the Partnership as of December 31, 2022 and 2021, and for each of the three years in the period ended December 31, 2022, and our report of March 27, 2023 included an unqualified opinion on the aforesaid financial statements.

Tel Aviv, March 27, 2023

Kost Forer Gabbay & Kasierer **Certified Public Accountants**	**Ziv Haft** **Certified Public Accountants**

Independent Auditors' Report to the Partners of NewMed Energy – Limited Partnership

We have audited the accompanying statements of financial position of NewMed Energy – Limited Partnership (the "**Partnership**") as of December 31, 2022 and 2021 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, 2022. The board of the general partner and the management of the Partnership 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 of the general partner and the management of the Partnership, 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, 2022 and 2021 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, 2022 in accordance with International Financial Reporting Standards (IFRS) and the provisions of the Securities Regulations (Annual Financial Statements), 5770-2010.

Key audit matters

Key audit matters are matters that were communicated, or should have been communicated, to the board of directors of the Partnership’s general partner, and which, in our professional judgement, were highly significant to the audit of the financial statements in the current period. These matters include, *inter alia*, any matter that: (1) refers or may refer to material sections or disclosures in the financial statements, and (2) our judgment in respect thereof was especially complicated, subjective or challenging. These matters will be addressed in our audit and the formation of our opinion regarding the financial statements as a whole. The communication of the following matters does not change our opinion regarding the financial statements as a whole and we are not using it as a means to provide a separate opinion regarding these matters or regarding the sections or disclosures to which they refer.

Evaluation of gas and condensate reserves

As described in Note 7 to the Partnership’s financial statements, the balance of investments in oil and gas assets as of December 31, 2022 is $2,547.2 million and the depletion costs for the investments in oil and gas assets for the year ended December 31, 2022 amounts to a total of $75.6 million.

According to the Partnership’s accounting policies, gas and oil assets are amortized in the depletion method based on the estimated amount of proved and probable reserves from said assets (2P).

Estimation of the gas and condensate reserves is a subjective process involving a significant degree of discretion based on the management's judgment and assumptions, via external experts having relevant knowledge and understanding regarding geological data, price estimation, future production costs, expected production rate and future development costs, if required.

Due to the extent of the impact of the estimate of gas and condensate reserves on the financial statements, and due to the judgments and subjectivity involved in the estimate as aforesaid, we identified the subject as a key audit matter. The investments in oil and gas assets, evaluation of reserves and depletion costs of the Partnership's oil and gas assets are described in Note 7 to the financial statements.

The audit procedures applied to address the key audit matter

The main procedures we applied to this key audit matter in the framework of our audit are as follows:

- Achieving an understanding of the Partnership's existing processes and procedures regarding the estimate of the evaluation of gas and condensate reserves, and auditing the planning and implementation of controls used in the process.
- Evaluating the qualifications of the experts on behalf of the Partnership, including their skill and objectivity in performing the gas and condensate estimate, and considering whether they have professional qualifications to carry out reserves estimates for oil and gas reservoirs.
- Checking the completeness of the data underlying the evaluation of the reserves, *inter alia*, by analyzing the key changes in 2022 and comparing the reserves estimated by the Partnership to, and checking their agreement with, the information included in the gas and condensate reserves report prepared by the external experts on behalf of the Partnership.
- Checking that the updated estimates of gas and condensate reserves were properly included in the accounting treatment for determination of the depletion rate of the oil and gas assets.
- Checking the agreement of the calculations and adequacy of disclosures in the Partnership's financial statements.

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, 2022 and our report as of March 27, 2023 included an unqualified opinion on the effective maintenance of such components.

Tel Aviv, March 27, 2023

Kost Forer Gabbay & Kasierer Certified Public Accountants	Ziv Haft Certified Public Accountants

NewMed Energy – Limited Partnership

Statements of Financial Position (Dollars in millions)

	Note	31.12.2022	31.12.2021
Assets:			
Current assets:			
Cash and cash equivalents	3	22.4	220.2
Short-term investments and deposits	4	395.9	120.7
Trade receivables	22G	199.0	152.5
Trade and other receivables	5	134.1	87.3
Current taxes receivable	20B	19.9	-
		771.3	580.7
Non-current assets:			
Investments in oil and gas assets	7	2,547.2	2570.4
Investments in a company accounted for at equity	6	59.7	62.8
Long-term deposits	4	0.5	100.7
Other long-term assets	8	560.3	535.4
		3,167.7	3,269.3
		3,939.0	3,850.0
Liabilities and equity:			
Current liabilities:			
Current maturities for bonds	10	424.8	-
Provision for tax and balancing payments	13D	-	86.2
Declared profits for distribution	13C	50.0	-
Trade and other payables	9	96.9	270.7
Other short-term liabilities	11	9.9	27.6
		581.6	384.5
Non-current liabilities:			
Bonds	10	1,731.0	2,224.8
Deferred taxes	20	269.8	207.8
Other long-term liabilities	11	69.2	94.4
		2,070.0	2,527.0
Equity:	13		
Partners' equity		154.8	154.8
Capital reserves		(29.9)	(30.7)
Retained earnings		1,162.5	814.4
		1,287.4	938.5
		3,939.0	3,850.0

The attached notes constitute an integral part of the financial statements.

March 27, 2023			
Date of approval of the Financial Statements	Gabi Last Chairman of the Board	Yossi Abu CEO	Tzachi Habusha VP Finance

NewMed Energy – Limited Partnership

Statements of Comprehensive Income (Dollars in millions)

	Note	For the year ended on 31.12.2022	31.12.2021	31.12.2020
Revenues:				
From natural gas and condensate sales	14	1,143.9	882.5	587.1
Net of royalties	15	172.0	128.7	86.3
Revenues, net		**971.9**	**753.8**	**500.8**
Expenses and costs:				
Cost of production of natural gas and condensate	16	134.1	118.4	89.7
Depreciation, depletion and amortization expenses	7	131.0	113.1	79.4
Other direct expenses	17	5.2	4.2	3.4
G&A	18	19.7	17.3	14.6
Total expenses and costs		**290.0**	**253.0**	**187.1**
The Partnership's share in the losses of a company accounted for at equity	6	(3.1)	(4.5)	(7.7)
Operating profit		**678.8**	**496.3**	**306.0**
Financial expenses	19	(155.3)	(211.3)	(231.8)
Financial income	19	71.1	31.4	88.0
Financial expenses, net		(84.2)	(179.9)	(143.8)
Profit before income taxes		**594.6**	**316.4**	**162.2**
Taxes on income	20	(116.0)	(207.8)	-
Profit from continuing operations		**478.6**	**108.6**	**162.2**
Profit (loss) from discontinued operations		(13.2)	151.7	203.1
Profit from the sale of natural gas and oil assets		4.3	144.6	-
Total profit (loss) from discontinued operations	**7C1**	**(8.9)**	**296.3**	**203.1**
Net income		**469.7**	**404.9**	**365.3**
Other comprehensive profit from continuing operations:				
Amounts which may subsequently be reclassified to profit or loss:				
Loss from cash flow hedging transactions		-	-	(4.7)
Carried to profit or loss in respect of cash flow hedging transactions		-	-	7.4
		-	-	2.7
Comprehensive income from continuing operations		**478.6**	**108.6**	**164.9**
Other comprehensive income (loss) from discontinued operations:				
Amounts which shall not subsequently be reclassified to profit or loss:				
Profit (loss) from investment in equity instruments designated for measurement at fair value through other comprehensive income		-	13.6	(29.3)
Comprehensive income (loss) from discontinued operations		**(8.9)**	**309.9**	**173.8**
Total comprehensive income		**469.7**	**418.5**	**338.7**
Basic and diluted profit (loss) per participation unit (in Dollars):				
From continuing operations		0.408	0.093	0.138
From discontinued operations		(0.008)	0.252	0.173
Profit per participation unit		0.400	0.345	0.311
Number of participation units which is weighted 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.

NewMed Energy – Limited Partnership –

Statements of Changes in the Partnership's Equity (Dollars in millions)

	The Partnership's equity	Capital reserve for equity-based financial instruments at fair value against other comprehensive income	Capital reserve for cash flow hedging transactions	Other capital reserves	Retained earnings	Total
Balance as of December 31, 2019	**154.8**	**(41.3)**	**(2.7)**	**19.1**	**683.6**	**813.5**
Changes in the year ended December 31, 2020:						
Net profit	-	-	-	-	365.3	365.3
Other comprehensive income (loss)	-	(29.3)	2.7	-	-	(26.6)
Total comprehensive income (loss)	-	(29.3)	2.7		365.3	338.7
Profits distributed (Note 13C)	-	-	-	-	(65.7)	(65.7)
Declared tax and balancing payments (Note 13D)	-	-	-	-	(36.5)	(36.5)
Tax advances on account of the tax owed by the participation unit holders (Note 13D)	-	-	-	-	(55.2)	(55.2)
Capital reserve for benefits from a control holder (Note 13G)	-	-	-	2.9	-	2.9
Balance as of December 31, 2020	**154.8**	**(70.6)**	**-**	**22.0**	**891.5**	**997.7**
Changes in the year ended December 31, 2021:						
Net profit	-	-	-	-	404.9	404.9
Other comprehensive income	-	13.6	-	-	-	13.6
Total comprehensive income	-	13.6	-	-	404.9	418.5
Profits distributed (Note 13C)	-	-	-	-	(200.2)	(200.2)
Declared tax and balancing payments (Note 13D)	-				(85.1)	(85.1)
Tax advances on account of the tax owed by the participation unit holders (Note 13D)	-	-	-	-	(227.9)	(227.9)
Tax revenues for previous years	-	-	-	-	31.2	31.2
Capital reserve for benefits from a control holder (Note 13G)	-	-	-	4.3	-	4.3
Balance as of December 31, 2021	**154.8**	**(57.0)**	**-**	**26.3**	**814.4**	**938.5**
Changes in the year ended December 31, 2022:						
Comprehensive income	-	-	-	-	469.7	469.7
Profits distributed (Note 13C)	-	-	-	-	(100.3)	(100.3)
Declared profits for distribution (Note 13C)					(50.0)	(50.0)
Balancing payments for previous years (Note 20A5)	-	-	-	-	2.1	2.1
Tax advances receivable for previous years (Note 13D)	-	-	-	-	26.6	26.6
Participation unit-based payment (Note 13H)	-	-	-	0.8	-	0.8
Balance as of December 31, 2022	**154.8**	**(57.0)**	**-**	**27.1**	**1,162.5**	**1,287.4**

The attached notes constitute an integral part of the financial statements.

NewMed Energy – Limited Partnership

Statements of Cash Flows (Dollars in millions)

	31.12.2022	31.12.2021	31.12.2020
Cash Flows - Current Operations:			
Net profit	**469.7**	**404.9**	**365.3**
Adjustments for:			
Depreciation, depletion and amortization	137.6	133.1	140.3
Change in fair value of financial derivatives, net	-	-	(2.9)
Taxes on income	59.5	207.8	-
Update of asset retirement obligation	(34.3)	(46.4)	(0.6)
Revaluation of short-term and long-term investments and deposits	(0.2)	-	2.4
Revaluation of liability due to participation unit-based payment (Note 13H)	1.0	-	-
Benefit from a control holder included in expenses against a capital reserve	-	4.3	2.9
Revaluation of other long-term assets	(66.4)	(43.0)	(84.8)
The Partnership's share in the losses of a company accounted for at equity, net	3.1	4.5	7.7
Income from the sale of oil and gas assets (Annex C)	(4.3)	(144.6)	-
Changes in assets and liabilities items:			
Increase in trade receivables	(46.5)	(8.0)	(98.9)
Decrease (increase) in trade and other receivables (including operator of joint ventures)	(4.6)	(15.3)	23.3
Decrease (increase) in other long-term assets	1.1	(6.8)	(5.7)
Decrease in trade and other payables (including operator of joint ventures)	(5.2)	(44.6)	(21.1)
Increase (decrease) in oil and gas profit levy liability	(5.8)	8.5	(1.4)
Increase (decrease) in another long-term liability	-	(0.7)	2.2
	35.0	**48.8**	**(36.3)**
Net cash deriving from current operations	**504.7**	**453.7**	**328.7**
Cash Flows - Investment Activity:			
Investment in oil and gas assets	(98.5)	(30.4)	(165.1)
Proceeds from the sale of oil and gas assets (Annex C)	14.9	954.9	-
Investment in fixed assets	(0.4)	-	-
Investment in other long-term assets	(28.4)	(34.4)	(14.6)
Proceeds from the disposition of financial assets	-	30.6	-
Repayment of loans given	12.5	14.3	14.8
Decrease (increase) in short-term deposits and investments, net	(175.0)	48.6	(105.9)
Long-term deposit in bank deposits	-	-	(100.0)
Repayment of long-term bank deposits	-	-	100.0
Decrease (increase) in other receivables – operator of the joint ventures	1.4	(1.6)	28.9
Net cash deriving from (used for) investment activity	**(273.5)**	**982.0**	**(241.9)**
Cash Flows - Financing Activity:			
Issuance of bonds (net of issuance costs)	-	-	2,217.3
Receipt of long-term loans from banking corporations (net of debt-raising costs)	-	-	103.8
Repayment of long-term loans from banking corporations	-	-	(2,050.0)
Distributed profits	(100.3)	-	-
Distributed profits, balancing payments and tax for the period up to and including 2021	(99.1)	(236.6)	(99.1)
Payments on account of the tax liable by participation unit holders for the period up to and including 2021	(170.2)	(16.8)	(35.0)
Reimbursement received from income tax for previous years	15.1	3.2	-
Early redemption of issued bonds	(74.6)	(19.9)	(4.9)
Repayment of bonds	-	(1,015.4)	(320.0)
Net cash generated by (used in) financing activity	**(429.1)**	**(1,285.5)**	**(187.9)**
Increase (decrease) in cash and cash equivalents	(197.8)	150.2	(101.1)
Cash and cash equivalents balance at the beginning of the year	220.2	70.0	171.1
Cash and cash equivalents balance at the end of the year	22.4	220.2	70.0
Annex A - Finance and investment activity not involving cash flows:			
Investments in oil and gas assets against liabilities, net	3.6	37.5	42.3
Investments in other long-term assets against liabilities, net	5.3	-	-
Declared distributable profits, balancing payments and tax	50.0	86.2	36.4
Annex B - Additional information on cash flows:			
Interest paid (including capitalized interest)	143.3	193.5	257.0
Interest received	7.3	4.2	1.7
Proceeds not yet received from the sale (see Annex C and Note 7C1)	-	10.5	-
Taxes paid	81.6	-	-

The attached notes constitute an integral part of the financial statements.

NEWMEDENERGY

NewMed Energy – Limited Partnership

Statements of Cash Flows (Dollars in millions)

	For the year ended		
	31.12.2022	31.12.2021	31.12.2020
Annex C – sale of rights in the Tamar and Dalit Leases (see also Note 7C1C)			
Includes the following assets and liabilities as of the selling date:			
Working capital, net	-	10.6	-
Oil and gas assets	-	830.0	-
Other long-term assets	-	21.3	-
Oil and gas asset retirement obligations	-	(40.9)	-
Total assets net of liabilities	**-**	**820.9**	**-**
Proceeds received from the sale	14.8	954.9	-
Proceeds not yet received from the sale	-	10.5	-
Profit from sale of oil and gas assets	**14.8**	**144.6**	**-**

The attached notes constitute an integral part of the financial statements.

NEWMEDENERGY

Note 1 – General:

A. NewMed Energy – Limited Partnership[1] (the "**Partnership**") was founded according to a partnership agreement signed on July 1, 1993 between NewMed Energy Management Ltd.[2] as general partner of the first part (the "**General Partner**"), and NewMed Energy Trusts Ltd. [3] as a limited partner of the second part (the "**Limited Partner**"), as amended from time to time (the "**Partnership Agreement**").

The ongoing management of the Partnership is carried out by the General Partner under the supervision of the supervisors, Fahn Kanne & Co., Accountants, together with Keidar Supervision & Management (jointly: the "**Supervisors**" or the "**Supervisor**"). On July 1, 1993, the Limited Partner and the Supervisor signed a trust agreement, as amended from time to time (the "**Trust Agreement**"), which confers on the Supervisor powers of supervision over the Partnership's management by the General Partner, as well as powers of supervision over the fulfillment of the Limited Partner's obligations to the unit holders.

The parent company of the General Partner is Delek Energy Systems Ltd. (the "**Parent Company**" and/or "**Delek Energy**"), a private company wholly owned by 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 operates in the energy field and its primary business is exploration, development, production and marketing of natural gas, condensate and oil in Israel and in Cyprus, and promotion of various natural gas-based projects, with the aim of increasing the volume of the sales of natural gas produced by the Partnership. At the same time, the Partnership is exploring various business opportunities in the field of exploration, development, production and marketing of natural gas, condensate and oil in additional countries (for further details regarding an exploration license in Morocco, see Note 7C5 below), and is examining and promoting possibilities for investments in projects in the field of renewable energy, within the collaboration with Enlight Renewable Energy Ltd. ("**Enlight**") (see Note L14 below), and is examining possible entry into the field of hydrogen, including blue hydrogen, which is produced from natural gas and can be a low-carbon substitute for energy consumers.

C. The Partnership's main petroleum asset, as of the date of approval of the financial statements, is holdings of 45.34% (out of 100%) of the Leviathan reservoir, the piping of gas from which commenced in December 2019. The Leviathan reservoir currently supplies natural gas to a number of customers in the Israeli and regional market. In addition, the Partnership holds rights in the Aphrodite reservoir that was discovered in the area of Block 12 in Cyprus ("**Aphrodite**" or "**Block 12**"), and in other petroleum assets, as specified in Note 7 below.

[1] The Partnership's previous name was Delek Drilling – Limited Partnership. On February 21, 2022, the Partnership's name was changed to its current name.

[2] The General Partner's previous name was Delek Drilling Management (1993) Ltd. On February 24, 2022, the General Partner's name was changed to its current name.

[3] The Limited Partner's previous name was Delek Drilling Trusts Ltd. On February 24, 2022, the Limited Partner's name was changed to its current name.

Note 1 - General (Cont.):

D. On March 27, 2023, the General Partner received a non-binding indicative offer (the "**Offer**") from Abu Dhabi National Oil Company (ADNOC) P.J.S.C. and BP Exploration Operating Company, two international energy companies (collectively: the "**Consortium**"), regarding a possible transaction in which the Consortium will purchase for cash all of the issued unit capital held by the public (~45%) and will purchase approx. 5% of the issued unit capital from Delek Group, subject, such that after the closing of the transaction, the Consortium and Delek Group will each hold 50% of the equity and controlling interests in the Partnership, by way of approval of an arrangement under Section 350 of the Companies Law, 5759-1999 (the "**Companies Law**"). The Consortium's Offer, which, as aforesaid, is non-binding and subject to conditions, is payment of ILS 12.05 per unit purchased. This price reflects a premium of approx. 72% relative to the closing price of the units on TASE on March 26, 2023 (ILS 6.996) or a premium of approx. 76% and approx. 60% relative to the average closing price of the units on TASE in the 30 and 90 trading days preceding the date of the Offer, respectively. The Offer included conditions which the Consortium wishes to agree on with Delek Group regarding the joint control of the Partnership after the closing of the transaction, as well as additional conditions for the transaction, including the completion of due diligence, obtaining detailed agreements with Delek Group on all relevant issues and obtaining all of the other required approvals and consents. It is clarified that the Consortium may withdraw and cancel the Offer at any time and for any reason.

On March 27, 2023, the General Partner's board held a discussion regarding the Consortium's Offer, and in view of Delek Group's personal interest in the transaction and the material nature of the transaction, decided to appoint the audit committee, comprised solely of 3 external directors (the "**Committee**"), to explore and resolve any issue pertaining to the purchase of the publicly held units in the offered transaction, and to take any and all actions required for the exercise of the Committee's powers. In addition, the Committee was authorized to decide also not to perform the transaction or to make its approval conditional or to request, obtain and explore alternative offers, all as it shall deem fit.

If the required agreements are reached with Delek Group and the Committee's recommendation is received to approve the transaction, then approval of the transaction by way of an arrangement under Section 350 of the Companies Law, and the closing of the transaction and performance thereof, will be subject to the approval of the court, which will supervise the arrangement, approval of the arrangement by the meeting of the unitholders by a majority of 75% of all of the unitholders (including Delek Group and affiliates thereof), and approval by an ordinary majority of the public unitholders (without Delek Group and affiliates thereof), and receipt of the other regulatory approvals, and consents from third parties, as required for the closing of a transaction of this type. It is emphasized that, as of the report approval date, there is no certainty that it will be possible to obtain all of the said approvals and consents, and consequently the chances of the closing of the transaction are uncertain.

Note 1 - General (Cont.):

E. According to the provisions of the Gas Framework that, *inter alia*, required the Partnership to sell its entire holdings in the Tamar and Dalit Leases (the "**Tamar Project**"), on September 2, 2021, the Partnership engaged in an agreement for the sale of its remaining interests at the rate of 22% in the Tamar Project to Tamar Investment 1 RSC Limited and Tamar Investment 2 RSC Limited[4] (in this section: the "**Buyers**" and the "**Agreement**", as applicable). On December 9, 2021, the transaction was closed and the Partnership received the sale proceeds in the sum of approx. $955[5] million. The results were classified in the financial statements as discontinued operations (see also Note 7C1).

F. 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 operators of the joint ventures in Israel, Chevron Mediterranean Ltd. ("**Chevron**" or the "**Operator**") and S.O.A. Energy Israel Ltd. ("**SAO**") and the operator of the joint venture in Cyprus, Chevron Cyprus Ltd. ("**Chevron Cyprus**").

G. On February 24, 2022, the Russian army invaded Ukraine as part of an initiated campaign which included mobilizing ground forces, alongside air and artillery assaults. As a result, the United States and the member states of the European Union imposed a series of economic punitive measures against Russia, which included, among others, sanctions on trade with Russia and Russian seniors, a decision to suspend the completion of the Nord Stream 2 project, which is intended to double the volume of gas exported from Russia to Germany, discontinuation of some collaboration with Russian entities by international companies, including significant companies in the fields of natural gas and oil production, and more. Subsequently, the sale of natural gas from Russia to the European market was significantly reduced, and considerable shortage of natural gas was created in countries that consumed significant quantities of natural gas from Russia. Furthermore, a sharp decline was recorded in the scope of sales of oil from Russia to western countries.

[4] To the best of the Partnership's knowledge, the Buyers are SPCs that were established for the purpose of the transaction and are held (indirectly) by MDC Oil & Gas Holding Company LLC, a corporation of the Mubadala Investment Company PJSC group, a company owned by the Government of Abu Dhabi.

[5] As of the date of approval of the financial statements, the final settlement of accounts for the object of sale was completed, an additional sum of approx. $14.8 million was transferred by the Buyers, such that the total consideration received for the object of sale is $969 million.

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 ("**IFRS**").

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 reporting 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 and Cash equivalents:

Cash equivalents are considered as highly liquid investments, including unrestricted short-term bank deposits with an original maturity of three months or less from the date of investment or with a maturity of more than three months, but which are redeemable on demand without penalty and which form part of the Partnership's cash management.

H. Short-term deposits:

Deposits in banking corporations with an original term maturity of more three months but shorter than one year on the date of the investment and which do not meet the definition of cash equivalents. The deposits are presented in accordance with the terms of their deposit.

Note 2 - Significant Accounting Policies (Cont.):

I. Long-term deposits:

Deposits in banking corporations with an original term maturity of more twelve months on the date of the investment and which do not meet the definition of cash equivalents. The deposits are presented in accordance with the terms of their deposit.

J. 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.):

J. 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 statement of profit or loss.

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 -
a. 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
b. 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 forecasted credit loss – for the remaining life of the instrument.
The Partnership applies the expedient 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 is determined on the report date that the instrument has low credit risk, for example when the instrument has an external "investment grade" rating.
With respect to trade receivables and other receivables, the Partnership applies the lenient approach in examining a provision according to the remaining life of the asset.
The impairment with respect to debt instruments measured according to a depreciated cost shall be carried to profit or loss against a provision while the impairment 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.):

J. 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, between the Partnership and the same lender, 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, between the Partnership and the same lender, 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.):

J. 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:

Derivatives embedded in financial assets are not 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 or loss while the ineffective part is immediately carried to profit or loss.

Other comprehensive profit or loss is carried to profit or loss when the 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.

Note 2 - Significant Accounting Policies (Cont.):

J. Financial instruments (Cont.):

8) Derivative financial instruments for hedging (protection) purposes (Cont.):

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.

K. Provisions:

A provision 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, economic resources are 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 L2 below regarding costs in respect of asset retirement obligations.

Onerous contracts

Provision for onerous contracts is recognized when the benefits expected to be received by the Partnership under the contracts are lower than the inevitable costs of meeting the contractual obligations. The provision is measured according to the present value of the projected cost of exiting from the contract and the present value of the net projected cost of fulfilling the contract, whichever is lower.

Note 2 - Significant Accounting Policies (Cont.):

L. 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 and are presented in the statement of financial position, subject to the performance of an examination of impairment, from the "exploration and appraisal assets" item to the "oil and gas assets" item, 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, pipelines for the transmission of gas from the wells to the production platform and from the production platform to the onshore terminal, 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, are amortized according to the production unit method and based on proved + probable reserves ("**2P**"). In the Partnership's estimation, depreciation of the oil and gas assets based on proved and probable reserves (2P) fairly reflects the pattern of projected use of the asset, enhances the comparativeness between the Partnership's results and the results of similar companies in Israel and the world (including 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.

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.

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 international accounting standards IAS 36 and IFRS 6 (see Paragraph P below).

Note 2 - Significant Accounting Policies (Cont.):

L. Expenses of oil and gas exploration, development of proved reservoirs and investment in oil and gas assets (Cont.):

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 1E 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, insofar as the asset was fully amortized, these changes shall be attributed directly to depreciation, depletion and amortization expenses in the statement of comprehensive income. 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.

M. 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.

N. A non-current asset or group of assets held for sale and discontinued operations:

A non-current asset or group of assets are classified as held for sale when their settlement is done mainly through a sale transaction and not through ongoing use. The aforesaid occurs where the assets are available for immediate sale in their "as is" condition, the Partnership has an obligation to sell, there is a plan to identify a buyer, and it is highly probable that the disposition will be completed within one year from the date of the classification. These assets are not depreciated from the date of their initial classification as such, and are presented as current assets separately, according to the lower of their value in the financial statements and their fair value net of sale costs. Other comprehensive income (loss) in respect of a non-current asset or group of assets classified as held for sale is presented separately under equity.

Where the Partnership changes the planning of the sale such that recovery of the asset will not be performed through a sale transaction, it ceases to classify the asset as held for sale and measures it according to the lower of the book value thereof had it not been classified as held for sale or according to the recoverable amount of the asset on the date of adoption of the decision not to sell.

Note 2 – Significant Accounting Policies (Cont.):

N. A non-current asset or group of assets held for sale and discontinued operations (Cont.):

Discontinued operations are a component of the Partnership which constitutes operations that have been disposed of or are classified as held for sale. The results of operations relating to discontinued operations (including comparison figures) are presented separately in profit or loss (see Note 7C1 below).

O. Recognition of income:

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, net of the royalties collected in favor of the State, in favor of related parties, and in favor of 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.

<u>Costs of obtaining a contract</u>

In order to obtain some of the Partnership's contracts with its customers, it incurs incremental costs in obtaining the contract. Costs incurred in obtaining the contract with the customer which would not have been incurred if the contract had not been obtained and which the Partnership expects to recover, are recognized as an asset and amortized on a systematic basis that is consistent with the provision of the services under the specific contract. The Partnership recognizes, in profit or loss, an impairment loss in respect of costs of fulfilling a contract, when the carrying amount of the asset exceeds the remaining amount of consideration that the Partnership expects to receive for the goods or services to which the asset relates, less the costs that relate to providing those goods or services and that have not yet been recognized as expenses.

P. 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.

Note 2 – Significant Accounting Policies (Cont.):

P. Impairment of non-financial assets (Cont.):

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.

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.

Q. 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 and probable Gas Reserves are amortized according to the depletion method as stated in Section L1(e) 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.

Note 2 – Significant Accounting Policies (Cont.):

Q. Critical accounting estimates and judgements (Cont.):

Evaluation of the proved and probable 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 for the settlement of the liability are based on estimation by the management of the General Partner of the Partnership, which relies, *inter alia*, on opinions of independent professional consultants and are examined periodically to ensure the fairness of such estimations.

Claims and legal proceedings – 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 – Pursuant to the Taxation of Profits and Natural Resources Law, 5771-2011 (the "**Levy**" or the "**Taxation of Profits and Natural Resources Law**"), starting from 2020, 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 (see also Note 20C below). In accordance with the estimates made by the Partnership, as of December 31, 2022, the Partnership recorded a provision on its books for payment of a levy for 2020-2021 for the Tamar Project. 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.

Note 2 – Significant Accounting Policies (Cont.):

Q. Critical accounting estimates and judgements (Cont.):

Deferred taxes – Deferred taxes are calculated in respect of temporary differences between the amounts included in the financial statements and the amounts taken into account for tax purposes. In calculating the deferred tax liability, management judgment is required to determine the amount of deferred tax liabilities that can be recognized, based upon the timing and level of future taxable profits, its source and the tax planning strategy. According to changes in these assumptions, the company will create or cancel recognition of deferred taxes.

R. 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.
   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 most advantageous 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.
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.

Note 2 – Significant Accounting Policies (Cont.):

S. 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 continuing operations, which is attributed to the Participation Unit Holders in the Partnership, in the event that such profit is presented.

T. Liability due to 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 calculation of the Partnership's liability for employee benefits is made in accordance with a valid employment agreement and is based on the employee's salary and term of employment which establish the right to severance pay.

   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, if any, the amount that is required to be deposited concurrently with receipt of the work services from the employee.

U. Participation unit-based payment:

Some of the Partnership's employees are entitled to benefits by way of participation unit-based payment that is settled in equity instruments and some of the employees are entitled to benefits by way of participation unit-based payment that is settled in cash and measured on the basis of increases in the value of the Partnership's participation units.

Note 2 - Significant Accounting Policies (Cont.):

U. Participation unit-based payment (Cont.):

Equity-settled transactions

The cost of equity-settled transactions with employees is measured according to the fair value of the equity instruments at the date of grant. Fair value is determined using a standard option pricing model. The cost of equity-settled transactions is recognized in profit or loss together with a corresponding increase in equity over the period in which the service and/or the performance conditions are fulfilled and ending on the date of entitlement to renumeration of the relevant employees (the "**Vesting Period**"). The cumulative expense recognized for equity-settled transactions at the end of each reporting date until the vesting date reflects the extent to which the Vesting Period has expired and the Partnership's best estimate of the number of equity instruments that will ultimately vest. No expense is recognized for awards that do not ultimately vest, other than awards whose vesting is independent of market conditions, which are treated as vested awards irrespective of whether market conditions are satisfied, provided that all other vesting conditions (performance and/or service) are satisfied. When the Partnership modifies the terms of an equity-settled award, an additional expense is recognized beyond the original expense that was calculated for any modification that increases the total fair value of the compensation that was awarded or is otherwise beneficial to the employee, according to the fair value at the date of the modification. A cancelled equity-settled award is treated as if vested as of the date of the cancellation and the expense that has not yet been recognized for the award is immediately recognized. However, if the cancelled award is substituted by a new award and is designated as a substitute award as of its date of grant, the cancelled award and the new award shall both be treated as a modification of the original award, as described above.

Cash-settled transactions

The cost of a cash-settled 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.

V. Benefit from control holders:

The Partnership records expenses in the statements of comprehensive income against a capital reserve for benefits received from the control holder. For further details see Note 13G below.

W. Taxes on income:

The financial statements include, starting from 2022, current income taxes expenses, since up to and including 2021, the tax liability on the Partnership's profits applies to its partners. Income tax payments made by the Partnership for the period up to and including 2021 are on account of the tax for which the holders of the Partnership's participation units are liable, and were deducted from the retained earnings item of the Partnership's equity. Following an amendment to the Income Tax Regulations that was published during 2021, starting from the 2022 tax year, the tax regime applicable to the Partnership has changed such that is taxed as a company. See Note 20A below.

Note 2 - Significant Accounting Policies (Cont.):

W. Taxes on income (Cont.):

Therefore, as of December 31, 2021, the Partnership recognized a deferred tax liability due to temporary differences that will reverse after January 1, 2022. Furthermore, starting from January 1, 2022, the Partnership recognized current tax expenses in the statement of comprehensive income.

Current taxes

The current tax liability is measured using the tax rates and tax laws that have been enacted or substantively enacted by the reporting date as well as adjustments required in connection with the tax liability in respect of previous years.

Deferred taxes

Deferred taxes are computed in respect of temporary differences between the carrying amounts in the financial statements and the amounts attributed for tax purposes. Balances of the deferred taxes are measured at the tax rate that is expected to apply when the asset is realized or the liability is settled, based on tax laws that have been enacted or substantively enacted by the reporting date.

Deferred taxes are reviewed at each reporting date according to their usage probability. Deductible carried-forward losses and temporary differences for which deferred tax assets had not been recognized, are reviewed at each reporting date and a corresponding deferred tax asset is recognized therefor if their utilization is probable. For the purpose of determining the amount of the deferred taxes, management judgment is required, based upon the timing, amount of the projected taxable income, the source of the taxable income and the tax planning strategy. According to changes in these assumptions, the Company creates or reverses recognition of deferred taxes.

Taxes that would apply in the event of the disposal of investments in investees have not been taken into account in computing deferred taxes, as long as the disposal of the investments in investees is not probable in the foreseeable future. Also, deferred taxes that would apply in the event of distribution of earnings by investees as dividends have not been taken into account in computing deferred taxes, since the distribution of dividends does not involve an additional tax liability or since it is the Company's policy not to initiate distribution of dividends from a consolidated company that would trigger an additional tax liability.

Taxes on income that relate to distributions of an equity instrument and to transaction costs of an equity transaction are accounted for pursuant to IAS 12.

X. **Oil and gas profit levy:**

The Partnership includes, in the financial statements, expenses in respect of its levy payment liability under the Taxation of Profits and Natural Resources. The Levy is calculated for each project separately.

The Levy is treated in accordance with the interpretation of IFRIC No. 21 by the International Financial Reporting Interpretations Committee – "Levies" ("**IFRIC 21**"). 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).

Note 2 - Significant Accounting Policies (Cont.):

Y. Leases:

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. In measuring the lease liability, the Partnership chose to apply the practical expedient provided in the International Financial Reporting Standard No. 16 – Leases (**IFRS 16**) 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.

With respect to the contracts in which the Operator engages in the context of the joint ventures, the Partnership reached the conclusions that in view of the nature of the Operator's engagement with lessors and the joint operating agreement signed in connection with the leases ("**JOA**"), such contracts do not meet the definition of a lease according to the provision of IFRS 16 in the Partnership.

Z. 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.

Note 2 - Significant Accounting Policies (Cont.):

Z. An investment treated according to the equity method (Cont.):

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.

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 "**Original Amendment**"). In October 2022, the IASB released a subsequent amendment to the aforesaid amendment (the "**Subsequent Amendment**").

   The Subsequent Amendment determines that:

   a. Only financial covenants which must be fulfilled by an entity on or before the end of the reporting period shall affect the classification of the liability as a current liability or non-current liability. In the case of liabilities for which the fulfillment of financial covenants is examined within the 12 months subsequent to the report date, the disclosure should be made in a manner enabling the users of the financial statements to assess the risks entailed by that liability. In other words, the Subsequent Amendment provides that the following should be disclosed: the liability's book value, information about the financial covenants and facts and circumstances as of the end of the reporting period which may lead to the conclusion that the entity may struggle to meet the financial covenants.
   b. The Original Amendment determined that a right to convert a liability shall affect the classification of the entire liability as current or non-current, other than in cases where the conversion component is equity-based.

      The Original Amendment and the Subsequent Amendments were applied to annual periods beginning on or after January 1, 2024. Earlier application is permitted. In the Partnership's estimate, such amendment will not have a material effect on the Partnership's financial statements.

2. Amendment to IAS 8 Accounting Policies, Changes in Accounting Estimates and Errors

   In February 2021, the IASB published an amendment to IAS 8: Accounting Policies, Changes in Accounting Estimates and Errors (the "**Amendment**"). The purpose of the Amendment is to provide a new definition of the term "accounting estimates".

   Accounting estimates are defined as "monetary amounts in the financial statements that are subject to measurement uncertainty". The Amendment clarifies what changes to accounting estimates are and how they differ from changes to the accounting policy and error corrections.

Note 2 – Significant Accounting Policies (Cont.):

AA. Disclosure on new IFRS in the period preceding their application (Cont.):

2. Amendment to IAS 8 Accounting Policies, Changes in Accounting Estimates and Errors (Cont.):

   The Amendment will be applied prospectively to annual periods commencing on January 1, 2023, and applies to changes in the accounting policy and accounting estimates occurring at the beginning of such period or thereafter. In the Partnership's estimate, such amendment will not have a material effect on the Partnership's financial statements.

3. Amendment to IAS 12 Income taxes
   In May 2021, the IASB published an amendment to IAS 12: Income Taxes ("**IAS 12**") that narrows the applicability of the "initial recognition exemption" of deferred taxes set forth in Section 15 and 24 of IAS 12 (the "**Amendment**"). Under the recognition of deferred tax assets and liabilities provisions, IAS 12 exempts the recognition of deferred tax assets and liabilities in respect of certain temporary differences arising from the initial recognition of assets and liabilities in certain transactions. This exception is referred to as the 'initial recognition exception'. The Amendment narrows the applicability of the 'initial recognition exception' and clarifies that it does not apply to the recognition of deferred tax assets and liabilities arising from a transaction that is not a business combination and which creates equal positive and negative temporary differences, even if they meet the other conditions of the exception. The Amendment will be applied for annual periods beginning on or after January 1, 2023. Early application is possible. With respect to lease transactions and recognition of liability due to liquidation and recovery – the Amendment will be applied starting from the earliest reporting period presented in the financial statements in which the Amendment was first applied, while recording the cumulative effect of the first application to the opening balance of the retained earnings (or other equity component, if relevant) as of such date.
   In the Partnership's estimation, the aforesaid Amendment is not expected to have a material effect on the Partnership's financial statements.

4. Amendment to IAS 1, Accounting Policies Disclosure
   In February 2021, the IASB released an amendment to IAS 1: Presentation of Financial Statements (the "**Amendment**"). According to the Amendment, companies will be required to disclosure their material accounting policies, instead of the requirement to disclose their significant accounting policies. One of the main reasons for the Amendment is that the term "significant" is not defined in the IFRS, while the term "material" is defined in various standards and specifically in the IAS 1. The Amendment will be applied to annual periods commencing on or after January 1, 2023. Earlier application is permitted. In the Partnership's estimation, the aforesaid Amendment is not expected to have a material effect on the Partnership's financial statements.

Notes to the Financial Statements as of December 31, 2022 (Dollars in millions)

Note 3 – Cash and Cash Equivalents:

Composition:

	Interest rate as of 31.12.2022	31.12.2022	31.12.2021
In Dollars:	%		
Cash in banks		19.8	194.1
Deposits in banks		-	20.0
		19.8	**214.1**
In ILS:			
Cash in banks		0.2	0.2
Deposits in banks	1.5	2.4	5.9
		2.6	6.1
Total		**22.4**	**220.2**

Note 4 – Short-Term and Long-Term Investments and Deposits[6]:

Composition:

	Interest rate as of 31.12.2022	31.12.2022	31.12.2021
	%		
Under current assets:			
ETF		-	20.0
Deposits in banks:			
in dollars	4.1-4.3	395.7	100.5
in ILS		0.2	0.2
		395.9	**120.7**
Under non-current assets:			
Deposits:			
in dollars		0.5	100.7

[6] With respect to pledges and guarantees, see Note 12K.

Notes to the Financial Statements as of December 31, 2022 (Dollars in millions)

Note 5 – Trade and Other Receivables:

Composition:

	31.12.2022	31.12.2021
Trade and other receivables within joint ventures	46.5	22.4
Receivables from a company accounted for at equity (see Note 22G4 below)	1.3	0.7
Receivables in connection with the sale of oil and gas assets (see Note 7C1 below)	-	10.5
A loan granted (see Note 8B below)	12.9	13.6
Royalties receivable (see Note 8B below)	66.4	24.4
Prepaid expenses and other receivables [7]	7.0	15.7
Total	**134.1**	**87.3**

Note 6 – Investment in a Company Accounted for at Equity EMED Pipeline B.V. ("EMED" or the "Company Accounted for at Equity"):

Composition:

	31.12.2022	31.12.2021
Investment in EMED	59.7	62.8

A. EMED was established in July 2018, and its operations began in September 2019.

B. As of December 31, 2022, the Partnership holds 25% (December 31, 2021: 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:

	31.12.2022	31.12.2021
Cost of investment	75.0	75.0
Accrued losses	(15.3)	(12.2)
Total	**59.7**	**62.8**

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:

	31.12.2022	31.12.2021
Assets	555.4	541.0
Liabilities	316.7	289.8

	For the year ended		
	31.12.2022	31.12.2021	31.12.2020
Loss before tax	(12.3)	(17.9)	(30.7)
Comprehensive Loss	(12.4)	(18.0)	(30.8)

[7] In the report period, the Partnership's amortized prepaid expenses incurred in connection with the structural change in the Statement of Comprehensive Income.

Notes to the Financial Statements as of December 31, 2022 (Dollars in millions)

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[8]	Total
Cost			
Balance as of December 31, 2020	**125.4**	**3,953.8**	**4,079.2**
Changes during 2021:			
Investments	5.9	35.8	41.7
Dispositions (see Section C1 below)	-	(1,118.1)	(1,118.1)
Balance as of December 31, 2021	**131.3**	**2,871.5**	**3,002.8**
Changes during 2022:			
Investments	8.8	56.4	65.2
Write-offs	(12.5)	(0.3)	(12.8)
Balance as of December 31, 2022	**127.6**	**2,927.6**	**3,055.2**
Accumulated Depreciation[9]			
Balance as of December 31, 2020	**-**	**639.3**	**639.3**
Changes during 2021:			
Depreciation and amortization[10,11]	-	81.3	81.3
Dispositions (see Section C1 below)	-	(288.2)	(288.2)
Balance as of December 31, 2021	**-**	**432.4**	**432.4**
Changes during 2022:	-		
Depreciation and amortization[8]	-	75.6	75.6
Balance as of December 31, 2022	**-**	**508.0**	**508.0**
Amortized cost as of December 31, 2021	**131.3**	**2,439.1**	**2,570.4**
Amortized cost as of December 31, 2022	**127.6**	**2,419.6**	**2,547.2**

[8] Including the balance of asset retirement amortized cost as of the date of the statement of financial position in the sum of approx. $57.6 million (December 31, 2021: approx. $81 million).
[9] The amortization rate of the Leviathan project in 2022 is approx. 3% (אhe amortization rate of the Leviathan project and the Tamar Project in 2021 is approx. 2.8% and 0.6%, respectively).
[10] In 2022, 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. $30.1 million (2021: approx. $27.14 million) recorded directly in the Statement of Comprehensive Income.
[11] In 2021, the balance includes amortization in the Tamar Project up to March 31, 2021 until the date of classification thereof as discontinued operations as set forth in Note 2M.

Notes to the Financial Statements as of December 31, 2022 (Dollars in millions)

Note 7 – Investments in Oil and Gas Assets (Cont.):

A. Composition (Cont.):

2. Composition by joint ventures:

	31.12.2022	31.12.2021
Oil and gas assets:		
Ratio-Yam joint venture (Section C2)	2,419.6	2,439.1
Exploration and appraisal assets:		
Block 12 Cyprus (Section C3)	127.6	121.8
New Ofek (Section C7)	-	9.0
New Yahel (Section C7)	-	0.5
	127.6	131.3
Total	**2,547.2**	**2,570.4**

B. Details on the Partnership's rights in oil and gas assets and in exploration and appraisal assets (as of December 31, 2022):

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 further information, see Section C10 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
Ratio-Yam	Lease	I/15 Leviathan North	13.2.2044	45.34%
Ratio-Yam	Lease	I/14 Leviathan South	13.2.2044	45.34%
Yam Tethys	Lease	I/10 Ashkelon	10.6.2032	48.5%
Yam Tethys	Lease	I/7 Noa	31.1.2030	48.5%
Block 12 in Cyprus	Concession	Block 12	7.11.2044	30%
Alon D	License	367/Alon D	21.6.2020	[12]52.941%

[12] 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 (discontinued operations):

a) The Michal-Matan joint venture is a venture for exploration, development and production of oil and gas in the area of the Tamar I/12 and Dalit I/13 leases (in this section: the "**Tamar Project**" and/or the "**Tamar and Dalit Leases**).

b) According to the provisions of the Gas Framework that, *inter alia*, required the Partnership to sell its entire holdings in the Tamar and Dalit Leases (in this section: the "**Leases**"), on September 2, 2021, the Partnership engaged in an agreement for the sale of the remaining interests of the Partnership at the rate of 22% in the Tamar Project to Tamar Investment 1 RSC Limited and Tamar Investment 2 RSC Limited[13] (in this section: the "**Buyers**" and the "**Agreement**", as applicable). On December 9, 2021, the transaction was closed and the Partnership received the sale proceeds in the sum of approx. $955[14] million (see Note 10E and Note 10F below for details regarding repayment of Tamar Bond bonds and Series A Bonds that were repaid using the sale proceeds).

Below is a concise description of the main clauses of the Agreement:

1) The Object of Sale, as defined in the Agreement, includes the Partnership's interests at the rate of 22% in each one of the Tamar and Dalit Leases, together with the Partnership's share in the shares of Tamar 10-Inch Pipeline Ltd. (the holder of the transmission license pursuant to Section 10 of the Natural Gas Sector Law, 5762-2002), and the Partnership's rights and undertakings in the joint operating agreement that applies to the Leases, the agreement for use of the Yam Tethys facilities (in relation to the Partnership's share as a holder of interests in the Tamar Lease), in agreements for the sale of natural gas and condensate from the Tamar Lease, in agreements for the export of natural gas (including the agreements relating to the agreements and permits for export to Jordan and to Egypt), and in other ancillary agreements between the holders of the interests in the Leases.
2) The Partnership's interests in the Leases will be transferred to the Buyers subject to the existing royalties in the Leases which were borne by the Partnership, and accordingly, the obligation to pay the royalty interest owners will apply to the Buyers .
3) As of August 1, 2021 (the "**Effective Date**"), the Buyers will bear, each according to its share, any and all expenses, payments, guaranties, securities and liabilities that apply in respect of the Object of Sale and pursuant to the provisions of any law, with the exception of certain liabilities in respect of which the Agreement determined would remain the Partnership's responsibility also after the closing of the transaction, as described below.

[13] To the best of the Partnership's knowledge, the Buyers are SPCs that were established for the purpose of the transaction and are held (indirectly) by MDC Oil & Gas Holding Company LLC, a corporation of the Mubadala Investment Company PJSC group, a company owned by the Government of Abu Dhabi.

[14] See footnote 5 above.

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 (discontinued operations) (Cont.):

b. (Cont.)

4) The Partnership will bear any and all expenses, payments, guaranties, securities and liabilities that apply in respect of the Object of Sale and pursuant to the provisions of any law until the Effective Date, including the taxes in respect of the sale of the Object of Sale and the levy under the Taxation of Profits from Natural Resources Law, 5771-2011 (the "**Petroleum Profits Levy**") for the quantities of hydrocarbons that were sold until the Effective Date .

   The Partnership will remain responsible for the following liabilities also after the closing of the transaction: (a) liabilities in connection with the Object of Sale in relation to the period that preceded the Effective Date (with the exception of faults and wear and tear in facilities and equipment of the Tamar Project which existed prior to the Effective Date but were not known to the Partnership); (b) liabilities in relation to hydrocarbons which were produced from the Leases prior to the Effective Date; (c) liabilities in connection with the class certification motion which was filed by a consumer of the Israel Electric Corp. Ltd. (the "**IEC**") against the holders of the interests in the Tamar Lease, including any appeal and other proceeding in connection therewith; (d) payment demands according to the joint operating agreement in the Leases, which were sent by the operator in the Tamar Project prior to the Effective Date; and (e) liabilities in connection with environmental hazards in the area of the Leases, insofar as they existed prior to the Effective Date or were known to the Partnership prior to the transaction closing date.

5) In the context of the Agreement, the Partnership made various representations to the Buyers, as is standard in transactions of this type, including representations with respect to its rights in the Object of Sale and disclosure to the Buyers of the material information pertaining to the Object of Sale, including, *inter alia*, compliance with the terms and conditions of the Leases, the validity of the material agreements and absence of breach, legal proceedings relevant to the Object of Sale, compliance with the legal provisions that apply to the Object of Sale, the applicable taxation and financial data of the joint project.

   The Agreement determined provisions whereby the Partnership undertook to indemnify the Buyers in respect of any damage or liability that shall be caused thereto in connection with lawsuits, claims or another legal proceeding as a result of a breach of a representation, provided that the Partnership shall not be liable for damage until the total damage exceeds $2.5 million, and that the indemnity amount for which the Partnership shall be liable shall not exceed 35% of the consideration paid for the Object of Sale, other than with respect to certain representations that were defined as 'fundamental representations' (for which the total indemnity will not exceed 100% of the consideration) or fraud (with respect to which no liability cap was determined).

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 (discontinued operations) (Cont.):

b. (Cont.)

5) (Cont.)

The Partnership will not be liable to the Buyers for breach of the representations unless an indemnity demand is delivered within 18 months from the transaction closing date (or 36 months with respect to the fundamental representations as aforesaid, until expiration of the applicable statute of limitations with respect to representations pertaining to tax liabilities).

6) The Partnership undertook to indemnify the Buyers for irregular events, including the overcharging of the Buyers with the Petroleum Profits Levy in connection with certain disputes existing between the Partnership and the tax authorities with respect to the method of calculation of the levy in relation to revenues and expenses in the period prior to the Effective Date, in accordance with the mechanism determined in the Agreement, up to a maximum indemnity cap of $15 million.

7) The law that governs the Agreement is the English law. Any dispute between the parties to the Agreement will be decided in an arbitration proceeding to be held before 3 arbitrators in London according to the London Court of International Arbitration rules.

c) On April 27, 2021, the Partnership entered into an agreement with a third party for the off-exchange sale of all of its holdings (22.6%) in Tamar Petroleum, in consideration for the total sum of approx. ILS 100 million in cash (approx. $30.6 million), which reflects a share price of 500.035 agorot. On May 5, 2021, the said transaction was closed, and in the context thereof, the shares were transferred against payment of the consideration. In May 2021, the Partnership paid the capital gain tax balance in the sum of approx. $15 million, which was deferred from the date of sale of the Partnership's interests (9.25%) in the Tamar Project to Tamar Petroleum, until the date of sale of the shares, as aforesaid.

Notes to the Financial Statements as of December 31, 2022 (Dollars in millions)

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 (discontinued operations) (Cont.):

d) Tamar Project discontinued operations

Below are figures on the results of the actions relating to discontinued operations:

	For the year ended		
	31.12.2022	**31.12.2021**	**31.12.2020**
Revenues:			
From natural gas and condensate sales	-	289.8	332.0
Net of royalties	[15](15.3)	(57.1)	(67.9)
Revenues (expenses), net	**(15.3)**	**232.7**	**264.1**
Costs and expenses:			
Cost of natural gas and condensate production	0.4	(29.7)	(24.3)
Depreciation, depletion and amortization expenses	-	(7.2)	(32.4)
Other direct expenses	-	(0.2)	(0.2)
Total costs and expenses	**0.4**	**(37.1)**	**(56.9)**
Operating income (loss) before oil and gas profit levy	(14.9)	195.6	207.2
Oil and gas profit levy	(2.1)	(43.9)	(3.8)
Operating income (loss)	**(17.0)**	**151.7**	**203.4**
Financial expenses	-	(0.4)	(0.6)
Financial income	-	0.4	0.3
Financial expenses, net	-	-	(0.3)
Income (loss) before income tax	**(17.0)**	**151.7**	**203.1**
Income tax	3.8	-	-
Profit (loss) from discontinued operations	(13.2)	151.7	203.1
Income from sale of petroleum assets and gas	4.3	144.6	-
Total profit (loss) from discontinued operations	**(8.9)**	**296.3**	**203.1**
Other comprehensive income (loss) from discontinued operations			
Amounts that will not be reclassified in the future to the income statement:			
Profit (loss) from investment in equity instruments designated for measurement at fair value through other comprehensive income	-	13.6	(29.3)
Total comprehensive income from discontinued operations	**(8.9)**	**309.9**	**173.8**

[15] Includes mainly royalties paid to the State, in excess and under protest, for revenues generated by the Partnership from gas supply agreements, which were signed between natural gas consumers and the Yam Tethys partners. In view of the receipt of a judgment as stated in Note 12L1 below, an asset for the said payment was depreciated to the Statement of Comprehensive Income.

Notes to the Financial Statements as of December 31, 2022 (Dollars in millions)

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 (discontinued operations) (Cont.):

d) Tamar Project discontinued operations (Cont.):

Below are figures on the net cash flows relating to discontinued operations and which derived from (were used for) operations:

	For the year ended		
	31.12.2022	31.12.2021	31.12.2020
Current	4.0	175.2	253.9
Investment	15.8	841.9	(18.7)
Financing	-	-	-

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**"), in which the participants are, as of the date of approval of the financial statements, the Partnership, Chevron and Ratio Energies – Limited Partnership ("**Ratio Energies**" and jointly, the "**Leviathan Partners**").

b) The development plan for the Leviathan reservoir:
On June 2, 2016, the development plan was approved by the Petroleum Commissioner at the Ministry of Energy (the "**Commissioner**"), as submitted by Chevron. On February 23, 2017, the Leviathan Partners adopted a final investment decision (FID) for the development of Phase 1 – First Stage, at a capacity of approx. 12 BCM per year. The total cost invested in the development of Phase 1 – First Stage amounted, as of the date of the financial statements, to a sum of approx. $3.8 billion (100%, the Partnership's share being approx. $1.7 billion). Following a running-in period, on December 31, 2019, the piping of the natural gas from the Leviathan reservoir began.

c) On July 12, 2021, the Leviathan Partners announced that they have adopted a resolution regarding the development and production of "Leviathan-8" well in the area of lease I/14 Leviathan South (the "**Well**"), with a total budget of approx. U.S. $248 million (100%, the Partnership's share being approx. $112 million) (including completion and connection to the existing production system of the Leviathan reservoir). The drilling of the Well as aforesaid ended in June 2022, according to schedule and under the planned budget. The cost of the Well as of the date of the financial statements is approx. $140.1 million (100%, the Partnership's share being approx. $63.5 million). As of the date of approval of the financial statements, completion operations are carried out at the well according to the work plan, and its connection to the existing subsea production system of the Leviathan project is expected to be completed during Q2/2023.

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.):

d) Review of different alternatives for increasing the production capacity of the Leviathan reservoir:

As of the date of approval of the financial statements, and according to the development plan, the capacity of gas supply from the Leviathan project to the INGL transmission system is approx. 1.2 BCF per day at maximum production. In order to increase this capacity to approx. 1.4 BCF per day, the Leviathan Partners are promoting a project in which a third subsea transmission pipeline shall be laid from the field to the platform (the "**Third Pipeline**"). The investments in the laying of the Third Pipeline, together with the investments in the platform's related systems, are estimated at approx. $562 million (100%, the Partnership's share in the sum of approx. $255 million), to be made starting from Q1/2023 until the expected operation of the Third Pipeline in mid-2025. Accordingly, the Leviathan Partners gave the project's operator approval for an initial expense of approx. $45 million (100%, the Partnership's share in the sum of approx. $20 million) for engineering design work and reserving of supply dates through preliminary engagements with suppliers, in order to enable the performance of the project at accelerated timelines and to have it ready for adoption of a final investment decision as part of the total budget. In addition, in the context of approval of the 2023 budget, the Leviathan Partners approved another approx. $163 million (100%, the Partnership's share in the sum of approx. $74 million) for the budgeting of the Third Pipeline. The total budgets approved up to the date of approval of the financial statements are approx. $208 million (100%, the Partnership's share in the sum of approx. $94 million) out of a budget of approx. $562 million, as aforesaid. In is clarified that a final investment decision has not yet been adopted in respect of the Third Pipeline project. In the estimation of the Partnership, such a decision is expected to be adopted by the Leviathan Partners in Q2/2023, after completion of the preliminary work mentioned above.

In addition, as of the date of approval of the financial statements, the Leviathan Partners are reviewing the promotion of various alternatives for the development of Phase 1 – Second Stage and increasing the production capacity up to a total of approx. 21 BCM per year, with the aim of adopting a final investment decision (FID). These development options may include development and expansion of the infrastructures for piping natural gas from the Leviathan reservoir to additional consumers in the target markets, primarily the Egyptian market, supply to the existing liquefaction facilities in Egypt and promotion of the option for natural gas liquefaction through a floating liquefaction facility (Floating Liquefied Natural Gas, "**FLNG**") for the purpose of marketing thereof to the global markets.

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.):

d) Review of different alternatives for increasing the production capacity of the Leviathan reservoir (Cont.):

Thus, the development plan for Phase 1 – Second Stage, as approved as aforesaid in June 2016 by the Petroleum Commissioner, may be updated according to the development alternative that will be chosen, and in such case further regulatory approval may be required for the change in the plan. For purposes of examining the various expansion alternatives, on February 20, 2023, the Leviathan Partners approved budgets for 2023 in accordance with the Joint Operating Agreement applying to the Leviathan project, in the sum total of approx. $96.4 million (100%, the Partnership's share is approx. $44 million), for the performance of Front End Engineering and Design for Phase 1 – Second Stage (Pre-FEED) (in this section: the "**Budgets**"). In the context of such design, and further to previous analyses, the Leviathan Partners promote a future construction of an FLNG owned thereby, with an annual production capacity of approx. 4.6 million tons of LNG for purposes of sale thereof to global markets, thus also enabling the increase of the quantities supplied to the domestic market. The budgets include the sum of $44.9 million (100%, the Partnership's share is $20 million), *inter alia* for the performance of Pre-FEED and commencement of FEED, for expansion of the Leviathan reservoir's production system, including the design of subsea infrastructures and of necessary changes on the production platform, as well as the sum of $51.5 million (100%, the Partnership's share is $23.3 million), *inter alia* for the performance of Pre-FEED for the FLNG facility, as aforesaid, in a competitive process between international groups specializing in the design and construction of FLNG facilities. On December 30, 2013, a general meeting of the unit holders was held, in which it was resolved, *inter alia*, to approve refraining from distribution of profits (as defined in Section 9.4 of 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.

e) Evaluation of reserves and contingent resources in the Leviathan Leases:

In March 2023, a report was received from Netherland Sewell & Associates Inc ("**NSAI**"), which is a qualified, expert an independent reserve and resource appraiser, on evaluation of reserves and contingent resources in the Leases according to the SPE-PRMS, updated as of December 31, 2022. According to the report, the overall quantity of natural gas and condensate resources is estimated at approx. 619.2 BCM and approx. 48.2 million barrels, respectively, and is divided into categories of resources classified as reserves and resources classified as contingent.
The quantity of the proved reserves is approx. 391.1 BCM and the quantity of the proved + probable reserves is approx. 440.9 BCM.
Additionally, the proved condensate reserves are approx. 30.4 million barrels, and the quantity of proved + probable reserves is approx. 34.3 million barrels.

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) Evaluation of reserves and contingent resources in the Leviathan Lease (Cont.):

In the contingent resources report, which includes resources classified as contingent – development pending, which are contingent on approval for drilling of further wells, on approval of future developments, on the demonstration of the existence of a future market for the sale of natural gas and on commitment to development of the resources, the said contingent resources are classified under two categories, pertaining to each one of the stages of development of the reservoir, as following:

Phase I – First Stage – Resources attributed to Phase I – First Stage of the development of the Leviathan reservoir, plus the Third Pipeline project.

Future Development – Resources attributed to development stages beyond Phase I – First Stage.

Accordingly, the quantity of contingent resources of natural gas ranges between approx. 297.9 BCM (high estimate) and approx. 59.5 BCM (low estimate). The quantity of contingent condensate resources ranges between approx. 23.1 million barrels (high estimate) and approx. 4.6 million barrels (low estimate). See Section 9 below on uncertainty in the evaluation of reserves.

f) 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, 2022, the details presented in the aforesaid report remain unchanged. See Section 7C9 below with regard to uncertainty in the evaluation of reserves.

The Partnership intends to explore the possibility of the specification, drilling and development of the deep exploration targets in the area of the lease.

3. 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.

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.

Note 7 – Investments in Oil and Gas Assets (Cont.):

C. The Partnership's oil and gas exploration business (Cont.):

3. Block 12 in Cyprus (Cont.):

c) On November 7, 2019, the right holders in the PSC (the "**Partners**") and the Government of Cyprus signed an amendment to the PSC (the "**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**").

Further to the aforesaid, the partners in the Aphrodite reservoir contacted the government of Cyprus to approve changes to the work plan determined under the Development Plan of November 7, 2019, pertaining mainly to the request to postpone for a period of 12 months their commitment to drill Appraisal Well A-3 until November 2022. On November 9, 2022, an additional amendment to the PSC was signed (the "**Additional Amendment to the PSC**").

In the PSC, 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 the license in accordance with the Development Plan, and completion thereof within 24 months from the date of receipt of the Exploitation License, namely until November 2021. According to the Additional Amendment to the PSC, the partners' commitment to the drilling was extended as aforesaid until August 2023.
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 November 2023).
3) The PSC determines specific conditions upon the fulfillment of which the Partners will be entitled to receive an extension for purposes of meeting the milestones as aforesaid, 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).

d) 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, etc.

Note 7 – Investments in Oil and Gas Assets (Cont.):

C. The Partnership's oil and gas exploration business (Cont.):

3. Block 12 in Cyprus (Cont.):

e) The Development Plan, that was approved by the Cypriot government on November 7, 2019, is subject to updates deriving, *inter alia*, from technical, commercial and financial conditions. The approved plan includes the construction of a floating processing and production facility in the area of the license, with a maximum production capacity of approx. 800 MMCF per day, through 5 first production wells and a subsea transmission system to the Egyptian market. Formulation of the Development Plan and adoption of a FID for development of the Aphrodite reservoir are subject, *inter alia*, to the update and approval of the Development Plan, completion of the FEED, performance of commercial arrangements for the development of the systems for export, the signing of agreements for the supply of natural gas, and fulfillment of the closing conditions in such agreements, receipt of regulatory approvals and performance of financing arrangements. Insofar as the aforesaid conditions precedent be fulfilled, supply of natural gas from the Aphrodite reservoir may begin in 2027 at the earliest.

In this context, the partners in the Aphrodite reservoir decided to engage with a drillship to drill the A-3 well, which will later serve as a production well, and on September 15, 2022, the partners in the Aphrodite reservoir decided to approve the budget for the aforesaid drilling, in the sum of approx. $130 million (100%, the Partnership's share is approx. $39 million). It is noted, that in the context of the approval of the budget of the A-3 appraisal well, the partners approved an additional sum of approx. $62 million (100%, the Partnership's share is approx. $19 million) for pre-FEED work for advancing the development of the reservoir.

f) As of the date of approval of the financial statements, the partners in the Aphrodite reservoir are examining additional development alternatives, at lower costs than those of the approved development plan as specified above, involving existing facilities and/or development plans of nearby assets in Egypt, Cyprus and/or Israel. Some of the said alternatives include 3 first production wells that will be connected via a 260-390 km long subsea pipeline to an existing subsea infrastructure near the Egyptian coast, with a maximum production capacity of about 600 MMSCFD. These alternatives refer to the connection of the aforesaid subsea production system to one of the existing systems related to the infrastructures of the WDDM and Temsah assets, which are not owned by the partners in Block 12, located in the Mediterranean near the Egyptian coastline. Note that the continued promotion of an alternative to the approved Development Plan is subject to the approval of the partners in Block 12 and the approval of the Cypriot government.

g) According to the Operator's recent evaluation, delivered to the Partnership and to the Cypriot government, and before the financial-technical feasibility tests have been completed, including performance of the FEED, the estimated cost of the approved Development Plan, including the cost of installation of the pipelines to the target markets, is evaluated at approx. $3.6 billion (100%).

Note 7 – Investments in Oil and Gas Assets (Cont.):

C. The Partnership's oil and gas exploration business (Cont.):

3. Block 12 in Cyprus (Cont.):

h) As of the date of approval of the financial statements, out of said budgets, the partners in Block 12 approved a budget for 2023 in the amount of approx. $169 million (100%, the Partnership's share is approx. $51 million), for which the approval of the Cyprus government has not yet been received. Note that this budget includes the cost of drilling the A-3 well, the costs of conducting surveys and design works.

i) Note that on September 21, 2022, the general meeting of the unit holders approved a decision not to distribute profits, for purposes of investment in Block 12.

j) 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 Note 21D.

k) According to a report prepared in March 2021 by NSAI according to the rules of the Petroleum Resource Management System (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. 128.7 BCM (the high estimate) and approx. 56.8 BCM (the low estimate). According to the aforesaid report, the condensate reserves in the Aphrodite reservoir, classified under the "Development Pending" stage as of December 31, 2020, range between approx. 10.9 million barrels (the high estimate) and approx. 3.9 million barrels (the low estimate). See Note 7C9 below with respect to uncertainty in the evaluation of reserves.

The vast majority of the Aphrodite reservoir is located in the EEZ of Cyprus, and a few percent thereof are in the area of the Yishai/370 license (the "**Yishai License**"), which is located in Israel's EEZ. It is further noted that the partners in the Aphrodite reservoir have received letters both from the partners in the Yishai license and from the Israeli 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.

In addition, 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. Since the parties reached no agreements and the date that was set by the Israeli Minister of Energy (at that time) for the signing of an agreement has passed, the governments of Israel and Cyprus started negotiations on the distribution of profits between the parties and the States.

Note 7 – Investments in Oil and Gas Assets (Cont.):

C. The Partnership's oil and gas exploration business (Cont.):

4. 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 March 2004 and was discontinued in May 2019, due to the depletion of the reservoirs. As of the date of approval of the financial statements, the project assets are primarily used for providing infrastructure services to the Tamar reservoir, according to an agreement entered on July 23, 2012 between the Partnership together with the other Yam Tethys partners and the Tamar partners (see Section B below). On May 3, 2020, the Partnership, Chevron, the Delek Group and Ratio Energies signed an agreement (the "**Agreement**") regulating the method of supply of natural gas to the customers in the Yam Tethys, to be performed by the Leviathan Partners which are partners in the Yam Tethys project (i.e. the Partnership and Chevron), who have a commitment by virtue of a gas sale agreement in the Yam Tethys project (the "**Yam Tethys Agreement**"), and by another Leviathan partner (i.e. Ratio Energies) which is not a partner in the Yam Tethys project (and which is not bound by the Yam Tethys Agreement as aforesaid).

The consideration determined in the Agreement is the average monthly price of the Leviathan project from sales to the domestic market. The consideration was divided such that consideration to Ratio Energies reflect a natural gas price that is equal to the (current) average monthly price of natural gas that was supplied to the domestic market in that month by virtue of agreements signed between the Leviathan Partners and their customers, and the financial balance that remained was divided between the Partnership and Chevron, according to their relative share in the Leviathan project, excluding the share of Ratio Energies. Such division allowed the maintaining of a balance in the gas quantities in the Leviathan project between the partners according to their share.

a) Agreement for the grant of usage rights in the facilities of the Yam Tethys Project:

On July 23, 2012, an agreement was signed between the Partnership together with the rest of the Yam Tethys partners and the Tamar partners, whereby the Yam Tethys partners granted the Tamar partners usage rights in the existing facilities of the Yam Tethys project for payment in the total sum of $380 million (the "**Usage Agreement**"). The term of the Usage Agreement will end upon the earlier of: (a) 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; (b) the giving of a notice by the Tamar partners of the permanent cessation of commercial gas production from the Tamar Project; (c) the abandonment of the Tamar Project. The Agreement includes various provisions with respect to the term of usage and with respect to the end of term of usage, including a settlement of accounts mechanism due to upgrades that will be made in the facilities.

In the context of selling the remaining interests of the Partnership in the Tamar and Dalit Leases the Partnership assigned the buyers its interests in the Usage Agreement as partners in the Tamar Project (see Note 7C1B above).

Note 7 – Investments in Oil and Gas Assets (Cont.):

C. The Partnership's oil and gas exploration business (Cont.):

4. The Yam Tethys joint venture (Cont.):

a) Agreement for the grant of usage rights in the facilities of the Yam Tethys Project (Cont.):

Note 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 provided a settlement of accounts mechanism relating to the value of such facilities at the end of the term of the Usage Agreement.

b) Abandonment of wells:

The Operator began the decommissioning and abandonment of the project facilities, other than the platform, and including the production wells and the subsea equipment, in accordance with a decommissioning plan and instructions of the Petroleum Commissioner, as updated from time to time. As of the date of approval of the financial statements, all of the project's wells have been plugged and abandoned according to the directions of the Petroleum Commissioner.

At the same time, 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 budget for the abandonment of the wells and subsea equipment which was approved by the partners of the Yam Tethys project, as of the date of approval of the financial statements, is in the sum of approx. $276 million (100%, the Partnership's share being approx. $134 million).

As of the date of the financial statements, the Yam Tethys partners invested approx. $257 million with respect to such abandonment expenses (100%, the Partnership's share being approx. $125 million). This budget does not include a budget for the abandonment of the Yam Tethys platform and the terminal which is expected at the end of the period of production from the Tamar Project.

5. The Boujdour License in Morocco:

On December 6, 2022, the Partnership, jointly with Adarco Energy Limited[16] ("**Adarco**"), signed agreements concerning oil and natural gas exploration and production activities in the Boujdour Atlantique exploration license, which is situated in the Atlantic Ocean off the coast of Morocco (in this section, the "**Petroleum Asset**" or the "**License**")[17], with the National Office of Hydrocarbons and Mines of Morocco (Office National des Hydrocarbures et des Mines, "**ONHYM**") (in this section, the "**Agreements**"). *Inter alia*, the Agreements that have been signed grant each of the Partnership and Adarco 37.5% of the interests in the License, with the remaining interests in the License, the rate of which is 25%, granted to ONHYM, in accordance with standard regulation in Morocco. On February 29, 2023, Delek Energy Ltd., a wholly-owned subsidiary of the Partnership that was incorporated in England ("**NewMed Morocco**"), signed the Agreements in lieu of the Partnership and stepped into its shoes.

[16] Adarco has informed the Partnership that Adarco is a private company whose shares are (indirectly) held for Mr. Yariv Elbaz (a Moroccan investor) and members of his family.

[17] The License includes 17 areas of different licenses.

Note 7 – Investments in Oil and Gas Assets (Cont.):

C. The Partnership's oil and gas exploration business (Cont.):

5. The Boujdour License in Morocco: (Cont.):

The Agreements further grant the Partnership, Adarco and ONHYM the right to search for hydrocarbons in the area of the License for a term of 8 years, subject to compliance with a work plan, which may be extended in the event of discovery. Note that the Partnership shall act as the operator of the License.

During the exploration period, the Partnership and Adarco shall also bear, in addition to their relative share of the costs, the costs in respect of ONHYM's share, in accordance with the regulation in Morocco. Furthermore, the agreements with ONHYM include additional provisions, *inter alia*, with respect to bonuses that are payable to ONHYM according to accomplishment of milestones of output from the License, royalties to the State of Morocco, fines in the event of noncompliance with obligations under the agreements, guarantees, stability in respect of economic terms, obligations of professional training in the domestic market, as well as provisions pertaining to the joint operation of the License. For details on the guarantee provided by the Partnership see Note 12K. According to local regulation in Morocco, the amount of the royalty depends on the depth of the water in the well and the type of finding (gas or oil).

In a well with water depth exceeding 200 meters, royalties will equal an annual rate of 7% in case of an **oil** discovery, while in case of a **gas** discovery in such depth or more, the royalties will equal 3.5%. The obligation to pay the royalty applies to volumes exceeding 500,000 tons of oil or 0.5 BCM of natural gas.

Further, in accordance with the regulation in Morocco, an exemption from corporate tax applies in the first 10 years after production begins, following which corporate tax shall be paid at a rate of 31% (for both gas discoveries and oil discoveries).

On January 2, 2023, the general meeting of the unit holders approved the Partnership's engagement in the Agreements, which are also subject to receipt of the approval of the Ministry of Energy Transition and Sustainable Development and Ministry of Finance of Morocco.

The License is located off the coast of Western Sahara, an area whose sovereignty is under dispute. In December 2020, a normalization agreement was signed between Israel and Morocco, under which, *inter alia*, Israel and the United States recognized Morocco's sovereignty over Western Sahara. The dispute regarding Morocco's sovereignty in Western Sahara as aforesaid may affect the receipt of regulatory approvals in connection with the Partnership's activity in the Boujdour License, the operation of the License, and promotion of further business in this region. On January 2, 2023, a general meeting of the unit holders was held at which it was resolved, *inter alia*, to approve the Partnership's engagement in agreements for the purchase of the rights in the Morocco license and participation in activities for oil and/or natural gas exploration and production in the license area, and to approve refrainment from distribution of profits (as defined in Section 9.4 of the Partnership Agreement) for the purpose of performance of the aforesaid actions in accordance with a work plan and budgets to be approved by the partners in the license and according to its terms.

Note 7 – Investments in Oil and Gas Assets (Cont.):
C. The Partnership's oil and gas exploration business (Cont.):

6. **Alon D License (in this section: the "License"):**

On June 21, 2020, the License expired after requests to extend it were denied by the Petroleum Commissioner. Due to the expiration of the License, the Partnership and Chevron, which were the partners in the License, submitted a bid 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**"). Thereafter, 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.

On September 30, 2020, the 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 Commissioner, whereby he should disregard the recommendation of the Concentration Committee as it is lacking, disregards material facts and is inaccurate.

To the best of the Partnership's knowledge, on the same day the Commissioner delivered a request to the Concentration Committee to hold another consultation on the matter. In addition, to the best of the Partnership's knowledge, its offer (together with Chevron) is superior to other offers submitted in the process, considering the conditions that were determined therein in advance. Therefore, the Partnership believes that it has the full right to win the License. As of the date of approval of the financial statements, the winner of the said competitive process with respect to Block 72 has not yet been announced, and in view of Government Resolution no. 1906, as detailed below, in the estimation of the Partnership, it is possible that the process will be cancelled with no winner being announced.

On October 27, 2022, Government Resolution no. 1906, ratifying the agreement regulating the maritime border between Israel and Lebanon, was published (the "**Maritime Agreement**"). Simultaneously, the Maritime Agreement was signed by the Israeli Prime Minister and the President of Lebanon. The Maritime Agreement determines, *inter alia*, the maritime border between the countries, and that the status quo along the coast, including along the existing buoy line, shall be maintained as is. The Maritime Agreement further determines that in case of a discovery of a natural gas reservoir which crosses the borderline as determined, development and production from it will be performed by the right holders in Block 9 in Lebanon, which borders Block 72. Further, on November 14, 2022, a memorandum of understandings was entered between the State of Israel, the French energy company Total Energies and the Italian energy company ENI (the consortium holding the license to develop Block 9 in Lebanon, which borders Block 72). According to the announcement of the Ministry of Energy, the objective of the MOU is to ensure that the potential reserve between the countries will not be developed without protection of Israel's economic rights.

Note 7 – Investments in Oil and Gas Assets (Cont.):

C. The Partnership's oil and gas exploration business (Cont.):

6. Alon D License (Cont.):

The MOU does not determine the financial consideration that Israel will be entitled to receive from the reserve. Further, the area of the potential reserve is partially included in the area of the Alon D license that was formerly held by the Partnership and Chevron, which filed a petition with the High Court of Justice in connection with the expiration of the interests therein.

For details regarding the petition filed with the Supreme Court, sitting as the High Court of Justice, in connection with the non-extension of the License, see Note 12L(10) below.

7. New Ofek/405 ("Ofek") and New Yahel/406 ("Yahel") Licenses:

On March 19, 2019, the Partnership entered into an agreement with SOA (in this section: the "**Seller**" or the "**Operator**") 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.

Upon fulfillment of the closing conditions in the purchase agreement, on October 10, 2019, the transaction for the purchase of the interests as aforesaid was closed, and on November 5, 2019, the Commissioner announced that the said transfer of interests was registered in the Petroleum Register. SOA acts as the Operator in such licenses.

On May 22, 2022, the Partnership informed the other interest holders in the New Ofek License that it no longer agrees to continue incurring further expenses in connection with the works in the Ofek 2 well, other than expenses connected to the sealing and abandonment of the well, and that it does not intend to support any proposal to extend the term of the license, insofar as proposed towards the expiration date of the license, which took place on June 20, 2022. On June 20, 2022, the Ofek and Yahel Licenses expired, and the Partnership did not join the application of the Operator of the licenses to the Commissioner to extend the terms thereof.

To the Partnership's best knowledge, the response of the Petroleum Commissioner to the said extension application has not yet been received. Accordingly, the costs of the investment in the New Ofek and New Yahel Licenses, in the sum of approx. $13 million, were amortized in the income statements by an amount. Further, the Partnership recognized in its financial statements its share in the commitment to abandon the Ofek 2 well, estimated at an amount of approx. $0.5 million.

On June 21, 2022, Globe Energy Resources (YCD), Limited Partnership, reported that the production tests ended and that the Operator of the New Ofek License began working towards permanently abandoning the well. To the Partnership's best knowledge, as it was informed by the Operator, the abandonment of the well and the site in the New Ofek License are expected to end during Q2/2023.

8. 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 that held approx. 22.67% of the interests in the license) 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.

Note 7 – Investments in Oil and Gas Assets (Cont.):

C. The Partnership's oil and gas exploration business (Cont.):

8. Eran License (Cont.):

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 refer to mediation 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 (pro rata to their holdings in the license). On April 11, 2019, a judgment was entered on the mediation arrangement agreed to by the parties, as aforesaid.

Negotiations were held between the Tamar partners, the State of Israel and the right holders in the Eran license regarding the regulation of the State's rights in additional related matters, but as of the date of approval of the financial statements, the parties have not yet reached agreements on how to implement the mediation arrangement, as specified above.

9. 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.

10. Additional information:

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.

Notes to the Financial Statements as of December 31, 2022 (Dollars in millions)

Note 8 – Other Long-Term Assets:

A. Composition:

	31.12.2022	31.12.2021
Royalties receivable (see Paragraph B Below)	256.7	237.8
Loan granted (see Paragraph B Below)	40.7	50.8
Ministry of Energy for royalties (see Notes 12B, 12L1 & 15)	30.5	34.5
Interested parties for overriding royalties (see Notes 12B & 15)	4.1	3.5
Third party for overriding royalties (see Notes 12B and 15)	7.7	5.4
Access fees for the Blue Ocean agreement (see Note 12C1(C))[18]	100.9	98.4
Receivables from a company accounted for at equity (see Note 22G(4))	23.6	16.7
Fixed Assets	0.3	-
Right-of-use asset for lease	2.8	-
Other long-term assets in joint ventures[19]	93.0	88.3
Total	560.3	535.4

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 Chevron[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) Additional contingent consideration, in the sum total of $108.5 million, will be paid to the Partnership after the adoption of a final investment decision (FID) in connection with the development of the Leases by Energean, 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 from the adoption of the investment decision as aforesaid. In March 2018, Energean notified the Partnership of the adoption of an investment decision, and on the same date, paid the Partnership the first annual installment. As of the date of approval of the financial statements, 5 of the 10 installments have been paid;

[18] The access fees are amortized in accordance with the length of the period of the Blue Ocean agreement.

[19] The balance mainly includes the cost for construction of the natural gas transmission systems from Israel to Jordan and Egypt in the Leviathan project in the sum total of approx. $93.0 million (2021: approx. $87.4 million). With respect to the construction of a transmission system from the Leviathan project to Jordan, see Note 12C(b) 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 Chevron were required to sell their entire interests in the Leases.

[21] In November 2015, the Partnership entered into a right conferral agreement with Chevron, whereby Chevron 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 (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: approx. 5.12% – prior to the payment of the petroleum profit levy under the Taxation of Profits from Natural Resources Law, 5771-2011 (the "**Levy**") and prior to the investment recovery date, approx. 2.47% – prior to the payment of the Levy and after the investment recovery date and approx. 3.22% – from the commencement of payment of the Levy and after the investment recovery date.
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.

On April 15, 2019, Energean announced a natural gas discovery at the Karish North well. According to Energean's reports, the plan for the development of the Karish North reservoir that was submitted thereby to the Commissioner 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. Based on Energean's reports of March 2023, the development of the Karish North reservoir is expected to be completed by the end of 2023, and will enable, together with the upgrading of the production systems, maximum annual production of approx. 8 BCM through a Floating Production Storage & Offloading Facility (FPSO).

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 reported by Energean on March 23, 2023. According to this report, as of December 31, 2022, the Reservoirs contain natural gas reserves (2P) of approx. 99.6 BCM and hydrocarbon liquids of approx. 95.6 million barrels.

Based on Energean's reports of March 2023, the sales forecast for 2023 is expected to be approx. 4.5 BCM to 5.5 BCM.

The Partnership engaged with an external independent appraiser in order to assess the fair value of the remaining royalties and Annual Installments. 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 6.95% (2021: 6.5%); the cap rate estimated for the royalties component is estimated at 10.5% (2020: 13.5%); dates of gas production from the Karish lease: from 2023 until 2042; forecast average annual production rate from the Karish lease: approx. 3.68 BCM natural gas; average annual production rate from Karish lease of approx. 4.56 million barrels of condensate; dates of gas production from Tanin lease: starting from 2030 until 2041; forecast average annual production rate from the Tanin lease: approx. 2.17 BCM natural gas; average annual production rate from the Tanin lease of approx. 0.37 million barrels of condensate; the sum total of the contingent resources of natural gas and hydrocarbon liquids that were used for the valuation to measure the royalties were estimated at approx. 99.6 BCM and approx. 95.6 MMBBL, respectively.

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.):

The update to the valuation as aforesaid derives mainly from a change in the estimations published by Energean regarding the contingent reserves and resources in the Leases, an update to the cap rates, a change in estimations published by Energean as to the production rate forecast, the price of sale and the lapse of time (see also Note 22F below).

The Agreement further stipulates that once Energean obtains financing ("**Financial Closing**") for the costs of the first phase of the approved development plan in Karish and Tanin plus the full (100%) financial consideration for the object of sale as determined in the sale agreement ($148.5 million), Energean will be required to immediately pay the balance of the consideration.

On April 30, 2021, Energean announced the issuance of bonds in the total amount of $2.5 billion and the release of the issue funds to the company's accounts. Following the aforesaid, the Partnership applied to Energean with a demand for immediate payment of the balance of the consideration, in accordance with the provisions of the Agreement, however, the Partnership's demand was rejected on the grounds that the condition for immediate payment of the balance of the consideration was not fulfilled.

On March 24, 2022, Energean informed the Partnership that in its view, it is operating under the terms of a "force majeure" event, as defined in the sale of rights agreement, and that as a result, the periodic payment for 2022 on account of the Loan (subsection 2 above), scheduled for March 2022, shall be deferred. Note that on September 22, 2022, Energean paid a sum of approx. $12.4 million for the periodic payment for 2022, which included principal and semiannual interest. In view of the aforesaid, the Partnership asserts its right to receive from Energean the balance of the annual interest cost as well.

On May 31, 2022, the Partnership filed a monetary claim against Energean, in the total amount of U.S. $65.1 million, plus lawful linkage differentials and agreed annual interest differentials of 4.6%. The Partnership's position is that Energean's announcement of April 30, 2021 regarding the issuance of bonds in the total amount of $2.5 billion and the release of the issue funds to its accounts, constitutes cause for immediate payment of the balance of the consideration. A pretrial hearing in the proceeding was scheduled for April 19, 2023.

It is noted that Energean and the Partnership exchanged letters in connection with claims raised by Energean with respect to the Partnership's right to receive royalties from the Karish and Tanin leases. Energean claimed that (1) the overriding royalty does not apply to the Karish North reservoir (as opposed to from the Karish reservoir) (2) not all hydrocarbon liquids to be produced from the Karish lease are deemed Condensate under the Agreement. It is the Partnership's position, based on its legal counsel, that according to the Agreement, the royalty documents and the records in the Petroleum Register, Energean's duty to pay royalties applies with everything related 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 reservoirs that in the area of the Leases constitute Condensate, as defined in the Agreement.

Note that towards late October 2022, Energean reported the production of first gas from the Karish lease and sale thereof to its customers, and has accordingly started paying royalties to the Partnership according to the Agreement as aforesaid.

Notes to the Financial Statements as of December 31, 2022 (Dollars in millions)

Note 9 – Trade and Other Payables:

Composition:

	31.12.2022	31.12.2021
Related parties (see Note 21)	0.5	0.3
Related parties for overriding royalties	6.3	2.8
Third parties for overriding royalties	8.8	2.1
Liability for participation unit-based payment (See Note 13H)	0.3	-
Income Tax (see Note 20A and 20B)[22]	-	168.1
Oil and gas profit levy (see Note 20C)	4.7	10.5
Ministry of Energy in respect of royalties	11.3	8.2
Payables in joint ventures[23]	58.7	57.1
Provision for balancing payments due to previous years (see Note 20A5A)	-	14.9
Current maturities for a lease liability	0.3	-
Interest due	-	0.8
Expenses due	2.9	1.2
Trade and other payables	3.1	4.7
Total	**96.9**	**270.7**

Note 10 – Bonds and credit facilities from banking corporations:

A. Composition and maturities by years after the date of the statement of financial position:

1) Composition of bonds:

	31.12.2022	31.12.2021
Leviathan Bond (see Section B below)	2,155.8	2,224.8
Net of current maturities	(424.8)	-
Total (net of current maturities)	**1,731.0**	**2,224.8**

[22] The balance includes a sum of approx. $154 million due to tax payments due to capital gain from the sale of the Partnership's interests in the Tamar Project as aforesaid in Note 7C1.
[23] Include mainly expenses incurred by the Operator of the joint ventures and not yet paid.

Notes to the Financial Statements as of December 31, 2022 (Dollars in millions)

Note 10 – Bonds and credit facilities from banking corporations (Cont.):

2) Maturities by years after the date of statement of financial position:

	Amount	Amortized Cost	Interest	Stated Maturity
Leviathan Bond-2023	500	424.8[24]	5.750%	June 2023
Leviathan Bond-2025	600	596.2	6.125%	June 2025
Leviathan Bond-2027	600	593.6	6.500%	June 2027
Leviathan Bond-2030	550	541.2	6.750%	June 2030
Total		**2,155.8**		

B. 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 is 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**").

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 sum of approx. $33 million, and the balance of the proceeds was 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 in the Leviathan 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.

[24] Net of buybacks as specified in subsection (c) below.

Note 10 – Bonds and credit facilities from banking corporations (Cont.):

B. Bonds of Leviathan Bond (Cont.):

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 control holder of 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:

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 in the Financing Documents; 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.

Note 10 – Bonds and credit facilities from banking corporations (Cont.):

B. Bonds of Leviathan Bond (Cont.):

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. 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.

Note 10 – Bonds and credit facilities from banking corporations (Cont.):

B. Bonds of Leviathan Bond (Cont.):

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[25].

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. 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 are rated by international rating agencies and an Israeli rating agency.

[25] 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 credit facilities from banking corporations (Cont.):

B. Bonds of Leviathan Bond (Cont.):

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 fulfills its undertakings as aforesaid.

C. On May 22, 2022, the board of directors of the Partnership's general partner approved a plan to purchase the bonds of Leviathan Bond, in an aggregate amount of up to $100 million for a period of two years. The Partnership made buybacks pursuant to said buyback plan in the sum of approx. $100 million. Further thereto, on January 22, 2023, the board of directors of the Partnership's general partner, authorized to adopt an additional plan to purchase the bonds of Leviathan Bond, in an aggregate amount of up to $100 million, by way of an off-exchange, TACT-Institutional or any other purchase method (the "**Additional Buyback Plan**"). The Additional Buyback Plan took effect on January 23, 2023 and shall end after two years, i.e., on January 23, 2025. As of the date of approval of the financial statements, the Partnership made buybacks pursuant to the Additional Buyback Plan in the sum of approx. $9 million.

D. Credit facilities from banking corporations:

On December 5, 2021, the Partnership signed an agreement with an Israeli bank for the provision of a bank credit facility, to be used by the Partnership for its current business. According to the terms and conditions of the credit facility, the Partnership may, from time to time, draw down loans in US dollars up to a sum total of $100 million during the availability period which commenced on December 6, 2021 and ended on December 6, 2022. In an amendment to the facility agreement, the availability period was extended until February 6, 2023 and expired on such date. The Partnership did not use this facility and did not make drawdowns therefrom during the availability period.

On February 5, 2023, the Partnership signed documents with an Israeli bank for the provision of two new bank credit facilities, intended to serve the Partnership in its current business. According to the terms and conditions of the credit facilities, the Partnership may draw down, from time to time, U.S. dollar loans up to a total sum of $150 million under two credit facilities, credit facility A of $100 million ("**Credit Facility A**") and credit facility B of $50 million ("**Credit Facility B**", and jointly with Credit Facility A, the "**Credit Facilities**") during an availability period commencing on February 6, 2023 and ending on February 6, 2024.

For the non-utilized part of each one of the Credit Facilities, the Partnership will pay a quarterly non-drawdown fee at an annual rate of 0.65%, until it is drawn down by the Partnership or until the end of the availability period, whichever is earlier.

Note 10 – Bonds and credit facilities from banking corporations (Cont.):

D. Credit facilities from banking corporations (Cont.):

Each loan drawn down from Credit Facility A will bear SOFR interest plus a margin of 2.7% per annum. The principal of the loan that shall be drawn down as aforesaid, shall be payable until May 30, 2025.

Each loan drawn down from Credit Facility B will bear SOFR interest plus a margin of 3% per annum. The principal of the loan, if drawn down, shall be payable in four equal quarterly payments beginning on the end of Q1/2024 and until the end of 2024. Further, for Credit Facility B, the Partnership paid on February 15, 2023, a one-time commitment fee at a rate of 0.75% of Credit Facility B. A condition precedent for applying for a drawdown from Credit Facility B is that the ratio between the value of the Partnership's rights to receive royalties from Karish Tanin on the basis of an independent external valuation plus the balance of the principal of the seller's loan to Energean (as aforesaid in Note 8B) and all of the loans drawn down from Credit Facilities A and B including the drawdown application, shall not be lower than 200%.

It is further noted that if Energean prepays amounts of the Partnership's loan to Energean, which are originally due and payable, under the terms of the loan given to Energean, after the last possible date for repayment of this loan, one half of the net proceeds shall be applied to prepayment of the loan and decrease of the Credit Facilities accordingly.

The provision of the Credit Facilities includes covenants whereby the ratio between the value of the Partnership's assets as defined in the agreement and the net financial debt as defined in the agreement shall not be lower than 1.5 on 2 consecutive inspection dates and that the ratio between the aggregate surplus of sources as of June 30, 2025 plus an amount equal to the balance of the Credit Facilities that have not yet been drawn down at such date and the amount of the Credit Facilities will not be lower than 1, as well as an undertaking that the Partnership shall not sell, transfer, pledge or mortgage all of its rights in connection with receipt of royalties from the Karish Tanin reservoirs and the seller's loan to Energean, in addition to other standard covenants.

In addition, if the control holder, Delek Group, ceases to hold directly or indirectly at least 25% of the means of control in the Partnership and to be the largest holder of means of control in the Partnership and/or if the Partnership will have another control holder, severally or jointly with Delek Group, which at such time shall not hold , directly or indirectly, at least 50% of the participation units of the Partnership, whether the Partnership will be private or public, and the banking corporation's consent to the aforesaid was not received (which consent shall not be unreasonably withheld), this shall constitute grounds for acceleration and the Partnership will be required to repay the balance of the loans within 30 days. Another reason for acceleration shall be established if the Partnership adopted a decision regarding a reorganization as defined in the credit documents. However, this reason is limited to the extent that such change will materially prejudice the Partnership's economic rights in the Karish and Tanin Leases or in the Leviathan reservoir, i.e. a change exceeding 10%.

Notes to the Financial Statements as of December 31, 2022 (Dollars in millions)

Note 10 – Bonds and credit facilities from banking corporations (Cont.):

D. Credit facilities from banks (Cont.):

Further grounds for acceleration shall be established upon a cross default with loans of material creditors, in an amount exceeding $15 million, apart from the Leviathan Bond loans, other loans that are limited recourse loans. In addition, a restriction is in place in connection with a change in the Partnership's business (which was broadly defined to include any energy-related business), without the bank's approval. The other covenants are standards and the additional breach events conform to the common practice in agreements of this type.
As of the date of approval of the financial statements, the Partnership has not yet used the said Credit Facilities.

E. Bonds of Tamar Bond:

In May 2014, the process of issuing bonds offered by Delek & Avner (Tamar Bond) Ltd., a special purpose company (SPC) wholly owned by the Partnership, was completed, whereby 5 series of bonds in the total sum of $2 billion were issued.
Following the sale of the Partnership's remaining interests in the Tamar project, as aforesaid in Note 7C1, in December 2021 the Partnership made a full and final payment in the sum of approx. $640 million for the balance of the principal of the bonds that were secured by pledges on the Partnership's interests in the Tamar Project.

F. Series A Bonds:

In December 2016, the Partnership issued to the public ILS 1,528,533,000 par value of Series A Bonds (approx. $400 million), which were listed on the TASE and with maturity date on December 31, 2021. The bonds were issued in consideration for their par value, linked to the Dollar rate on the issuance date and they bore fixed annual interest of 4.50%. The consideration received net of issue costs totaled approx. $392.6 million.
In 2020 the board of director of the Partnership's General Partner approved a buyback plan for Series A Bonds at a total estimated cost of up to $80 million. The Partnership performed buybacks in the sum of ILS 18,863,393 par value of Series A Bonds in total consideration for approx. $5 million.
On August 12, 2021, the board of director of the Partnership's General Partner approved a buyback plan for Series A Bonds at a total estimated cost of up to $100 million. The Partnership performed buybacks in the sum of ILS 76,006,633 par value of Series A Bonds in total consideration for approx. $20 million. The balance of the principal of Series A Bonds was repaid on time on December 31, 2021 in the sum of approx. $375.4 million.

Note 11 - Other Short-Term and Long-Term Liabilities:

A. Other Long-Term Liabilities:

	31.12.2022	31.12.2021
Oil and gas asset retirement obligation (see Note 2L2 and Section B)	66.5	94.4
Long-term lease liability	2.6	-
Other long-term liabilities	0.1	-
Total	**69.2**	**94.4**

Notes to the Financial Statements as of December 31, 2022 (Dollars in millions)

Note 11 - Other Short-Term and Long-Term Liabilities (Cont.):

B. Transactions in oil and gas asset retirement obligation:

	2022	2021
Balance as of January 1	122.0	195.5
Additions	24.4	45.2
Effect of the passing of time	1.5	2.2
Effect of update of the cap rate and indexation	(19.9)	(11.3)
Amounts incurred for decommissioning of oil and gas assets (see Note 7C4(b) above)	(51.7)	(68.6)
Dispositions (see Note 7C1 above)	-	(41.0)
Balance as of December 31	**76.4**	**122.0**
Net of short-term gas asset retirement obligation (See Note 7C4(b) above)	(9.9)	(27.6)
Total	**66.5**	**94.4**

The cap rate for the measurement of the oil and gas asset retirement obligation as of December 31, 2022 is 6.7% (December 31, 2021: 3.6%-3.8%).

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 and the limited partner (the Trustee) will be entitled to 99.99% of the revenues and shall bear 99.99% of the expenses and losses of the Partnership.

Up to January 1, 2022, the General Partner was entitled to a reimbursement of certain direct expenses involved in the management of the Partnership, as specified in the agreement, and was also 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.

On September 21, 2022, the general meeting of the holders of the Partnership's participation units approved a new arrangement for the provision of management services (the "**New Management Arrangement**"), as well as an amendment to the Partnership Agreement in connection therewith. According to the New Management Arrangement, starting from January 1, 2022, the Partnership will directly bear all of the expenses entailed by the management of its business and assets, including the management expenses of the General Partner, which, according to the provisions of Section 65B(a) of the Partnerships Ordinance, has no operations other than the management of the Partnership. Accordingly, the Partnership does not pay the General Partner or Delek Group any management fees or operator's fees. In the context of the New Management Arrangement, the Partnership bears the costs of the remuneration of all of the directors of the General Partner and the fees of the active chairman of the board of directors, other than directors serving as officers of Delek Group or other companies controlled thereby.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

A. (Cont.)

In addition, the Partnership bears rent of the Partnership's offices, and accordingly, the General Partner assigned to the Partnership all of its rights and obligations under the lease agreement.

In addition, according to the New Management Arrangement, generally, the General Partner does not bear the Partnership's management expenses, and the Partnership is not be required to reimburse its expenses.

Insofar as the General Partner shall incur any part of the Partnership's management expenses, it will be reimbursed for said expenses, however, in no event will the General Partner be reimbursed for expenses paid thereby, directly or indirectly, to Delek Group or expenses in which Delek Group has a personal interest (within the meaning of such term in the Partnerships Ordinance), unless all of the approvals required therefor under the law shall be obtained.

B. Engagements for the payment of royalties:

1. Following the closing of the merger between the Partnership and Avner Oil Exploration Limited Partnership ("**Avner**" or "**Avner 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 the 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 the 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 Note 12L6 below.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

B. Engagements for the payment of royalties (Cont.):

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.

4. **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.
   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 Leviathan Lease in July 2022. For details regarding the directives, see Section P4 below.

C. Engagements for the supply of natural gas:

a) 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 which were signed by the Partnership, together with the other Leviathan Partners, that are valid as of the date of approval of the financial statements[26]:

[26] The data in the table do not include agreements for the supply of natural gas from the Leviathan project on an interruptible basis, as well as agreements for which the closing conditions were not fulfilled, as specified below. In this context note that on September 7, 2022, the agreement for the supply of natural gas from the Leviathan project to Or Power Energies (Dalia) Ltd. ("**Or Energies**"), signed between the Leviathan Partners and Or Energies on November 30, 2016, expired with the parties' consent and in accordance with its terms, due to the non-fulfillment of the closing conditions thereof. In addition, on November 14, 2022, the agreement for the supply of natural gas from the Leviathan project to Edeltech Ltd. ("**Edeltech**"), signed between the Leviathan Partners and Edeltech on January 30, 2016, expired with the parties' consent and in accordance with its terms, due to the non-fulfillment of the closing conditions thereof. The data in the table include short-term bridging agreements signed further to the delay in the date of commencement of production of gas from the Karish lease, which are expected to terminate by the end of Q1/2023.

Notes to the Financial Statements as of December 31, 2022 (Dollars in millions)

Customer	Supply commencement date	Agreement period[27]	Total maximum contract quantity for supply (100%) (BCM)	Total quantity supplied until December 31, 2022 (100%) (BCM)	Main linkage basis of the gas price
Independent power producers	2020, or the date of commencement of the commercial operation of the buyers' power plant (whichever is later).	The agreements are for a long term of 9 to 25 years. Some of the agreements grant each of the parties an option to extend the agreement in the event that the total quantity set in the agreement is not purchased.	Approx. 24	Approx. 6	In most of the agreements the linkage formula of the gas price is based on the Electricity Production Tariff and includes a "floor price". One of the agreements determines a fixed price without linkage.
Industrial customers	2020	The agreements are for a period of 2.5 to 15 years. [28] In most of the agreements the parties are not granted an option to extend the agreement period.	Approx. 5	Approx. 1.4	In most of the agreements the linkage formula 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 crack spread index and to the general TAOZ index published by the Electricity Authority. Some of the agreements determine a fixed price without linkage.
NEPCO export agreement (described in Section (b) below)	2020	15 years. The agreement stipulates that in the event that the buyer does not purchase the total contract quantity, the supply period will be extended by another two years.	Approx. 45	Approx. 7.3	The linkage formula is based on linkage to the Brent prices and includes a "floor price".
Blue Ocean export agreement (described in Section (c) below)	2020	15 years. The agreement stipulates that in the event that the buyer does not buy the total contract quantity, the period of the supply will be extended by another two years.	Approx. 60	Approx. 10.2	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. 133**	**Approx. 25**[29]	

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

[28] One of the agreements, expiring at the end of March 2023, which includes a non-material amount, is an agreement for a period that is shorter than a year.

[29] It is noted, that the total quantity supplied from the Leviathan project by December 31, 2022 (100%) (both under the agreements appearing in the table and both under SPOT agreements and agreements that ended) is approx. 29 BCM.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

C. Engagements for the supply of natural gas (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 the agreements for the sale of natural gas to independent power producers and to industrial customers, excluding SPOT agreement (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**"). It is noted that in the context of the Agreements, provisions and mechanisms are provided, which allow each of the said buyers, after paying for natural 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 in the years consecutive to the year when the payment was made. In addition, the Agreements determine a mechanism for accrual of a balance in respect of surplus quantities (over the take-or-pay) 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.
2) 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 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.
3) 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. 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 option as stated in the 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. 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.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

C. Engagements for the supply of natural gas (Cont.):

b) **Agreement for the Export of Natural Gas from the Leviathan Project to the Jordanian National Electric Power Company:**

In September 2016, an agreement was signed for the supply of natural gas between NBL Jordan Marketing Limited (the "**Marketing Company**") and NEPCO (the "**NEPCO Agreement**"). 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 connection between the Israeli transmission system and the Jordanian transmission system on the border between Israel and Jordan. 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. $109 million (100%, the Partnership's share being approx. $49 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. The price of the gas that was set 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 commission and piping fees. In addition, NEPCO will bear the piping payments to INGL.

In November 2016, the Leviathan Partners and the Marketing Company signed a back-to-back GSPA ("**Back-to-Back**"), 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.

c) **Agreement for the Export of Natural Gas from the Leviathan Project to Blue Ocean in Egypt:**

In February 2018, an agreement was signed between the Partnership and Chevron and Blue Ocean (in this section: the "**Buyer**" or "**Blue Ocean**") for the export of natural gas from the Leviathan project to Egypt.

On September 26, 2019, the signing of an agreement for amendment of the original Leviathan-Blue Ocean agreement between the Leviathan Partners and Blue Ocean was closed (in this section: the "**Leviathan 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. On January 15, 2020, the flow of natural gas began in accordance with the Leviathan Agreement. In a tax decision 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 set in the Leviathan Agreement, which is based on the Brent oil barrel price, while making several adjustments as specified in the tax decision, including in view of the location of the delivery point in the Leviathan Agreement.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):
C. Engagements for the supply of natural gas (Cont.):

c) Agreement for the Export of Natural Gas from the Leviathan Project to Blue Ocean in Egypt (Cont.):

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 EAPC site in Ashkelon was completed. The installation of the compressor enabled the quantity of gas piped from the Leviathan reservoir to Egypt to be increased.

<u>Below is a summary of the details and terms and conditions of the Leviathan export agreement</u>:

1) The total contract gas quantity which the Leviathan Partners undertook to supply to the Buyer on a firm basis is approx. 60 BCM (the "**TCQ**").
2) The supply of gas began on January 15, 2020, and will be until December 31, 2034 or until the supply of the full TCQ, whichever is earlier (the "**Term of the Leviathan Agreement**"). In the event that the Buyer does not purchase the TCQ, each party will be entitled to extend the supply period by two additional years.
3) The Leviathan Partners undertook to supply the Buyer with annual gas quantities as follows: (i) in the period that commenced on January 15, 2020 and ended on June 30, 2020, approx. 2.1 BCM per year; (ii) in the period that commenced on 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 end of the Term of the Leviathan Agreement, approx. 4.7 BCM per year. It is noted that the increase of the supply as aforesaid is made by upgrading the systems at the EMG terminal in Ashkelon, including the installation of another compressor, and by increasing the transmission capacity in INGL's system and/or transport of natural gas from Israel to Egypt via Jordan. See Note 12N below.
4) The Buyer has undertaken to take or pay for quarterly and annual quantities according to mechanisms set forth in the Leviathan 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. If the contract quantity is reduced in the case of a disagreement about the gas price update, as stated in Paragraph 5 below, Blue Ocean's right to reduce the take-or-pay quantity as aforesaid will be revoked (see Note 12L9 below regarding a claim and a motion for class certification thereof which was filed against the Partnership in connection with such clause).
5) The price of the gas to be supplied to the buyer will be determined according to a formula based on a Brent oil barrel, and a "floor price". Export to Egypt includes a mechanism for a price update of up to 10% (up or down) after the fifth and tenth years of the agreement, upon certain conditions specified in the agreement. If the parties do not reach an agreement on the price update as aforesaid, the buyer shall have the right to reduce the contractual quantity by up to 50% on the first adjustment date and 30% on the second adjustment date. The agreement includes an incentives mechanism, subject to quantities and the oil barrel price.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):
C. Engagements for the supply of natural gas (Cont.):

c) Agreement for the Export of Natural Gas from the Leviathan Project to Blue Ocean in Egypt (Cont.):

6) The Leviathan Agreement includes accepted provisions relating to conclusion of the agreement, as well as provisions in the case of conclusion of the export agreement, signed between the Tamar partners and Blue Ocean as a result of a breach thereof, and the Leviathan Partners' not agreeing to supply also the quantities according to the said Tamar agreement, and also includes compensation mechanisms in such a case.
7) It is noted that in the context of the set of agreements described above, the Leviathan Partners and Blue Ocean signed an amendment to the export to Egypt agreement, in which agreements were reached, *inter alia*, on defining the delivery point in Aqaba, Jordan, as an additional point of delivery under the Leviathan Agreement, and adjustments to the price of the natural gas to be supplied at the additional point of delivery as aforesaid, in accordance with the additional costs entailed by the transmission of the gas from the additional point of delivery, to be borne by Blue Ocean. It was also agreed in the framework of said amendment that the calculation of the quantities made available by the Leviathan Partners to Blue Ocean shall be performed in 2022 on an annual average basis, such that at the end of the year the parties will review the quantities supplied, including on a Spot basis, during the year, such that oversupplied quantities shall be offset against the quantities of gas nominated by Ocean but not supplied thereto during such period.

Concurrently with the signing of the Leviathan Agreement, an agreement was signed between the Partnership and Chevron and the rest of the Leviathan Partners and the Tamar partners in connection with allocation of the capacity (in this section: the "**Capacity Allocation Agreement**") in the transmission from Israel to Egypt system.
The allocation of the capacity in the transmission from Israel to Egypt system (the EMG pipeline and the transmission in Israel pipeline) 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.

Pursuant to the Capacity Allocation Agreement, on the date of the closing the EMG transaction, the Leviathan Partners and the Tamar partners paid the Partnership and Chevron the sum of $250 million (80% by the Leviathan Partners and 20% by the Tamar partners), as participation fees, in consideration for the undertaking to allow the piping of natural gas from the Leviathan and Tamar reservoirs and guaranteeing capacity in the EMG Pipeline. Pursuant to the agreement, the amount of the aforesaid payments will be updated according to the formula and dates determined in the agreement, based on the actual use of the EMG pipeline.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

C. Engagements for the supply of natural gas (Cont.):

c) Agreement for the Export of Natural Gas from the Leviathan Project to Blue Ocean in Egypt (Cont.):

In view of the aforesaid, for the period between January 1, 2022 and June 30, 2022, the distribution of payments between the Leviathan Partners and the Tamar partners was approx. 83% and approx. 17%, respectively. The Capacity Allocation Agreement determines further arrangements for bearing the additional costs and investments that will be required for refurbishment of the EMG pipeline and maximum utilization of the pipeline capacity, which shall be paid by both the Leviathan Partners and the Tamar partners. In this context it is noted that on June 30, 2022, the parties updated the distribution of payments between the Leviathan Partners and the Tamar partners, and held a reconciliation accordingly in non-material amounts, for purposes of adjusting the parties' respective rates of participation in the actual costs of usage of the EMG pipeline capacity in such period. The Capacity Allocation Agreement further determines that 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 Blue Ocean, 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 agreement, 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; or in a case where the Competition Authority shall not have approved extension of the capacity and operatorship agreement according to the decision of the Competition Commissioner. 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.

D. Agreement for the supply of condensate to ORL:

In December 2019, an agreement was signed (the "**ORL Agreement**") whereby condensate produced from the Leviathan reservoir will be piped to the existing fuel pipeline of EAPC which leads to a container site of Petroleum & Energy Infrastructures Ltd. ("**PEI**") and from there it will be piped to ORL's facilities, according, *inter alia*, to regulatory directives.

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 MoEP.

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 relating to the piping of the condensate.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

D. Agreement for the supply of condensate to ORL (Cont.):

In the context of correspondence between the Leviathan Partners and ORL in Q1/2022, the Leviathan Partners claimed against ORL that failure to pay for the condensate supplied to ORL as aforesaid constitutes prohibited and unlawful abuse of ORL's power as a monopsony in the purchase of condensate. In the context of this claim the Leviathan Partners invited ORL to enter into negotiations to remedy the aforesaid violation immediately and retroactively. In its reply ORL rejected the Leviathan Partners' arguments. The Leviathan Partners reiterated their position whereby ORL's failure to pay for the condensate supplied thereto as aforesaid constitutes a violation of the law which causes material damage to the Leviathan Partners. As of the date of approval of the financial statements, the Leviathan Partners are considering institution of legal measures against ORL. Note that following the signing of the agreement with PAR (as set forth in Section E below), ORL sent a letter to the Leviathan Partners whereby the engagement with PAR is a breach of the agreement with ORL, an expected breach of the agreement and bad faith conduct. The Partnership's position is that ORL's said allegations are unfounded.

E. Agreement for the transport of condensate from the Leviathan reservoir

On September 1, 2022, Chevron and Energy Infrastructures Ltd. ("**PEI**") signed an agreement intended to regulate an alternative for the transport of condensate from the Leviathan project through an existing 6" pipe of PEI and the systems related thereto (the "**Agreement**" and the "**Pipe**", respectively), with the following main provisions:

1. The Agreement will take effect on the date of fulfillment of the closing conditions specified therein (the "**Effective Date**"), and the transport of the condensate through the Pipe will begin on the date of fulfillment of various additional conditions, as specified below (the "**Transport Commencement Date**"). The Agreement will be valid for 20 years from the Transport Commencement Date. In the Partnership's estimation, the Transport Commencement Date is expected to take place in Q4/2023, subject to the fulfillment of the closing conditions of the transport agreement.
2. PEI will be responsible for planning and carrying out the work for connection and adjustment of the Pipe to transport of the condensate as aforesaid (the "**Connection Work**"). PEI will be responsible for receiving all approvals for the transport of condensate through the Pipe and for the ongoing operation and maintenance of the Pipe.
3. In accordance with the Agreement, Chevron (through the Leviathan Partners, per their share in the Leviathan leases) will bear the costs associated with the Connection Work in accordance with the scope and mechanism stipulated in the Agreement, in amounts agreed upon by the parties in advance, and which are not material to the Partnership.
4. The Agreement will take effect upon the fulfillment of the following closing conditions: (a) receipt of the regulatory approvals specified in the Agreement; (b) signing and taking effect of an agreement for the sale of condensate (signed with PAR as set forth in Section F below); and (c) Chevron's approval of the PEI's plan to implement the recommendations of a report prepared by an external professional consultant who examined the suitability of the Pipe for the provision of the transmission services contemplated in the Agreement.
5. The Transport Commencement Date will be upon completion of the Connection Work and receipt of the required approvals for the transport of the condensate through the Pipe.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

E. Agreement for the transport of condensate from the Leviathan reservoir (Cont.):

6. Each of the parties may bring the Agreement to an end if the closing conditions were not met within 12 months from the date of signing or if the Transport Commencement Date was not met within 12 months from the Effective Date of the Agreement.
7. During the piping period, PEI will make the Pipe available for Chevron's use (other than in emergencies defined in the Agreement, in which the piping of condensate through the Pipe will be temporarily discontinued), and reserve an agreed capacity in the Pipe in exchange for fixed capacity fees stated in the Agreement. In addition, PEI will transport the condensate through the Pipe, in consideration for transport fees agreed upon in the Agreement.
8. The Agreement includes provisions regarding the possibility of canceling it before the end of the period specified in Section 1 above, in certain cases and under certain conditions.

In November 2022, the Leviathan Partners approved a budget of approx. \$27 million (100%, the Partnership's share is approx. \$12.2 million) for implementation of the Agreement as aforesaid.

F. Agreement for the sale of condensate from the Leviathan reservoir with Paz Ashdod Oil Refinery Ltd. ("PAR")

On January 18, 2023, the Leviathan Partner, including the Partnership (the "**Sellers**") engaged with PAR in an agreement for the sale of condensate to PAR (the "**Agreement**"), with the following main provisions:

1. The Sellers undertook to provide to PAR, condensate that is produced from the Leviathan reservoir, which will be transported through PEI's pipe.
2. The Agreement stipulates, *inter alia*, provisions regarding limitations on the maximum quantities (on a daily and monthly level) of the condensate to be provided to PAR, fines in the event of a breach of the provisions of the Agreement, and other standard provisions in agreements of this type.
3. The piping of the condensate to PAR will begin on the date of commencement of transport in PEI's pipe (the "**Transport Commencement Date**"), and will continue for a period of 4 years. In the Partnership's estimation, the Transport Commencement Date will take place during Q4/2023, subject to the fulfillment of the closing conditions of the transport agreement.
4. The price to be paid to the Sellers was determined according to the price of a Brent oil barrel less a margin, in a graduated manner, as specified in the Agreement.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

G. Estimates regarding gas and condensate quantities and supply dates:

The estimates regarding the natural gas and condensate quantities which will be purchased by the aforesaid buyers in the Leviathan project, 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 prices of gas and condensate, 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 index of energy demand management (TAOZ) which is published by the Electricity Authority and the crack spread index (insofar as they are 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.

H. Reimbursement of indirect expenses to the project operators:

The Partnership's operations in the joint ventures Ratio-Yam, and Yam Tethys is carried out by Chevron, 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 Chevron Cyprus.

According to the joint operation agreements in such joint ventures and licenses, it was agreed that Chevron, SOA or Chevron 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, Chevron, SOA and Chevron Cyprus are entitled to reimbursement of indirect expenses calculated as a percentage of the direct expenses, as specified below:

Ratio-Yam joint venture:

Chevron is entitled to reimbursement of all of the direct expenses it incurs in connection with the fulfillment of its duties as operator and to a rate of 1%-4% for exploration expenses, with the rate of payment to the operator decreasing as the exploration expenses increase, and additionally, to a rate of 1% of all the direct development and operating expenses, as defined in the agreement, subject to certain exceptions.

Yam Tethys joint venture:

Chevron 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 and evaluation expenses. As of the date of approval of the financial statements, the rate of reimbursement of development expenses is yet to be determined.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):
H. Reimbursement of indirect expenses to the project operators (Cont.)

Block 12 Cyprus:
Chevron Cyprus is entitled to reimbursement of all of the direct expenses it incurs in connection with fulfillment of its duties as operator as well as amounts for payment of indirect expenses of the operator at a rate of 1%-4% in connection with exploration expenses, note that the rate of payment of the indirect expenses to the operator decreases as the exploration expenses increase. Furthermore, Chevron Cyprus is entitled to payment of indirect expenses at the rate of 1.5% for the operator's indirect expenses out of the overall direct expenses in connection with development activity, subject to specific exceptions, such as marketing activity. As of the date of approval of the financial statements, the operator fees, with respect to indirect expenses in connection with the production activity, have not yet been determined.

I. Dependence on a customer:

As of December 31, 2022, NEPCO and Blue Ocean are the Partnership's largest customers and therefore, termination of the agreements signed between them 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, see Note 22G below.

J. 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, approval for operation of a natural gas production system under the Petroleum Law and in addition, a license was given to Yam Tethys Ltd. (a company owned by the Yam Tethys partners) by the Minister of Energy, 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.
2. In Phase 1 – First Stage 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.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

K. Pledges and guarantees:

1. Short-term bank deposits as of December 31, 2022 include the sum of approx. $131 million used for debt service and current payments in the context of the issue of the Leviathan Bond bonds, a sum of approx. $101.7 million used as a safety cushion for repayment of the principal of the bonds in the context of the issue of Leviathan Bond bonds and a sum of approx. $151.6 million used as a safety cushion for repayment of the principal of the series 2023 bonds (see Note 10B above).
2. A long-term bank deposit as of December 31, 2022 in the sum of $0.5 million used to secure a guarantee in the sum of $1 million, provided by the Partnership and Chevron (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 Government of Cyprus in the framework of the PSC as stated in Note 7C3 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 project, 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 67.6 million.
6. In the context of the abandonment actions in the Yam Tethys project, the Partnership provided a personal guarantee in connection with equipment imported by the operator of the transaction in the sum of approx. ILS 57.7 million in favor of the Israel Tax Authority (Customs).
7. 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.
8. 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.
9. To secure a transmission agreement for the export of gas to Egypt (see Section N) in the context of the Partnership’s activity in the Leviathan project, the Partnership provided bank guarantees in favor of INGL. As of the date of approval of the financial statements the total sum is approx. ILS 151 million, against which the Partnership pledged a dollar deposit in the sum of approx. $11.5 million.
10. In the context of the Partnership’s operations in Morocco, the Partnership provided a guarantee in the sum of approx. $1.75 million to ONHYM (see Note 7C5 above).
11. As of the date of approval of the financial statements, the Partnership provided guarantees in the sum of approx. $54.7 million to the Ministry of Energy in connection with its rights in the oil and gas assets, see Section P3 below.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

L. Legal proceedings:

1. On March 12, 2015, the Partnership and Chevron (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 derived to the Plaintiffs from gas supply agreements which were signed between natural gas consumers and the Yam Tethys partners, some of which was supplied from the Tamar Project, according to the accounting mechanism designated to maintain a balance of the gas quantities in the Tamar Project between the partners therein according to their share. The restitution remedy that the State is being sued to pay is, as of December 31, 2022, approx. $28 million, with the Partnership's share being approx. $13 million. Alternatively, the Plaintiffs' claim that they are at least entitled to a partial restitution amount which as of December 31, 2022 is $19.4 million, with the Partnership's share being approx. $9 million. On November 14, 2022, the court's judgment was received, dismissing the claim, other than in connection with the Plaintiffs' position regarding repayment of interest amounts collected by the Defendant from the Plaintiffs in an immaterial amount, and charging the Plaintiffs with payment of the Defendant's expenses and legal fees. On February 6, 2023, the Plaintiffs filed an appeal from the judgment with the Supreme Court. In the Partnership's estimation, based on the opinion of its legal counsel, it is difficult to estimate the chances of acceptance of the Plaintiffs' claims in the appeal, further to the issuance of the judgment since the Defendant's answer to the appeal has not yet been filed and no hearing has yet been held in the appeal.
According to the aforesaid, the Partnership recorded expenses for the period until the sale of its full holdings in the Tamar Project in the sum of approx. $13.6 million for the Tamar Project and approx. $1.7 million for the Leviathan project, which were included under the 'profit (loss) from discontinued operations' and under the 'royalty expenses in the continued operations', respectively. The expenses include the royalties paid by the Partnership to the State under protest, overriding royalties payables in connection with revenues arising from such gas supply agreements, and an update of the rate of the royalty at the wellhead in the Tamar and Leviathan projects. Note that the decision on this matter, once it is final and non-appealable, shall apply *mutatis mutandis* also to the overriding royalties paid by the Partnership over the years for the Tamar Project. Accordingly, if the court's said decision of November 14, 2022 stands, the Partnership will bear an additional payment (including interest and linkage) to royalty holders for gas quantities supplied by the Partnership to customers of the Yam Tethys project, in the sum of about $6.4 million (including approx. $2.1 million to related parties). According to the agreement for the sale of the Partnership's rights in the Tamar and Dalit Leases, as stated in Note 7C1 above, the Partnership is liable and entitled, as the case may be, in respect of amounts in dispute vis-à-vis the State and the royalties holders, also after the closing of the transaction.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

L. Legal proceedings (Cont.):

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) with respect to the price at which the Tamar partners sell natural gas to the IEC. On August 6, 2021, a judgment of the District Court was issued, denying the Certification Motion. On September 30, 2021, the Petitioner filed an appeal from the judgment with the Supreme Court, in which the Supreme Court was moved to certify the class action and order the District Court to hear the class action. A hearing on the appeal was held on January 9, 2023, at the end of which, at the Supreme Court's recommendation, the Petitioner withdrew the appeal and it was dismissed by the court.
3. On December 25, 2016, the holders of participation units in Avner prior to the merger (the "**Petitioners**"), filed a motion for class certification (in this section: the "**Certification Motion**") 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**"). The motion argues, among other claims, 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 (approx. $91 million).
   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 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**").
   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, and *inter alia*, the duty of care of the said officers and the Partnership's duties as a shareholder and controlling shareholder of Tamar Petroleum prior to the IPO.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

L. Legal proceedings (Cont.):

4. (Cont.)

   The remedies sought in the Certification Motion mainly included 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 gives notice, by September 15, 2019, of whether he wishes to join the proceeding. On November 1, 2020, the Petitioners filed a motion to amend the Certification 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 and to increase the amount of the alleged damage to $153 million.

   On April 6, 2021, the court granted the Petitioners' motion to amend the Certification Motion and ruled that the Petitioners are entitled to file the amended Certification Motion in accordance with the language filed with the court and on January 23, 2022, an amended certification motion was filed.

   The Partnership estimates, based on the opinion of its legal counsel, that the chances of the Certification Motion being granted are lower than 50%.

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**") with the Tel Aviv District Court by an electricity consumer (in this section: the "**Petitioner**") against the Partnership and Chevron 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 Chevron (in this section: the "**Amendment to the Tamar Agreement**").

   The Petitioner's principal arguments are 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 Chevron'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 Chevron under this agreement, while harming competition, amount to unjust enrichment.

   The Petitioner asserts that such actions of the Partnership and Chevron have caused and are expected to cause damage to the classes he seeks to represent in the sum of approx. ILS 1.16 billion, and according to which the court is moved to award compensation and fees.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

L. Legal proceedings (Cont.):

5. (Cont.)

   The main remedy in the Certification Motion is a ruling by the court that the Partnership and Chevron are not entitled to prevent the Other Holders in the Tamar Project from signing the Amendment to the Tamar Agreement. On February 26, 2023, a pretrial was held, at the end of which the court set dates for trial hearings in March-April 2023.
   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%.

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 Tomer Royalties (formerly, Tamar 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.
   On April 4, 2019, the Royalty Interest Owners filed an answer and a counterclaim against the Partnership, the General Partner 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, and of the royalties that the Royalty Interest Owners are entitled to receive, and to deliver such calculation to the Royalty Interest Owners.
   On April 5, 2021, a pretrial hearing took place, during which the parties were offered to refer to mediation, following which the parties agreed to apply to former Supreme Court Justice Yoram Danziger as a mediator. As of the date of approval of the financial statements, the mediation process has not yet been exhausted.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

L. Legal proceedings (Cont.):

6. (Cont.)

   The Partnership estimates that any decision to be made regarding the method of calculation of the investment recovery date in the Tamar Project will apply, *mutatis mutandis*, also to the Partnership's liabilities for royalties in the Leviathan project (in view of the fact that the royalty arrangements in the Tamar Project are similar to the royalty arrangements in the Leviathan project).

   In the Partnership's estimation, based on the opinion of its legal counsel, the chances of the Counterclaim being granted are lower than 50%.

7. 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.) (in this section: the "**Appellants**") filed an administrative appeal with the Jerusalem District Court (sitting as the Competition Court) against the Commissioner (as a respondent) and against EMG and EMED. In essence, it was argued in the administrative appeal that the Merger will enable the Partnership and Chevron 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 (on the date of filing of the appeal, the Partnership has not yet sold its rights in the Tamar reservoir), 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 21, 2022, a judgment was issued in the appeal, in which the court ruled that the Appellants failed to demonstrate that the Merger raises a reasonable concern of significant damage to competition and therefore denied the remedy seeking to cancel the approval given for the Merger transaction.

   However, the court ordered the Commissioner to issue a supplementary decision regarding the conditions which she imposed on the Merger, in view of difficulties raised by these conditions. The court further ruled that each party will bear its own costs. Since no appeal was filed from the judgement, the judgement became final on February 5, 2023.

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, Delek Group, Yitzhak Sharon (Tshuva), the directors of the General Partner (including the former chairman of the board) and the CEO of the General Partner (in this section: the "**Certification Motion**" and the "**Respondents**", respectively), with the Economic Department of the Tel Aviv District Court.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

L. Legal proceedings (Cont.):

8. (Cont.)

   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 Blue Ocean (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.

   According to the court's decision and the stipulation between the parties, the Petitioner and the Respondents shall file summations and responding summations in 2023, by July 11, 2023. 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. On July 20, 2020, the Partnership received a letter of demand from the ISA to provide information and documents in the context of an administrative inquiry conducted by the ISA with regard to the reduction clause in the export to Egypt agreements, in connection with which the motion for class certification described in Section 8 above was filed. The Partnership filed a response to the said letter of demand on November 10, 2020, and on April 12, 2022 the Partnership received a notification of the ISA regarding the closure of such administrative inquiry case, according to the decision of the chairman of the ISA not to open an administrative enforcement proceeding against the Partnership on the matter.

10. On June 18, 2020, the Partnership and Chevron which held the Alon D license filed a petition with the Supreme Court sitting as the High Court of Justice (in this section: the "**Petitioners**" and "**Petition**", respectively). In the Petition the court was moved to issue an order nisi ordering the Minister of Energy and the 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 Petitioners granted a substitute license in its stead, and why the Petitioners 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 areas. A motion was also made for an interim order preventing the expiration of the license or 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 an interim order.

    Already on the same day a decision was issued ordering the Minister of Energy and the Commissioner to file their response to the motion for an interim order by June 28, 2020.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

L. Legal proceedings (Cont.):

10. (Cont.)

In the decision the court rejected the motion for a preliminary order, and pursuant thereto the Alon D license expired on June 21, 2020. Pursuant thereto, on June 23, 2020, the Ministry of Energy announced a competitive process for an oil and natural gas exploration license in Block 72 whose area was covered by the license.

On May 13, 2020, the State filed its preliminary response to the Petition in the context of which it claimed, *inter alia,* that the Petition ought to be dismissed with prejudice because Energean was not added as a respondent. On May 19, 2021, a hearing was held on the Petition in whose context the parties reached an agreement whereby Energean will be added as a respondent to the proceeding, file a response on its behalf within 60 days, and on such date the parties will also provide an update regarding the progress in the competitive process in Block 72, based on an assumption that a winner in the competitive process will be chosen by such date, which is expected to affect the arguments in the Petition. The court approved the stipulation between the parties, such that on August 19, 2021, Energean filed its response to the Petition and on October 25, 2021, the Petitioners filed their reply to Energean's response.

Following the signing of the maritime agreement as specified in Note 7C6 above, on December 8, 2022 the State filed notice of update whereby, in view of the signing of the maritime agreement, such developments may make the Petition redundant. On December 15, 2022, a hearing on the Petition was held, and in the end, the court suggested that the Petitioners withdraw the Petition, and also allowed them to file their position in writing with respect thereto. On December 25, 2022, the Petitioners filed a notice whereby they are not withdrawing the Petition. As of the report approval date, the parties are waiting for the court's decision. In this context, it is noted that as of the report approval date, a decision has not yet been made on the competitive process in Block 72.

11. On May 3, 2021, Haifa Port Co. Ltd. (in this section: "**Haifa Port**") filed a claim against Chevron, Coral Maritime Services Ltd. (in this section: "**Coral**") and Gold Line Shipping Ltd. (in this section: "**Gold Line**") in the sum of approx. ILS 77 million (the "**Main Case**"). According to Haifa Port, direct unloading of cargos in the area of the Leviathan platform, as was done by Chevron, without first unloading such cargos at one of Israel's ports, is unlawful and was done so as to evade making mandatory payments to the port, and financial loss was thus incurred by the port. The complaint claims that from July 2018 forth, Chevron performed direct unloading as aforesaid, while declaring to the tax authorities that Haifa Port was the 'unloading port', even though the cargos that were unloaded did not pass through Haifa Port in practice. The claim against the companies Coral and Gold Line is that they acted, at the relevant times, as the shipping agents for Chevron, which imposes on them, so Haifa Port claims, a duty to pay the handling fees on Chevron's behalf.

    Chevron filed an answer on August 31, 2021, and Haifa Port filed a replication on December 1, 2021. Concurrently, Chevron filed a counterclaim against Haifa Port in the sum of approx. ILS 4.4 million, for a claim in the sum of about ILS 0.7 million for handling fees and infrastructure fees actually and unlawfully charged by Haifa Port, and a claim of some ILS 3.7 million for mooring fees charged to Chevron and unlawfully not reduced by 30%, in cases of self-routing of ships which passed through the port area.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

L. Legal proceedings (Cont.):

11. (Cont.)

    On September 11, 2022, a pretrial hearing was held, in which it was determined that the parties will negotiate with the aim of reaching agreement on the completion of the preliminary proceeding, failing which they will file motions accordingly. Despite the attempt to reach agreements, the parties filed mutual motions regarding the preliminary proceedings. The parties are required to respond to the motions by April 9, 2023 and these shall be discussed in the pretrial hearing scheduled for April 20, 2023.

    In the Partnership's estimation, based on the opinion of its legal counsel, the Main Case is more likely to be denied than granted.

12. On December 15, 2020, a motion for class certification was filed with the Tel Aviv District Court against Chevron (in this section: the “**Respondent**”) 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 “**Certification Motion**”, the “**Petitioner**” and the “**Class Members**”). In essence, the Certification Motion argues that the Respondent 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 Respondent to immediately fulfill the obligations imposed thereon in the Clean Air Law and the regulations promulgated thereunder. In the Partnership's estimation, based on the opinion of its legal counsel, the main case is more likely to be denied than granted.

    In its decision of June 26, 2022, the court denied the main part of the discovery motion and granted a part thereof, ruling that Chevron must discover the decisions of the Ministry of Environmental Protection regarding the imposition of penalties and transcripts of hearings held towards the imposition of penalties. Chevron has submitted the relevant documents for inspection by the court, together with a submission arguing and moving for various details to be protected by privilege. On February 21, 2023 the court dismissed the motion of the Petitioner to submit the regulator opinion which was filed in another case and which, according to the Petitioner, has implications on the Certification Motion.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):
L. Legal proceedings (Cont.):

13. Further to the filing of the motion as provided in Note 12P below, on May 11, 2021, an objection to the motion was filed with the court on behalf of the holders of Participation Units, and on May 11, 2021 and May 12, 2021, the court's decisions were received in connection with the objection, whereby a preliminary hearing will be held on the objection only after the lapse of the deadline for the filing of objections to the motion on May 25, 2021. It is noted that on May 24, 2021 and May 26, 2021, the Partnership reported their response to the motion of the Tel Aviv Stock Exchange Ltd. and of the ISA, respectively.
    On July 5, 2021, Cohen Development Gas & Oil Ltd., Y.N.U Nominee Company Ltd. and J.O.E.L. Jerusalem Oil Exploration Ltd. (the "**Parties Moving to Join the Proceeding**") filed a motion to join the proceeding as a party and for clarification of provisions of the Arrangement, on July 18, 2021 the General Partner filed a response to the said motion, and on July 26, 2021 the court ruled that the Parties Moving to Join the Proceeding would be joined to the proceeding as a party, and that there was no room to split the hearing. On October 13, 2021, a hearing was held on the motion. On November 10, 2021 and November 14, 2021, some of the respondents and the Israel Securities Authority, respectively, filed their response. The General Partner and the Limited Partner, as well as Delek Group, filed their response on December 12, 2021. In the judgment which was issued on December 27, 2021 as aforesaid, the motion to convene a general meeting to approve the arrangement was approved and it was ruled that the right of Delek Group, the control holder of the Partnership, to receive overriding royalties from the Partnership will not be subject to reapproval in the future. On February 23, 2022, an appeal from the judgment as well as a motion to stay its execution was filed with the Supreme Court by the holders of the participation units in the Partnership. The hearing of the appeal was scheduled for June 27, 2022. On April 4, 2022, a decision was handed down by the Supreme Court dismissing the motion for stay of execution according to the agreements between the parties. On May 31, 2022, the General Partner and the Limited Partner filed an answer to the appeal, and on the same date the ISA filed its position in the appeal. In addition, on June 1, 2022, Delek Group filed an answer to the appeal. On June 30, 2022 the hearing of the appeal was held, and on July 25, 2022 the Supreme Court issued its judgement in the appeal, according to the parties' agreements, reversing the judgement of the District Court of December 27, 2021. At the same time, it was ruled that it will be possible to convene the unitholders meeting to approve the arrangement until September 22, 2022, with the closing of the arrangement contingent on the issuance of an appropriate order by the Minister of Justice according to Section 351A(b) of the Companies Law (which order may be issued after the convening of the meeting). On August 15, 2022, the respondents filed a motion to correct an error in the judgement issued in the appeal, and on August 17, 2022, the Supreme Court denied the motion to correct an error, but granted the respondents' alternative motion for an extension to convene the general meeting of unitholders.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):
L. Legal proceedings (Cont.):
13. (Cont.)

On October 6, 2022 (for the sake of caution), a motion was filed with the Tel Aviv District Court by the General Partner and the Limited Partner for instructions on the continued conduct of the proceedings, in view of changes made in the original arrangement, including exchange of the participation units of the Partnership for ordinary shares of an existing company traded on the London Stock Exchange, in lieu of a new company incorporated in England (in this section below: the "**Motion for Instructions**"). On October 31, 2022, a decision was issued by the court approving the Motion for Instructions. On December 25, 2022, the General Partner and the Limited Partner filed a motion to postpone the date for convening the unitholders' meeting to approve the arrangement, and according to the court's decision of December 27, 2022, an answer to the motion was filed on January 1, 2023 by the ISA, as well as the appellants' response to the motion. On January 10, 2023, a decision was issued by the court approving the postponement of the date for convening of the unitholders' meeting.

M. Engagement in a transmission agreement for the export of gas to Egypt:

On May 28, 2019, Chevron and INGL engaged in an agreement for supply of interruptible transmission services in relation to the piping of natural gas from the Leviathan reservoir and Tamar reservoir to EMG's terminal in Ashkelon, for the purpose of gas export to Egypt (in this section: the "**2019 Agreement**"). The payment pursuant to the 2019 Agreement will be made based on the gas quantity actually piped through the transmission system, subject to Chevron's undertaking to pay for certain minimum quantities.

In July 2020, upon the operation of a compressor at the entrance to the EMG system in Ashkelon, the transport capacity of the EMG pipe increased, within the infrastructure limits of the current INGL transmission system, to approx. 500 MMCF per day (approx. 5 BCM per year). According to the export to Egypt agreement, as described in Note 12C(c) above, the additional compressor was installed in Ashkelon, such that together with the construction of the Combined Section Ashdod-Ashkelon by INGL, the transmission capacity in the EMG system could be increased to approx. 650 MMCF per day, and even more, given certain conditions in the Israeli and Egyptian transmission systems.

On January 18, 2021, Chevron engaged with INGL in an agreement for the provision of transmission services on a firm basis for the piping of natural gas from the Leviathan and Tamar reservoirs to the EMG terminal in Ashkelon and for the transmission thereof to Egypt, which took effect on February 14, 2021 (the "**Transmission Agreement**" or, in this section: the "**Agreement**"). Below is a concise description of the principals of the agreement:

1) In the Transmission Agreement, INGL undertook to provide transmission services for the natural gas that shall be supplied from the Leviathan and Tamar reservoirs, 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, Chevron 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.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

M. Engagement in a transmission agreement for the export of gas to Egypt (Cont.):

1) (Cont.)

For transmission of the additional quantities as aforesaid, Chevron 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 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, Chevron 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 (the "**Combined 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 Combined Section (see Paragraph 6)(the "**Council's Decision**"), and doubling of the Dor-Hagit and Sorek-Nesher transmission system segments in a manner which will allow the piping of the full quantities under the Transmission Agreement (in this section: the "**Transmission Commencement Date**").
4) The Transmission Agreement will end upon the earlier of: (1) the date on which the total quantity that is piped is 44 BCM; (2) 8 years after the Transmission Commencement Date; 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.
5) The transmission period under the 2019 Agreement will be extended until January 1, 2024 or until the Transmission Commencement Date according to the Transmission Agreement, whichever is earlier.
6) In accordance with the principles determined in the Council's Decision, Chevron undertook to pay INGL the amount for the share of the partners in the Leviathan and Tamar projects 56.5% out of the total cost of construction of the Combined Section, which is estimated at ILS 738 million. On May 2, 2022, INGL updated the budget of the Combined Section to a total of approx. ILS 796 million. As of the date of approval of the financial statements, the remaining commitment for the Combined Section is approx. ILS 40 million. In addition, in order to meet the transmission capacity in Ashkelon, INGL is required to accelerate the doubling of the Dor-Hagit and Sorek-Nesher sections at the cost of approx. ILS 48 million. Therefore, Chevron undertook to pay ILS 27 million for such partners' share (56.5%), see Note 12P5 above. As of the date of approval of the financial statements, the balance of the undertaking for the doubling is approx. ILS 13.5 million.
7) In accordance with the Council's Decision, the Leviathan Partners and the Tamar partners provided a bank guarantee to secure INGL's share in the cost of construction of the foregoing infrastructure, and to cover Chevron's commitment to pay the capacity and transmission fees. As of the date of approval of the financial statements, the guarantees in favor of INGL for the Partnership's share in the Leviathan project, are approx. approx. ILS 151 million, and also pledged in favor of the facility for the guarantees a deposit in the sum of approx. $11.5 million (see Note 12K9).

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

M. Engagement in a transmission agreement for the export of gas to Egypt (Cont.):

8) The Leviathan Partners and the Tamar partners will bear the costs stated in Paragraph 6 at the rates of 69% and 31%, respectively.
9) The Transmission Agreement stipulates that in case of cessation of the export of natural gas from the Tamar and Leviathan projects to Egypt, Chevron 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 110% of the costs of construction of the Combined Section, plus the costs of accelerating the doubling of the Sorek-Nesher and Dor-Hagit sections, net of the amounts Chevron 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) The Partnership estimates that its share in the cost of construction of the Combined Section, in the costs of accelerating the doubling of the Dor-Hagit and Sorek-Nesher transmission system sections may amount to approx. $46.2 million.
11) Concurrently with the signing of the Transmission Agreement, Chevron, the Leviathan Partners and Tamar partners signed a back-to-back services agreement which determined that the Leviathan Partners and Tamar partners will be entitled to transmit gas (through Chevron) under the Transmission Agreement, and will be responsible for fulfillment of Chevron's undertakings under the Transmission Agreement as if the Leviathan Partners and the Tamar partners were a party to the Transmission Agreement in Chevron'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 Chevron 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.
12) On February 26, 2023, Chevron received a letter from INGL, according to which, following a malfunction on a vessel carrying out infrastructure work for the laying of the offshore pipeline for INGL in the Combined Section, and further to a preliminary evaluation that INGL received from the construction contractor for the Combined Section, a delay of at least 6 months is expected in the date of its completion, such that the window of time in which the Transmission Commencement Date has been postponed to the period from October 1, 2023 until April 1, 2024. INGL's said letter received from INGL was given as a notice of *force majeure* according to the Transmission Agreement, and stated that the full repercussions thereof are not yet known thereto at this stage. On March 9, 2023, Chevron responded to such letter on behalf of the Leviathan and Tamar partners, stating that it rejects the notice of *force majeure*. The Partnership estimates that such deferral shall not materially affect the Partnership's business and the results of its operations.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

M. Engagement in a transmission agreement for the export of gas to Egypt (Cont.):

13) The Leviathan Partners have signed a set of agreements, aimed to allow for the piping of natural gas under the Export to Egypt Agreement, through Jordan, using the Israeli transmission system to Jordan and the transmission system that connects Jordan to Egypt in the Aqaba-Taba area (the Arab Gas Pipeline). Under such set of agreements, in March 2022, natural gas piping to Egypt through Jordan had commenced, which allows for maximizing the sale of the natural gas produced from the Leviathan reservoir and transmitting natural gas surpluses that are not consumed in Israel and Jordan and/or piped to Egypt via the EMG pipeline, to the Egyptian market, via the Jordanian transmission system, mainly until the Combined Section is completed by INGL as aforesaid. As of the date of approval of the financial statements, and as the Partnership was informed by the Operator in the Leviathan Project, using the existing transmission infrastructure and current operating conditions, natural gas can be flowed to Egypt, via Jordan, in an average daily amount of up to approx. 350 MMCF (approx. 3.5 BCM per year). It is noted in this context that the Ministry of Energy has granted the Leviathan Partners its approval to add a delivery point of natural gas to Egypt, which is expected to be located in Aqaba, Jordan.

The aforesaid set of agreements includes the agreements specified below:

1. Agreement between Chevron and FAJR, the Jordanian transmission company, for supply of interruptible transmission services in relation to piping of natural gas from the Leviathan and Tamar reservoirs through the transmission system in Jordan, from the point of entry at the border between Israel and Jordan to the delivery point at the border between Jordan and Egypt, near Aqaba (the "**FAJR Agreement**"). The payment pursuant to the FAJR Agreement will be made based on the gas quantity actually piped in the FAJR transmission system.
2. Concurrently with the signing of the FAJR Agreement, Chevron and the other Leviathan and Tamar partners engaged in a back-to-back services agreement, in the context of which the holders of interests to the Leviathan and Tamar reservoirs will be entitled to transmit gas (through Chevron) in the FAJR Agreement, and according to which, *inter alia*, the use of the FAJR transmission system for the purpose of export of natural gas to Egypt from the Leviathan and Tamar reservoirs will be made in accordance with the mechanism, terms and conditions, and order of priority specified in the aforesaid agreement.
3. Agreement between Chevron and INGL for supply of interruptible transmission services in relation to the piping of natural gas from the Leviathan reservoir to the point of connection to the FAJR transmission system at the border between Israel and Jordan (the "**INGL Agreement**"). The payment pursuant to the INGL Agreement will be made based on the gas quantity actually piped through the INGL transmission system, subject to Chevron's undertaking to pay for a minimum quantity as specified in the INGL Agreement.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

M. Engagement in a transmission agreement for the export of gas to Egypt (Cont.):

13) (Cont.):

3. (Cont.):

It is noted that the term of the INGL Agreement was extended until January 1, 2024, unless it expires prior thereto pursuant to the provisions thereof or if the parties consensually extend it, subject to the decisions of the Natural Gas Authority at such time. Concurrently with the signing of the INGL Agreement, Chevron and the other Leviathan Partners engaged in a back-to-back services agreement in connection with the INGL Agreement.

4. The Leviathan and Blue Ocean partners signed an amendment to the Export to Egypt Agreement as specified in Note 12C(c) above.

14) It is noted that since the aforesaid transmission agreements are for provision of interruptible transmission services, on the date of approval of the financial statements, it is uncertain whether piping the full additional quantities which the Leviathan partners undertook to supply to Blue Ocean, through Jordan, will be possible. However, effective from July 1, 2022, and as of the date of approval of the financial statements, the Leviathan Partners piped, through Jordan, the full additional quantities they undertook to provide to Blue Ocean.

15) In April 2022, the Commissioner notified Chevron that commencing on June 1, 2022, and until September 15, 2022, the Leviathan Partners must ensure the supply of natural gas to the domestic market in a greater quantity than the daily quantity which the Leviathan Partners committed to supply to the domestic market under the gas supply agreements in which they engaged. It is clarified that the aforesaid did not have a material effect on the business results of the Partnership.

N. Engagement for collaboration in renewable energies:

On September 21, 2022, the general meeting of the Unit holders gave approval to the Partnership to make investments in renewable energy projects, up to the aggregate investment amount (the Partnership's share only) of US $100 million (by capital and/or by shareholder's loan including a capital note or by way of guarantee in respect of loans to be provided), as required by TASE Rules, and in such context, approved the outline of the transaction with Enlight, while noting, *inter alia*, Mr. Abu's personal interest in the transaction.

Accordingly, on March 13, 2023 the Partnership engaged with Enlight in a detailed agreement regarding exclusive collaboration for a fixed term regarding the initiation, development, financing, construction and operation of renewable energy projects, including in the following fields: solar projects, wind projects, energy storage, and other segments of renewable energy, insofar as relevant in several target countries, including Egypt, Jordan, Morocco, the UAE, Bahrain, Oman and Saudi Arabia (in this section: the "**Agreement**" and the "**Transaction**", respectively). As specified below, under the Transaction, Enlight will allocate a certain part of its interests in the Transaction to Mr. Yossi Abu, CEO of the Partnership ("**Mr. Abu**"). Accordingly, on March 13, 2023, an agreement was signed between Mr. Abu and Enlight (the "**Abu Agreement**").

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):
N. Engagement for collaboration in renewable energies (Cont.):

Below is a concise description of the main parts of the Agreement:

1) The parties will act together, on an exclusive basis for a fixed term, for the initiation, development, financing, construction and operation of renewable energy projects in the aforementioned target countries (in this section: the "**Joint Venture**"). For the purpose of the Joint Venture, the parties will form corporations that will engage in the promotion of the joint operations (the "**Co-Owned Corporations**"). The rate of the Partnership's holdings in the Co-Owned Corporations will be 33.33%, with the remaining interests in the Co-Owned Corporations (66.67%) held by a corporation that will be held by Enlight (70%) and Mr. Abu (30%) (the "**Enlight Corporation**"). According to the Abu Agreement, Mr. Abu's share in the investments required in the Enlight Corporation will be provided for his benefit by Enlight by way of providing a non-recourse loan.
2) As part of the Joint Venture, the Partnership will utilize its business connections in the aforementioned target countries to promote the Joint Venture, with Mr. Abu's active personal involvement. The Enlight Corporation, via Enlight, will provide the joint operations with professional design, development and management services in the interest of promoting the Joint Venture.
3) Control during the projects' construction and operation stages will be held by Enlight. The agreement stipulates provisions with respect to the parties' rights to appoint board members of the Co-Owned Corporations based on their holding rates, and it also stipulates that Mr. Abu will serve as chairman of the board of the Co-Owned Corporations in the first 24 months.
4) In the context of the Joint Venture, one of the Co-Owned Corporations will perform feasibility studies and due diligence for any project it deems suitable for the collaboration and thereafter, each party will notify the other party whether it wishes to participate and promote the proposed project in the context of the Joint Venture. If the Partnership does not approve its participation in a specific project or objects to its promotion, the Enlight Corporation will be entitled to perform the project independently without the Partnership, in which case the Partnership will be entitled to reimbursement of its expenses in the aforesaid project together with interest.
5) In the Agreement it has been agreed that resolutions of the Co-Owned Corporations will be adopted by a majority vote, subject to the requirement of the Partnership's consent in certain resolutions so long as the Partnership holds 15% or more of the capital of the Co-Owned Corporations. Provisions have also been specified with respect to the manner of financing of the operations of the Joint Venture and the investments in projects to be made thereunder, based on the relative share of each of the parties.
6) The term of the parties' exclusive collaboration will be 3 years from the Agreement signing date, which, under certain circumstances, may be extended up to a term of 5 years from the Agreement signing date (the "**Term of Exclusivity**"). Following the expiration of the Term of Exclusivity, the collaboration will continue with respect to projects that shall have commenced prior to the expiration date, and Enlight may promote projects that are in advanced development stages without the Partnership's participation.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

N. Engagement for collaboration in renewable energies (Cont.):

The Agreement specifies additional provisions on other matters, as is standard in transactions of this type, *inter alia*, with respect to resolutions that require the consent of the Partnership, so long as the Partnership holds 15% or more of the capital of the Co-Owned Corporations, provisions regarding the restrictions that will apply to the transfer of interests in the Co-Owned Corporations to third parties, early termination of the Term of Exclusivity, provisions regarding the joining of third parties to the projects and provisions regarding the Co-Owned Corporations' profit distribution policy. On September 21, 2022, the general meeting of the unit holders gave approval to the Partnership to make investments in renewable energy projects, up to the aggregate investment amount (the Partnership's share only) of US $100 million (by capital and/or by shareholder's loan including a capital note or by way of guarantee in respect of loans to be provided), as required by TASE Rules, and in such context, approved the outline of the transaction with Enlight, while noting, *inter alia*, Mr. Abu's personal interest in the transaction.

As of the date of approval of the financial statements, the parties are acting to find opportunities to make investments in renewable energy projects in the context of the collaboration.

O. Transaction for restructuring and business combination with Capricorn, which was cancelled:

On May 4, 2021, the General Partner and Limited Partner filed a motion with the Tel Aviv District Court pursuant to Sections 350 and 351 of the Companies Law for approval of the convening of a general meeting of the unit holders for approval of an arrangement which mainly concerns substitution of all of the issued participation units with ordinary shares of a new company incorporated in Britain, whose shares were intended to be listed for dual listing on the London Stock Exchange and TASE. After objections to the motion of the participation unit holders, the response of the Tel Aviv Stock Exchange Ltd. and of the Israel Securities Authority to the motion, and the joining of Cohen Development Gas & Oil Ltd., Y.N.U. Nominee Company Ltd. and J.O.E.L. Jerusalem Oil Exploration Ltd. as a party to the proceeding, and for clarification of the provisions of the arrangement. On December 27, 2021, the request to convene a general meeting for approval of the arrangement was approved, and it was also determined that the right of Delek Group, the control holder of the Partnership, to receive overriding royalties from the Partnership would not require repeat approvals in the future.

On February 23, 2022, an appeal was filed with the Supreme Court from the judgment, as well as a motion for a stay of its execution, by the holders of the Partnership's participation units. On July 25, 2022, the Supreme Court entered a judgment on the settlement suggested by the justices, in which the respondents were given a possibility to convene a special general meeting for approval of the arrangement until September 22, 2022. The court further ruled that approval of the arrangement by the court is contingent on the issuance of an order by the Minister of Justice. Further to the respondents' motion of August 15, 2022 to correct an error in the said judgment, on August 17, 2022 the court denied the motion to correct an error, but granted their alternative motion for extension of the timeframe for the convening of the general meeting until April 2, 2023.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

O. Transaction for restructuring and business combination with Capricorn, which was cancelled (Cont.):

Further to the aforesaid, on September 29, 2022, the Partnership and the General Partner engaged with the British company Capricorn Energy PLC ("**Capricorn**") in a contingent agreement for the performance of a transaction for a business combination of the Partnership and of Capricorn, such that after the closing of the Transaction, all the holders of the Partnership's participation units (including the General Partner) are expected to hold approx. 89.7% of the share capital of the consolidated company, whose shares were intended to be listed on the LSE's premium listing segment and also "cross-listed" on the Tel Aviv Stock Exchange. However, on February 15, 2023, the Partnership and Capricorn agreed on the cancellation of the transaction with immediate effect, *inter alia* in view of developments in Capricorn in the period after the signing of the Agreement, including a fundamental change in the composition of Capricorn's board of directors and executive management.

P. Regulation:

1. **The Gas Framework:**

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 Energies and Chevron (in this section: the "**Parties**") by the former 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.

a) **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.
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.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

P. Regulation (Cont.):

1. The Gas Framework (Cont.):

5) With respect to their activity in the Tamar and Leviathan reservoirs only, the Partnership and Chevron being the holders of a monopoly according to the Competition Commissioner's declarations.

b) The exemption from the restrictive trade practices detailed in Paragraph (a) 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[30], an undertaking to invest in local content[31]. 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.

c) As of the date of approval of the financial statements, the Partnership has sold all of its holdings in the Karish and Tanin reservoirs (see Note 8B above), and all of its holdings in the Tamar and Dalit Leases (see Note 7C(1) above) in accordance with the Gas Framework.

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 May 20, 2020, Chevron received a notice from the MoEP 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. Chevron informed the Partnership that that it submitted a request to the MoEP to receive information by virtue of the Freedom of Information Law, 5758-1998, which directly contemplates arguments raised in said notice and that the MoEP 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.

[30] 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 7C(8) above.

[31] This undertaking regarding investment in local content was fully fulfilled.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

P. Regulation (Cont.):

2. Environmental Regulation:

b) On November 1, 2021, Chevron received a cease-and-desist letter and invitation to a hearing before the MoEP for non-compliance with the conditions of the sea discharge permit which was granted to the Leviathan platform and violation of the Prevention of Sea Pollution from Land-Based Sources Law, 5748-1988, in the framework of which it was argued that Chevron deviated from the standards determined for sea discharge from the open system. The hearing was held on January 6, 2021 and in its context it was determined that Chevron is required to institute any and all acts to prevent deviations from the sea discharge permit and that the MoEP is considering to exercise its full powers pursuant to the law, including a possible recommendation on a financial penalty by law. On June 28, 2022, Chevron received a letter of demand for the receipt of details about the annual sales turnover according to Section 5(c)(b)(2) of the Prevention of Sea Pollution Law.

The letter stated that the information is required for determining the amount of the financial penalty that the MoEP intends to impose on Chevron for violating conditions in the discharge of wastewater to the sea permit (gas production) numbered 24/2021, in connection with the discharge of wastewater that exceeds the standards for discharge into the sea. Chevron submitted the required documents to the MoEP. It is not possible at this stage to estimate for which violations the financial penalty will be imposed and the amount of the financial penalty that will be imposed, if any.

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 approval of the financial statements, the Partnership has deposited autonomous bank guarantees with the Ministry of Energy, in connection with its rights in the oil and gas assets, against a bank credit facility (see Section K11 above).

4. Directives on the manner of calculation of the value of the royalty at the wellhead:

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**"):

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.

b) The Directives determine additional provisions, including a specification of the types of deductible and non-deductible expenses for the above calculation.

c) In September 2020, it released the Specific Directives regarding calculation of the royalty value at the wellhead for the Tamar lease, which specified the deductible expenses for calculation of the royalty at the wellhead.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

P. Regulation (Cont.):

4. **Directives on the manner of calculation of the value of the royalty at the wellhead (Cont.):**

   d) In July 2022, it released the Specific Directives regarding the calculation of the royalty value at the wellhead for the Leviathan lease. Below is a summary of the directives received regarding calculation of the royalty value at the wellhead in the Leviathan 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 Leviathan platform (the "**Platform**"), will be recognized at a rate of 100%; (b) Capital costs in respect of the Platform will be recognized at a rate of 82%; and (c) Capital cost in respect of the transmission pipeline from the Platform up to the entrance to the terminal (DVS) will be recognized at a rate of 100%.
   2. Operating expenses arising directly from the types of Capex specified above, will be recognized at a rate of 82%: salary expenses of the workers at the Platform; maintenance and repair expenses; expenses for travel and transportation to the platform; expenses for food for the workers at the Platform; expenses for guarding and security at the Platform; expenses for professional and engineering consulting; insurance expenses and communications expenses at the Platform.

   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 to INGL directly by the lease holders and that are included in the contractual sale price, will be recognized according to the relevant transmission tariff.

   Abandonment costs will be recognized for calculation of the royalty according to the provisions set forth in the general directives, cumulatively: a. P2 Reserves balance in the Leviathan field according to an updated resources report shall be less than 125 BCM. b. The abandonment plan has been approved by the Commissioner.

   e) On September 2022, the partners in the Leviathan project filed their response to such Specific Directives. As of the date of approval of the financial statements, the response of the Ministry of Energy has not yet been received.

5. **Projects for export through the national transmission system:**

   a. On June 23, 2020, the Director General of the Natural Gas Authority announced his determination that the cost of the Combined Section designated for the piping of natural gas from the Leviathan and Tamar reservoirs to EMG's terminal in Ashkelon for purposes of piping gas to Egypt according to the export agreements is estimated (as of the date of signing of the Transmission Agreement) at a sum total of ILS 738 million which will be updated according to an update and accounting mechanism between the parties as set forth in the Transmission Agreement with INGL. On May 2, 2022, INGL updated the project's budget to approx. ILS 796 million.

   According to the announcement of the Director General of the Gas Authority, 43.5% of the section's cost, as shall be determined in accordance with the aforesaid, will be financed by the holder of the transmission license (INGL) and 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.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

P. Regulation (Cont.):

5. **Projects for export through the national transmission system (Cont.):**
   a. (Cont.):

   In addition thereto, the exporter shall pay the holder of the transmission license ILS 27 million (the Partnership's share approx. ILS 8.5 million) for its share in the cost deriving from the bringing forward of the doubling of the Dor-Hagit and Sorek-Nesher sections (which is estimated at approx. ILS 48 million) and that 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 above (the share of the holder of the transmission license in the cost of construction of the Combined Section plus ten percent), and in the sum of ILS 21 million (the share of the holder of the transmission license in the cost of acceleration of the doubling of the Dor-Hagit and Sorek-Nesher sections), which will decrease in accordance with the provisions of the addendum to the Decision.

   The announcement of the Director General of the Authority further determines that 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 and that 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 the section plus ILS 48 million (the cost derives from the acceleration of the doubling of the Dor-Hagit and Sorek-Nesher sections), 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 the aforesaid.

   With regard to Chevron'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 N below.

   b. As of the date of approval of the financial statements, the Partnership is examining, together with Chevron, other possibilities for increasing the export amounts of natural gas through the Jordan North pipeline and the Jordanian transmission system, and through construction of a new onshore connection that will be built by INGL between the Israeli transmission system and the Egyptian transmission system at the Nitzana area (the "**Nitzana Line**"). In this context, it should be noted that in June 2022, the Natural Gas Authority published a request for information regarding the ability and intention of the partners in the producing projects to export natural gas through Jordan North pipeline and via the Nitzana Line, in the context of which the said partners were asked to evaluate the quantities of natural gas which are expected to be exported through such infrastructure. Subsequently, in July 2022 Chevron replied to the Natural Gas Authority that the Leviathan Partners are interested in using the full transmission capacity in such infrastructure, and in November 2022, the Natural Gas Authority notified the Leviathan Partners that in 2023, they will be allocated additional export capacity of 1 BCM for piping in Jordan North pipeline on an interruptible basis, over and above the quantities piped through Jordan North pipeline in the context of the Export to Jordan Agreement.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

P. Regulation (Cont.):

5. Projects for export through the national transmission system (Cont.):

b. (Cont.):

In the Partnership's estimation, the said decision is not expected to affect the quantities piped to Egypt via Jordan, or the transmission tariffs.

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.

After the release of the Decision, INGL contacted Chevron with a demand to apply the Decision retroactively from the beginning of 2020 with respect to the Leviathan project, and also forwarded for the inspection of Chevron, a notice in this spirit which it provided to its customers.

Further to the above notice, Chevron 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.

On April 7, 2021, the Partnership, together with the other Tamar partners and Leviathan Partners filed a petition against the Natural Gas Commission and the Ministry of Energy (in this section: the "**Respondents**"). In the petition, the respondents moved for annulment of decision no. 5/2020 of December 29, 2020 – Amendment to Commission decision 8/2019 – criteria and tariffs for the operation of the transmission system in a flow control regime (Amendment No. 2), of the Natural Gas Commission (in this section, the "**Commission**"), which was published on January 3, 2021 (in this section: the "**Decision**"). According to the Decision, the natural gas suppliers shall bear the cost of one half of the "Unaccounted For Gas Target (UFG-T)", which is defined in the Decision as a difference of up to 0.5% between the quantity of gas measured by the meter at the entrance to the national natural gas transmission system and the quantity measured by the meter at the exit therefrom. The petition argued that this Decision was issued without any lawful authority and is extremely unreasonable.

On October 26, 2021, Energean, which was joined as a respondent in the petition, filed its response according to which the petition is justified, and on October 27, 2021, INGL, which too was joined as a respondent in the petition, filed its response, in the framework of which it was argued that the petition is tainted with bad faith and unclean hands due to the concealment of material facts and failure to join parties that may be harmed by the petition and that the Decision contemplated in the petition was adopted with authority and reasonably.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):
P. 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.):**

   Additionally, on November 5, 2021, the Respondents of the State filed their response to the petition, according to which the petition should be summarily dismissed with prejudice due to failure to join the gas consumers as respondents and the petition should be denied on the merits since the Decision was adopted with authority and is reasonable on the merits. A hearing on the petition was conducted on February 9, 2023. At the end of the hearing, the court recommended the petitioners to withdraw the petition. The petitioners did so and the petition was dismissed with no order for costs.

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, 2022: 1,173,814,691 units of par value ILS 1 which are listed on TASE. In respect of options convertible into participation units of the Partnership which were granted to the Partnership's CEO, see Note 21C.

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. Other than limitations under the financing agreements, no external limitations which may affect the Partnership's ability to distribute profits in the future, exist on the date of approval of the financial statements.
   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 of Dollar	Distribution amount per participation unit in Dollar
17.11.2020	7.12.2020	65	0.05537
22.9.2021	13.10.2021	100	0.08519
9.12.2021	23.12.2021	100	0.08519
22.5.2022	16.6.2022	50	0.04260
17.8.2022	22.9.2022	50	0.04260
23.11.2022	19.1.2023	50	0.04260
27.3.2023	20.4.2023	60	0.05112

3. **Distributions to the Limited Partner:**
   a) On February 12, 2020, the General Partner's board approved a distribution to the Limited Partner in the sum of ILS 1 million (approx. $0.3 million).
   b) On November 1, 2020, the General Partner's board approved a distribution to the Limited Partner in the sum of ILS 1 million (approx. $0.3 million).
   c) On May 27, 2021, the board of directors of the General Partner approved a distribution to the Limited Partner in the sum of approx. ILS 1 million (approx. $0.3 million).
   d) On March 23, 2022, the board of directors of the General Partner approved a distribution to the Limited Partner in the sum of approx. ILS 1 million (approx. $0.3 million).
   e) On March 1, 2023, the board of directors of the General Partner approved a distribution to the Limited Partner in the sum of approx. ILS 1 million (approx. $0.3 million).

   Such distributions are 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 20B), as specified below:

Tax Year	Type of Income	Tax Advances in ILS millions	ILS per Participation Unit
2020	Current	Approx. 76.9	0.0655
2021	Current	Approx. 217.3	0.1851
2021	Capital gain	Approx. [32]527.9	0.4497

[32] Of which a sum of approx. ILS 477.9 million in respect of the sale of the Tamar and Dalit project.

Notes to the Financial Statements as of December 31, 2022 (Dollars in millions)

Note 13 – Equity (Cont.):

D. Payments of Tax Advances, Tax and Balancing Payments (Cont.):

1. (Cont.)

   With respect to the change of the tax regime that applies to the Partnership, such that it is taxed as a company for its taxable income commencing on 2022, see Note 20A1.

2. 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.
3. On December 26, 2021, the Partnership declared tax payments to individual holders and balancing payments to non-individual holders in the amount of approx. ILS 268 million that constitute approx. 0.2283281 per participation unit that were distributed on January 20, 2022.

E. The composition of equity as of December 31, 2022 is as follows:

	The Limited Partner	The General Partner	Total
The Partnership's equity	154.8	-[33]	154.8
Capital reserves	(29.9)	[31]-	(29.9)
Retained earnings	1,162.4	0.1	1,162.5
Balance as of December 31, 2022	**1,287.3**	**0.1**	**1,287.4**

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 31, 2022, the Partnership released a shelf prospectus for the issuance of various securities including, *inter alia*, participation units, bonds and warrants. The shelf prospectus is in effect for 24 months with an option of extension by 12 additional months.

G. In accordance with Note 12A above, commencing on January 1, 2022, the Partnership does not record expenses against a capital reserve since the payments are made by the Partnership.

H. With respect to the payment based on participation units granted to the CEO of the General Partner in the Partnership, see Note 21C.

[33] Less than $0.1 million.

Notes to the Financial Statements as of December 31, 2022 (Dollars in millions)

Note 14 – Revenues from the Sale of Natural Gas and Condensate:

A. The Partnership's revenues originate from natural gas sales to its customers, all in accordance with agreements signed therewith, as specified in Note 12 above.

B. The Partnership's income in the report period from the sale of natural gas is affected mainly by the volume of natural gas consumption for the domestic market, Egypt and Jordan (the "**Regional Market**"). Below is the Partnership's share in the income and in the natural gas quantities sold to the domestic market and to the Regional Market in the report period from the Leviathan project:

	For the year ended on		
	31.12.2022	31.12.2021	31.12.2020
Revenues:			
Domestic market	284.7	319.5	263.5
Regional market	859.2	563.0	323.6
	1,143.9	**882.5**	**587.1**
Quantities (BCM)			
Domestic market	1.71	2.06	1.57
Regional market	3.45	2.80	1.71
	5.16	**4.86**	**3.28**

Note 15 – Royalties:

A. Composition:

	For the year ended on		
	31.12.2022	31.12.2021	31.12.2020
Royalties to the State	126.4	94.7	63.5
Royalties to interested parties	15.2	11.4	9.4
Royalties to third parties	30.4	22.7	13.4
Total	**172.0**	**128.8**	**86.3**

(see Note 12B above and Paragraph B below)

B. Royalties to the State and overriding royalties (to interested and third parties) as included on the Partnership's books:

	For the year ended on		
	31.12.2022	31.12.2021	31.12.2020
Effective rate of the royalties in Leviathan project:			
To the State	10.93%	10.73%	10.81%
To interested parties	1.31%	1.29%	1.61%
To a third party	2.62%	2.57%	2.28%

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 date of commencement of the supply of gas from the Leviathan reservoir, the Leviathan Partners pay the State advances on account of the State's royalties on revenues from the Leviathan project, at the rate of approx. 11.26%, in accordance with a letter of request received from the Ministry of Energy in January 2020. Such advances rate is higher than the calculation made by Chevron, according to the royalty report submitted by Chevron to the Ministry of Energy for 2020, the rate of royalties to the State in the Leviathan project is approx. 9.58%. The rate of the royalties on which the Partnership's financial statements for 2022 are based is approx. 10.9% (2021: 10.7%, 2020: 10.8%). Further to the aforesaid, on December 27, 2022, the Leviathan Partners sent a letter to the Ministry of Energy regarding the reduction of the rate of advances starting from January 2023. As of the date of approval of the financial statements, the response of the Ministry of Energy has not yet been received.

   It is noted that it is the position of the Partnership that the calculation of the actual rate of the State's royalties should reflect the complexity of the project, the risks involved therein and the amount of the investments in the project.
   It is clarified that there are substantial differences between the royalties actually paid to the Ministry of Energy in the aggregate starting from commencement of production from the Tamar and Leviathan projects, and the amounts recorded in the Comprehensive Income Statement as royalty expenses.
2. The difference between the advances for royalties that were actually paid to the State and the effective royalty rate applied by the Partnership in its financial statements in the Tamar (until the date of sale of the project) and Leviathan projects amounted to approx. $30.5 million (2021: approx. $25 million, 2020: approx. $19.5 million), and was included in the other long-term assets item. See Note 8A above.
3. 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 (until the date of sale of its holdings in the Tamar and Dalit leases, as specified in Note 7C1 above) and of the Leviathan project, amounts to approx. $11.8 million (2021: approx. $8.8 million, 2020: approx. $7.8 million), is included in the other long-term assets item, see Note 8A above.
4. In June 2020, the Director of Natural Resources at the Ministry of Energy released general directives on the method of calculation of the value of the royalty at the wellhead with respect to offshore petroleum interests, and in September 2020 released specific directives on the method of calculation of the value of the royalty at the wellhead in the Tamar project (in this section: the "**Specific Directives**"), which determined the rate of the deductible expenses in the calculation of the value of the royalty at the wellhead in the Tamar project. During the course of 2022, the Ministry of Energy sent Chevron draft royalties audit reports for 2013-2018 in accordance with the instructions and directives of the Commissioner. The operator delivered its response to the said draft reports to the Ministry of Energy.

Notes to the Financial Statements as of December 31, 2022 (Dollars in millions)

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.):

4. (Cont.)

In the Partnership's estimation, no material gaps are expected between the amounts carried to the statement of comprehensive income under the item expenses for royalties to the State (from 2013) and the expenses for royalties as they were required to be calculated in accordance with the Commissioner's directives.

Note 16 – Cost of Natural Gas and Condensate Production:[34]

Composition:	For the year ended		
	31.12.2022	31.12.2021	31.12.2020
Salaries and social benefits	19.5	22.2	23.5
Guarding and security	2.0	2.8	2.3
Insurance	17.4	16.1	17.6
Delivery, transmission and transportation costs	49.9	25.7	15.6
Operation management and operator fee	19.5	18.0	12.7
Maintenance	15.8	16.4	11.0
Others	9.9	17.2	7.0
Total	**134.1**	**118.4**	**89.7**

Note 17 – Other Indirect Expenses[35]:

Composition:	For the year ended		
	31.12.2022	31.12.2021	31.12.2020
Seismic surveys	-	0.1	-
Direct and other expenses, including professional services[36]	5.2	4.1	3.4
Total	**5.2**	**4.2**	**3.4**

[34] Mostly through the joint ventures.

[35] Mostly through the joint ventures.

[36] Mostly G&A expenses of the Cyprus project.

Notes to the Financial Statements as of December 31, 2022 (Dollars in millions)

Note 18 – G&A Expenses:

Composition:	For the year ended		
	31.12.2022	31.12.2021	31.12.2020
Salaries and social benefits	6.3	4.1	3.7
General Partner management fee expenses (Note 12A above)	-	1.0	1.0
Cost of participation unit-based payment to the CEO (see Note 21C below)	1.0	-	0.5
Professional services, net[37]	8.7	8.6	6.6
Other	3.7	3.5	2.8
Total	**19.7**	**17.2**	**14.6**

Note 19 – Financial Expenses and Income:

Composition:

	For the year ended		
	31.12.2022	31.12.2021	31.12.2020
Expenses:			
Due to bonds (Notes 10B, 10C, 10E and 10F above)	145.9	207.0	122.3
Due to liability to banking corporations	0.7	0.7	99.4
Due to transactions in financial derivatives (hedge accounting)	-	-	7.4
Due to a guarantee fee to Delek Group (Notes 12K4 and 21D)	0.4	0.4	0.4
Due to changes in oil and gas asset retirement obligation due to lapse of time	1.5	1.8	1.6
Other[38]	13.5	1.4	0.8
Net of financing costs capitalized to gas and oil assets[39]	(6.7)	-	-
Total expenses	**155.3**	**211.3**	**231.9**
Income:			
Due to deposits in banks and short-term investments	5.4	0.6	1.8
Revaluation of royalties receivable (Note 8B above)	60.9	20.0	80.3
Revaluation of loan receivable (Note 8B above)	1.6	6.4	2.4
Update of amounts receivable from a company accounted for at equity	3.1	1.9	1.9
Other	0.1	2.5	1.6
Total income	**71.1**	**31.4**	**88.0**
Total financial expenses, net	**(84.2)**	**(179.9)**	**(143.9)**

[37] Including expenses in the sum of approx. $4.3 million and approx. $3.0 million in 2021 and 2020 respectively, carried against a capital reserve (see Note 13G above) and in the report year are paid by the Partnership.
[38] See footnote 6 above.
[39] The cap rate used for determining the borrowing costs capitalized in 2022 is approx. 6.5%.

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 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**" or the "**Regulations**"). In September 2021 an amendment to the Income Tax Regulations as aforesaid was published in the Official Gazette whereby, effective from tax year 2022 a change has occurred in the tax regime that applies to the Partnership, such that it is taxed as a company with respect to its taxable income (while setoff of losses will be possible, subject to the tax laws, on the level of the Partnership itself without the same being attributed to the holders of the participation units). As a result of this change, commencing from tax year 2022, holders of participation units in the Partnership are subject to a tax regime that applies with respect to profit distributions made by the Partnership, which is similar to the tax applying to shareholders of a company for dividend distributions (i.e. pursuant to the two-stage method).

   It is noted that in view of the aforesaid amendment, up to and including tax year 2021 the accounting with holders of the participation units and the reporting on the Partnership's taxable income will be as being prior to the amendment as explained below.

2. Until December 31, 2021 the Partnership acted as 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**") i.e. the Partnership's taxable income and the losses for tax purposes were 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" was defined in the Participation Unit Regulations as an entity that held participation units at the end of December 31 of the tax year. 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 did not include current taxes on income.

3. Further to approval of the amendment to the Regulations as provided in Section 1 above, the Partnership recorded, in 2021, a liability for deferred taxes in the sum of approx. $208 million against an expense in the Statement of Comprehensive Income. The amount of the liability as aforesaid is due to temporary differences created until the date of the financial statements, of which $186 million due to depreciation and amortization on oil and gas assets (including due to retirement of oil and gas assets). It is noted that commencing from January 1, 2022 the Partnership presents current tax expenses in the Statement of Comprehensive Income, in addition to deferred tax expenses 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.):

4. According to the provisions of Section 19 of the Law, 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 (see later in the section), 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, on December 31 of each tax year, are liable), according to the share in the Partnership of the Entitled Holders who are a body corporate and the share in the Partnership of the Entitled Holders who are individuals. Note that the General Partner is liable for payment of tax advances calculated according to the tax rates applicable to companies (in 2019 to 2021 – 23%). See Section 1 above with regard to the change that is effective from 2022 to the tax regulations which apply to the Partnership, according to which a corporate tax rate of 23% applies to the Partnership.

5. Implementation of the provisions of Section 19 of the Law raised difficulties and questions of interpretation in view of the difference in the tax rates applicable to companies and individuals, which were deliberated in the framework of several legal proceedings.

On June 28, 2021 the judgment of the Tel Aviv District Court was received, ruling mainly that:

a) With respect to payments for assessment differences made by the Partnership for the tax years 2015 and 2016, the Partnership is required to pay corporate holders in the past balancing payments in accordance with the "net of the financial loss" alternative described in the judgment, i.e., supplementation of the "surplus" amount that was paid for the individual holders who are subject to the higher tax rate.

On July 1, 2021, several holders filed a clarification motion with the court, in which the court was moved to order how the payment should be made according to the "net of the financial loss" alternative set forth in the judgment with respect to payment of interest and linkage, and on August 9, 2021, the court ruled that lawful interest and linkage differentials be added to the said payment, in accordance with the provisions of the Adjudication of Interest and Linkage Law, 5721-1961.

Accordingly, on July 21, 2022, the Partnership transferred to the account of Reznik Paz Nevo Trusts Ltd., which was appointed by the court as the trustee responsible for the making of the payment, in accordance with the outline determined by the court, for payment to entitled holders that are a body corporate in each of the years 2015-2016, the sum of approx. ILS 39.7 million (approx. $11.4 million), including linkage and interest.

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.):

5. (Cont.):

b) With respect to 2017 through 2021 (regarding which the Partnership paid tax advances in accordance with the corporate tax rate and further thereto a "balancing" profit distribution was made considering the different tax rates of companies/individuals – see Section C below), it is the Partnership that will bear payment of the tax assessment differences, if any, but no balancing payments will be made in respect thereof. With regards to the future balancing and assessment differences payments, according to the judgment, the Partnership will continue to act in accordance with the arrangement according to which it has acted since tax year 2017, and the judgment thus grants all of the holders of the Partnership certainty as to the manner of the making of future balancing and assessment differences payments.

6. 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 the Partnership's business for 2017 (the "2017 Tax Agreement"). In the context of the agreement, the Partnership supplemented additional tax payments in accordance with the maximum tax rate which applies to individuals due to the aforesaid estimated taxable income, by way of deduction of withholding tax from balancing distributions made to participation unit holders (the withholding tax was deducted from the distributions made to participation unit holders who are individuals, and no withholding tax was deducted from distributions made to corporate participation unit holders). In the tax years 2018 to 2021, the Partnership acted similarly to the manner in which it acted pursuant to 2017 Tax Agreement, including with regard to calculation of the estimation of the Partnership's taxable income for the aforesaid tax years and supplementation of payments made by the Partnership in relation thereto in January for the following tax year.

It is clarified that the estimated taxable income calculated toward the end of the tax year for each of the years 2017-2021 was calculated based on estimates and assessments and financial figures that are unaudited.

B. Income tax assessments and tax certificates:

1. On October 20, 2021 the Partnership published final tax certificates for an entitled holder for the holding of a participation unit of the Partnership and of Avner (the Partnership and Avner will be referred to below as the "**Partnerships**") for the 2015 tax year.

Note 20 – Oil and Gas Profit Levy and Taxes (Cont.):
B. Income tax assessments and tax certificates (Cont.):

2. On December 13, 2017, the Partnership published temporary tax certificates for an entitled holder for the holding of a participation unit for the tax year 2016 of the Partnerships. It is 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 Assessments**"), whereby the taxable income from a business for 2016 of the Partnership and the Avner Partnership is approx. $136.9 million and approx. $124.0 million, respectively (instead of approx. $113.4 million and approx. $100.6 million, respectively, as included in the partnerships' tax reports, which were filed with the Tax Authority). The capital gain for 2016 of the Partnerships is approx. $49.3 million and approx. $65.6 million, respectively (instead of approx. $6.7 million and approx. $15.6 million, respectively, as included in the partnerships' tax reports, which were filed with the Tax Authority). The said amounts were translated from shekels to dollars according to the dollar rate known as of December 31, 2022. 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 Income Tax Ordinance (the "**Orders**") by the Tax Authority. The dispute over the Orders primarily pertains to 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 Orders, 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. $45.9 million. On September 15, 2020, 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 in accordance with the decision of the court. The notice stating the grounds for the appeal was filed by the Partnership on May 3, 2021. A pretrial hearing on the appeal was held on November 25, 2021 and a date for an additional pretrial hearing was scheduled for April 17, 2023.
3. On November 8, 2018, the Partnership published a temporary tax certificate for an entitled holder for holding a participation unit for the tax year 2017. 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 (in this section: the "**Tax Assessment**"), and on December 10, 2020, the Partnership filed a reasoned objection to the Tax Assessment. On December 21, 2022, the Partnership received an assessment under an order for the 2017 tax year under Section 152(b) of the Income Tax Ordinance (the "**Order**"). On January 22, 2023, the Partnership filed an appeal from the Order with the Tel Aviv District Court. According to such Order, the Partnership's taxable business income in 2017 is approx. $354.7 million (*in lieu* of approx. $211.8 million, as included in the Partnership's tax report filed with the Tax Authority) and the Partnership's capital gain including deferred capital gain in 2017 is approx. $674.2 million (*in lieu* of approx. $528.4 million as included in the Partnership's tax report filed with the Tax Authority).

Note 20 – Oil and Gas Profit Levy and Taxes (Cont.):

B. Income tax assessments and tax certificates (Cont.):

3. (Cont.):

The said amounts were translated from shekels to dollars according to the dollar rate known as of December 31, 2022.

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 assets 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 Partnership's interests in the Tamar and Dalit Leases.

As of the date of the financial statements and according to such 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 holders of participation units of the Partnership, in the amount of approx. $108.2 million.

4. On February 19, 2020, the Partnership released a temporary tax certificate for an entitled holder due to the holding of a participation unit of the Partnership for the tax year 2018. 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 2018, on March 24, 2021, an 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**"). According to the Tax Assessment the Partnership's taxable income from a business for 2018 is approx. $185 million (in lieu of approx. $142 million, as included in the Partnership's tax report that was filed with the Tax Authority) and the Partnership's capital gain for 2018 is approx. $16.4 million, as declared in the report filed thereby as aforesaid. The said amounts were translated from ILS to $ according to the dollar rate known as of December 31, 2022. The main disputes pertain to the interpretation of the manner of recognition of financial expenses and additional expenses borne by the Partnership *de facto*, similar to the disputes for which assessments to the best judgment were issued for 2016 and 2017, as specified above. As of the date of approval of the financial statements 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. $13.8 million. On June 10, 2021 the Partnership filed a reasoned administrative objection regarding all of the assessing officer's determinations in the tax assessment.

5. As of the date of approval of the financial statements, discussions are held and are expected to continue to be held, between the Partnership and the Assessing Officer with respect to the assessments for tax years 2016-2018.

6. In the Partnership's estimation, based on the opinion of its professional advisors, the chances of the Partnership's main arguments being accepted or at least of authorization of deduction of the expenses that are the subject matter of the disputes for tax years 2016-2018 in such years and/or in the following years, are higher than 50%.

7. On July 14, 2021 the Partnership published a temporary tax certificate for an entitled holder for the holding of a participation unit of the Partnership for 2019. According to the tax report filed by the Partnership for 2019 which is subject to an audit by the Tax Authority, the taxable income is approx. ILS 573.6 million.

Note 20 – Oil and Gas Profit Levy and Taxes (Cont.):
B. Income tax assessments and tax certificates (Cont.):

8. On April 12, 2022, the Partnership released a temporary tax certificate to an entitled holder due to the holding of participation units of the Partnership for 2020. According to the tax report filed by the Partnership for 2020 which is subject to an audit by the Tax Authority, the taxable income is approx. ILS 277.6 million.

9. According to the tax report filed by the Partnership for 2021, which is subject to the audit of the Tax Authority, the Partnership's taxable income for tax purposes is approx. ILS 919 million, net capital gain mainly due to the sale of the Partnership's holdings in the Tamar and Dalit leases (see Note 7C1B above) is approx. ILS 1,868 million, and deferred capital gain for the sale of the Partnership's holdings in Tamar Petroleum (see Note 7C1C above) is approx. ILS 203.1 million.

10. It is clarified that in respect of each of the tax years 2016 through 2021, regarding which the Tax Authority's audit of the Partnership's tax reports has not yet ended and/or final income tax assessments have not yet been issued, it may transpire, after completion of the Tax Authority's audit and issuance of final tax assessments (including after decisions in the administrative objections and/or appeals) that Assessment Differences exist, such that the final tax assessment is higher than the tax payments 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.

It is clarified that in accordance with the provisions of the aforementioned judgment of June 28, 2021, no balancing payments will be made due to Assessment Differences as aforesaid, starting from tax year 2017 (if any). If in the future it transpires that the Partnership made advance payments in amounts exceeding the amounts required pursuant to the law, the balance will be returned to the Partnership.

11. In view of the aforesaid, the issuance of a final tax certificate for an entitled holder for holding participation units of the Partnerships for the tax year 2016 through 2021 may be delayed, pending conclusion of the proceedings required to determine the final assessment. Upon determination of the taxable income amount for an entitled holder for each tax year, a final certificate will be published for the purpose of calculation of the taxable income of an entitled holder in respect of the aforesaid tax years, in accordance with the Income Tax Regulations.

12. 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 2016 through 2021, 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 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.):
B. Income tax assessments and tax certificates (Cont.):

13. 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.

14. Taxation in Cyprus:

In the amendment to the 2019 production sharing contract a new mechanism was determined for the distribution of the natural gas output, which is based on a factor of the R-Factor type. Accordingly, 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, in which, *inter alia*, the following provisions were determined – the Partnership operations in Block 12 shall not prejudice the Partnership's status as a "partnership" for the purposes of the Participation Unit Regulations; 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; insofar as 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;

Note 20 – Oil and Gas Profit Levy and Taxes (Cont.):

B. Income tax assessments and tax certificates (Cont.):

14. Taxation in Cyprus (Cont.):

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.

It is noted that the 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.

C. Taxation of Profits from 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, and 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 a 18% tax rate. According to the corporate tax rate in 2022, the maximum rate is 46.8%.

   Additional provisions were also determined, *inter alia*, that 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.

Note 20 – Oil and Gas Profit Levy and Taxes (Cont.):

C. Taxation of Profits and Natural Resources Law, 5771-2011 (Cont.):

1) (Cont.)

According to the Law, the holder of the petroleum right will be given fixed annual accelerated depreciation on a deductible asset, as defined in the law, which is owned thereby, at a fixed rate of up to 10% (at the choice of the holder of the petroleum right) or, alternatively, variable current annual depreciation up to the amount of the taxable income in that year (and not more than 10%).

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, the date of commencement of commercial production from which occurred before the commencement date, will be subject to the provisions of this Law with the following changes:
   (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.
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) On November 10, 2021, the Knesset approved, in the second and third readings, amendment no. 3 to the Taxation of Profits from Natural Resources Law, 5782-2021 (the "**Amendment to the Law**"), according to which, inter alia, in the case of a dispute, it will be necessary to bring forward payment of the oil and gas profit levy in the sum of 75% of the amounts in dispute, subject to the decision of the assessing officer in the administrative objection (prior to completion of legal hearings on the dispute at the court, if any). In accordance with the said Amendment to the Law, 75% of the amounts in dispute might be brought forward.

Note 20 – Oil and Gas Profit Levy and Taxes (Cont.):

C. Taxation of Profits and Natural Resources Law, 5771-2011 (Cont.):

5) 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.

   A levy assessment agreement was signed in December 2019 between the Assessing Officer for Large Enterprises and the holders of the rights in Leviathan, with respect to the levy reports for the years 2016-2017, and in October 2021 an assessment agreement was signed with respect to the Leviathan levy assessment for 2018.

   In December 2021, the Leviathan Partners received an assessment to the best of judgment for the Leviathan levy for 2019, which includes interpretive disputes are being heard in the context of administrative objection proceedings vis-à-vis the assessing officer with regard to the implementation of the provisions of the Law in the levy reports of the Leviathan Leases for 2019, including pertaining to recognition of payments borne by the holders of the interests in the leases in order to enable feasibility of export of natural gas to Egypt. An administrative objection to the assessment to the best of judgment was submitted to the tax assessor for large enterprises (TALE) in March 2022. On October 23, 2022, an appeal was filed with the Tel Aviv District Court in respect of a levy assessment order for 2019, which was delivered to the Leviathan partners in September 2022, and on March 15, 2022, the assessment reasoning of the TALE for the said appeal was received.

   On January 6, 2022, a Leviathan lease levy report for 2020 was submitted to the Tax Authority.

   It is noted that the rate of the levy coefficient in the Leviathan Leases as of the date of the financial statements is lower than 1.5 and the effect of the above-mentioned assessments and disputes may be reflected in the levy amount calculation. However, even if the assessing officer's position is fully accepted, to date it is not expected to result in a coefficient rate higher than 1.5 from which actual collection of the levy begins.

   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.

Note 20 – Oil and Gas Profit Levy and Taxes (Cont.):

C. 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 Tamar venture as to the Tamar venture levy reports for the years 2013-2020, pertaining, *inter alia*, to the dispute in connection with the sale of gas from the Tamar reservoir for the supply of gas by virtue of agreements signed between natural gas consumers and the Yam Tethys partners, where, the Tax Authority's position is that the Tamar venture should be attributed with notional revenues for the supply of natural gas from the aforesaid Tamar reservoir to customers with whom the Yam Tethys Partners engaged and not determine the venture's revenues according to the actual proceeds received, the method of recognition and classification of exploration and construction investments in the Tamar SW reservoir and Tamar SW reservoir construction payments and recognition of various payments borne by the holders of the interests in the venture including costs borne thereby in order to enable feasibility of export of natural gas to Egypt (jointly below, the "**Disputed Issues**"). It is noted that the disputes as to the levy reports for the years 2013-2020 are adjudicated between the parties in the context of appeals conducted before the Tel Aviv District Court. It is noted that on March 15, 2022, the assessment reasons of the Assessing Officer for Large Enterprises were received for the appeal for 2019. It is clarified that insofar as it is determined in a final and binding proceeding that the Tax Authority's position regarding the aforesaid disputes is accepted in full, the Partnership may incur an additional liability of payment of an oil and gas profit levy to the Tax Authority and registration of an expense for the period until the sale of its rights in the Tamar project (see Note 7C1 above) in an estimated amount, as of December 31, 2022, of approx. $36 million (which includes an amount of approx. $24 million for 2020).

   In May 2022, the TALE issued an assessment to the best of judgment for the tax year 2020, which was mainly in respect of the same disputes that arose in respect of 2013-2019. In July 2022, the holders of the interests in the Tamar venture submitted an administrative objection to the TALE regarding the said assessment .

   In this context, it is noted that November 14, 2022 saw receipt of the judgment of the Jerusalem District Court dismissing the claim against the State for restitution of the royalties that were paid by the Partnership and Chevron in respect of notional income that derived from the supply of natural gas to Yam Tethys customers, as mentioned above (see Note 12L1 above).

   On January 25, 2023, a levy assessment order for 2020 was received. On February 8, 2023, 75% of the levy liability was paid in the sum of approx. ILS 62.7 million (the amount includes interest and linkage) (approx. $18 million), in accordance with the Amendment to the Law as stated in Paragraph 4 above.

   In the Partnership's estimation, based on the opinion of its legal counsel, the chances that the Partnership's arguments with respect to the Disputed Issues (including the issue of notional revenues) will be accepted are higher than the chances of rejection thereof, taking into consideration also the above judgement.

Notes to the Financial Statements as of December 31, 2022 (Dollars in millions)

Note 20 – Oil and Gas Profit Levy and Taxes (Cont.):

C. Taxation of Profits and Natural Resources Law, 5771-2011 (Cont.):

7) It is noted that disputes have arisen between the Assessing Officer for Large Enterprises and the holders of rights in the Ashkelon venture and the Noa venture (jointly below, the "**Yam Tethys Ventures**"), in respect of the levy reports of the Yam Tethys Ventures for the years 2018-2019. It is noted that the disputes in respect of the levy reports for the years 2018-2019 are being heard by the Tel Aviv District Court. The Partnership's share in the disputed amounts is approx. $1.7 million.
8) **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 "**Advances Regulations**") were published. The Advances Regulations regulate 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 Advances 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 mainly pertain to the determination of the calculation of the advances, the dates of payment thereof, and the reporting thereon.
As of the date of approval of the financial statements, for 2020 through 2022, the Partnership paid oil and gas profit levy advances (for revenues from sales of gas until the date of sale of the Tamar and Dalit projects) in the total amount of approx. $63.2 million, due to its rights in the Tamar Project (including the advance for 2020 in the sum of $18 million as aforesaid). According to the Partnership's estimation and appraisals, based on the existing disputes with the Tax Authority, in 2022 the Partnership recorded expenses due to an oil and gas profit levy in the amount of approx. $2.1 million (2021: approx. $43.9 million), which are presented in the item of discontinued operations due to sale of Tamar Project as provided in Note 7C1 above.

D. Income taxes included in the Statement of Comprehensive Income

	31.12.2022	**31.12.2021**	**31.12.2020**
Current taxes	(50.2)	-	-
Deferred taxes	(62.0)	(207.8)	-
Total income taxes	(112.2)	(207.8)	-
Net of taxes attributed to discontinued operations	(3.8)	-	-
Total taxes attributed to continuing operations	**(116.0)**	**(207.8)**	**-**

Notes to the Financial Statements as of December 31, 2022 (Dollars in millions)

Note 20 – Oil and Gas Profit Levy and Taxes (Cont.):

E. Deferred taxes

1. **Composition:**

	31.12.2022	31.12.2021
Deferred tax liabilities		
Oil and gas assets	265.7	186.0
Other long term assets	8.3	24.8
Total	**274.0**	**210.8**
Deferred tax assets		
Share-based payment and social benefits	(1.9)	(2.5)
Costs of bond issue	-	(0.5)
Short term retirement obligation	(2.3)	-
Total	**(4.2)**	**(3.0)**
Deferred tax liabilities, net	**269.8**	**207.8**

2. Deferred tax is calculated according to a tax rate of 23% (2021 – identical) based on the tax rate which is expected to apply on the reversal date.

3. No obligations (assets) were recorded in respect of temporary differences in the total sum of approx. $0.1 million (2021: approx. $(8.7) million) in reference to investments in companies accounted for at equity because the disposal of these investments is not expected in the foreseeable future.

Notes to the Financial Statements as of December 31, 2022 (Dollars in millions)

Note 20 – Oil and Gas Profit Levy and Taxes (Cont.):

F. Theoretical tax

Below is a reconciliation between the tax amount that would have applied if all revenues and expenses, profits and losses in profit or loss were taxable at the statutory tax rate, and the amount of income taxes recognized in the Statement of Comprehensive Income:

	For the year ended 31.12.2022	For the year ended 31.12.2021	For the year ended 31.12.2020
Profit before income taxes from continuing operations	**594.6**	**316.4**	**162.2**
Statutory tax rate	23.0%	-[40]	[38]-
Tax calculated according to the statutory tax rate	**(136.8)**	**-**	**-**
Decrease (increase) in income taxes due to the following factors:			
Change of estimate of the tax basis for other long-term assets[41]	25.0	-	-
Difference between the income measurement basis as reported for tax purposes (ILS) and the income measurement basis as reported in the financial statements ($)	(3.9)	-	-
Others	(0.3)	-	-
Income taxes	**(116.0)**	**-**	**-**

Note 21 – Transactions and Balances vis-à-vis Interested Parties, Related Parties and Control Holders:

A. Balances:

		December 31, 2022		December 31, 2021	
	Note	Parent companies	Related parties and other interested parties	Parent companies	Related parties and other interested parties
Trade and other receivables		-	1.3	-	0.7
Other long-term assets		2.6	25.2	2.2	18.0
Trade and other payables		5.0	1.8	2.7	1.1
The highest current debt balance this year		-	-	-	1.7

[40] For details regarding the tax regime applicable to the Partnership until December 31, 2021, see Note 20A2 above.

[41] As a result of a change in the projected method of recovery of the value of a financial asset.

Notes to the Financial Statements as of December 31, 2022 (Dollars in millions)

Note 21 – Transactions and Balances vis-à-vis Interested Parties, Related Parties and Control Holders (Cont.):

B. Transactions with related parties and interested parties:

For the year ended December 31, 2022:

	Note	Parent companies	Related parties and other interested parties
Revenues from gas sale	14	0.2	-
Expenses due to overriding royalties (continuing operations)	15	0.1	15.1
Expenses due to overriding royalties (discontinued operations)	7C1	2.6	-
Compensation of directors		-	0.3
Guarantee fee to Delek Group	21D 12K4	0.4	-
Rent	21E4	0.4	-

For the year ended December 31, 2021:

	Note	Parent companies	Related parties and other interested parties
Revenues from gas sale	14, 7C1	0.2	5.2
Expenses due to overriding royalties	15	-	11.4
Expenses of General Partner management fees	12A	1.0	-
Compensation of directors		-	0.3
Guarantee fee to Delek Group	21D 12K4	0.4	-
Expenses due to control holder benefit against a capital reserve	13G	4.3	-

Notes to the Financial Statements as of December 31, 2022 (Dollars in millions)

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, 2020:

	Note	Parent companies	Related parties and other interested parties
Revenues from gas sale[42]	14	0.4	21.9
Expenses due to overriding royalties (continuing operations)	15	6.1	3.3
Expenses due to overriding royalties (discontinued operations)	7C1	-	15.8
Expenses of General Partner management fees	12A	1.0	-
Compensation of directors		-	0.3
Guarantee fee to Delek Group	21D 12K4	0.4	-
Expenses due to control holder benefit against a capital reserve	13G	2.9	-
D&O insurance	21E5	0.1	-

C. Terms of Employment of the CEO of the General Partner, Mr. Yossi Abu ("Mr. Abu" or the "CEO"):

Mr. Yossi Abu serves as CEO of the General Partner in a full-time position (100%) since April 1, 2011. According to the new arrangement for provision of management services (see Note 12A above), commencing from January 1, 2022, the Partnership bears the full cost of his employment (100%), in lieu of the General Partner.

On September 28, 2022, the compensation committee and the Board decided, after reopening the discussion thereon, to approve the updated terms of office and employment for the CEO, despite the objection of the meeting of the holders of the Partnership's participation units held on September 21, 2022.

Below is a brief description of the main updated terms of office and employment:

1. The CEO's monthly salary as of December 31, 2022 is ILS 202 thousand (in gross terms) that shall be updated according to changes in the Consumer Price Index (positive only) once every 3 months.
2. In addition to his monthly salary, Mr. Abu is entitled to standard 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. Abu with a car, as is standard for his position, and bears any and all expenses entailed by the use of the car. The value of the use of the car is grossed-up and paid by the Partnership.

[42] Including the share of 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 (Cont.:)

2. (Cont.):
   Mr. Abu is also entitled to additional related benefits, such as his inclusion in officer indemnification, exemption and insurance arrangements, communication expenses (mobile telephone, internet, newspapers and payment of expenses in respect of reasonable use of his home phone), executive physicals, private health insurance at the Partnership's expense, participation in professional continuing education, severance pay (since 2016 Mr. Abu has not signed Section 14 of the Severance Pay Law, 5723-1963, and therefore the severance pay to which he is entitled is pursuant to the law as aforesaid), receipt of loans from the Partnership, reimbursement of expenses for the performance of his duties, and reimbursement of per diem expenses during foreign travel on behalf of the Partnership. The Partnership may grant Mr. Abu, each year, an annual bonus for the previous calendar year, provided that he shall be employed by the Partnership at least 3 months in such year, and a special bonus, a retention bonus, and in the case of separation from employment, an adjustment bonus and a retirement bonus, all in accordance with the compensation policy as updated from time to time. The parties may terminate the Employment Agreement at any time by giving prior written notice of 6 months. In addition, the employment agreement includes provisions regarding confidentiality and a non-compete clause for a period of 12 months.
3. The term of employment of Mr. Abu was extended until April 30, 2027.
4. Mr. Abu was granted on July 27, 2022 (the date of grant), for no consideration, 3,295,599 non-marketable options exercisable for 3,295,599 participation units, in accordance with the compensation policy and an option plan pursuant to Section 102 of the Income Tax Ordinance [New Version], 5721-1961. The options will vest in 3 equal annual installments, commencing from August 1, 2022. The exercise price of the first installment is ILS 8.66, which is equal to the average closing price of the participation units on TASE at the close of the 30 trading days that preceded the date of grant. The exercise price of the remaining two installments will increase by 5% each year relative to the previous year. The annual benefit value that derives from the granting of the options, i.e. the economic value of the options on the date of grant, divided by 3, shall not exceed ILS 3,300 thousand.
   The fair value of the options on the date of grant (equity compensation) granted to the CEO totals approx. ILS 9.8 million. The fair value was calculated using the Binomial model, based on the following key assumptions: (1) participation unit price of ILS 9.35; (2) exercise price of each option (adjusted to a profit distribution) calculated according to ILS 8.66 for the first installment, ILS 9.1 for the second installment, and ILS 9.55 for the third installment; (3) standard deviation rate of 49.9%; (4) risk-free interest rate of approx. 2.31%; (5) expiration date: August 1, 2027.
5. Until the date of approval of the updated terms of office and employment by the compensation committee and the board as aforesaid, the terms of office and employment to which Mr. Abu was entitled were the terms approved on July 10, 2019 by the meeting of unit holders, according to the previous compensation policy (the "**2019 Terms**"). Under the 2019 Terms, the General Partner granted Mr. Abu 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 (the "**Phantom Units**").

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 (Cont.:)

5. (Cont.)

   As of the date of approval of the financial statements, all of the Phantom Units have vested, and each one of the installments included in the total package is exercisable until June 1, 2023. In addition, the exercise price of the 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 Partnership, the economic value of the Phantom Units as of December 31, 2022 totaled approx. ILS 1 million, and was calculated using the Binomial model, based on the following assumptions: (a) participation unit price, as of December 31, 2022, of ILS 7.85; (b) the exercise price of each option (adjusted to a profit distribution and tax advances until and inclusive of 2021) was calculated according to ILS 7.96 for the first installment, ILS 8.50 for the second installment, and ILS 9.06 for the third installment; (c) standard deviation of 26.8%; (d) risk-free interest rate of approx. 3.47%; (e) contractual life of approx. 0.42 years from December 31, 2022; (f) rate of abandonment before and after vesting - 0%; and (g) limitation of the maximum benefit that Mr. Abu shall derive from exercise of each Phantom Unit shall not exceed 100% of the exercise price determined for the Phantom Unit. In accordance with the decision of the participation unit holders regarding the New Management Arrangement, as detailed above, the General Partner will bear any increase in the amount of the Phantom Units that shall derive from an increase in the market price of the participation units in the period before January 1, 2022, and the Partnership shall bear any increase in the amount of the Phantom Units that shall derive from an increase in the market price of the participation units from such date forth, with respect to all 3 installments.
6. In 2022, Mr. Abu received an annual bonus for 2021 in the sum of approx. ILS 2,090 thousand, as well as a special bonus equal to one gross monthly salary, in the sum of approx. ILS 160 thousand (in 2021, the CEO received bonuses in the sum of approx. ILS 3,977 thousand, and in 2020, the CEO received bonuses in the sum of approx. ILS 2,169 thousand).

D. Further to Note 7C3 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 12K4 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.):

D. (Cont.):

1. (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 Chevron Cyprus under the production sharing contract are jointly and severally, an agreement was signed between Delek Group and Chevron Cyprus, and the parent company of BG Cyprus, regarding division of the responsibilities and mutual indemnification among themselves, in respect of the operations in Block 12, according to the respective holding percentage of the Partnership, Chevron Cyprus and BG Cyprus in 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.

E. Additional information regarding transactions with related parties and interested parties:

1. See Notes 12B and 15 above regarding the payment of royalties by the Partnership to its control holders.
2. The Partnership has gas sale agreements with Rapac Energy Ashkelon Ltd. (formerly, I.P.P. Delek Ashkelon Ltd.) and Rapac Energy Sorek Ltd. (formerly, I.P.P. Delek Sorek Ltd.). For information regarding sale volumes, revenues from sale of gas to related parties and other interested parties, see Section B above. In 2021, the aforementioned ceased being related parties.
3. In 2021 and 2020, 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,. 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. $0.4 million and $0.3 million in 2021 and 2020, respectively.
4. On September 21, 2022, the general meeting of the participation unit holders in the Partnership approved an amendment to the Partnership Agreement, whereby commencing from January 1, 2022, the Partnership shall bear all of the management expenses of the Partnership and the General Partner, due to the expiry of the management arrangement determined in the Partnership Agreement, whereby the General Partner incurred these expenses. Accordingly, the Partnership engaged with Delek Group in a lease agreement in connection with the offices used by the General Partner and the Partnership.

Note 21 – Transactions and Balances vis-à-vis Interested Parties, Related Parties and Control Holders (Cont.):

E. Additional information regarding transactions with related parties and interested parties (Cont.):

5. On June 26, 2022, the compensation committee, in accordance with the compensation policy, approved the Partnership's engagement in a D&O insurance policy, which covers the officers of the general partner, the Partnership and the general partner and its subsidiaries, including Leviathan Bond, for a period of one year commencing on July 1, 2022, with a total limit of liability of $200 million per claim and in the aggregate for the insurance period, all under terms and conditions which comply with the compensation policy.
6. In the matter of the commercial arrangement for the supply of natural gas between the Yam Tethys partners and the Leviathan Partners, see Note 7C4A above.
7. On July 26, 2021, the General Partner's board of directors approved a pledge of approx. 4.5% of the Partnership's participation unit capital held by the General Partner to secure bonds issued by Delek Group, which holds (indirectly) all of the issued share capital of the General Partner. On February 6, 2023, the General Partner's board of directors approved an additional pledge of approx. 1.1% more of the Partnership's participation unit capital held by the General Partner to secure bonds issued by Delek Group, which holds (indirectly) all of the issued share capital of the General Partner.
8. In the matter of the engagement in a renewable energies cooperation with Enlight and the personal interest of the Partnership in the engagement, see Note 12N above.
9. On December 23, 2021, the General Partner's board of directors approved the General Partner's engagement with Delek Group in an agreement for the provision of management services by Delek Group, including director services to the General Partner through the directors serving also as officers in Delek Group according to the terms and conditions set forth, commencing January 1, 2021.
10. Mr. Tzachi Habusha was appointed as the Partnership's VP Finance on November 18, 2021, and took office on January 1, 2022.
11. Mr. Gabi Last has served as active chairman of the board at the General Partner in a full-time position, since April 2022 (prior to which, from May 2001, he held office as a director of the General Partner, and from January 2020 held office as chairman of the board at the General Partner). Since November 1, 2022, the Partnership has borne the full cost of his employment (100%). (See Note 12A regarding the New Management Arrangement).
12. 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" the Israeli Oil Company Ltd., an affiliated company of Delek Group, receipt of services from the NYX Herzliya Hotel of the Fattal Hotels Chain, an accounting with Delek Group and Mr. Yitzhak Sharon (Tshuva) in connection with legal costs in the context of a motion for certification of a class action (see Note 12M8) and purchase of a vehicle from Delek Group that will be made available to the Active Chairman of the board, as part of his terms of office and employment.

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.

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 with regard to the asset or liability, directly or indirectly.
Level 3	-	Inputs that are not observable for the asset or liability.

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:

	31.12.2022			
	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)	-	-	320.8	**320.8**
- Loan to Energean from the sale of the Karish and Tanin leases (see Note 8B above)	-	53.6	-	**53.6**
Total Financial assets at fair value through profit or loss:	**-**	**53.6**	**320.8**	**374.4**

Notes to the Financial Statements as of December 31, 2022 (Dollars in millions)

Note 22 – Financial Instruments (Cont.):

B. Fair value hierarchy (Cont.):

	31.12.2021			
	Level 1	Level 2	Level 3	Total
Financial assets at fair value through profit or loss:				
- ETFs	20.0	-	-	**20.0**
- Royalties receivable from the Karish and Tanin leases (see Note 8B above)	-	-	262.2	**262.2**
- Loan to Energean from the sale of the Karish and Tanin leases (see Note 8B above)	-	64.4	-	**64.4**
Total Financial assets at fair value through profit or loss:	**20.0**	**64.4**	**262.2**	**346.6**

Adjustment due to fair value measurements classified as level 3 in the financial instruments fair value hierarchy:

	For the year ended December 31, 2022	
	Future production-based royalties	Total
Balance as of January 1	**262.2**	**262.2**
Revenues	(2.3)	(2.3)
Remeasurement recognized in profit or loss	60.9	60.9
Balance as of December 31	**320.8**	**320.8**

	For the year ended December 31, 2021	
	Future production-based royalties	Total
Balance as of January 1	**242.2**	**242.2**
Remeasurement recognized in profit or loss	20.0	20.0
Balance as of December 31	**262.2**	**262.2**

Notes to the Financial Statements as of December 31, 2022 (Dollars in millions)

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, 2022	
	Fair value	Book value
Bonds:		
Leviathan Bond	2,115.7	2,155.8
Total	**2,115.7**	**2,155.8**

	As of December 31, 2021	
	Fair value	Book value
Bonds:		
Leviathan Bond	2,392.6	2,224.8
Total	**2,392.6**	**2,224.8**

D. Groups of financial instruments:

	As of December 31,	
	2022	2021
Financial assets:		
Cash and cash equivalents	22.4	220.2
Investments and deposits	396.4	221.3
Trade receivables	199.0	152.5
Trade and other receivables	130.0	73.4
Other long-term assets	321.0	305.3
Total financial assets	**1,068.8**	**972.7**
Financial liabilities:		
Trade and other payables	3.5	5.5
Profits declared for distribution	50.0	-
Bonds (see Note 10 above)	2,155.8	2,224.8
Total financial liabilities	**2,209.3**	**2,230.3**

Notes to the Financial Statements as of December 31, 2022 (Dollars in millions)

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 SOFR interest rate. The general risk management plan of the Partnership focuses on acts to reduce the 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**:
   Exchange rate risk derives mainly from assets and liabilities stated in ILS and from the fact that the tax advances paid by the Partnership are based on a Shekel tax report. Also, the Partnership has expenses in ILS that are exposed to exchange rate changes.
2. **Interest risk**:
   An interest risk derives from the risk that the fair value or the future cash flows of a financial asset will change as a result of changes in the market interest rates. Financial instruments that bear variable interest expose the Partnership to a cash flow and profit and loss risk due to changes in the interest rate. The Partnership's credit facility, as provided in Note 10D above, is based on the SOFR interest. In 2021, some of the Partnership's short-term investments incurred variable interest.

   Following are the balances of financial instruments that bear interest according to their book value:

	As of December 31,	
	2022	2021
Financial instruments at variable interest:		
Assets:		
Deposits in banks (including cash and cash equivalents)	398.3	320.9
Trade and other receivables in the context of joint ventures	46.5	23.3
Total	**444.8**	**344.2**

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%**
2022	2.2	(2.2)
2021	1.7	(1.7)

Notes to the Financial Statements as of December 31, 2022 (Dollars in millions)

Note 22 – Financial Instruments (Cont.):

F. Market risks (Cont.):

2. Interest risk (Cont.):

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. $320.8 million (as of December 31, 2021 in the sum of approx. $262.2 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. $53.6 million (as of December 31, 2021: in the sum of approx. $64.4 million).

Following are tests of sensitivity to a change in the capitalization interest, with the other variables remaining constant:

	As of December 31, 2022				
	Profit (loss) from the change in the capitalization interest				
	2%	1%	**Fair value**	-1%	-2%
Royalties receivable from the Karish and Tanin leases	(22.8)	(12.2)	**320.8**	11.8	25.5
Loan to Energean in the context of the sale of the Karish and Tanin leases (See Note 8B above)	(2.0)	(1.0)	**53.6**	1.0	2.1
Total	**(24.8)**	**(13.2)**	**374.4**	**12.8**	**27.6**

	As of December 31, 2021				
	Profit (loss) from the change in the capitalization interest				
	2%	1%	**Fair value**	-1%	-2%
Royalties receivable from the Karish and Tanin leases	(19.0)	(9.8)	**262.2**	10.6	21.9
Loan to Energean in the context of the sale of the Karish and Tanin leases (See Note 8B above)	(2.8)	(1.4)	**64.4**	1.5	3.1
Total	**(21.8)**	**(11.2)**	**326.6**	**12.1**	**25.0**

3. Price risk:

Natural gas and condensate prices risk:

Agreements for the supply of natural gas determine the gas price according to price formulas which include various linkage components, including mostly linkage to the Brent barrel price, linkage to the Electricity Production Tariff, linkage to the ILS/$ exchange rate, linkage to the general TAOZ index published by the Electricity Authority and linkage to the crack spread index. In most of the agreements for the supply of natural gas in which the Partnership engaged, and other than contracts that include a non-linked fixed price, determine, in addition to the price formulas, also floor prices which limit, to a certain extent, the exposure to fluctuations in the linkage components.

Note 22 – Financial Instruments (Cont.):

F. Market risks (Cont.):

3. Price risk (Cont.):

Nevertheless, there is no certainty that the Partnership will be able to determine such floor prices also in new agreements that shall be signed thereby in the future.

Furthermore, a decline in the brent prices and/or Electricity Production Tariff and/or a rise in the ILS/$ exchange rate (a devaluation of the shekel against the dollar), may have an adverse effect on the Partnership's revenues from the existing and future gas sale agreements.

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 the 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*, by significant changes in the prices of oil, natural gas including LNG, and the prices of other energy sources, including coal, sources of renewable energy and other substitutes for produced natural gas that is marketed by the Partnership, 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 markets relevant to the Partnership and adversely affect the Partnership's revenues from the Leviathan reservoir.

An increase in supply, a decrease in demand or a decrease in prices of energies that are alternative sources to natural gas, including coal, sources of renewable energy 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, the financial position and results of operations thereof.

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.

Notes to the Financial Statements as of December 31, 2022 (Dollars in millions)

Note 22 – Financial Instruments (Cont.):

F. Market risks (Cont.):

3. **Price risk (Cont.):**

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, extensive military conflicts between countries 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.

4. **Securities and commodities prices risk:**

The Partnership sometimes invests some of its surplus cash in dollar bonds. These investments are exposed 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. These investment decisions are made by the Partnership's management, based on the recommendations of professional advisors and the guidance of the investment committee of the board of the Partnership's General Partner. As of December 31, 2022, there are no investments in securities that are exposed to market fluctuations, and as of December 31, 2021 there are ETFs, the fair value of the balance of the investment in which was approx. $20 million.

Below are tests of sensitivity relative to a change in the price, while the other variables are constant:

	As of December 31, 2021 [sic]				
	Securities price				
	10%	5%	**Fair value**	-5%	-10%
ETFs	2.0	1.0	**20.0**	(1.0)	(2.0)

Below are expanded tests of sensitivity relative to a change in the prices of the natural gas and condensate, while the other variables are constant:

	As of December 31, 2022								
	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	43.0	26.8	14.6	6.6	**320.8**	14.8	8.7	(7.1)	(25.2)

Notes to the Financial Statements as of December 31, 2022 (Dollars in millions)

Note 22 – Financial Instruments (Cont.):

F. Market risks (Cont.):

4. Securities and commodities prices risk (Cont.):

	As of December 31, 2022								
	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	26.2	20.4	10.0	5.0	**320.8**	19.1	13.2	4.5	(7.1)

	As of December 31, 2021								
	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	14.8	12.2	72.2	(2.0)	**262.2**	(6.7)	(12.1)	(18.2)	(25.1)

	As of December 31, 2021								
	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	7.8	7.2	0.8	(2.8)	**262.2**	(4.7)	(8.9)	(11.8)	(20.7)

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 are Blue Ocean which accounted for approx. 48% of the sales in the report period, NEPCO which accounted for approx. 27% of the sales in the report period (34% and 30% of the sales, respectively, in 2021). The trade receivables balance as of December 31, 2022 is a current balance. The Partnership estimates that the credit risk deriving from the sales of natural gas supplied to Blue Ocean and Nepco is low in light of past experience and since their current balances are partially backed up by collateral that was provided thereby. In addition, up to the date of approval of the financial statements, the Partnership received from its customers all of the revenues recorded as trade receivables balance as of the date of the financial statements.

Notes to the Financial Statements as of December 31, 2022 (Dollars in millions)

Note 22 – Financial Instruments (Cont.):

G. Credit risks (Cont.):

1) Below are turnover and aging of trade receivables, the value of which was not affected:

	Revenues for the year ended December 31, 2022	Trade receivables balance as of December 31, 2022		
		Total	Current balance	Disputed balance
NEPCO	324.8	54.6	54.6	-
Blue Ocean	534.4	130.4	130.4	-
Other customers	284.7	14.0	14.0	-
Total	**1,143.9**	**199.0**	**199.0**	**-**

	Revenues for the year ended December 31, 2021	Trade receivables balance as of December 31, 2021		
		Total	Current balance	December 31, 2022
IEC	91.1	0.1	0.1	-
NEPCO	264.8	35.5	35.5	-
Blue Ocean	298.2	96.9	96.9	-
Other customers	228.4	20.0	20.0	-
Total	**882.5**	**152.5**	**152.5**	**-**

2) The Partnership has cash and cash equivalents and deposits that are mostly held with large banking corporations in Israel. The Partnership expects no material losses due to the credit risk deriving from these balances.
3) The balance of the financial assets presented in the statement of financial position, Paragraph D above, reflects the maximal exposure deriving from the credit risk as of the date of the financial statements.
4) The Partnership has amounts receivable from a company accounted for at equity in the sum of approx. $24.9 million, which were included under trade and other receivables and other long-term assets. Amounts receivable are measured at fair value and discounted at an interest reflecting the credit risk that reflects the business environment of the company accounted for at equity, based on the Partnership's evaluations on the date of recovery thereof.

Notes to the Financial Statements as of December 31, 2022 (Dollars in millions)

Note 22 – Financial Instruments (Cont.):

H. Liquidity risk:

Liquidity risks result from the management of the Partnership's working capital, from the financial expenses and from principal repayments of the debt instruments. A liquidity risk is the risk that the Partnership will have difficulties in fulfilling undertakings related to its financial liabilities.
The management of the General Partner reviews the expected cash flows 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 deposits and short-term investments, together with the forecasted income, shall ensure the fulfillment of its obligations on the respective maturity dates thereof and to further maintain their real value according to the Partnership Agreement. 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:

2022	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	3.5	-	-	-	-	**3.5**
Declared distribution of profits	50.0					**50.0**
Bonds	-	548.3	807.4	732.8	642.8	**2,731.3**
Total	**53.5**	**548.3**	**807.4**	**732.8**	**642.8**	**2,784.8**

2021	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	5.5	-	-	-	-	**5.5**
Bonds	-	141.6	740.1	770.6	1,299.4	**2,951.7**
Total	**5.5**	**141.6**	**740.1**	**770.6**	**1,299.4**	**2,957.2**

Notes to the Financial Statements as of December 31, 2022 (Dollars in millions)

Note 22 – Financial Instruments (Cont.):

H. Liquidity risk (Cont.):

Changes in liabilities deriving from financing activity:

	Balance as of December 31, 2021	Cash Flow	Effect of changes in amortized cost	Other changes	Balance as of Dec. 31, 2022
Bonds	**2,224.8**	(74.5)	5.4	-	**2,155.8**
Profits for distribution, declared and provision for balancing and tax payments	**86.2**	(186.7)	-	150.5	**50.0**
Total liabilities deriving from financing activity	**2,311.0**	**(261.1)**	**5.4**	**150.5**	**2,205.8**

	Balance as of December 31, 2020	Cash Flow	Effect of changes in amortized cost	Other changes	Balance as of Dec. 31, 2021
Bonds	**3,248.5**	(1,035.3)	11.6	-	**2,224.8**
Profits for distribution, declared and provision for balancing and tax payments	**36.5**	(236.6)	-	286.3	**86.2**
Total liabilities deriving from financing activity	**3,285.0**	**(1,271.9)**	**11.6**	**286.3**	**2,311.0**

Note 23 – Material Subsequent Events:

A. See Note 12M12 for details regarding INGL's notice to Chevron.

B. See Note 7C2 for details regarding the approval of budgets for performance of engineering design in the context of Phase 1 – Second Stage of the development of the Leviathan reservoir.

C. See Note 12P for details regarding the termination of the transaction with Capricorn.

D. See Note 10C for details regarding the decision of the board of the Partnership's General Partner to adopt an additional buyback plan for the bonds of Leviathan Bond.

E. See Note 12F for details regarding an engagement for the sale of condensate from the Leviathan reservoir to PAR.

F. See Note 12L2 for details regarding the dismissal of the appeal from a judgment in a motion for class certification concerning the price at which the Tamar partners sell natural gas to the IEC.

G. See Note 7C5 for details regarding the approval of the general meeting for engagement in agreements pertaining to the exploration license in Morocco.

H. See Note 13C for details regarding the approval of the board of the Partnership's General Partner on the distribution of profits in the sum of $60 million.

I. See Mote 1D for details regarding a possible transaction and an offer to purchase the Partnership's participation units.

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Part D

Additional details about the corporation

Name of the Corporation:	NewMed Energy – Limited Partnership[1]	**Corporation No. at the Registrar**:	550013098
Address:	19 Abba Eban Blvd., Herzliya, 4672537		
Telephone:	09-9712424	**Facsimile**:	09-9712425
Balance Sheet Date:	December 31, 2022	**Report Date**:	March 27, 2023

Below are additional details regarding the Partnership, according to the Securities Regulations (Periodic and Immediate Reports), 5730-1970 (the "**Reports Regulations**"):

Regulation 8B: Valuations

For details regarding a very material valuation on royalties receivable from the I/16 Tanin and I/17 Karish leases which are owned by Energean Israel Ltd., see Annex B to the Board of Directors' Report (Chapter B of this Report) and Note 8B to the financial statements (Chapter C of this Report). The said valuation is attached at the end of this Report.

Regulation 9D: Status of liabilities report according to payment dates

Concurrently with the release of this 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 this Report.

Regulation 10A: Summary of the Partnership's statements of comprehensive income for each one of the quarters in 2022 and for 2022 in its entirety

See Section 2B of Part One of the Board of Directors' Report (Chapter B of this Report).

Regulation 10C: Use of the proceeds from securities with reference to the purposes of the proceeds according to the prospectus

On May 30, 2022, the Partnership released a shelf prospectus. For further details, see the Partnership's immediate report of May 30, 2022 (Ref. no.: 2022-01-055113), the information appearing in which is incorporated herein by reference.

[1] The Partnership's previous name was Delek Drilling – Limited Partnership. On February 21, 2022, the Partnership's name was changed to its current name.

Regulation 11: **List of the Partnership's investments in subsidiaries and companies accounted for at equity thereof**[2,3]

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, 2022	Price of the shares listed on TASE as of December 31, 2022 (in Agorot)	% of the holding in the capital, in voting and in the authority to appoint directors	Balance of loans to subsidiaries and to companies accounted for at equity as of December 31, 2022 (Dollars in thousands)	Main terms of the loans		
								Final maturity date	Linkage terms	Additional details
Yam Tethys Ltd.[4]	Ordinary shares	48,500	ILS 48,500	-	-	48.5	-	-	-	-
Leviathan Bond Ltd. ("Levithan Bond") [5]	Ordinary shares	100	ILS 100	-	-	100	100,000	June 2030	Dollar	_[6]
Leviathan Transmission System Ltd.[7]	Ordinary shares	45,340	ILS 4,534	-	-	45.34	-	-	-	-
NBL Jordan Marketing Limited[8]	Ordinary shares	4,534	$4,534	-	-	45.34	-	-	-	-

[2] For further details regarding the Partnership's subsidiaries and companies accounted for at equity, see Section 1.7 of Chapter A of this Report.

[3] The Partnership undertook to keep in escrow for New Med Energy Plc. ("**New Med**"), a wholly (indirectly) owned subsidiary of the Partnership, the sum of £50 thousand, which was transferred thereto for the purpose of its establishment by Delek Energy Limited, a wholly-owned subsidiary of the Partnership which was incorporated in England and is New Med's parent company, and which shall be paid to New Med upon its request.

[4] A special purpose company (SPC) established by the partners in the Yam Tethys project for purposes of receiving a gas transmission license. For further details, see Section 1.7.1 of Chapter A of this Report.

[5] An SPC wholly owned by the Partnership which was established for the offering of bonds to the institutional market in Israel and overseas, which are secured by the Partnership's interests in the Leviathan leases. For further details, see Sections 1.7.6 and 7.19.2 of Chapter A of this Report and Note 10B to the financial statements (Chapter C of this Report).

[6] 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 Leviathan Bond. For further details, see Notes 4 and 10B to the financial statements (Chapter C of this Report) and Part Five of the Board of Directors' Report (Chapter B of this Report). It is noted that the loan principal does not include accrued interest in the sum of approx. $1.7 million.

[7] An SPC which was established for the purpose of obtaining a license for transmission of natural gas from the Leviathan project. For further details, see Section 1.7.2 of Chapter A of this Report.

[8] An SPC incorporated in the Cayman Islands for the purpose of engagement in the gas supply agreement with the Jordan National Electric Power Company. For further details, see Sections 1.7.3 and 7.10.3(b) of Chapter A of this Report.

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, 2022	Price of the shares listed on TASE as of December 31, 2022 (in Agorot)	% of the holding in the capital, in voting and in the authority to appoint directors	Balance of loans to subsidiaries and to companies accounted for at equity as of December 31, 2022 (Dollars in thousands)	Main terms of the loans		
								Final maturity date	Linkage terms	Additional details
EMED Pipeline B.V. ("EMED B.V.")[9]	Ordinary shares	5,000	$5,000	$75,005,000	-	25	39,847	_[10]	Dollar	-
EMED Pipeline[11]	Ordinary shares	5,000	€5,000	-	-	100	-	-	-	-
Eastern Mediterranean Gas Company S.A.E ("EMG")[12]	Ordinary shares	57,330,000	$57,330,000	-	-	9.75	-	-	-	-

[9] An SPC incorporated in Holland in connection with the EMG transaction (as defined in Section 7.24.6 of Chapter A of this Report). For further details, see Section 1.7.4 of Chapter A of this Report.

[10] The loan is for the Partnership's investments in refurbishment of the EMG pipeline, which were made through EMED B.V. The loan agreement between EMED Pipeline Holding Limited ("**EMED Pipeline**") and EMED B.V. was signed on September 7, 2022.

[11] An SPC wholly owned by the Partnership which was incorporated in Cyprus in connection with the EMG transaction (as defined in Section 7.24.6 of Chapter A of this Report). For further details see Section 1.7.4 of Chapter A of this Report.

[12] A private company incorporated in Egypt which owns the EMG pipeline. For further details see Sections 1.7.5 and 7.24.6 of Chapter A of this Report.

Regulation 12: **Changes in investments in subsidiaries and in companies accounted for at equity in the report period**

In the report period, no changes were made to investments in subsidiaries and in companies accounted for at equity.

Regulation 13: **Revenues of and from the Partnership's subsidiaries and companies accounted for at equity (Dollars in thousands)**

Name of the company	Profit (loss) before tax	Other comprehensive income (loss)	Profit (loss) after tax	Dividends received as of December 31, 2022	Dividends received (or receivable by the Partnership) after December 31, 2022	Dividend payment dates after December 31, 2022	Management fees received as of December 31, 2022	Management fees received (or receivable by the Partnership) after December 31, 2022	Management fee payment dates after December 31, 2022	Interest	Interest payment dates
Leviathan Bond	1,146	-	1,146	-	-	-	-	-	-	-	-
EMED Pipeline	(25)	-	(19)	-	-	-	-	-	-	-	-
EMED B.V.	(12,378)	-	(12,450)	-	-	-	-	-	-	-	-
EMG	11,011	-	9,222	-	-	-	-	-	-	-	-

Regulation 21: **Compensation of interested parties and senior officers**[13]

(a) Below is a specification regarding the compensation given, in the report year, to the highest-paid senior officers of the Partnership and/or a corporation controlled thereby in connection with their term of office at the Partnership and/or a corporation controlled thereby, as well as regarding the compensation given to interested parties of the Partnership in connection with services provided by them as office holders at the Partnership in 2022 (Dollars in thousands), as recognized in the financial statements as of December 31, 2022[14]:

[13] For further details regarding the terms of employment of the officers and the interested parties stated in the table, see Regulation 21(b) below.

[14] For details regarding the new arrangement in connection with the Partnership's management expenses (the "**New Management Arrangement**"), according to which from January 1, 2022, the Partnership bears all of the Partnership's management expenses which, according to the previous management arrangement, were borne by the General Partner, including the cost of employment of officers and employees, including the CEO and the Active Chairman of the Board, see Regulation 22 below.

Senior officers and interested parties of 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	Manage-ment fees	Consult-ing fees	Comm-ission	Other	Interest	Rent	Other	
Yossi Abu[15]	CEO	100%	0.05%	839.3	665.3	1,037.9[16]	-	-	-	-	-	-	284.9	**2,827.4**
Zvi Karcz	VP Exploration	100%	-	394.1	94.6	-	-	-	-	-	-	-	70.8	**559.5**
Sari Singer Kaufman	General Counsel, EVP	100%	-	383.7	93.4	-	-	-	-	-	-	-	80.8	**557.9**
Nadav Perry	VP Regulatory & Public Affairs	100%		340.6	82.8	-	-	-	-	-	-	-	55.9	**479.3**
Tzachi Habusha	VP Finance	100%	-	388.1	23.9	-	-	-	-	-	-	-	27.2	**439.2**
Gabi Last	Active Chairman of the Board	100%	0.00%[17]	95.9	-	-	-	-	-	-	-	-	7.2	**103.1**
External directors[18]	-	-	-	323.0	-	-	-	-	-	-	-	-	-	**323.0**

[15] In accordance with the New Management Arrangement, as detailed in Regulation 22 below, from January 1, 2022, Mr. Abu is employed by the Partnership, which also bears the cost of his employment.

[16] For details regarding Mr. Abu's holdings in options that are exercisable for the Partnership's participation units (the "**Participation Units**"), see Regulation 21(b)(2) below.

[17] Mr. Last holds 12,109.60 Participation Units.

[18] Messrs. Amos Yaron and Jacob Zack have held office as external directors on the board of NewMed Energy Management Ltd. (the "**General Partner**" and the "**Board**", respectively) since October 22, 2015 (a first term of office which was extended on October 10, 2018 for a second 3-year term of office, until October 22, 2021, and on October 14, 2021, for a third and final 3-year term of office until October 22, 2024). Mr. Efraim Sadka has held office as an external director on the Board since April 1, 2019 (a first term of office which was extended on March 24, 2022 for a second 3-year term of office, until April 1, 2025).

(b) Below is a specification regarding the terms of office and employment of officers who are the highest-paid senior officers of the Partnership:

(1) <u>Compensation policy</u>

For details on the compensation policy for officers of the Partnership and the General Partner, that was approved by the meeting of the participation unit holders on July 10, 2019 for a period of 3 years from that date, as amended from time to time, see the Partnership's immediate reports of May 23, 2019, June 3, 2019, July 1, 2019, July 2, 2019, July 3, 2019, July 10, 2019, July 13, 2020, August 6, 2020, August 10, 2020 and August 18, 2020 (Ref. no.: 2019-01-043911, 2019-01-047886, 2019-01-056580, 2019-01-056889, 2019-01-057213, 2019-01-059625, 2020-01-067288, 2020-01-085728, 2020-01-076858 and 2020-01-080758, respectively), the information appearing in which is incorporated herein by reference (the "**Previous Compensation Policy**").

On September 21, 2022, the meeting of the Participation Unit holders decided not to approve an updated compensation policy for officers of the Partnership and the General Partner. For further details, see the Partnership's immediate reports of September 6, 2022 and September 21, 2022 (Ref. no.: 2022-01-092520 and 2022-01-120358, respectively), the information appearing in which is incorporated herein by reference.

Consequently, on September 28, 2022, the compensation committee and the Board decided, after reopening the discussion thereon, to approve the said updated compensation policy, with a change to the cap on the annual bonus for the Partnership's CEO and other officers, for a period of 3 years from that date, despite the objection of the meeting of the Participation Unit holders (the "**Compensation Policy**"). For further details, see the Partnership's immediate report of September 29, 2022 (Ref. no.: 2022-01-121942), the information appearing in which is incorporated herein by reference.

(2) <u>Yossi Abu</u>

Mr. Yossi Abu ("**Mr. Abu**" or the "**CEO**") has served as CEO of the Partnership since April 1, 2011.

In accordance with the New Management Arrangement, as specified in Regulation 22 below, from January 1, 2022 the

Partnership bears the full cost of his employment (100%), in lieu of the General Partner.

On September 21, 2022, the meeting of the Participation Unit holders decided not to approve the updated terms of office and employment for Mr. Abu. For further details, see the Partnership's immediate reports of September 6, 2022 and September 21, 2022 (Ref. no.: 2022-01-092520 and 2022-01-120358, respectively), the information appearing in which is incorporated herein by reference.

Consequently, on September 28, 2022, the compensation committee and the Board decided, after reopening the discussion thereon, to approve the updated terms of office and employment for the CEO, despite the objection of the meeting of the Participation Unit holders. For further details, see the Partnership's immediate report of September 29, 2022 (Ref. no.: 2022-01-121942), the information appearing in which is incorporated herein by reference.

Accordingly, Mr. Abu's updated terms of office and employment are as follows (the "**Updated Terms of Office and Employment**"):

Mr. Abu's monthly salary is approx. ILS 202 thousand gross (100%)[19] (the salary is updated every 3 months in accordance with the CPI). According to the terms of his employment (in this section: the "**Employment Agreement**"), Mr. Abu is entitled to standard 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. Abu with a car, as is standard for his position, and bears any and all expenses entailed by the use of the car. The value of the use of the car is grossed-up and paid by the Partnership. Mr. Abu is also entitled to additional related benefits, such as his inclusion in officer indemnification, exemption and insurance arrangements, communication expenses (mobile telephone, internet, newspapers and payment of expenses in respect of reasonable use of his home phone), executive physicals, private health insurance at the Partnership's expense, participation in professional continuing education, severance pay (since 2016 Mr. Abu has not signed Section 14 of the Severance Pay Law, 5723-1963, and therefore the severance pay to which he is entitled is pursuant to law), receipt of loans from the Partnership, reimbursement of expenses for the performance of his duties, and reimbursement of per diem expenses during

[19] As of December 31, 2022.

foreign travel on behalf of the Partnership. The Partnership may grant Mr. Abu, each year, an annual bonus for the previous calendar year, provided that he shall be employed by the Partnership at least 3 months in such year, and a special bonus, a retention bonus, and in the case of separation from employment, an adjustment bonus and a retirement bonus, all in accordance with the Compensation Policy as updated from time to time.

The parties may terminate the Employment Agreement at any time by giving prior written notice of 6 months. In addition, the Employment Agreement includes provisions regarding confidentiality and a non-compete clause for a period of 12 months.

Approval has also been given to grant Mr. Abu, for no consideration, 3,295,599 non-marketable options exercisable for 3,295,599 Participation Units, which constitute approx. 0.28% of the Partnership's issued and paid-up Participation Unit capital (on a fully diluted basis) on the date of the notice of the meeting for approval of the updated terms of office and employment (after the allotment)[20], in accordance with the Compensation Policy and an option plan pursuant to Section 102 of the Income Tax Ordinance [New Version], which was adopted by the Board on July 27, 2022 (the "**Options**" and the "**Grant Date**", respectively).

The Options will vest in 3 equal annual installments, commencing from the Grant Date. The exercise price of the first installment will be 866 Agorot, which is equal to the average closing price of the Participation Units on the Tel Aviv Stock Exchange Ltd. ("**TASE**") at the close of the 30 trading days that preceded the Grant Date. The exercise price of the remaining two installments will increase by 5% each year relative to the previous year.

The annual benefit value that derives from the granting of the Options, i.e. the economic value of the Options on the Grant Date, divided by 3, shall not exceed ILS 3,300 thousand.

According to the said approval, on October 3, 2022, Mr. Abu was granted (unregistered) Options. For further details, see the Partnership's immediate reports of October 3, 2022 and October 12, 2022 (Ref. no.: 2022-01-100665, 2022-01-100692

[20] For details regarding the rate of Mr. Abu's holdings (on a fully diluted basis) as of the report approval date, see Regulation 24 below.

and 2022-01-125926, respectively), the information appearing in which is incorporated herein by reference.

According to a valuation received by the Partnership, the economic value of the Options on the Grant Date totaled approx. ILS 9.8 million, and was calculated using the Binomial model, based on the following assumptions: (a) Participation Unit price, as of the Grant Date, of ILS 9.35; (b) the exercise price of each option (adjusted to a profit distribution) was calculated according to ILS 8.66 for the first installment, ILS 9.10 for the second installment, and ILS 9.55 for the third installment; (c) expiration date: August 1, 2027; (d) vesting date: as specified in this section above; (e) standard deviation rate of 49.9%; and (f) risk-free interest rate of approx. 2.31%.

For further details regarding the Updated Terms of Office and Employment, see the Partnership's immediate report of September 6, 2022 (Ref. no.: 2022-01-092520), the information appearing in which is incorporated herein by reference.

Until the date of approval of the Updated Terms of Office and Employment by the compensation committee and the Board as aforesaid, the terms of office and employment to which Mr. Abu was entitled were the terms and conditions approved on July 10, 2019 by the meeting of the Participation Unit holders, according to the Previous Compensation Policy (the "**2019 Terms**"). For details on the 2019 Terms, see Regulation 21(b)(2) of Chapter D of the 2021 periodic report, as released on March 24, 2022 (Ref. no.: 2022-01-033988).

Under the 2019 Terms, the General Partner granted Mr. Abu 2,742,231 phantom units (whose underlying asset is a participation unit granting a right of participation in the rights of NewMed Energy Trusts Ltd. (the "**Limited Partner**" or the "**Trustee**")[21] (in this section: the "**Phantom Units**"). As of the report approval date, all of the Phantom Units have vested, and each one of the installments included in the total package is exercisable until June 1, 2023. In addition, the exercise price of the 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.

[21] The exercise prices, as specified above, and/or the number of the current 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 rights offerings of securities and/or in circumstances of mergers and acquisitions.

According to a valuation received by the Partnership, the economic value of the Phantom Units as of December 31, 2022 totaled approx. ILS 1 million, and was calculated using the Binomial model, based on the following assumptions: (a) Participation Unit price, as of December 31, 2022, of ILS 7.85; (b) the exercise price of each option (adjusted to a profit distribution and tax advances until and inclusive of 2021) was calculated according to ILS 7.96 for the first installment, ILS 8.50 for the second installment, and ILS 9.06 for the third installment; (c) standard deviation of 26.8%; (d) risk-free interest rate of approx. 3.47%; (e) contractual life of approx. 0.42 years from December 31, 2022; (f) rate of abandonment after the vesting period that was taken into account - 0%; and (g) limitation of the maximum benefit that Mr. Abu shall derive from exercise of each Phantom Unit shall not exceed 100% of the exercise price determined for the Phantom Unit. In accordance with the decision of the participation unit holders regarding the New Management Arrangement, as detailed in Regulation 22 below, the General Partner will bear any increase in the amount of the Phantom Units that shall derive from an increase in the market price of the Participation Units in the period before January 1, 2022, and the Partnership shall bear any increase in the amount of the Phantom Units that shall derive from an increase in the market price of the Participation Units from such date forth, with respect to all three installments.

According to the 2019 Terms, in 2022, Mr. Abu received an annual bonus for 2021 in the sum of approx. ILS 2,090 thousand, as well as a special bonus equal to one gross monthly salary. The annual bonus was granted to Mr. Abu based on the following components:

(a) <u>A business target-dependent component (40%)</u> – Mr. Abu met the business targets specified below, and was therefore entitled, in respect of this component, to the sum of ILS 880 thousand: the sale of the Partnership's holdings in the Tamar project by way of a sale to a third party for consideration of no less than \$850 million; the performance of a profit distribution of no less than \$100 million; the performance of production tests in the New Ofek license; adjustment of the work plan in Block 12 in Cyprus vis-à-vis the Cypriot government for the purpose of reducing the investment obligation by around \$30 million (100%); natural gas nominations from the Leviathan project by the Egyptian customer in an annual amount of no less than 90% of the annual quantity in accordance with the export to Egypt agreement; (b) <u>A component dependent on the</u>

following quantitative tests (35%): (1) change in adjusted net profit[22] (5%). Mr. Abu met this criterion, because the change in the adjusted net profit was 158%, and therefore Mr. Abu was entitled, in respect of this criterion, to an annual bonus of ILS 110 thousand; (2) the making of investments/adoption of an investment decision (25%): the actual making of investments by the Partnership in a petroleum asset in an 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%), all excluding investments in exploration wells. Mr. Abu met this criterion because investments were made in the Leviathan project and in the Tamar project in a total sum exceeding \$50 million, and therefore Mr. Abu was entitled, in respect of this criterion, to an annual bonus of ILS 550 thousand; (3) raising of money/signing of natural gas sale agreements/signing of export agreements (5%): 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 at a volume of over 25 BCM, or alternatively the signing of export agreements. Mr. Abu did not meet this criterion, and therefore was not entitled to an annual bonus therefor; and (c) Board of directors' discretion component (25%): ILS 550 thousand.

(3) Zvi Karcz

Mr. Zvi Karcz ("**Mr. Karcz**") has served as VP Exploration in a full-time position since August 2014 (prior to which, from September 2011, he was employed as the Partnership's Chief Geologist).

Mr. Karcz's gross monthly salary is approx. ILS 82 thousand[23] (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 standard 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 is standard for his position, and bears any and all expenses entailed by the use of the car. The value of the use of the car is grossed-up and paid by the Partnership. Mr. Karcz is also entitled to additional related benefits, such as his inclusion in officer indemnification, exemption and insurance

[22] The rate received from division of the adjusted net profit (within the meaning thereof below) in the year for which the bonus is paid, by the average adjusted net profit of the Partnership in the 3 years preceding the year for which the bonus is paid ("**Change in the Adjusted Net Profit**").
[23] As of December 31, 2022.

arrangements, communication expenses (mobile telephone, internet, newspapers and payment of expenses in respect of reasonable use of his home phone), executive physicals, private health insurance at the Partnership's expense, participation in professional continuing education, reimbursement of expenses for the performance of his duties, and reimbursement of *per diem* expenses during foreign travel on behalf of the Partnership. The Partnership may grant Mr. Karcz, each year, an annual bonus for the previous calendar year, provided that he shall be employed by the Partnership at least 3 months in such year, all in accordance with the Compensation Policy and as shall be updated from time to time.

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 confidentiality and a non-compete clause for a period of 9 months. Mr. Karcz is entitled to an adjustment bonus in the sum of 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. In addition, phantom units were allotted to Mr. Karcz, but since he did not exercise them, they expired.

In 2022, Mr. Karcz received from the Partnership an annual bonus for 2021 equal to 4 gross monthly salaries, as a derivative of the components of the CEO's annual bonus.

(4) Sari Singer Kaufman

Ms. Sari Singer Kaufman ("**Ms. Singer**") has served as EVP and General Counsel on a full-time basis since May 2018 and August 2017 respectively (prior to which, from March 2012, she was employed as a legal counsel at the Partnership).

Ms. Singer's monthly salary is approx. ILS 81 thousand[24] (the salary is updated every 3 months according to the CPI). In accordance with the terms of her employment (in this section: the "**Employment Agreement**"), Ms. Singer is entitled to standard 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 is standard for her position, 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. Ms. Singer is

[24] As of December 31, 2022.

further entitled to additional related benefits, such as her inclusion in officer indemnification, exemption and insurance arrangements, communication expenses (mobile phone, internet, newspapers and payment of expenses in respect of reasonable use of her home phone), executive physicals, private health insurance at the Partnership's expense, participation in professional training, reimbursement of expenses for performance of her duties and reimbursement of *per diem* expenses during foreign travel on behalf of the Partnership. The Partnership may grant Ms. Singer, each year, an annual bonus for the previous calendar year, provided that she shall be employed by the Partnership at least 3 months in such year, all in accordance with the Compensation Policy and as shall be updated from time to time.

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 confidentiality and a non-compete clause for a period of 3 months.

In 2022, Ms. Singer received from the Partnership an annual bonus for 2021 in an amount equal to 4 gross monthly salaries, as a derivative of the components of the CEO's annual bonus.

(5) <u>Mr. Nadav Perry</u>

Mr. Nadav Perry ("**Mr. Perry**") has served as VP Regulatory & Public Affairs in a full-time position since May 2018 (prior to which, from June 2015, he was employed as Head of Media & Public Affairs at the Partnership).

Mr. Perry's gross monthly salary is approx. ILS 72 thousand[25] (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. Perry is entitled to standard 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. Perry with a car, as is standard for his position, and bears any and all expenses entailed by the use of the car. The value of the use of the car is grossed-up and paid by the Partnership. Mr. Perry is also entitled to additional related benefits, such as his inclusion in officer indemnification, exemption and insurance arrangements, communication expenses (mobile telephone, internet, newspapers and payment of expenses in respect of

[25] As of December 31, 2022.

reasonable use of his home phone), executive physicals and private health insurance at the Partnership's expense, participation in professional continuing education, reimbursement of expenses for the performance of his duties, and reimbursement of *per diem* expenses during foreign travel on behalf of the Partnership. The Partnership may grant Mr. Perry, each year, an annual bonus for the previous calendar year, provided that he shall be employed by the Partnership at least 3 months in such year, all in accordance with the Compensation Policy and as shall be updated from time to time.

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 confidentiality and a non-compete clause for a period of 3 months.

In 2022, Mr. Perry received from the Partnership an annual bonus for 2021 equal to 4 gross monthly salaries, as a derivative of the components of the CEO's annual bonus.

(6) Tzachi Habusha

Mr. Tzachi Habusha ("**Mr. Habusha**") has served as VP Finance at the Partnership in a full-time position since January 2022.

Mr. Habusha's gross monthly salary is approx. ILS 84 thousand[26] (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. Habusha is entitled to standard social benefits, a study fund, a pension plan, annual leave days, sick days and recuperation pay. The Partnership provides Mr. Habusha with a car, as is standard for his position, and bears any and all expenses entailed by the use of the car. The value of the use of the car is grossed-up and paid by the Partnership. Mr. Habusha is also entitled to additional related benefits, such as his inclusion in officer indemnification, exemption and insurance arrangements, a mobile telephone and the costs of reasonable use in respect thereof, reimbursement of expenses for the performance of his duties, and reimbursement of *per diem* expenses during foreign travel on behalf of the Partnership. The Partnership may grant Mr. Habusha, each year, an annual bonus for the previous calendar year, provided that he shall be employed by the Partnership at least 3 months in such year, all in accordance with the Compensation Policy and as shall be updated from time to time.

[26] As of December 31, 2022.

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 confidentiality and a non-compete clause for a period of 3 months.

In 2022, Mr. Habusha received from the Partnership a retention bonus equal to one gross monthly salary, subject to his undertaking to continue to serve in his position at the Partnership for one year from the date of approval of the said bonus by the compensation committee and the Board.

(7) Gabi Last

Mr. Gabi Last ("**Mr. Last**") has served as Active Chairman of the Board at the General Partner in a full-time position since April 2022 (prior to which, from May 2001, he held office as a director of the General Partner, and from January 2020 held office as Chairman of the Board at the General Partner).

Since November 1, 2022 the Partnership has borne the full cost of his employment (100%).

Mr. Last's gross monthly salary is approx. ILS 121 thousand[27] (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. Last is entitled to standard social benefits, a study fund, a pension plan, annual leave days, sick days and recuperation pay. The Partnership provides Mr. Last with a car, as is standard for his position, and bears any and all expenses entailed by the use of the car. The value of the use of the car is grossed-up and paid by the Partnership. Mr. Last is also entitled to additional related benefits, such as his inclusion in officer indemnification, exemption and insurance arrangements, communication expenses (mobile telephone, internet, newspapers and payment of expenses in respect of reasonable use of his home phone), executive physicals and private health insurance at the Partnership's expense, participation in professional continuing education, reimbursement of expenses for the performance of his duties, and reimbursement of *per diem* expenses during foreign travel on behalf of the Partnership. The Partnership may grant Mr. Last, each year, an annual bonus for the previous calendar year, provided that he shall be employed by the Partnership at least 3 months in such year, and in the case of separation from employment, an adjustment bonus, all in

[27] As of December 31, 2022.

accordance with the Compensation Policy and as shall be updated from time to time.

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 confidentiality and a non-compete clause for a period of 12 months.

(8) External directors

On October 22, 2015, the meeting of the participation unit holders decided that Messrs. Amos Yaron and Jacob Zack, who were appointed on such date as external directors by the said meeting, would be entitled to annual compensation and participation compensation, in accordance with the fixed amounts appearing in the Second Schedule and the Third Schedule to the Companies Regulations (Rules Regarding Compensation and Expenses for External Directors), 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.

From commencement of his second term of office (i.e., from October 22, 2018), Mr. Zack, who is classified as an expert external director, as defined in the Compensation Regulations, is entitled to participation compensation and annual compensation in the maximum amounts set forth in the Fourth Schedule to the Compensation Regulations, as being from time to time, and according to the Partnership’s rank, as being from time to time.

For further details regarding the appointment of the said external directors for a second term of office and for a third and final term of office, see the Partnership’s immediate reports of September 20, 2018, October 10, 2018, September 5, 2021, October 3, 2021, October 14, 2021 and October 24, 2021 (Ref. no.: 2018-01-085579, 2018-01-091300, 2021-01-144591, 2021-01-150285, 2021-01-156177 and 2021-01-158988, respectively) the information appearing in which is incorporated herein by reference.

Further to the resolution of the meeting of Participation Unit holders of January 28, 2019 to approve the appointment of Mr. Sadka as an external director commencing from April 1, 2019, it was determined that Mr. Sadka, who is classified as an expert external director, as defined in the Compensation Regulations, will be entitled, from commencement of his term of office as aforesaid, to participation compensation and annual compensation in the maximum amounts set forth in the Fourth Schedule to the Compensation Regulations, as being from time to time, and according to the Partnership's rank, as being from time to time.

For further details regarding the appointment of Mr. Sadka as an external director for a first term of office and for a second term of office, see the Partnership's immediate reports of December 16, 2018, January 28, 2019, February 17, 2022 and March 24, 2022 (Ref. no.: 2018-01-115258, 2019-01-008335, 2022-01-019783 and 2022-01-034714, respectively), the information appearing in which is incorporated herein by reference.

(9) <u>The Supervisors</u>

1. Fahn Kanne & Co., CPAs, together with Keidar Supervision and Management (collectively: the "**Supervisors**" or the "**Supervisor**") are entitled to receive from the Trustee, out of the trust assets, a fee of approx. ILS 63 thousand per month[28] (plus VAT). The monthly fee will be updated every 3 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 its additional work that is entailed by the publication of the prospectus, in an amount in ILS equal to $40 thousand (plus VAT, 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 shall also include compensation in respect of all of the work that shall be required of the Supervisor after publication of the shelf prospectus, in connection with the shelf prospectus in respect of which the Supervisor received the Additional Compensation, insofar as required, including shelf offering reports that shall be published under the shelf prospectus and/or any offering performed under the shelf prospectus and/or any financing round performed under the shelf prospectus (in this section: "**Work After the Publication of the Shelf Prospectus**"). It is further clarified that after the Supervisor is paid the Additional

[28] As of December 31, 2022.

Compensation, the Supervisor will not be entitled to any additional payment for his work in connection with the publication of the prospectus as aforesaid, in respect of which the Additional Compensation was paid to the Supervisor, as well as in connection with the Work After the Publication of the Shelf Prospectus.

The Supervisor is further entitled to a payment in ILS equal to $40 thousand (plus VAT), 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 lawfully incurred thereby for the purposes of its role, provided that it received therefor the approval of the meeting of the participation unit holders or that the expenses are within the amount and type approved for such purpose by the meeting of the participation unit holders. It is noted that on December 22, 2016, the meeting of the participation unit holders confirmed, without derogating from the provisions of the Partnership Agreement signed on July 1, 1993 (as amended from time to time) between the General Partner and the Limited Partner (the "**Partnership Agreement**"), and the trust agreement of July 1, 1993, which was signed between the Trustee and the Supervisors (as amended from time to time) (the “**Trust Agreement**”), that the types of expenses for which the Supervisor will be entitled to reimbursement of expenses out of the trust assets will include expenses of traveling to meetings of the Partnership’s organs, to meetings with the General Partner’s management and to meetings with the representatives of the General Partner vis-à-vis various regulators, courier services, and parking expenses in respect of all of the above, and that the sum of the expense reimbursement 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 said meeting, see the Partnership’s immediate reports of August 10, 2020 and August 18, 2020 (Ref. no.: 2020-01-076858 and 2020-01-

080758, respectively), the information appearing in which is incorporated herein by reference.

3. Further to the decision of the meeting of Participation Unit holders to approve a budget for the Supervisor for overseeing the restructuring process of July 17, 2019, and further to the decision of the meeting of Participation Unit holders to approve a supplementary budget and a fee in addition to its monthly fee for overseeing the restructuring process of March 3, 2021, on January 2, 2023, the meeting of the Participation Unit holders approved a supplementary budget for the Supervisor, for its continued engagement with professional consultants and a fee in addition to its monthly fee in connection therewith. For further details regarding the said meetings, see the Partnership's immediate reports of July 2, 2019, July 17, 2019, February 8, 2021, March 3, 2021, December 12, 2022 and January 3, 2023 (Ref. no.: 2019-01-056910, 2019-01-061854, 2021-01-015963, 2021-01-025905, 2022-01-150004 and 2023-01-002016, respectively), the information appearing in which is incorporated herein by reference.

4. Further to the decision of the meeting of Participation Unit holders to approve a budget for advising the Supervisor in the process of examination of the investment recovery date in the Tamar project (the "**Supervisor's Claim**") of September 6, 2018, on June 1, 2020, the meeting of the participation unit holders approved the Supervisor's budget for an additional engagement with an expert for the purpose of advising the Supervisor in the Supervisor's Claim and engaging therewith for examination of the draft directives released by the Ministry of Energy. For further details regarding the said meetings, see the Partnership's immediate reports of September 2, 2018, September 12, 2018, May 25, 2020 and June 1, 2020 (Ref. no.: 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 authorized the Supervisor to use the legal and economic consultants retained thereby for the conduct of the Supervisor's Claim also for monitoring and supervising the Partnership's management of the defense in the counterclaim regarding the investment recovery date. For further details regarding the said meeting, see the Partnership's immediate reports of February 8, 2021 and March 3, 2021 (Ref. no.: 2021-01-015963 and 2021-01-025905, respectively), the information appearing in which is incorporated herein by reference.

(10) The Trustee

1. The Trustee is entitled to receive, out of the trust assets, a fee equal to $1,000 (plus VAT) for every year in which it serves as 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 for which it is being paid. In addition, the Trustee is entitled to receive payment for expenses explicitly permitted in the Trust Agreement or which were approved in advance and in writing by the Supervisor.

2. On January 2, 2023, the meeting of the Participation Unit holders approved for the Trustee a fee in addition to its annual fee for completion of the restructuring process. For further details regarding the said meeting, see the Partnership's immediate reports of December 12, 2022 and January 3, 2023 (Ref. no.: 2022-01-150004 and 2023-01-002016, respectively), the information appearing in which is incorporated herein by reference.

Regulation 21A: **The Partnership's controlling interest holder**

As of the report approval date, the controlling interest holder (indirectly) of the Partnership is Mr. Yitzhak Sharon (Tshuva).

To the best of the Partnership's knowledge, Delek Group Ltd. ("**Delek Group**"), which is controlled by Mr. Yitzhak Sharon (Tshuva), holds, directly and indirectly (through Delek Energy Systems Ltd. ("**Delek Energy**") and the General Partner, and through an indirect holding in Avner Oil & Gas Ltd. ("**Avner Oil & Gas**")) approx. 54.66% of the issued unit capital of the Partnership[29].

[29] To the best of the Partnership's knowledge, and according to Delek Group's reports, as of the report approval date, the vast majority of the Participation Units held by Delek Group is pledged in favor of the holders of the bonds issued by Delek Group. In addition, on July 26, 2021 and February 6, 2023, the Board approved a pledge of approx. 4.5% and approx. 1.1% of the Participation Unit capital held by the General Partner, respectively, to secure bonds issued by Delek Group, which holds (indirectly) all of the issued share capital of the General Partner. Accordingly, as of the report approval date, all of the Participation Units held by the General Partner are pledged.

Regulation 22: **Transactions of the Partnership with the General Partner or transactions in which the General Partner's controlling shareholder has a personal interest**

Below are details, 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 report approval date, or which is still in effect on the report approval date, with the exception of negligible transactions, as defined in Section 6 of Part Three of the Board of Directors' Report (Chapter B of this Report):

(a) According to the Partnership Agreement, the General Partner is entitled to 0.01% of the Partnership's income and bears 0.01% of the expenses and losses of the Partnership, as well as the expenses and losses of the Partnership which, due to the limitation on the Limited Partner's liability for obligations of the Partnership, were not borne by the Limited Partner. In addition, according to the provisions of the Partnership Agreement, until April 23, 2021, the date on which 6 years lapsed from the date of commencement of the Law for Amendment of the Partnerships Ordinance (No. 5), 5775-2015 (the "**Commencement Date**" and "**Amendment No. 5**", respectively), the General Partner was entitled to current management fees in an amount in ILS equal to $40,000 per month[30] and in addition, to management fees at a rate of 7.5% of one half of the Partnership's expenses for petroleum exploration activities, on a quarterly basis, and no less than a total sum of $120,000 per quarter.

The General Partner was also entitled to reimbursement of any and all direct expenses entailed by management of the Partnership and incurred by the General Partner. Unless the Supervisor's approval was received for expenses of other types, the said expenses included only the following expenses: Fees for accounting services, legal advice, geological advice, investment advice, reservoir engineering and geophysical advice, engineering advice,

[30] The management fees were paid for management of the Partnership, including in respect of the services of the directors on the Board (who are not external directors), the General Partner's CEO, comptroller services, secretarial services and rent for the Partnership's offices, which are located in a building that is owned by Delek Group.

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 ventures, 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 Partnership Agreement further determined that, the aforesaid notwithstanding, the Partnership was entitled to directly employ employees and/or officers who would provide the Partnership with services of the type for which the General Partner was entitled to reimbursement of expenses as specified above, and in such a case the Partnership bore the full cost of their salary, and the General Partner was not entitled to reimbursement of expenses in respect of such services (the "**Previous Management Arrangement**").

According to the transitional provisions included in Amendment No. 5, an arrangement for the provision of services between the Partnership and the General Partner will require the approval of the audit committee, the Board and the meeting of the Participation Unit holders by a super majority, pursuant to Section 65YY(c) of the Partnerships Ordinance [New Version], 5735-1975 (the "**Partnerships Ordinance**"), within 6 years from the Commencement Date.

Accordingly, on September 21, 2022, the meeting of the Participation Unit holders approved the New Management Arrangement, as well as an amendment to the Partnership Agreement in connection therewith.

According to the New Management Arrangement, from January 1, 2022, the Partnership directly bears any and all expenses required for the management of its business and assets, including the management expenses of the General Partner, which according to the provisions of Section 65B(a) of the Partnerships Ordinance, has no other activity aside from management of the Partnership. Accordingly, the Partnership does not pay the General

Partner or Delek Group any management fees or operator fees.
In the context of the New Management Arrangement, the Partnership bears the costs of the compensation of all of the directors on the General Partner's board and the fees of the Active Chairman of the Board, with the exception of directors who serve as officers of Delek Group or other companies controlled thereby.

In addition, the Partnership bears the cost of the rent of the Partnership's offices, and accordingly the General Partner assigned to the Partnership all of its rights and obligations under the lease agreement.

In addition, according to the New Management Arrangement, the General Partner does not, as a general rule, bear the Partnership's management expenses, and consequently the Partnership will not be required to reimburse its expenses thereto. Insofar as the General Partner shall pay, out of pocket, any part of the Partnership's management expenses, it will be paid a reimbursement in respect of the said expenses, but in any event the General Partner will not be reimbursed with expenses paid thereby, directly or indirectly, to Delek Group or expenses in which Delek Group has a personal interest (within the meaning thereof in the Partnerships Ordinance), unless all of the approvals required by law are received in connection therewith. For this purpose, "**personal interest**" – except a personal interest deriving from Delek Group's mere holding in the General Partner, and with respect to an engagement with an officer or with an employee – except a personal interest deriving from the mere office or employment at the General Partner.

For further details, see the Partnership's immediate reports of September 6, 2022 and September 21, 2022 (Ref. no.: 2022-01-092520 and 2022-01-120358, respectively), the information appearing in which is incorporated herein by reference.

(b) According to a 1993 agreement, Delek Group and Delek Energy are entitled to receive royalties from the Partnership, as specified in Section 7.24.9(c)2 of Chapter A of this Report. As of the report approval date, the holder of the right to the royalties of Delek Group and Delek Energy in the Leviathan project is Delek Leviathan

Overriding Royalty Ltd. ("**Delek Overriding Royalty**"), a wholly owned subsidiary of Delek Energy[31].

In 2022, the Partnership recorded expenses in respect of royalties to Delek Overriding Royalty for the Leviathan project in the total sum of approx. $15.2 million.

(c) According to the terms and conditions of the Production Sharing Contract (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 provided a performance guarantee in an unlimited amount in favor of the Republic of Cyprus to secure fulfillment of all of the Partnership's undertakings under the PSC (the "**Guarantee**"), all as specified below:

1. For provision of the Guarantee by Delek Group, the Partnership pays a fee, on an annual basis, from the date of provision of the Guarantee and so long as the Guarantee is in effect, of $368 thousand. If the holding rate of the Partnership in Block 12 decreases, 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 interests in Block 12 by the Partnership, the Partnership and Delek Group agreed that payment of the fee will be discontinued immediately. The sum of the Guarantee fee that the Partnership paid Delek Group in 2022 totaled approx. $368 thousand.[32]

2. From the date of provision of the Guarantee and so 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

[31] To the best of the Partnership's knowledge, and according to Delek Group's reports, in October 2020, Delek Group and Delek Energy transferred their right to receive Delek Group's royalties from the Partnership's share (45.34%) in the petroleum and/or gas and/or other valuable substances that shall be produced and exploited from the Leviathan leases to Delek Overriding Royalty.

[32] The engagement was approved on April 14, 2013 by the Board and on April 18, 2013 by the meeting of the participation unit holders. For further details, see the Partnership's immediate reports of April 18, 2013 and April 14, 2013 (Ref. no.: 2013-01-039418 and 2013-01-036844, respectively). Furthermore, on July 8, 2018, the audit committee approved that fixing the payment in respect of the Guarantee for a guarantee period of 25 years, as determined on the date of first approval of the Guarantee transaction, is a reasonable period.

Chevron Cyprus Limited ("**Chevron Cyprus**"[33] and "**Block 12 Work Plan**"[34], respectively), in the absence of: (a) insurance that covers expenses of taking control of a well, control of which was lost, 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 (insurance policies for loss of control of a well and third party liability)[35]; and (b) approval pursuant to the law by the Partnership's competent organs of the terms of the engagement with Delek Group, as specified above and below, and of the arrangements regarding payment of a Guarantee fee by the Partnership to Delek Group.

3. In addition, the Partnership undertook that from the date of provision of the Guarantee and so long as the Guarantee is in effect, the following provisions will apply:

   a. In a case where the Partnership sells its interests in Block 12, the Partnership will act to release Delek Group from the Guarantee, or from its proportionate share (in the case of a partial sale of the interests) in the context of such sale, all subject to the provisions of the PSC and the decisions of the authorities in Cyprus on the matter. It is noted that the sale of some of the interests in Block 12 will be possible only subject to reaching arrangements on division of liability and mutual indemnification with the potential buyer of some of the interests as aforesaid, in respect of its proportionate share.

   b. Delek Group will have the right to demand, in a written notice, at any time and at its discretion, that the Partnership act for its release from the Guarantee. In the case of such a demand, the Partnership undertakes to

[33] Chevron Cyprus is a wholly-owned subsidiary of Chevron Corporation ("**Chevron Corp.**").
[34] The Partnership will deliver to Delek Group prior notice of any intention to approve a Block 12 Work Plan.
[35] 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 third party liability insurance in relation to the activity in Block 12.

perform the actions required for the release of Delek Group from the Guarantee, including, if and insofar as required for the release of Delek Group from the Guarantee as aforesaid, the sale of its interests, in whole or in part, in Block 12 and/or waiver thereof, with no need for additional approvals at the Partnership. In the case of such a demand, the Partnership undertakes that within 12 months from the date of the giving of the written demand, it will cause the release of Delek Group from the Guarantee or will alternatively sign an agreement for the sale of the interests in Block 12. In the case of such a sale, the Partnership undertakes to close the sale within 6 months from the date of the signing 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 Delek Group (including expenses and/or legal fees and/or experts' fees) in respect of enforcement of the Guarantee and/or a claim and/or demand, whose cause is related to the Guarantee and/or 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 the said claim and/or demand upon its receipt thereby, and will allow the Partnership and/or another on its behalf to conduct a proper legal defense as is deemed necessary by the Partnership in the circumstances against any such demand and/or claim, and/or negotiations for a settlement as aforesaid and/or to mitigate the damage insofar as it is able to do so.

4. Since the undertakings of the Partnership and Chevron Cyprus according to the PSC are joint and several, an agreement was signed between Delek Group and Chevron Corp., and the parent company of BG Cyprus, regarding division of liability and mutual indemnification between them, with respect to the activity in Block 12, according to the holding rates of the Partnership, Chevron Cyprus and BG

Cyprus in the interests 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 relating to the activity in Block 12 according to the rate of the corporation's participation in respect of which it provided a guarantee in favor of the Republic of Cyprus as aforesaid in Block 12 (i.e., Delek Group at a rate of 30%, Chevron Corp. 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 for damage and/or liability relating to activity in Block 12 over and above the rate of the corporation's participation in respect of which it provided a guarantee in favor of the Republic of Cyprus, as aforesaid, in Block 12.

c. The parties' undertaking as aforesaid is not limited in amount or by the scope of the insurance coverage of the Partnership, Chevron Cyprus and BG Cyprus in the context of their activity in Block 12.

d. Each party to the Agreement undertook to obtain from its insurer a waiver of a right of subrogation against the other party to the Agreement in respect of damage or liability relating to its activity in Block 12.

e. The Agreement determines a binding arbitration mechanism for resolution of disputes between the parties.

f. The Agreement will be in effect until conclusion of the joint operating agreement that applies to Block 12, subject to a final accounting between the parties with respect to the Agreement.

(d) On May 3, 2020, the Partnership, Chevron Mediterranean Limited ("**Chevron**"), Delek Group and Ratio Energies –

Limited Partnership ("**Ratio**") signed an agreement for the supply of natural gas, in the context of which the supply of gas to customers which had signed previous agreements with each of the Yam Tethys partners would be performed from the Leviathan reservoir. Accordingly, the Yam Tethys partners that are Leviathan partners, i.e., the Partnership and Chevron, 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 for supply by each of the Yam Tethys partners is 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 further details, see Section 7.5 of Chapter A of this Report. In 2022, the Partnership's share in the revenues from the sale of gas for Delek Group's share in the Yam Tethys project totaled approx. $200 thousand.

(e) For details regarding exercise of an option for the purchase of a policy for an extended run-off period in the context of the D&O liability insurance policy that was approved in the context of a previous policy of the Partnership and in the context of a group insurance policy that was purchased by Delek Group, see Regulation 22(k) of the 2020 periodic report, as released on March 17, 2021 (Ref. no.: 2021-01-036588) (the "**2020 Periodic Report**").

(f) For details regarding a compensation policy for officers of the Partnership and the General Partner, see Regulation 21(b)(1) above.

(g) During the course of the report year, the Partnership promoted a transaction for a possible restructuring by way of approval of an arrangement pursuant to Sections 350 and 351 of the Companies Law, 5759-1999 (the "**Companies Law**" and "**Arrangement**", respectively). In this context, on September 29, 2022, the Partnership and the General Partner engaged with the British company Capricorn Energy Plc. ("**Capricorn**") in a contingent agreement for the performance of a transaction for combination of the businesses of the Partnership and of Capricorn. However, on February 15, 2023, the Partnership and Capricorn agreed on termination of the transaction with immediate effect. For further details, see

Section 7.24.14 of Chapter A of this Report. It is noted that, for the sake of caution, the Arrangement was expected to be presented for approval as a transaction in which Delek Group has a personal interest.

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 the Board of Directors' Report (Chapter B of this Report), such as: receipt of "*dalkan*" [automatic billing for fueling services] from "Delek" The Israel Fuel Corporation Ltd., an affiliate of Delek Group ("**Delek**"), 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 the purchase of a car from Delek Group for the purpose of provision thereof to the Active Chairman of the Board as part of the terms of his office and employment.

Regulation 24: **Holdings of interested parties and senior officers**

For details regarding holdings of interested parties and senior officers of the Partnership and/or the General Partner as of September 30, 2022, see the Partnership's immediate report of October 12, 2022 (Ref. no.: 2022-01-125926), the information appearing in which is incorporated herein by reference[36].

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

CONVERTIBLE SECURITIES	
(UNREGISTERED) OPTIONS	3,295,599

[36] To the best of the Partnership's knowledge, no change has occurred in the said holdings as of December 31, 2022.

Regulation 24B: **Register of the Partnership's participation unit holders**

	Name of Holder	Number of Units
1	Delek Group Ltd.	1
2	Mizrahi Tefahot Nominee Company Ltd.	1,173,116,181.89
3	Chaim Leventhal	1.19
4	Nathan Turkia	1
5	Yaakov Maroz	1
6	Moshe Kramer	1.19
7	Avner Andera	1
8	Ariel Yanko	289.47
9	Ran Levy	184.8
10	Tova Berger	12
11	Azriel Zolti	1.19
12	Varda and Baruch Kotlarsky	143,562.10
13	Daniel Goldstein	18.80
14	Yasmin Even	1,317.67
15	Yaffa Dayan	234,962.37
16	Dorit Dayan	234,962.37
17	Yosef Vank	52,505.44
18	Amikam Reshef	590.60
19	Tamar and Avraham Adani	62.59
20	Sarah Morah	30,032.89
21	Yehuda Luria	0.19
	Total	**1,173,814,690.76**

Regulation 25A: **Registered address**

Address: 19 Abba Eban Blvd., Herzliya, 4672537

Telephone: 09-9712424

Facsimile: 09-9712425

E-mail address: info@newmedenergy.com

Regulation 26:The directors of the General Partner[37]

Details	Gabi Last	Leora Pratt Levin	Idan Wells	Tamir Polikar
I.D. number:	004787933	057906919	033658246	059749408
Position at the General Partner:	Active Chairman of the Board	Director	Director	Director
Date of birth:	September 9, 1946	October 12, 1962	January 8, 1977	August 14, 1965
Address for service of process:	19 Abba Eban Blvd., Herzliya	19 Abba Eban Blvd., Herzliya	19 Abba Eban Blvd., Herzliya	19 Abba Eban Blvd., Herzliya
Nationality:	Israeli	Israeli	Israeli	Israeli and Portuguese
Membership of board committees:	No	No	No	No
Independent director?	No	No	No	No
External director?	No	No	No	No
(a) If so, accounting and financial expertise or professional qualifications?	-	-	-	-
(b) If so, an expert external director?[38]	-	-	-	-
Employee of the General Partner, a subsidiary, an affiliate or of an interested party?	Active Chairman of the Board, Chairman of the Board of the Delek Foundation for Education, Culture and Science (CIC) (the "**Delek Foundation**"), and a director of a private subsidiary (SPC) of the Partnership	Senior VP, Chief Legal Counsel and Secretary of Delek Group and director of subsidiaries of Delek Group	CEO of Delek Group and director of subsidiaries of Delek Group	Deputy CEO and CFO of Delek Group and director of subsidiaries of Delek Group
Date of commencement of office as director:	May 17, 2001, from January 8, 2020 as Chairman of the Board, and from April 1, 2022 as Active Chairman of the Board	August 26, 2015	January 7, 2020	September 10, 2020
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.	LLB from the University of Reading, England, B.A. in Political Science from Tel Aviv University, attorney, member of the Israel Bar	LL.B from Tel Aviv University, attorney, member of the Israel Bar	B.A. in Accounting from the College of Management, MBA from Heriot-Watt University, CPA
Occupation in the last five years:	Active Chairman of the Board of the General Partner, Chairman of the Board of Delek Group and the Delek Foundation, a director of subsidiaries of Delek Group, a director of a private subsidiary (SPC) of the Partnership and a member of management of various NPOs	A director of the General Partner, EVP, Chief Legal Counsel and Corporate Secretary of Delek Group and director of subsidiaries of Delek Group	A director of the General Partner, CEO of Delek Group, Deputy CEO of Delek Group, CEO and representative of Delek Group's controlling shareholder (Tshuva group (through El-Ad USA Holdings and Tashluz Investments and Holdings) and director of subsidiaries of Delek Group	A director of the General Partner, real estate developer in Israel and overseas, business consultant and director of Polikar Holdings Ltd. and director of subsidiaries of Delek Group and other private companies

[37] The specification of this regulation presents the directors who serve on the Board as of the report approval date.

[38] Within the meaning of the term in Section 1 of the Compensation Regulations.

Details	Gabi Last	Leora Pratt Levin	Idan Wells	Tamir Polikar
Other directorships:	The Delek Foundation (chairman), a private subsidiary (SPC) of the Partnership.	Delek Energy, Delek Sea Maagan 2011 Ltd., Delek Israel Holdings Group Ltd., Delek Infrastructures Ltd., Delek Power Plant Management Ltd., Delek Petroleum Ltd., Delek Group Royalty Ltd., Delek Property Development Ltd., Delek Overriding Royalty, DKL Investments Limited, DKL Energy Limited and an observer on the compensation committee of Ithaca Energy Plc	Delek Energy, Ithaca Energy Plc, Wells Consulting Ltd. and Wells Investments (2018) Ltd.	Delek Energy, Delek Sea Maagan 2011 Ltd., Delek Israel Holdings Group Ltd., Delek Infrastructures Ltd., Delek Power Plant Management Ltd., Delek Petroleum Ltd., Delek Group Royalty Ltd., Delek Property Development Ltd., Delek Overriding Royalty, Delek Israel Properties (D.P.) Ltd., Delek, Delek Hungary Limited, Polikar Holdings Ltd., Gallipoli Real Estate Investments Ltd., Briza Lgyrp Ltd., and subsidiaries thereof, Elysee Downtown Ltd. and an observer on the audit committee and the board of Ithaca Energy Plc
Relative of another interested party of the General Partner?	No	No	No	No
Deemed by the General Partner 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?	No	No	No	Yes

Details	**Amos Yaron**	**Jacob Zack**	**Efraim Sadka**
I.D. number:	005301262	004868048	046002747
Position at the General Partner:	External director	External director	External director
Date of birth:	February 5, 1940	April 11, 1946	July 10, 1946
Address for service of process:	22 Shazar St., Ramat Gan	5 Hashoftim St., Herzliya	5 Dulchin Arieh St., Tel Aviv
Nationality:	Israeli	Israeli	Israeli
Membership of board committees:	Audit committee member Compensation committee member, Chairman Member of the Financial Statements Review Committee (“**Finance Committee**”) Investment committee member	Audit committee member, Chairman Finance Committee member, Chairman Compensation committee member Investment committee member	Audit committee member Finance Committee member Compensation committee member Investment committee member, Chairman
Independent director?	Yes	Yes	Yes
External director?	Yes	Yes	Yes
(a) If so, accounting and financial expertise or professional qualifications?	Professional qualifications	Accounting and financial expertise	Accounting and financial expertise
(b) If so, an expert external director?[39]	No	Yes	Yes
Employee of the General Partner, a subsidiary, an affiliate or of an interested party?	No	No	No
Date of commencement of office as director:	October 22, 2015	October 22, 2015	April 1, 2019
Education:	B.A. in General History from Tel Aviv University, Graduate of the National Security College.	B.A. in Accounting and Economics from Tel Aviv University, MBA from Tel Aviv University, CPA	B.A. in Economics and Statistics from Tel Aviv University, Ph.D. in Economics from the Massachusetts Institute of Technology (MIT)
Occupation in the last five years:	A director of the General Partner, consultant to Israel Aerospace Industries, and a director of ICIC – Israeli Credit Insurance Company Ltd. of the Harel Group	A director of the General Partner	A director of the General Partner, external director of Paz, independent director of Ravad Ltd., and a director of other companies and NPOs
Other directorships:	-	-	Artzdka Ltd. (Chairman), Babylonian Jewry Heritage Center (Chairman), The Pinhas Sapir Center for Development (Chairman), Atidim High Tech Industries Co. Ltd., and the TAU Sports Complex
Relative of another interested party of the General Partner?	No	No	No
Deemed by the General Partner 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?	No	Yes	Yes

[39] Within the meaning of the term in Section 1 of the Compensation Regulations.

Regulation 26A: Senior officers of the Partnership and/or the General Partner[40]

officer	I.D. number	Date pf Birth	Date of commencement of office	Position at the Partnership, the General Partner, a subsidiary, affiliate or interested party	Interested party of the Partnership and/or the General Partner?	Relative of another senior officer or of an interested party of the Partnership and/or the General Partner?	Education	Experience in the last 5 years
Yossi Abu	033840372	December 7, 1977	April 1, 2011	CEO of the Partnership, director of private subsidiaries (SPCs) of the Partnership, Chairman of the Board of a partnership in formation in connection with the Enlight transaction, as specified in Section 7.8 of Chapter A of this Report.	Yes	No	LL.B from the Hebrew University of Jerusalem, attorney, member of the Israel Bar Association.	CEO of the Partnership, CEO of Delek Energy, CEO of Avner Oil & Gas Exploration – Limited Partnership ("Avner Partnership"), Chairman of the board of Tamar Petroleum Ltd., a director of Ithaca Energy Inc., and a director of private subsidiaries (SPCs) of the Partnership and private companies owned by him.
Sari Singer Kaufman	037485174	February 22, 1980	May 14, 2018 – EVP, August 1, 2017 – General Counsel March 10, 2012 – attorney	EVP and General Counsel	No	No	LL.B from Tel Aviv University, attorney, member of the Israel Bar Association	General Counsel and EVP of the Partnership, General Counsel of the Avner Partnership, and an external director of Steakholder Foods Ltd.
Zvi Karcz	059784355	February 24, 1967	August 12, 2014 - VP Exploration, September 8, 2011 - Chief Geologist	VP Exploration	No	No	B.Sc. in Geology from the Hebrew University of Jerusalem, M.Sc. in Geology from the Hebrew University of Jerusalem, Ph.D. in Geology and Geophysics from Columbia University, New York, U.S.	VP Exploration, Chief Geologist of the Partnership and Chief Geologist of the Avner Partnership
Tzachi Habusha	027268317	March 23, 1974	January 1, 2022	CFO	No	No	B.A. in Economics from Bar-Ilan University, LL.M from Bar-Ilan University, MBA from the College of Management, CPA	CFO at Israel Airports Authority, a director of Eilat Ashkelon Pipeline Co. Ltd.

[40] The specification of this regulation presents the officers who hold office at the Partnership as of the report approval date.

officer	I.D. number	Date pf Birth	Date of commencement of office	Position at the Partnership, the General Partner, a subsidiary, affiliate or interested party	Interested party of the Partnership and/or the General Partner?	Relative of another senior officer or of an interested party of the Partnership and/or the General Partner?	Education	Experience in the last 5 years
Ronen Edward	024652745	October 13, 1969	January 1, 2022 - VP Leviathan Project August 1, 2017 – CFO May 17, 2017 – CFO at the Avner Partnership	VP Leviathan Project	No	No	B.A. in Accounting and Business Administration from the College of Management, CPA	VP Leviathan Project at the Partnership, CFO at the Partnership and at the General Partner, and CFO at the Avner Partnership
Tal Levi	034837245	April 19, 1979	May 23, 2022 – VP Budget & Control June 1, 2018 – Head of Control & Investments February 10, 2013 – Controller	VP Budget & Control	No	No	B.A. in Economics and Accounting from Haifa University, MBA from the Technion – Israel Institute of Technology, CPA	VP Budget & Control of the Partnership, Head of Control & Investments of the Partnership and Controller of the General Partner
Nadav Perry	040365447	April 24, 1980	May 14, 2018 - VP Regulatory & Public Affairs June 14, 2015 - Head of Media & Public Affairs	VP Regulatory & Public Affairs	No	No	B.A. in Government, Diplomacy and Strategy from Reichman University (the Interdisciplinary Center Herzliya), MBA from Bar-Ilan University	VP Regulatory & Public Affairs at the Partnership and Head of Media & Public Affairs at the Partnership
Saar Prag	037693942	October 17, 1975	June 3, 2021 – VP Natural Gas Trade August 1, 2017 – Head of Natural Gas Trade	VP Natural Gas Trade	No	No	LL.B from the Hebrew University of Jerusalem, attorney, member of the Israel Bar Association	VP Natural Gas Trade at the Partnership, and Head of Natural Gas Trade at the Partnership
Lior Cohen	303014237	April 3, 1989	July 25, 2021	Financial Controller	No	No	B.A. in Accounting and Economics from Tel Aviv University, CPA	Controller at the Partnership, controller at Gottex Retail Brands, and auditor at Kost Forer Gabbay & Kasierer
Gali Gana	059674770	June 2, 1965	February 1, 2016	Internal auditor of the Partnership and the General Partner, and chief internal auditor of Delek Group	No	No	B.A. in Accounting from the College of Management, M.A. in Internal Audit and Public Administration from Bar-Ilan University, certified information system auditor (CISA), certified internal auditor (CIA), certification in risk management assurance (CRMA), certified in Risk and	Internal auditor of the Partnership and the General Partner, chief internal auditor of Delek Group, and partner at Rosenblum-Holtzman, CPAs. Mr. Gana has information security and/or cyber expertise.

officer	I.D. number	Date pf Birth	Date of commencement of office	Position at the Partnership, the General Partner, a subsidiary, affiliate or interested party	Interested party of the Partnership and/or the General Partner?	Relative of another senior officer or of an interested party of the Partnership and/or the General Partner?	Education	Experience in the last 5 years
							Information Systems Control (CRISC), CPA	

Regulation 26B: **Independent authorized signatories**

As of December 31, 2022, and as of the report approval date, there are no independent authorized signatories at the Partnership or the General Partner.

Regulation 27: **The Partnership's CPAs**

Ziv Haft CPAs, of 46-48 Menachem Begin Rd., Tel Aviv, and the accounting firm Kost, Forrer, Gabbay & Kasierer of 144 Menachem Begin Rd., Tel Aviv, jointly serve as the auditors of the Partnership.

Regulation 28: **Modification of the Partnership Agreement**

On September 21, 2022, the meeting of the Participation Unit holders decided to approve an amendment to Sections 5, 8, 9 and 10, as well as the addition of Section 28, to the Partnership Agreement, in connection with the Partnership's possibility of making investments in the renewable energies sector, the New Management Arrangement and the Partnership's possibility to give donations and assistance to the community, and on January 2, 2023, the meeting of the Participation Unit holders decided to approve an amendment to Section 5.1 of the Partnership Agreement, such that the "Boujdour Atlantique" license in Morocco (the "**Morocco License**") be added to the list of petroleum assets mentioned in this section. For further details, see Regulation 29(c) below and the Partnership's immediate reports of September 21, 2022 and January 2, 2023 (Ref. no.: 2022-01-120367 and 2023-01-001458, respectively), the information appearing in which is incorporated herein by reference.

Regulation 29: **Recommendations and decisions of the directors**

Regulation 29(a):

(a) For details on the Board's decision to approve plans to purchase the bonds that were issued by Leviathan Bond, see the Partnership's immediate reports of May 23, 2022 and January 23, 2023 (Ref. no.: 2022-01-062266 and 2023-01-010464, respectively), the information appearing in which is incorporated herein by reference, and Section E of Part One of the Board of Directors' Report (Chapter B of this Report).

(b) On May 22, 2022, August 17, 2022 and November 23, 2022, the Board decided, after receiving the recommendation of the

Finance Committee, to approve profit distributions in the sum of $50 million each, with the record dates for the said distributions being May 30, 2022, August 25, 2022 and December 26, 2022, respectively, and the dates of the said distributions being June 16, 2022, September 22, 2022 and January 19, 2023, respectively. For further details, see the Partnership's immediate reports of May 23, 2022, August 18, 2022 and November 24, 2022 (Ref. no.: 2022-01-062296, 2022-01-104986 and 2022-01-141307, respectively), the information appearing in which is incorporated herein by reference. In addition, on March 27, 2023, the Board decided, after receiving the recommendation of the Finance Committee, to approve a $60 million profit distribution, with the record date for the said distribution being April 9, 2023, and the date of the said distribution being April 20, 2023.

(c) For details on amendments to the Partnership Agreement, see Regulation 28 above.

Regulation 29(c):

(a) For details on the decision of the meeting of the Participation Unit holders of March 24, 2022 to approve the appointment of external director Mr. Sadka for a second term of office and to approve his terms of office, see Regulation 21(b)(10) above.

(b) For details on the decisions of the meeting of the Participation Unit holders of September 21, 2022, as follows: (1) to approve the New Management Arrangement; (2) to approve the addition of a new section to the Partnership Agreement in order to allow the Partnership to put together a plan for donations and assistance to the community; (3) to authorize the General Partner to refrain from profit distributions as shall be required for the performance of the development plan of "Block 12", and to approve the use of the cash surpluses that have accrued and shall accrue for investment thereof in the development plan of such petroleum asset; (4) to authorize the Partnership to operate and make investments in projects in the renewable energies sector, in the context of the collaboration with Enlight Renewable Energy Ltd. ("**Enlight**") which, *inter alia*, constituted approval of all of the aspects pertaining to the personal interest of and the benefits that shall be received by the Partnership's CEO in the context of his share in the Enlight transaction (in the context of which Enlight shall allot to him a certain part of its rights in the transaction), considering his obligations vis-à-vis the Partnership pursuant to Section 254 of the Companies Law; (5) not to approve an updated compensation policy for officers of the Partnership and the General Partner; and (6) not to approve updated terms of office and employment for the Partnership's CEO, including the granting of equity compensation, see the Partnership's immediate reports of September 6, 2022 and September 21, 2022 (Ref. no.: 2022-01-092520 and 2022-01-120358, respectively), the information appearing in which is incorporated herein by reference.

(c) For details on the decision of the meeting of the Participation Unit holders of January 2, 2023 to approve a supplementary budget for the Supervisor for its continued engagement with professional consultants and a fee in addition to its monthly fee for overseeing the restructuring process, and to approve for the Trustee a fee in addition to its annual fee in connection therewith, see Regulation 21(b)(7) above.

For details on the decision of the meeting of the Participation Unit holders of the same date to approve the Partnership's engagement in agreements for the purchase of the interests in the Morocco License and participation in oil and/or natural gas exploration and production activities in the area of the license, to amend for such purpose Section 5.1 of the Partnership Agreement, and to authorize the General Partner, in accordance with the provisions of Section 9.4 of the Partnership Agreement, to refrain from profit distributions for the performance of the said actions, see the Partnership's immediate reports of December 12, 2022 and January 3, 2023 (Ref. no.: 2022-01-150004 and 2023-01-002016, respectively), the information appearing in which is incorporated herein by reference.

Regulation 29A: **Decisions of the Partnership**

Regulation 29A(4): **Exemption, insurance or undertaking to indemnify an officer**

(a) For details regarding indemnification undertakings and exemptions from liability that were granted in the past to directors and officers of the Partnership, the General Partner and Leviathan Bond, and for details regarding D&O liability insurance policies, see Regulation 29A(4) of Chapter D of the 2020 Periodic Report.

(b) For details regarding engagement in a D&O insurance policy by way of exercise of an option for a run-off period, see Regulation 22(k) of Chapter D of the 2020 Periodic Report.

(c) On June 26, 2022, the compensation committee, in accordance with the Previous Compensation Policy and the recommendation of the Partnership's insurance consultant, approved the Partnership's engagement in a D&O insurance policy, which covers the officers of the General Partner, the Partnership and its subsidiaries, including Leviathan Bond, for a period of one year from July 1, 2022, with a total limit of liability of $200 million per claim and in the aggregate, all under terms and conditions which comply with the Previous Compensation Policy, as specified in Regulation 21(b)(1) above.

(d) In the context of the Capricorn transaction that was terminated, as specified in Section 7.24.14 of Chapter A of this Report, the Partnership purchased a POSI policy to cover, *inter alia*, the liability of the officers of the Partnership, the General Partner and the consolidated company, as well as of the control holder of the Partnership, in respect of the prospectus. This policy is expected to be cancelled, without payment of any premium, in accordance with the terms and conditions thereof.

NewMed Energy - Limited Partnership

by the General Partner, NewMed Energy Management Ltd.

Names and positions of signatories:
Gabi Last, Chairman of the Board
Yossi Abu, CEO

Date: March 27, 2023

Part E

Report on the effectiveness of internal control over financial reporting and disclosure

NewMed Energy – Limited Partnership

<u>Annual report for 2022 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</u>:

The management of NewMed Energy – Limited Partnership (the "**Partnership**"), under the supervision of the board of directors of NewMed Energy Management Ltd., the General Partner of the Partnership (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 Partnership;
3. Tzachi Habusha, VP Finance and Market Risk Manager of the Partnership.

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 Partnership, 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 Partnership, 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 Partnership'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 and 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 Partnership under the supervision of the board of directors of the General Partner, as specified above, the board of directors of the General Partner and the Partnership's management came to the conclusion that the internal control over financial reporting and disclosure at the Partnership, as of December 31, 2022, 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 NewMed Energy – Limited Partnership (the "**Partnership**") for 2022 (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 at 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 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 of the General Partner and the Partnership's management 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 27, 2023	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, Tzachi Habusha, represent that:

(1) I have reviewed the financial statements and other financial information included in the reports of NewMed Energy – Limited Partnership (the "**Partnership**") for 2022 (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 at 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 of the General Partner in the Partnership and the Partnership's management, 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 27, 2023	Tzachi Habusha, CPA	VP Finance	
Date	Full Name	Position	Signature

Valuation

GIZA SINGER EVEN

NewMed Energy - Limited Partnership

Valuation of Royalties
From the Sale of the I/16 “Tanin” and I/17 “Karish” Leases

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March 2023

This document is a translation of the original Hebrew-language document of Giza Singer Even Ltd. of March 2023. 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.

GIZA SINGER EVEN

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GIZA SINGER EVEN

1. Introduction and Disclaimer

1.1 General

This paper (the "**Paper**" and/or the "**Opinion**") was prepared by Giza Singer Even Financial Advisory Ltd. ("**GSE**") for the purpose of valuation of the royalties to which the limited partnership NewMed Energy[1,2] ("**NewMed Energy**" and/or the "**Partnership**") is entitled for the sale of its interests in the I/16 "Tanin" (the "**Tanin Royalties**") and I/17 "Karish" (the "**Karish Royalties**") leases (collectively: the "**Royalties**") as of December 31, 2022 (the "**Valuation Date**"). We are aware that the Paper is intended to be used by NewMed Energy, *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.

[1] On May 17, 2017, NewMed Energy merged with the partnership Avner Oil Exploration – Limited Partnership ("**Avner**") and as a result, Avner partnership was stricken off with no dissolution.

[2] On February 22, 2022, the Partnership changed its name from "Delek Drilling – Limited Partnership" to "NewMed Energy – Limited Partnership".

The Paper does not include accounting auditing regarding the compliance with the accounting principles. Giza Singer Even 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.

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

The main sources of information used in the preparation of the Opinion are specified below:

- Information regarding the terms of the transaction for the sale of the Partnership's interests 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, 2022 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 GSE.

- Meetings and/or phone calls with office holders at the Partnership.

1.3 Details of the valuating company

Giza Singer Even 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 prepared by a team headed by Gadi Beeri, Head of the Economic Department and Corporate Finance and a senior partner at Giza Singer Even. Gadi Beeri has expertise and vast experience in corporate finance and financial and financing advice. He holds a BA in Economics and an MBA from the Tel Aviv University.

Sincerely,

Giza Singer Even Financial Advisory Ltd.
March 27, 2023

2. Executive Summary

2.1 Background

NewMed Energy – Limited Partnership (formerly: "Delek Drilling – Limited Partnership") 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**"), NewMed Energy and Avner (jointly, the "**Partnerships**") (which jointly held (in equal shares between them) 52.941% of the reservoirs) and Chevron Energy Mediterranean ("**Chevron**") (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 interests 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 Buyer's decision to develop the reservoir, or on the date on which the Buyer'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 Buyer 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,[3] by which the Partnerships are charged regarding the original share of NewMed Energy and Avner in the leases (the "**Royalties**'). The first payment to NewMed Energy for the Debt Component had been made by Energean on March 29, 2018 and was since regularly paid every year in March, up to and including the fourth payment that was received in March 2021.

[3] As defined in the reports of NewMed Energy and Avner to the TASE on December 25, 2016.

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In March 2022, Energean failed to transfer the fifth payment to the Partnership. In May 2021, Energean informed the Partnership that, per its position, it was operating under "force majeure" circumstances due to the Covid crisis. Subsequently thereto, in September 2022, Energean made late payment of the fifth installment and part of the interest payment for the Debt Component to the Partnership. A legal proceeding is currently being conducted between the parties for the balance of the loan, including the interest thereon, the outcome of which we are unable to assess. Therefore, and for the sake of caution, it was assumed in this valuation, as of the date hereof, that the balance of the interest not yet transferred to the Partnership will not be paid at all.

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 March 23, 2023 by Energean Oil & Gas plc,[4] the parent company of Energean Israel Limited[5]:

Reservoir	Reserves and Resources	
	Natural Gas (BCM)	Hydrocarbon Liquids (MMBBL)
	2P	**2P**
Karish	39.4	54.2
Karish North	34.2	36.9
Tanin	26.1	4.5
Total	**99.6**	**95.6**

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 crisis). According to the assumptions specified in the Paper itself, the total value of the Royalties as of December 31, 2022 is estimated at approx. $320.8 million (the value of the Karish Royalties (including Karish North) and the Tanin Royalties are estimated at approx. $294.1 million and approx. $26.6 million, respectively).

[4] https://www.energean.com/media/5400/dm-final-report-energean-israel-2022ye.pdf.

[5] Formerly Ocean Energean Oil and Gas Ltd.

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 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	276.3	281.1	299.1	293.7	310.8	325.3	342.2
	+150 bp	285.8	290.7	309.2	303.9	321.6	336.6	354.1
	+50 bp	296.0	301.0	320.1	314.9	333.3	348.8	367.1
	-	301.3	306.5	325.9	**320.8**	339.5	355.4	373.9
	-50 bp	307.0	312.2	332.0	326.9	346.0	362.2	381.1
	-150 bp	318.9	324.3	344.8	340.0	359.8	376.8	396.4
	-250 bp	331.9	337.5	358.8	354.3	375.0	392.8	413.2

3. Description of Transaction for the Sale of the Interests in the Karish and Tanin Leases

3.1 Description of the Partnership

NewMed Energy is a limited partnership (within the meaning thereof in the Partnerships Ordinance) listed on the TASE. The Partnership engages in the exploration, development, production and sale 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 interests

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

[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 7.24.7 of NewMed Energy's periodic report for 2021.

Commissioner at the Ministry of Energy award the holders of rights in the exploration licenses, NewMed Energy (26.4705%), Avner (26.4705%) and Chevron (47.059%), the lease deeds of "Tanin" and "Karish", respectively. It is noted that in May 2017, NewMed Energy merged with Avner and consequently the Avner partnership was stricken off without dissolution.

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 interests of the Partnership in the natural gas reservoirs Tamar, Leviathan, Karish and Tanin. Under the Framework the gas and petroleum corporations operating 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 Chevron the right to sell the share of Chevron 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 Chevron, 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 then Prime Minister Netanyahu (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 interests in the Karish and Tanin leases between NewMed Energy 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..[7] The Buyer's principal business 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. In addition, on January 14, 2021, Energean reported the adoption of a Final Investment Decision (FID) in the "Karish North" reservoir.

[7] Energean Israel Ltd. serves as the operational arm of Energean E&P Holdings Ltd. in Israel.

On October 25, 2022, the Ministry of Energy approved for Energean commencement of production of gas from the Karish reservoir, and the following day Energean reported on initial gas production from the reservoir.

In November 2022, Energean transferred to the Partnership the first payment due to overriding royalties from its revenues in the Karish reservoir.

3.3 The consideration

Following is a description of the consideration components in the purchase agreement:

a. The Buyer will purchase from NewMed Energy and Avner (the "**Sellers**") all of the interests of the Sellers and of Chevron in the Karish and Tanin leases (the "**Sold Interests**").

b. In consideration for the Sold Interests, the Buyer 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 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 Buyer in relation to the development of the leases will exceed $150 million, whichever is earlier[8];
   iv. The Buyer 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, March 2020 and March 2021 it paid NewMed Energy the first four payments.

[9] As defined in the reports of NewMed Energy and Avner to 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:

- **Reduced energy costs in the 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 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 2014-2021 saved the Israeli market an estimated total of approx. ILS 115.62 billion[14]. Most of such saving derives from the electricity sector (approx. ILS 81.0 billion), total consumption by which in 2021 amounted to approx. 9.71 BCM, which represents 79% of the demand for natural gas. The rest of the amount saved due to the transition to use of natural gas is attributed to the industrial sector (approx. ILS 35.0 billion), total consumption by which in 2021 amounted to approx. 2.62 BCM which represents an increase of 4% versus 2020. ILS 64.8 billion out of the total market savings are attributed to 2021 due to the exceptionally high fuel prices worldwide in this year, versus the stable natural gas prices in Israel.

- **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

[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.

[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] Review of Developments in the Natural Gas Sector, Summary as of 2021 – Natural Gas Authority.

[14] The calculation of the cost saving is made based on the assumption that without the entry of natural gas, it would have been necessary to both build new coal-fired power plants D and E, and supplement production with diesel and fuel oil. The savings derive only from fuel price differences and do not take into account capital investments for the construction of power plants and conversions to natural gas.

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 domestic 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[15]. 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.

- **Upgrade of Israel's geostrategic position** – Thanks to the development of the gas reservoirs in Israel's exclusive economic zone (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, *inter alia*, regarding the costs of inputs for electricity production, and in particular, the costs of natural gas. In 2022, the IEC purchased approx. 4.95 BCM of natural gas from the Tamar and Leviathan partners and from the Karish reservoir and also imported and consumed another approx. 0.1 BCM of LNG, compared to 2021 in which it

[15] Other than the electricity and industrial sectors in which consumers do not pay excise tax for the gas.

purchased approx. 4.5 ton BCM of natural gas from the Tamar and Leviathan partners and also imported and consumed another approx. 0.2 BCM of LNG. The rate of electricity produced by the IEC through natural and liquefied gas is estimated in 2021 and 2022 at approx. 55.5% and approx. 57.0%, respectively. In such context it is noted that according to the decision of the Minister of Energy by the end of 2022 the IEC should have ended the engagement with the regasification vessel used for reception and regasification of imported LNG. Accordingly, on December 8, 2022, the IEC ended its engagement with the regasification vessel and the remaining LNG that was then on the vessel was sold to Hadera Gateway.[16]

- **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, renewable energies IPPs, pumped energy (this technology does not produce power but rather stores the energy for use during peak hours or hours where it is not possible to produce power from renewable energies) 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 2021, the natural gas consumption of the IPPs amounted to approx. 4.08 BCM, which represents approx. 33% of the overall consumption of natural gas in that year in the entire market.

- **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, 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 2021, natural gas consumption by the industrial sector amounted to approx. 2.62 BCM, an increase of 4% compared with 2020. The increase chiefly derives from the higher demand of a number or large industrial consumers.

[16] Source: IEC's financial statement for 2022.

- **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 Compressed 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 industrial 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 and sale of natural gas from reservoirs in the territorial waters of the State of Israel are subject to regulatory restrictions pertaining to the amount of gas produced, restrictions on the export of the gas outside of Israel, and others. 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 are making annual advance payments on account of royalties at the rate of 11.3% of the Tamar project revenues, and in 2017 and 2018 at the rate of 11.65%. In the

[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.

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 specific characteristics of the lease. On September 6, 2020, the Ministry of Energy published specific instructions for the Tamar reservoir.

- **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 November 10, 2021, the Knesset approved in the second and third reading a bill which prescribes, *inter alia*, rules on payment of disputed assessments.[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 grants an exemption to NewMed Energy, Chevron 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 NewMed Energy and Chevron being holders of a monopoly by virtue of the declaration

[18] Taxation of Profits from Natural Resources Law (Amendment no. 3), 5782-2021. https://main.knesset.gov.il/Activity/Legislation/Laws/Pages/LawBill.aspx?t=lawsuggestionssearch&lawitemid=2155633

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:

a. The sale of the interests of NewMed Energy and Chevron 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 interests in the Karish and Tanin leases between NewMed Energy and Energean.
b. The sale of all of the interests of NewMed Energy in the Tamar reservoir to a third party not affiliated therewith or to any of the holders of interests in the Leviathan, Karish and Tanin reservoirs as well as limitation of the interests of Chevron in the Tamar reservoir to a maximum rate of 25% within 72 months. In January 2018, Chevron sold to Tamar Petroleum Ltd. 7.5% of its interests in the Tamar reservoir, and as a result, it went down to a 25% holding rate in the Tamar reservoir. On May 5, 2021, the Partnership engaged with a third party in an agreement for the sale of all of its holdings in Tamar Petroleum (22.6%) in consideration for a sum of ILS 100 million in cash.
c. On December 9, 2021, the Partnership closed the sale of its interests at the rate of 22% in the I/13 Dalit and I/12 Tamar leases to a group of investors headed by Mubadala Petroleum (Tamar Investment 1 RSC Limited and Tamar Investment 2 RSC Limited) in consideration for approx. $1.0 billion.
d. 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

[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.

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, upon completion of the sale of the Partnership's holdings in the Tamar reservoir in December 2021, the price control in the natural gas sector by virtue of the Restrictive Trade Practices Law was limited to the imposition of reporting requirements regarding profitability and the gas price, provided that during this period, the holders of the interests 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 released, each quarter, the weighted price of natural gas and the price of natural gas for IPPs. Starting from the completion of the sale of the Partnership's holdings in Tamar, as aforesaid, the Gas Authority ceased to release the natural gas prices as aforesaid, and the partners in the gas reservoirs are no longer required to offer such prices to their customers.

  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 Buyer 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 Electricity Authority on an annual basis, from 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. 8.2% and approx. 9.8% of actual power production in the State of Israel in 2021 and H1/2022, respectively, 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.

- **Competition in gas supply** – Over the past two decades, 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 domestic market. Israel granted exploration licenses in its EEZ following two competitive processes (in 2017 and 2019), which may lead to further discoveries. 2017 saw the commencement of substantial production from the Egyptian "Zohr" reservoir, which supplies gas to the Egyptian market. In addition, significant reservoirs were discovered in the EEZ of Cyprus, for which reservoirs development decisions have yet to be made. Furthermore, additional

[20] "Status Report – Renewable Energy Targets in the Electricity Sector" – the Electricity Authority, June 2022: Files_netunei_hasmal_doch_yaad_mithadshot_06_2022_f.pdf (www.gov.il)

reservoirs may be discovered in the future, both in Israel and in other countries in the Eastern Mediterranean Basin, the development of which reservoirs may lead to the entry of additional natural gas supply competitors into the domestic market and into neighboring countries, thus increasing the 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. On January 6, 2019, the Government approved the recommendations of the Adiri Committee in Government Resolution 4442.[21] On October 13, 2021, the Adiri II Committee recommended to keep the natural gas export restrictions for existing reservoirs as determined in Government Resolution 4442, but to cancel the export restriction on new reservoirs that shall be discovered.

- **Dependence on the proper function of the national transmission system** – The ability to supply the gas to be produced from the reservoirs to potential consumers is dependent, *inter alia*, on the proper function of the national gas transmission system and 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 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.

[21] Website of the Ministry of Energy, Spokesman's Notice of January 10, 2019
https://www.gov.il/he/departments/news/ng_060119

- **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.

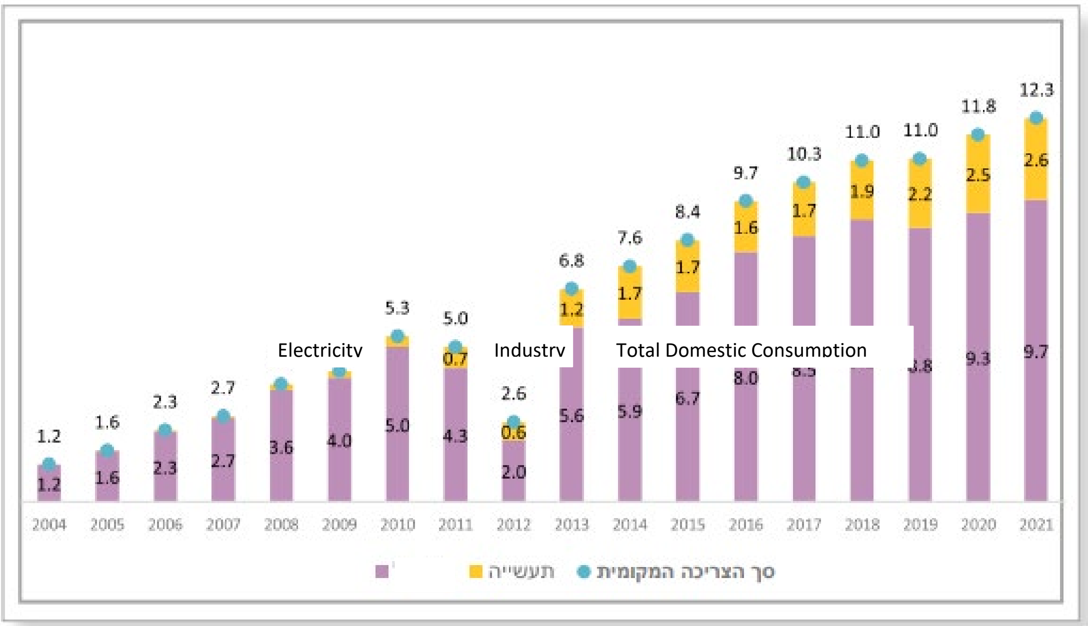
- **Regulatory changes** – The operating segment requires many regulatory approvals, mainly by the entities authorized under the Petroleum Law and the Natural Gas Sector Law, as well as related approvals of the State's authorities (including the Ministry of Energy, the Ministry of Defense, the Ministry 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.

Additional 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

<u>Chart 1 – Natural gas consumption in the domestic market in 2004-2021 in BCM per year[22]</u>



The consumption of natural gas in the Israeli market in 2021 (including export of Israeli gas to neighboring countries) amounted to approx. 19.47 BCM, an increase of approx. 21.3% compared with the consumption in 2020. Approx. 50.1% of the amount was supplied from the Leviathan reservoir, approx. 44% of the amount was supplied from the Tamar reservoir, and the balance (approx. 6%) from the import of LNG via the offshore LNG buoy. From 2004 until the end of 2021, a total quantity of approx. 130 BCM of natural gas was supplied. According to the Natural Gas Authority, the upward trend in natural gas consumption will also continue in the coming years, both as a result of domestic demand and as a result of demand for export.

[22] Source: Review of the developments in the natural gas sector, 2021 summary, Natural Gas Authority https://www.gov.il/BlobFolder/reports/ng_2021/he/ng_2021.pdf

According to a report prepared by the professional team at the Ministry of Energy for a second periodic review of the government's policy with respect to the natural gas sector[23], the natural gas consumption in Israel (excluding export to neighboring countries) in 2025 is expected to amount to approx. 15.7 BCM and in 2030 to approx. 16.9 BCM. The forecast assumes a normative increase in the demand for electricity in the next decades in accordance with achievement of the proposed target in the energy efficiency field and achievement of the government's targets in the electricity production from renewed energies field (approx. 2.13% per year), an average increase in industry (approx. 1.5% per year after conversion of industrial plants to natural gas in the coming decade) and transportation demand according to government incentive programs. The scenario also takes into account the establishment of a plant for natural gas-follow-on products, such as ammonia or methanol, as well penetration of 1.5 million electric cars by 2032 as a result of the prohibition on petrol and diesel car sales from 2030.

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 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. As of the Valuation Date, these units are still active.

- 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,

[23] Source: The report of the professional team for second periodic review of the government's policy on the issue of the natural gas sector https://www.gov.il/BlobFolder/rfp/ng_210621/he/ng_report_2_draft.pdf

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, followed by the plenum of the Knesset approved the orders, which prescribed, *inter alia*, that the excise tax on coal will be increased as of March 15, 2019 by approx. 125% in view of the government's policy to reflect 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. On January 10, 2023, the Minister of Finance issued an order postponing the increase of excise tax on coal until the end of 2023. 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 industrial 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, 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).

- 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 domestic 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.[26]

- On April 18, 2021, the Ministry of Energy released a Road Map[27] until 2050 for the low carbon energy sector, which continues the program to reduce the use of polluting energy which was presented in 2018. In accordance with the program, the following targets for the sectors were determined:

    a. Electricity sector – The production of electricity by using 70% natural gas and 30% renewable energies beginning in 2030, while ending the use of coal for electricity production in Israel by 2025.

    b. The transportation sector – A gradual shift to electric cars and natural gas trucks, so that by 2030 the number of electric cars sold will be 50% of the total cars sold in Israel. Furthermore, Israel will adopt the common regulation worldwide and

[24] Website of the Ministry of Energy, Spokesman's Notice of June 8, 2020: https://www.gov.il/he/departments/news/press_080620
[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.calcalist.co.il/local/articles/0,7340,L-3892470,00.html
[27] https://www.gov.il/he/departments/publications/reports/energy_180421

beginning in 2030 it will impose a total prohibition on the import of cars which run on polluting fuels.

In addition, it was determined that by 2030 greenhouse gas emissions in the energy sector will be reduced by approx. 23% compared with 2015, and by 2050, 80% of greenhouse gas emissions will be reduced compared with 2015.

- On June 10, 2021, the Electricity Authority (the "**Authority**") announced a call with respect to an update to the demand hour clusters. In this context, the Authority requested public comment on an update to the electricity demand hours.[28]

- According to the current forecast of the Electricity Authority,[29] the production of electricity from natural gas is expected to increase significantly, amounting to approx. 77% in 2025.

4.5.2 Transition to use of natural gas in industry

- Natural gas is a central component of the industry's energy consumption (approx. 32.5% of the total use of fuels in Israeli industry in 2020).[30] 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 a summary review of the developments in the natural gas market by the Natural Gas Authority at the Ministry of Energy for 2021, approx. 575 km of distribution pipelines have been laid out to date throughout Israel (approx. 160 km of which in 2021, an increase of approx. 38% relative to 2020) and approx. 830 km of transmission pipelines (approx. 30 km of which in 2021). An expansion 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, representing 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 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

[28] https://www.gov.il/BlobFolder/rfp/kol_kore_mashab/he/Files_Kol_Kore_kol_kore_mashab_malle.pdf
[29] Source: 2021 Electricity Sector Status Report – Electricity Authority
https://www.gov.il/he/departments/publications/reports/doch_meshek_hachashmal_2021
[30] Source: 2020 Israeli Energy Sector Review - the Ministry of Energy
energy_sector_review_2020.pdf (www.gov.il)

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 export 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 partners 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 NewMed Energy 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 NewMed Energy and Chevron, and Dolphinus, an Egyptian company, 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 NewMed Energy (25%), Chevron (25%) and the East Gas Company (50%)). Further to the foregoing, an agreement was signed between EMED and EMG, under which the capacity and operation rights in connection with the EMG pipeline were transferred in their entirety to the buyer (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 of September 7, 2014 regarding the funding of projects for export via the Israeli transmission system and distribution of the costs of construction of the combined Ashdod-Ashkelon section. The addendum to the decision determines, *inter alia*, that the offshore section of the transmission system to be built between Ashdod and Ashkelon, enabling transmission to Egypt of the full gas quantities specified in the Dolphinus agreements, shall be funded by the holder of the transmission license (43.5%) and by the exporter (56.5%), according to 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.

- On October 13, 2021, the Adiri 2 committee recommended leaving in place the natural gas export restrictions on existing reservoirs, as determined in Government Resolution 4442, but cancelling the export restriction on new reservoirs that shall be discovered.

- On February 16, 2022, the Ministry of Energy[31] approved commencement of the piping of the natural gas to Egypt, via the Kingdom of Jordan. The export via the new route, which was approved in view of the increasing demand for natural gas in Egypt, is expected to be

[31] "New route for the export of natural gas to Egypt – North Jordan!" – Ministry of Energy, February 16, 2022 https://www.gov.il/he/departments/news/ng_160222

2.5-3 BCM in 2022, and may increase to 4 BCM in subsequent years. Actual piping of the natural gas began on March 1, 2022[32] and is expected to increase the volume of natural gas exported to neighboring countries in a manner that shall secure supply of the annual contract quantity required under the export agreements in 2022.

- Natural gas export in 2021 amounted to approx. 7.14 BCM (an increase of about 68% from 2020). Approx. 86% of the exported gas was produced from the Leviathan reservoir, and the rest from the Tamar reservoir. In 2021 the Ministry of Energy promoted the construction of another onshore pipeline to Egypt, in addition to the existing offshore pipeline (EMG). The new onshore pipeline to Egypt, which is currently in design, is expected to transmit between 3 and 6 BCM per year, and is intended to be built between Ramat Hovav and Nitzana.

4.5.4 Repercussions of the Covid crisis in the Israeli and global energy sectors

- In a review of the developments in the natural gas sector in Israel in 2020, the Ministry of Energy examined the impact of Covid on the domestic energy sector by comparing the data for the period from March 2020 to the end of the year with the data for the corresponding period in the previous year. It is found that the Israeli market continued to operate and consume natural gas under the restrictions which existed during the crisis, despite the Covid pandemic which erupted at the end of Q1/2020. Overall, the total natural gas production for the domestic market from March until the end of the year recorded a year-over-year increase of approx. 43% in the total supply.[33]

- In a review of the 2021 global energy crisis released by the Natural Gas Authority, it was estimated that the global energy market is currently trying to find a new equilibrium point in the short-medium term between demand and supply of fossil fuels (such as natural gas), in view of the transition period in which the world is striving to increase energy production through renewable energies, but still requires fossil fuels in order to supply the current demand for energy. The natural gas prices in Europe rose during 2021, and soared in recent months up to approx. $35 and higher per MMBTU, prices over ten times higher than last year.
  The global demand for energy in 2021 was restored to pre-Covid levels, and with cancelation of the lockdown policy in the various countries, the demand for all energy types increased. The response on the supply side was slow relative to the demand side, due to the need to resume investments, rehire employees, and thus restart the business. Therefore, the sharp rise in demand, along with the uncertainty surrounding the rate of

[32] https://mayafiles.tase.co.il/rpdf/1433001-1434000/P1433795-00.pdf
[33] Ministry of Energy:
https://www.gov.il/BlobFolder/reports/ng_2020/he/ng_2020.pdf

recovery from the pandemic, was not met with adequate supply, which led to a price increase.
As a result of the global rise in coal prices (as of December 31, 2022, a ton of coal is traded for approx. $190.5[34]), and given the global energy crisis that led to an increase in the fuels prices in 2022 and is expected to continue in 2023, and also in view of the electricity production mix in Israel (coal constitutes approx. 26% of all electricity production), the Electricity Authority increased the electricity tariff for 2023 by approx. 8.2% for the domestic consumer.[35] The worldwide rise in petroleum prices (as of December 2022, the average price of a Brent barrel was approx. $80.9[36]) led to a rise in the prices of oil products – petrol, LPG, fuel oil, and others. Furthermore, although the State of Israel does not depend on the import of natural gas and supplies the principal part of the demand itself, natural gas prices in Israel will be indirectly affected due to the linkage components under the contracts for the purchase of natural gas in Israel, mainly to the dollar and to the production component in the electricity tariff. The global energy crisis is expected to lead to an increase in natural gas prices in Israel under the various contracts to a varying degree, and at varying timing, but overall the Natural Gas Authority expects a moderate increase only.

According to a forecast prepared for the Partnership by an outside consultant, the domestic demand for natural gas in 2022 is expected to total approx. 12.6 BCM and gradually increase to approx. 17 BCM in 2025, and to approx. 20.5 BCM in 2030. The increase in domestic demand between 2020-2030 is expected to derive mainly from an addition of approx. 4.3 BCM as a result of discontinuance of the use of coal for electricity production, an addition of approx. 5 BCM as a result of natural growth in the demand for electricity (population growth, improvement in the standard of living and in disposable income), and an addition of approx. 2.3 BCM as a result of the use of electric transportation. Conversely, the demand forecast includes a decline in domestic demand for natural gas due to renewable energies penetrating 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 *de facto* compliance with this target, with the government target aiming for approx. 17 GW of installed capacity in 2030, gas and the said forecast assuming that this target will be accomplished in 2033.

[34] https://markets.businessinsider.com/commodities/coal-price
[35] Decision No. 63608 – Update of the Electricity Tariff for IEC Consumers
[36] A World Bank Monthly Commodity Price Data (The Pink Sheet), January 2023

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. Further thereto, it was reported that on January 1, 2020 and on January 15, 2020, the gas flow from the Leviathan reservoir began to Jordan and to Egypt, respectively.

- On October 2, 2020, Noble Energy, 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 this company by American company Chevron in consideration for approx. $5 billion.

- On September 13, 2020, Delek Group Ltd. (in this section: "**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 Delek Energy's holdings in Tomer Royalties (approx. 39.93% as of such date) for a total consideration of approx. ILS 46 million.

- On September 23, 2020, NewMed Energy 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 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 19, 2021, the Partnership and INGL reported that INGL had entered into an agreement with Chevron 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, Chevron 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, in the Partnership's estimation, 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. The report further clarified that the Partnership does not expect any difficulty extending the agreement upon its expiry. On February 15, 2021, INGL reported the fulfillment of the closing conditions determined in the agreement.

- On February 23, 2021, NewMed Energy 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 "**Separate Marketing Agreement**"). 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. On May 26, 2021, the Partnership reported that on May 11, 2021, the Separate Marketing Agreement took effect.

- On December 9, 2021, the Partnership closed the sale of its interests at a rate of 22% in the I/13 Dalit and I/12 Tamar leases to a group of investors headed by Mubadala Petroleum (Tamar Investment 1 RSC Limited and Tamar Investment 2 RSC Limited), in consideration for approx. $1.0 billion. The Partnership thus completed fulfillment of all of the conditions determined for the granting of the Exemption (as defined in Section 4.3 above), as determined in the Gas Framework of December 17, 2015.

- On December 20, 2021, the Tamar partners reported the signing of an amendment to the gas supply agreement between Dalia and the Tamar partners, with the exception of Tamar Investment 1 RSC Limited and Tamar Investment 2 RSC Limited (the "**Remaining Tamar Partners**"). The amendment mainly concerns the extension of the term of the agreement by three years, such that it expire on July 8, 2035 (rather than July 8, 2032), and reduction of the minimum annual gas quantity charged ("Take or Pay") that is specified in the agreement. Furthermore, Dalia will undertake to buy an additional minimal daily quantity of gas that is required for its operations according to its needs, subject to the deductions specified in the agreement. The price for a daily gas quantity and the price linkage mechanism shall remain as provided by the original agreement. The gas price for the additional daily gas quantity that Dalia will buy over and above the minimal quantity shall be lower than the gas price for the minimal quantity and primarily linked to the Electricity Production Tariff, as determined from time to time by the Electricity Authority. The entry of the amendment to the agreement into effect is subject to the satisfaction of several conditions precedent[37]. On February 28, 2022, the partners reported the satisfaction of the condition precedent of the Remaining Tamar Partners joining the amendment to the agreement[38]. On July 24, 2022, all of the conditions precedent were satisfied and the agreement took effect. The amendment to this agreement was signed concurrently with the termination of the sale agreement between Dalia and Energean for the supply of 0.2 BCM of natural gas per year from the Karish reservoir (for details, see Section 4.6.2).

- On January 24, 2022, the partners in the Tamar reservoir reported the signing of an amendment to the 2012 IEC-Tamar Agreement[39], whereby the gas price by which the IEC is bound in 2021 under the IEC-Tamar agreement of 2012 will be reduced by a rate several percent higher than the rate of the maximum reduction determined in the reduction mechanisms in this agreement for that year and for subsequent years. It was also determined that the parties to the agreement will reserve the right to a price adjustment (10% up or down) on January 1, 2025 (instead of July 1, 2024 in the 2012 IEC-Tamar Agreement)[40]. In addition, the term of the 2012 IEC-Tamar Agreement was extended by another 2.5 years, such that this agreement will end on December 31, 2030 (the "**Date of Conclusion of the Amended Agreement**"). The gas price in the 2012 IEC-Tamar Agreement after the reduction determined in 2021 will be linked to the U.S. Consumer Price Index (the "**U.S. CPI**"), as follows:

  - An increase of up to 2.25% will be taken into account in full.
  - An increase of between 2.25% and 3.75% will not be taken into account in the relevant year, and may accrue and be taken into account in subsequent years only insofar as the rate of the rise in the U.S. CPI therein is less than 2.25%, and in any event the linkage in such years shall not exceed 2.25%.
  - An increase of over 3.75% will be taken into account in full (the portion exceeding 3.75%).
  - 1% per annum will be deducted from the above weighted linkage rate.

  The IEC also undertook to purchase an additional 16 BCM (over and above the quantity to which it committed in the 2012 IEC-Tamar Agreement) until the Date of Conclusion of the Amended Agreement (in accordance with its operational needs). Insofar as the IEC does not consume the total natural gas quantity to which it committed until such date, the agreement will automatically be extended until consumption of the full natural gas

[37] https://maya.tase.co.il/reports/details/1419083/2/0.
[38] https://maya.tase.co.il/reports/details/1433483/2/0.
[39] https://maya.tase.co.il/reports/details/1427402/2/0.
[40] In the IEC-Tamar agreement of 2012, the Parties determined two dates on which each party may request adjustment of the purchase price, July 1, 2021 and December 31, 2024. According to the mechanism determined, the IEC may request a price adjustment of up to 25% on the first date and up to 10% on the second date.

quantity. The price per unit of heat (MMBTU) for this additional quantity was determined in the agreement at approx. $4, without linkage and without rights to adjustments in the future. On July 24, 2022, the agreement took effect after the satisfaction of all conditions precedent.

- On May 1, 2022, Alon Gas Energy Development Ltd. ("**Alon Gas**"), that holds approx. 4% of the Tamar reservoir, announced that its controlling shareholder, "Alon", Israeli Fuel Company Ltd., engaged in an agreement for the sale of its entire holdings in Alon Gas, which constitute approx. 79.56% of the company's shares, to Noy Reserves Limited Partnership for a consideration of approx. ILS 395 million.

- On December 21, 2022, Mr. Aaron Frenkel, through a company he owns, bought Tamar Investment 2, which had been owned by a group from Abu Dhabi and holds approx. 11% of the Tamar reservoir, in consideration for approx. $0.5 billion.

- On January 19, 2023, Tomer Energy Royalties (2012) Ltd. ("**Tomer Energy**") reported that its controlling shareholder, Essence Partners Ltd. ("**Essence**"), had entered a transaction with the Noy Fund for joint control of Alon Gas and conversion thereof into a private company. In consideration for joint control and a post-transaction holding rate of approx. 29.4% in Alon Gas, Essence will pay approx. ILS 47.2 million and transfer its holdings in Tomer Energy (approx. 50.8%) to Alon Gas. On February 9, 2023, Alon Gas became a private company and was delisted from the trade on TASE. On March 8, 2023, Tomer Energy reported that the transaction received the approval of the Competition Commissioner. As of the date of the Paper, the conditions precedent for the closing of the transaction are yet to be fully satisfied.

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, March 2020 and March 2021 it paid the Partnership the first, second, third and fourth payments in the sum of $10.85 million, $15.34 million, $14.84 million and $14.34 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 section of the infrastructure for gas transmission from the leases** – On June 25, 2019, Energean announced that it signed an agreement with INGL, whereby it would build and transfer to INGL the eastern section of the gas infrastructure, which includes an offshore section approx. 10 km off the coast and an onshore section. 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 NewMed Energy 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 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 that were sold (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 floor price 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 the refinancing of a loan in the sum of $1.45 billion such that its maturity date will be postponed by 9 months from December 2021 to September 2022.

- On March 24, 2021, Energean announced the completion of the issue of four series of preferred secured bonds, for a total sum of approx. $2.5 billion ($625 million each) with a duration of 3, 5, 7 and 10 years at interest rates of 4.500%, 4.875%, 5.375% and 5.875%, respectively (in this section: the "**Secured Bonds**"). The Secured Bonds were rated BB (international) by the rating agency S&P and are traded on TASE UP (formerly TACT-Institutional).

- On June 28, 2021, Energean reported that Energean Israel signed a drilling agreement with Stena Drilling Limited as part of the plan for drilling and development of its reservoirs in Israel for the years 2022-2023. The planned drilling will be performed in 2022 in the Karish, Karish North and Block 12 reservoirs (drilling may be carried out at two more sites).

- On November 3, 2021, Energean reported the receipt of a letter on immediate termination of a contract for sale of natural gas in the volume of approx. 0.8 BCM per year that was previously signed between the company and Dalia Energy Companies Ltd. ("**Dalia**"). On May 15, 2022, Dalia reported that, upon conclusion of an arbitration proceeding, Energean and Dalia had signed an agreement for immediate termination of the above sale agreement with neither party being awarded damages.

- On November 11, 2021, Energean announced its intention to issue, on November 18, 2021, several series of secured senior bonds in a total sum of $450 million, due to mature on April 30, 2027. The annual interest rate of these series is 6.50%, to be paid in semi-annual installments on April 30 and October 30 of each year. Starting from January 7, 2022, the above-mentioned bonds are traded on TISE (the International Stock Exchange). According to the report, Energean intends to use such sum to repay all of its liabilities related to the reservoirs in Egypt and Greece, to repay deferred debt, to pay fees and other expenses related to the offering and for general purposes of the company.

- On December 13, 2021, Energean reported that it had signed an agreement with Kanfa AS for the construction of a second Oil Train Module (OTM) for the Karish reservoir. The construction of the additional OTM will allow for increase of the hydrocarbon liquids output of the FPSO platform from 18 KBO per day to 32 KBO per day. The OTM is expected to be connected during H2/2023.

- **A natural gas sale SPOT agreement signed with IEC** – On March 14, 2022, Energean reported that it had entered into a SPOT agreement with IEC for supply of natural gas from the Karish reservoir (the "**SPOT Agreement**"). Under the SPOT Agreement, IEC has the right to purchase natural gas at a variable monthly price in quantities to be determined on a daily basis (without a commitment). The SPOT Agreement shall apply for one year from the date of production of first gas from the Karish reservoir, with extension options subject to both parties' consent.

- **Signing of an agreement for the sale of natural gas with Hagit East Power Plant partnership** – On May 3, 2022, Energean reported its engagement in agreements for the supply of natural gas from the Karish reservoir with the Hagit East Power Plant partnership (Edeltech and Shikun & Binui Energy). According to the agreements, Energean will sell the Hagit East Power Plant partnership natural gas from the date of commencement of first gas production from the Karish field, in an annual quantity of up to approx. 0.8 BCM. The agreements include provisions on a floor price, Take-or-Pay mechanism and linkages (with no linkage to the Brent price), and are expected to generate for Energean up to approx. $2.0 billion throughout the life of the contracts. The total natural gas sold under the agreement is expected to be up to approx. 12 BCM over a period of about 15 years. The agreement is subject to the closing of the acquisition of the plant by Edeltech and Shikun & Binui Energy. On June 1, 2022, IEC reported that the process for sale of the plant to Edeltech and Shikun & Binui Energy had been closed.

- On May 3, 2022, Energean reported that the FPSO had departed and was sailing from Singapore towards Israel. On June 6, 2022, Energean reported that the FPSO had reached its destination.

- On October 9, Energean reported the piping of natural gas from the shore to the FPSO platform via the gas transmission systems as part of the tests and the trial run of the systems conducted by the company in preparation for the commencement of natural gas production from the Karish reservoir.

- On October 26, 2022, Energean reported initial natural gas production from the Karish reservoir and on October 28, 2022, it began selling natural gas to its customers. The gas production system has an annual production capacity of up to approx. 6.5 BCM, while at the end of 2023, Energean is expected to complete the installation of additional system components which will make it possible to increase the production capacity from the reservoir to up to approx. 8.0 BCM per annum. In Energean's estimation, commercial gas sales are expected to reach an annual production level of approx. 6.5 BCM within around four to six months from the date of the initial gas production.

- On November 17, 2022, Energean reported that it had signed a sale agreement with Vitol SA for initial marketing of deliveries of hydrocarbon liquids. On February 14, 2023, the company supplied a first delivery of hydrocarbon liquids from the Karish reservoir according to the aforementioned agreement. Energean also reported that commencement of production from the Karish North reservoir is expected at the end of 2023 (in lieu of H2/2023 in previous reports).

- On January 19, 2023, Energean reported that in 2022 it produced approx. 0.28 BCM of natural gas from the Karish reservoir. In addition, Energean is predicting that the production rate in 2023 will be between approx. 4.5 BCM based on take-or-pay contracts, and 5.5 BCM based on total annual contract quantity. The company mentioned that these quantities do not take into consideration sales based on the SPOT agreement with IEC in 2023. On March 23, 2023, the company updated that it meets the target of producing between 4.5 and 5.5 BCM in 2023.

- **Update of the volume of resources attributable to the Karish, Karish North and Tanin reservoirs** – On March 23, 2023, Energean released a resource and reserve report as of December 31, 2021, prepared by the resource estimation firm DeGolyer and MacNaughton, whereby the Karish, Karish North and Tanin reservoirs (in this section: the "**Reservoirs**") have reserves of natural gas and hydrocarbon liquids (2P) of approx. 99.6 BCM and approx. 95.6 million barrels, respectively.[41] Energean has postponed the estimated date of commencement of production from the Tanin reservoir to 2030 (rather than 2028). Furthermore, Energean 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.

[41] https://www.energean.com/media/5400/dm-final-report-energean-israel-2022ye.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 on the date on which the Buyer shall have made a final investment decision (FID) or the Buyer shall have 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 Buyer to the Sellers, which is contingent upon the development of the leases, whether by an FID or the actual performance of the investment. 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.
In view of the bond offering, during May-June 2021, letters were exchanged between Energean and the Partnership in connection with the Partnership's demand for payment of the balance of the consideration for the Debt Component in a single and immediate payment, in accordance with the terms and conditions of the agreement for the sale of the interests in Karish and Tanin. As of the date of the Paper, the Partnership's position has not yet been accepted by Energean, and we are unable to estimate the likelihood of Energean's granting this demand and/or the outcome of a legal proceeding, insofar as conducted. Consequently, no assessment was made herein of a Debt Component prepayment scenario.

ii. Royalties from revenues (net of existing royalties[42]) 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 Buyer to produce revenues from natural gas and condensate from the reservoirs.

[42] The Sold Interests were transferred to the Buyer together with the existing overriding royalties in the leases borne by each of the Sellers, with respect to their original share (26.4705%).

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 assumptions

5.2.1 General

The main working assumptions as specified below are based primarily on a resource and reserve report as of December 31, 2022, prepared by the consulting firm DeGolyer and MacNaughton, a competent resource appraiser ("**D&M CPR**"), released by Energean on March 23, 2023, with adjustments as specified below, 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 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 aforementioned reports, first gas production began in Q4/2022. It was further reported that the production well in the Karish North reservoir was drilled and completed during Q3/2022, and first gas from the reservoir is expected at the end of 2023. According to these reports, production from the Tanin lease is expected to begin in 2030.

In the context of the valuation, it was assumed that the production of gas from the Karish North and Tanin reservoirs will begin in Q1/2024 and Q1/2030, respectively. It was further assumed that the natural gas reserves in the Karish, Karish North and Tanin reservoirs would be depleted in 2042, 2042 and 2041, respectively, according to assumptions presented in the D&M CPR.

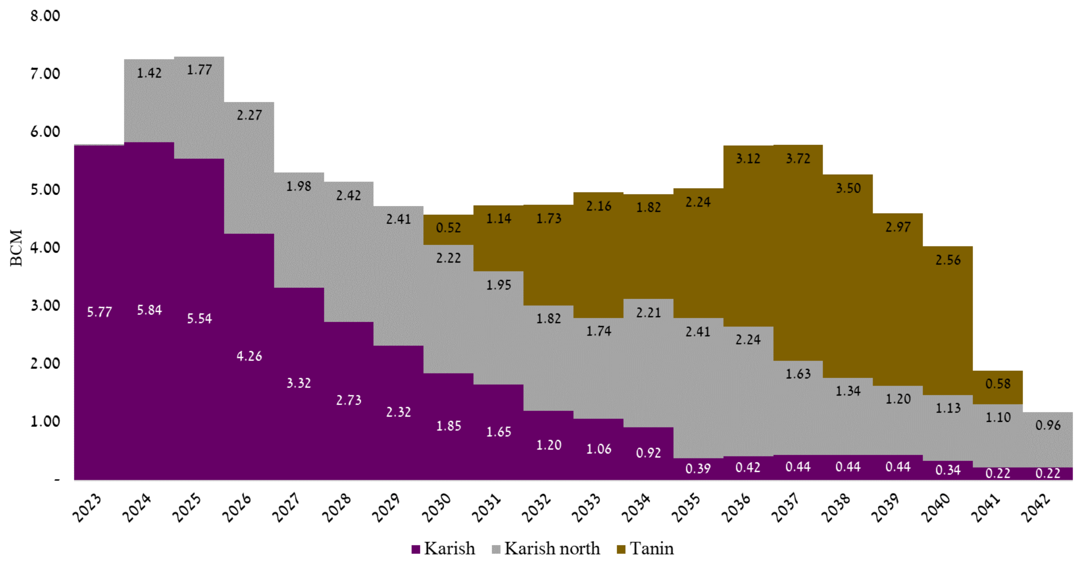
5.2.3 Quantity forecast and annual production rate

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:

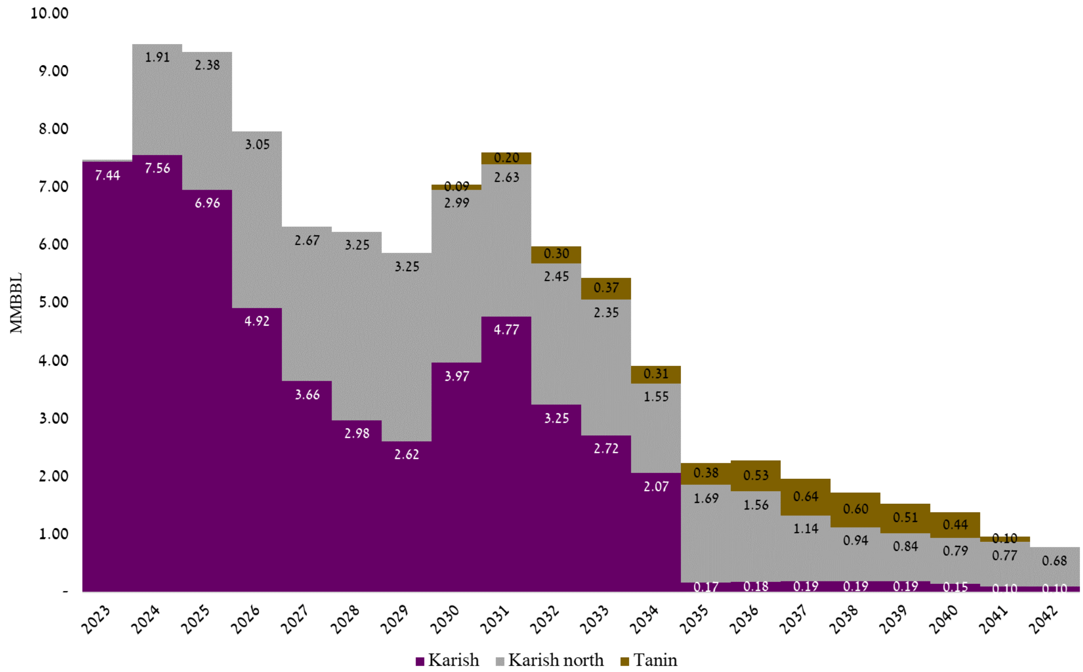
Reservoir	Reserves and Resources	
	Natural Gas (BCM)	Hydrocarbon Liquids (MMBBL)
	2P	**2P**
Karish	39.4	54.2
Karish North	34.2	36.9
Tanin	26.1	4.5
Total	**99.6**	**95.6**

According to the D&M CPR, Energean estimates that it is expected to sell up to 7.3 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.

The chart below describes the production rate of natural gas from the reservoirs according to the D&M CPR (2P reserves):



The chart below describes the production rate of hydrocarbon liquids (condensate and natural gas liquids) from the reservoirs according to the D&M CPR (2P reserves):



The forecasted annual pace of production of natural gas and condensate used in the valuation was based on the pace of production specified in the D&M CPR, which in our estimation reflects the likely scenario considering the public information available in relation to the contracts that have been signed, the extent of the demand and the expected competition in the domestic market (for a detailed forecast of the annual production rate of natural gas and condensate, see Annex A). In addition, an adjustment was made to the natural gas production rate in 2023 in accordance with the various reports of Energean that pertain to the forecasted production from the reservoirs, which were released in proximity to the publication of the D&M CPR. The remaining quantity that was reduced in the production rate in 2023 was spread out over the next years. These reports include forecasts which are based on a ramp-up in the pace of production, the feasibility and likelihood of occurrence of which we cannot assess in the absence of further publicly-available information. As of the date of this Paper, such reports are the only source for Energean's forecasts of the expected pace of production from the reservoirs.

In addition, according to the D&M CPR, a conversion factor of 37.2 million MMBTU 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 31.19 Agorot (December 2022)[43]. 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 IPPs and other production costs. According to our forecasts, the production component tariff is expected to range between approx. 23.16-31.73 Agorot throughout 2023-2037.

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 supplied to the Ramat Hovav power plant and that the remaining gas amount which will be sold will be equally distributed between IPPs (such as the contract with OPC) and industrial producers (such as the contracts with ICL and ORL).

Note that for the base scenario and the low scenario, the D&M CPR assumed natural gas price of approx. U.S. $4.34 per MMBTU for 2023, and a fixed natural gas price of approx. U.S. $4.04 per MMBTU starting from 2024 and throughout all the years of the forecast.

5.2.5 Condensate price forecast

The condensate prices forecast was estimated based on the Partnership's estimations.

Note that the base scenario in the D&M CPR assumed a condensate price of approx. U.S. $80 per barrel in 2023 and approx. U.S. $70 per barrel starting from 2024 and throughout all the years of the forecast (fixed).

[43] On January 24, 2023, the Electricity Authority decided to decrease the production component tariff to 30.81 Agorot. This decision derives mainly from the global decrease in coal prices. In addition, on March 2, 2023, the Electricity Authority published a hearing for a further decrease of the production component tariff to 30.48 Agorot. These changes were unknow on the date of the Paper and were therefore not taken into account in the valuation.

5.2.6 Royalty 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[44]. 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 clarifications, the effective royalty rate which will be paid to the State for the gas and condensate is 11.25%. Furthermore, the rate of the existing royalties in the leases, borne by each of the Partnerships, were similarly adjusted.

5.2.7 Petroleum profit 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[45]) with the Investment Coverage Ratio reaching 2.3. The levy will be calculated and imposed for every lease 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.

5.2.8 Royalties cap rate

The cap rate (before tax) was estimated at approx. 10.5% based on a weighted average of the required return on equity which was estimated using the CAPM model, the normative debt price and net of the royalties risk, as specified in the table below:

[44] 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

[45] Corporate tax of 23% was assumed according to the statutory tax rate known as of the Valuation Date.

Parameter	Value	Note
Risk-free interest	4.09%	A
Beta	1.39	B
Market premium	7.16%	C
Specific risk premium	6.2%	D
The company's equity price	**20.3%**	
Debt price	6.9%	E
Tax rate	0.0%	F
Leverage ratio	60%	G
Weighted equity price	**12.2%**	
Net of royalties risk	-1.70%	H
Weighted equity price net of royalties risk	**10.5%**	

Below are the working assumptions that were used in the calculation of the cap rate:

a. U.S. government bond yield for the average duration of the cash flow (4.13 years).

b. Based on an average of unleveraged betas of benchmark companies, as specified in the table below:

Company	Unleveraged Beta
Isramco Negev 2, Limited Partnership	0.62
Ratio Energies Limited Partnership	0.84
Tamar Petroleum Ltd.	0.23
Tomer Energy Royalties (2012) Ltd.	0.28
NewMed Energy Limited Partnership	0.81
Benchmark company average	**0.55**

The leveraged beta was estimated based on the average beta of the benchmark companies above and the normative leverage ratio, without tax (see Note F).

c. The market risk premium in Israel (Damodaran January 2023).

d. Size risk premium according to Duff & Phelps International Valuation Handbook 2023, plus a specific risk premium for the risk level inherent in forecasts, the fluctuation in petroleum prices and the competition in the domestic market.

e. The debt price was estimated based on the yield of the bonds issued by Energean on November 18, 2021. The average duration of the cash flow (4.13) is similar to the average duration of the bonds (3.8) and therefore, in our estimation, they represent the normative debt price of the company for the average duration of the cash flow.

f. The valuation model is a pre-tax model and therefore no tax was taken into account in the cap rate.

g. The average leverage ratio of the benchmark companies (in Section 2 above), as of December 31, 2022, was estimated at approx. 50.0%. In our estimation, the normative leverage ratio for the long-term is 60.0%

h. The cap rate of 12.2%, which was estimated using the CAPM model (the "**Operating Cap Rate**"), includes many operational risks to which the recipient of the overriding royalties is not exposed. In our experience, the Operating Cap Rate is 1.5% to 2.0% higher than the cap rate for the royalties. Consequently, we deducted approx. 1.7% from the operational risk rate.

5.3 Results of the valuation

According to the assumptions specified in the Paper itself, the value of the Royalties as of December 31, 2022 is estimated at approx. $320.8 million (the value of the Karish Royalties (including Karish North) and the Tanin Royalties are estimated at approx. $294.1 million and approx. $26.6 million, respectively). **To clarify, the valuation does not address the disputes, if any, between Energean and the Partnership, and the implications thereof** (for further details, 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	276.3	281.1	299.1	293.7	310.8	325.3	342.2
	+150 bp	285.8	290.7	309.2	303.9	321.6	336.6	354.1
	+50 bp	296.0	301.0	320.1	314.9	333.3	348.8	367.1
	-	301.3	306.5	325.9	**320.8**	339.5	355.4	373.9
	-50 bp	307.0	312.2	332.0	326.9	346.0	362.2	381.1
	-150 bp	318.9	324.3	344.8	340.0	359.8	376.8	396.4
	-250 bp	331.9	337.5	358.8	354.3	375.0	392.8	413.2

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 the Annual Production Rate of Natural Gas (BCM)						
		-1.00	-0.50	-0.25	-	0.25	0.50	1.00
Change in Cap Rates (in Base Points)	+250 bp	287.7	302.9	309.2	293.9	301.1	307.7	316.2
	+150 bp	298.2	313.4	319.7	304.0	311.3	317.9	326.3
	+50 bp	309.6	324.9	331.2	314.9	322.3	328.9	337.2
	-	315.7	331.0	337.2	**320.8**	328.2	334.8	342.9
	-50 bp	322.1	337.4	343.6	326.8	334.3	340.9	348.9
	-150 bp	335.9	351.1	357.2	339.8	347.2	353.8	361.5
	-250 bp	351.2	366.1	372.0	354.0	361.4	367.9	375.3

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 the Condensate Price Vector (U.S. $ per bbl)						
		-30.00	-20.00	-10.00	-	10.00	20.00	30.00
Change in Cap Rates (in Base Points)	+250 bp	281.9	293.1	303.8	293.7	305.1	312.6	324.2
	+150 bp	291.8	303.2	314.1	303.9	315.6	323.1	335.1
	+50 bp	302.5	314.1	325.3	314.9	327.0	334.6	347.0
	-	308.2	320.0	331.2	**320.8**	333.1	340.7	353.3
	-50 bp	314.1	326.0	337.4	326.9	339.4	347.1	359.9
	-150 bp	326.8	338.9	3,506.0	340.0	352.8	360.7	373.9
	-250 bp	340.6	353.0	365.0	354.3	367.6	375.5	389.2

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Annex A – Cash Flow Forecast

Year	Unit	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Production											
*Gas production - Karish**	*bcm/y*	*5.00*	*7.26*	*7.31*	*6.52*	*5.30*	*5.15*	*4.74*	*4.07*	*3.61*	*3.02*
Gas production - Tanin	*bcm/y*	-	-	-	-	-	-	-	*0.52*	*1.14*	*1.73*
*Condensate production - Karish**	*bbl/y m*	*7.44*	*9.48*	*9.35*	*7.97*	*6.32*	*6.24*	*5.87*	*6.96*	*7.40*	*5.69*
Condensate production - Tanin	*bbl/y m*	-	-	-	-	-	-	-	*0.09*	*0.20*	*0.30*
Prices											
Natural gas price	*US$*	*4.28*	*4.37*	*4.10*	*4.03*	*4.00*	*4.01*	*4.01*	*3.97*	*3.90*	*3.90*
Condensate Price	*US$*	*89.61*	*82.18*	*79.74*	*78.02*	*75.74*	*76.28*	*76.15*	*76.54*	*77.00*	*77.61*
Revenues											
*Karish - Revenues**											
Natural Gas Revenues	*US$ MM*	*796.3*	*1,180.2*	*1,113.9*	*977.4*	*789.7*	*768.6*	*706.2*	*600.1*	*523.1*	*438.2*
Condensate Revenues	*US$ MM*	*667.0*	*778.8*	*745.2*	*621.8*	*478.8*	*475.6*	*446.8*	*532.7*	*570.1*	*441.9*
Total Gross Revenues	*US$ MM*	*1,463.3*	*1,958.9*	*1,859.1*	*1,599.2*	*1,268.4*	*1,244.2*	*1,152.9*	*1,132.8*	*1,093.2*	*880.1*
Tanin - Revenues											
Natural Gas Revenues	*US$ MM*	-	-	-	-	-	-	-	*77.0*	*165.7*	*251.0*
Condensate Revenues	*US$ MM*	-	-	-	-	-	-	-	*6.8*	*15.2*	*22.9*
Total Gross Revenues	*US$ MM*	-	-	-	-	-	-	-	*83.9*	*181.0*	*273.9*
K&T - Total Gross Revenues	*US$ MM*	*1,463.3*	*1,958.9*	*1,859.1*	*1,599.2*	*1,268.4*	*1,244.2*	*1,152.9*	*1,216.7*	*1,274.2*	*1,154.0*
New-Med Energy - Transaction Revenues											
*Karish ORRI, Net**	*US$ MM*	*67.4*	*90.2*	*53.7*	*42.5*	*29.3*	*23.1*	*17.8*	*17.5*	*16.9*	*13.6*
Tanin ORRI Net	*US$ MM*	-	-	-	-	-	-	-	*2.4*	*5.2*	*7.9*
Transaction ORRI, Net**	*US$ MM*	***67.4***	***90.2***	***53.7***	***42.5***	***29.3***	***23.1***	***17.8***	***19.9***	***22.1***	***21.5***
Instalments	*US$ MM*	*13.3*	*12.8*	*12.3*	*11.8*	*11.3*	-	-	-	-	-
*Karish Discounted Transaction Revenues**	*US$ MM*	*64.1*	*77.7*	*41.8*	*30.0*	*18.7*	*13.4*	*9.3*	*8.3*	*7.2*	*5.3*
Tanin Discounted Transaction Revenues	*US$ MM*	-	-	-	-	-	-	-	*1.1*	*2.2*	*3.1*
Total Discounted Transaction Revenues	*US$ MM*	***64.1***	***77.7***	***41.8***	***30.0***	***18.7***	***13.4***	***9.3***	***9.4***	***9.5***	***8.3***

*Including Karish North

**Net of Existing ORRI net of Petroleum Tax

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Year	Unit	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Production											
Gas production - Karish*	bcm/y	2.80	3.13	2.89	2.75	2.16	1.87	1.73	1.57	1.42	1.30
Gas production - Tanin	bcm/y	2.16	1.82	2.24	3.12	3.72	3.50	2.97	2.56	0.58	-
Condensate production - Karish*	bbl/y m	5.07	3.61	1.86	1.75	1.33	1.13	1.03	0.94	0.87	0.81
Condensate production - Tanin	bbl/y m	0.37	0.31	0.38	0.53	0.64	0.60	0.51	0.44	0.10	-
Prices											
Natural gas price	US$	3.90	3.90	3.90	3.90	3.90	3.90	3.89	3.89	3.89	3.89
Condensate Price	US$	77.61	77.61	77.61	77.61	77.61	77.61	77.61	77.61	77.61	77.61
Revenues											
Karish - Revenues*											
Natural Gas Revenues	US$ MM	406.8	453.4	419.6	399.2	313.5	271.0	250.2	227.0	204.8	188.3
Condensate Revenues	US$ MM	393.1	280.4	144.3	135.7	103.4	87.5	79.9	73.3	67.7	63.2
Total Gross Revenues	US$ MM	799.9	733.8	563.9	534.8	416.9	358.5	330.1	300.3	272.4	251.4
Tanin - Revenues											
Natural Gas Revenues	US$ MM	313.5	263.3	324.4	452.5	538.9	507.7	429.1	370.6	83.7	-
Condensate Revenues	US$ MM	28.6	24.1	29.6	41.3	49.3	46.4	39.3	34.0	7.8	-
Total Gross Revenues	US$ MM	342.2	287.4	354.0	493.7	588.2	554.1	468.4	404.6	91.5	-
K&T - Total Gross Revenues	US$ MM	1,142.1	1,021.2	918.0	1,028.6	1,005.0	912.6	798.5	704.9	363.9	251.4
New-Med Energy - Transaction Revenues											
Karish ORRI, Net*	US$ MM	12.3	11.3	8.7	8.2	6.4	5.5	5.1	4.6	4.2	3.9
Tanin ORRI Net	US$ MM	9.9	8.3	10.3	13.9	12.6	8.5	7.2	6.2	1.4	-
Transaction ORRI, Net**	US$ MM	**22.3**	**19.6**	**19.0**	**22.1**	**19.0**	**14.1**	**12.3**	**10.9**	**5.6**	**3.9**
Instalments	US$ MM	-	-	-	-	-	-	-	-	-	-
Karish Discounted Transaction Revenues*	US$ MM	4.3	3.6	2.5	2.1	1.5	1.2	1.0	0.8	0.7	0.6
Tanin Discounted Transaction Revenues	US$ MM	3.5	2.6	2.9	3.6	3.0	1.8	1.4	1.1	0.2	-
Total Discounted Transaction Revenues	US$ MM	**7.8**	**6.2**	**5.4**	**5.8**	**4.5**	**3.0**	**2.4**	**1.9**	**0.9**	**0.6**

*Including Karish North
**Net of Existing ORRI net of Petroleum Tax

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Definitions

NewMed Energy/the Partnership	NewMed Energy 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 Buyer/Energean	Energean E&P Holdings Ltd. through Energean Israel Limited (Formerly Ocean Energean Oil and Gas Ltd.).
The Partnerships/Sellers	NewMed Energy and Avner.
The Petroleum Law	The Petroleum Law, 5712-1952.
The Gas Framework or **the Framework**	The resolution of the Israeli Government to create 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.
Chevron	Chevron 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 adoption of a decision to invest in the development of the Karish and Tanin natural gas reservoirs.
LNG	Liquefied Natural Gas.
MMBTU	A Million BTU – an energy unit used as a basis for the determination of natural gas prices.