NEWMEDENERGY

2023
Periodic Report
as of December 31, 2023

NEWMEDENERGY

Table of Contents

NEWMED IN NUMBERS

23 Number of employees[2]

330 Area of Leviathan reservoirs (km²)

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

11.0 Natural gas sales from the Leviathan reservoir (BCM)

5,337[2] Value of the Partnership's share in Leviathan

760[8] EBITDA

434 Net Profit

1,094 Revenues

3,846 Total assets

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

1,512 Equity

3,366[4] Market value

Footnotes:

1. The above figures relate to 2023 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 18 2024
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, 2023 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

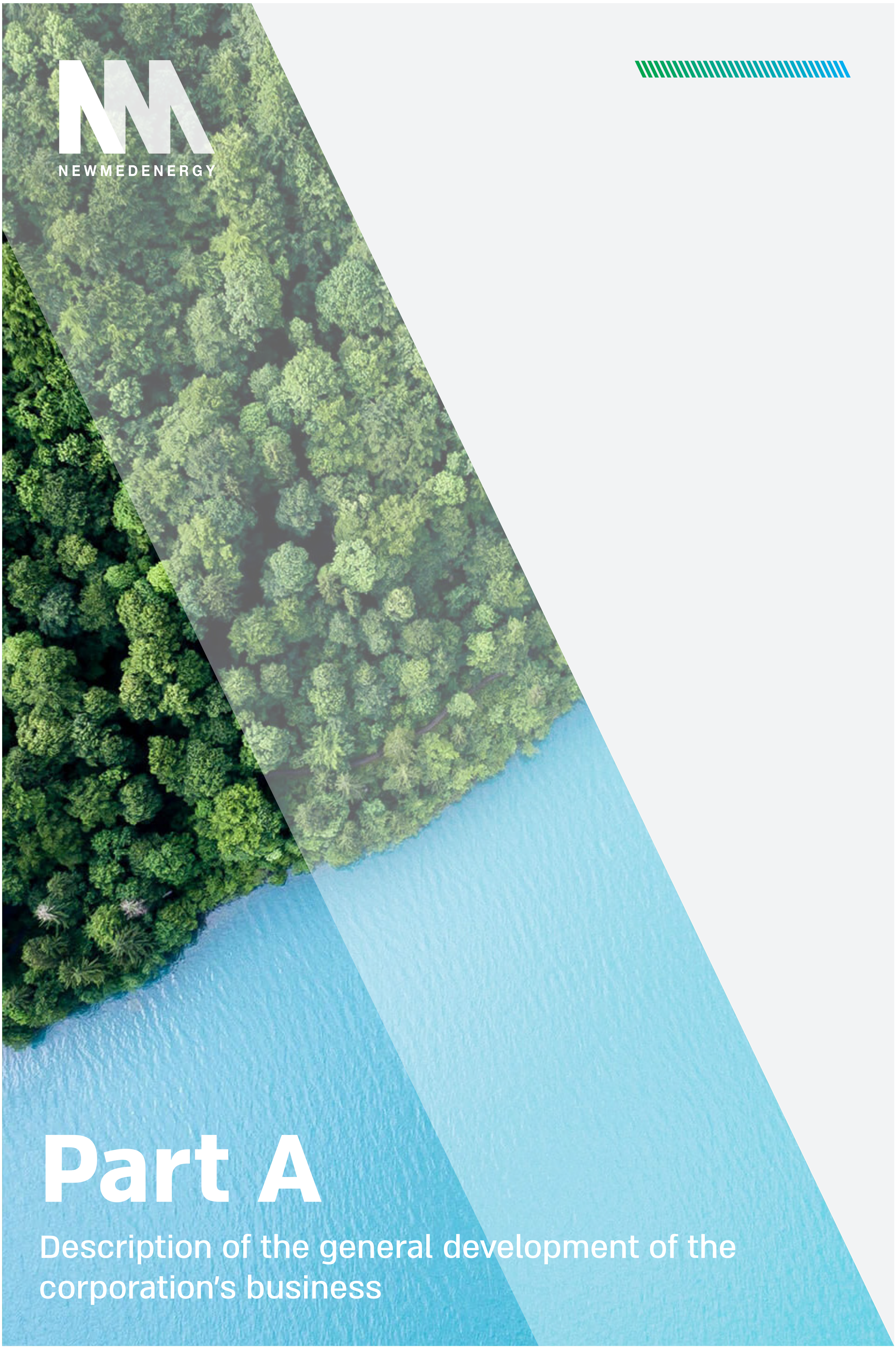
2017 Leviathan gets underway - NewMed Energy and Chevron begin developing the Leviathan reservoir

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



Part A

Description of the general development of the corporation's business

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

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, Cyprus and Morocco, as well as exploring and promoting possibilities for the making of investments in renewable energy projects.

1.2. The Partnership was established under a partnership agreement signed on 1 July 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 25 July 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 1 July 1993, the Limited Partner and the Supervisor signed a trust agreement, as amended from time to time (the "**Trust Agreement**")[5], which

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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 21 February 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 24 February 2022, their names were changed to their current names.

[4] As published in the Partnership's immediate report of 18 December 2023 (Ref.: 2023-01-137343).

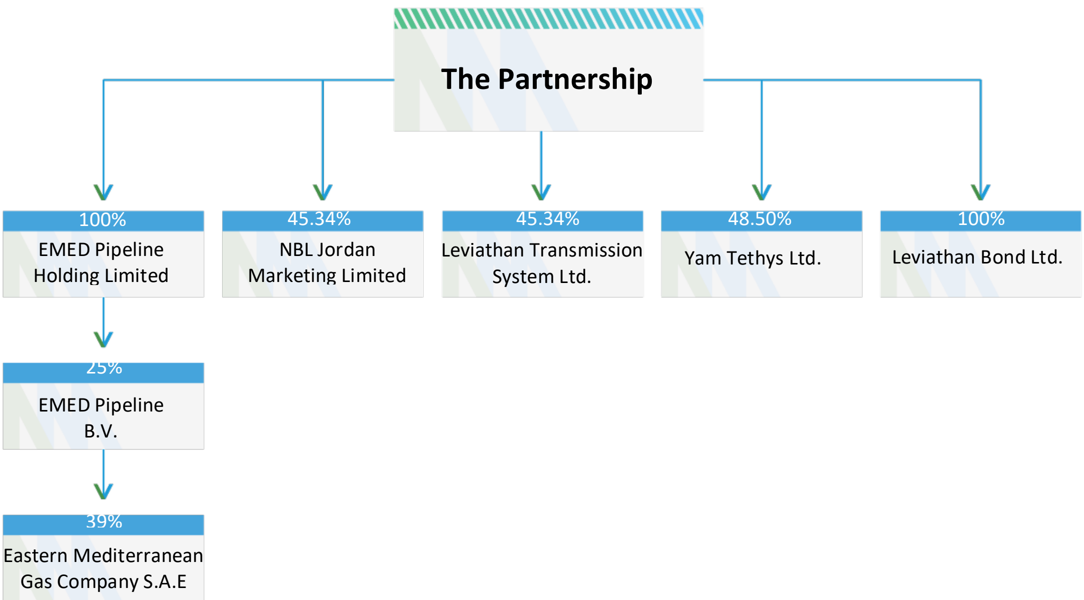
[5] As published in the Partnership's immediate report of 7 June 2020 (Ref.: 2020-01-058218).

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.

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



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

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[6] As of the report approval date, Mr. Yitzhak Sharon (Tshuva) holds approx. 49.52% of the issued capital and approx. 49.52% 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 majority of the units owned by Delek Group are pledged in favor of the holders of the bonds issued by Delek Group.

(the Ashdod Onshore Terminal, AOT) (the "**Terminal**"), as mandated by the provisions of the Natural Gas Sector Law, 5762-2002 (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 and infrastructures (the "**Minister of Energy**") on 29 April 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 7.11.3(b) below.

1.7.4. EMED Pipeline B.V. is an SPC ("**EMED**") which was established for the EMG Transaction (as defined in Section 7.25.5 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 7.25.5 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 7.20.2 below.

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

1.8. On 27 March 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 Limited, two international energy companies (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**"). On 27 March 2023, the General Partner's board decided to appoint the audit committee, comprised solely of 3 external directors (in this section: the "**Committee**"), to explore and decide on any issue pertaining to the purchase of the publicly held units in the Transaction. It is clarified that the Consortium may withdraw and cancel the Offer at any time and for any reason. For further details, *inter alia* regarding the Offer and appointment of the Committee, see the Partnership's immediate report of 28 March 2023 (Ref. 2023-01-032823), the information appearing in which is incorporated herein by reference.

During 2023, the Committee held regular meetings for the purpose of promoting the Transaction, and used legal and economic advisors who it appointed for such purpose, and concurrently the Consortium performed a due diligence with respect to the Partnership, its assets and its business.

On 13 March 2024, the Partnership and the Committee advised in an immediate report that the Committee and the Consortium had agreed, due to the uncertainty created by the external environment, to suspend discussions in relation to the Transaction. They further reported that the Consortium had reiterated its interest in the Transaction and that the process will remain

[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.

suspended until such time as discussions resume or the process is terminated. There can be no certainty that discussions will resume or that an agreement will be reached in the future, nor as to the terms of an agreement should one be reached.

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 (the "Securities Law"). 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.

1.9. Following the deadly attack perpetrated by the terrorist organization Hamas on 7 October 2023, targeting communities and military bases in the south of Israel, the Israeli government declared the "Iron Swords" war against this terrorist organization (the "**Iron Swords War**" or the "**War**"). As of the report approval date, the War is ongoing and it is impossible to predict how long it will last or its impact on the Partnership, its business and its assets. For further details, see Section 6.9 below and the risk factor relating thereto in Section 7.29.1 below.

The Partnership's management and its employees are committed to the national effort, express their deepest condolences to the families of those who have fallen and were murdered, hope for the safe return of the hostages, and wish all the injured a swift recovery.

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 7.9 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 7.27 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 natural gas 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 ("**BOE**" or "**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 7.23.1 below, in December 2021, the Partnership completed the sale of 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 7.14 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 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, the TASE Rules allow the Partnership, under specific conditions, to invest in projects that were not expressly defined in the Partnership Agreement and to invest in renewable energy projects. Accordingly, on 21 September 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 7.9 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.

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[10] Chevron Corp. is a foreign public corporation whose shares 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**"), Tamar Petroleum Ltd. (16.75%) ("**Tamar Petroleum**"), Mubadala Energy (Tamar) RSC Ltd. (11%), Tamar Investment 2 Limited (11%), Dor Gas Exploration, Limited Partnership (4%) ("**Dor**") and Everest Infrastructure, Limited Partnership (3.5%) ("**Everest**", and collectively, the "**Tamar Partners**").

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 31 December 2023, 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[12] (100%)			Optimal Evaluation (2C) of the Quantity of Contingent Resources (100%)		Optimal Evaluation (2P) of the Total Quantity of Reserves (100%)	
		Natural Gas BCF	Condensate Million barrels	Oil Million barrels	Natural Gas BCF	Condensate Million barrels	Natural Gas BCF	Condensate Million barrels
Leviathan Reservoir	45.34%	-	-	-	6,302.8	13.9	15,171.4	33.4
Leviathan Deep Prospects	45.34%	390.2	-	379.2	-	-	-	-
Aphrodite Reservoir	30.00%	79	0.1	-	3,537	7.9	-	-

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:

2.8.1 Yam Tethys project in leases I/7 "Noa" and I/10 "Ashkelon" (the "**Noa Lease**" and the "**Ashkelon Lease**", respectively), as detailed in Section 7.4 below;

2.8.2 Rights to receive royalties from the I/16 "Tanin" and I/17 "Karish" leases (the "**Tanin Lease**" and the "**Karish Lease**", respectively), as detailed in Section 7.5 below;

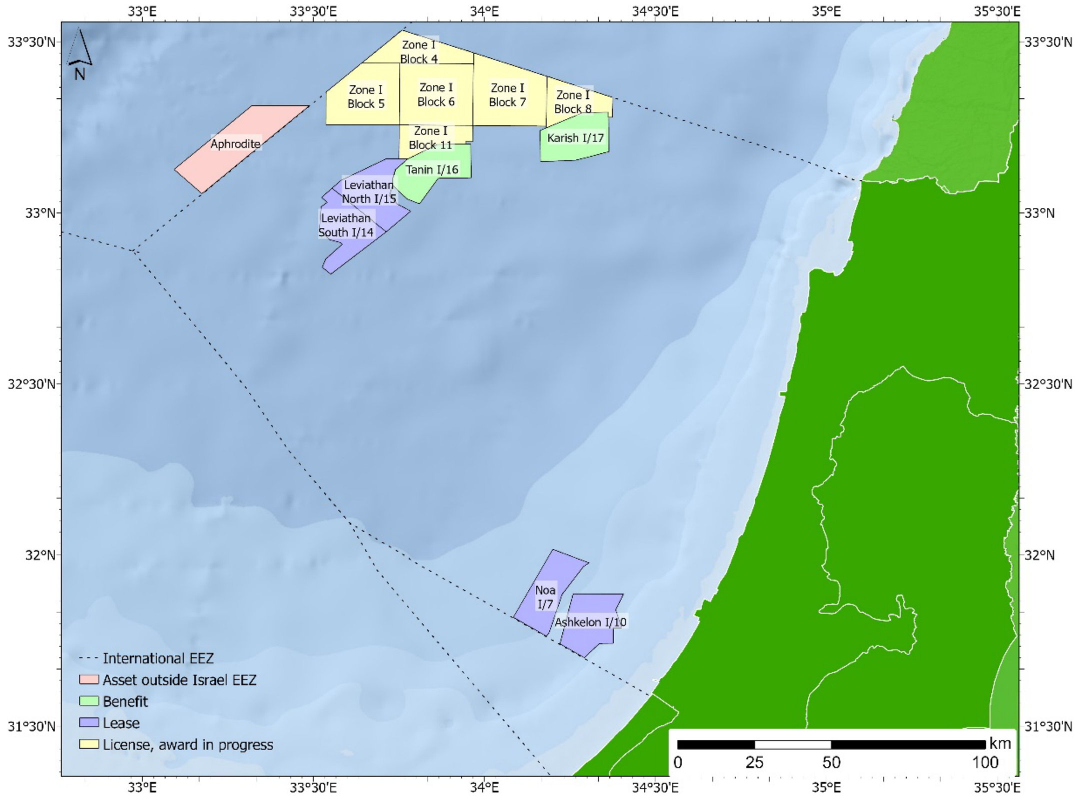
2.8.3 Interests in the Boujdour Atlantique exploration license located in the Atlantic Ocean off the shores of Morocco, which are expected to be granted, as specified in Section 7.6 below;

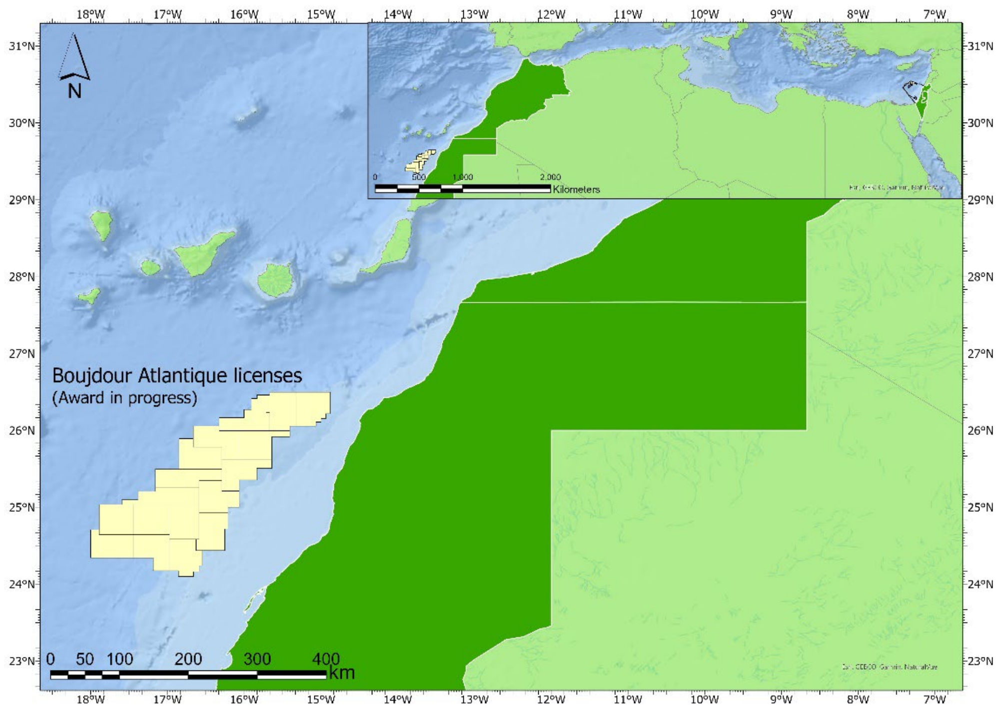
2.8.4 Interests in the exploration licenses in Zone I in the area of Blocks 4, 5, 6, 7, 8 and 11, in the exclusive economic zone (EEZ) of the State of Israel, which are expected to be granted, as specified in Section 7.7 below.

2.9 For details on the Partnership's petroleum assets on the report approval date, see Sections 7.2-7.7 below. For details on petroleum assets, the activity in which has been discontinued, see Section 7.8 below.

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

Below is a map showing the location of the Partnership's petroleum assets in Israel and a map showing the location of the license in Morocco, as of the report approval date:





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

To the best of the Partnership's knowledge and according to the reports of the Delek Group, as of the date of approval of the report, most of the participation units owned by Delek Group are pledged in favor of the holders of the bonds issued by Delek Group, including ~4.5% of the participation unit capital owned by the General Partner.

4. Distribution of Profits

4.1. In the period from 1 January 2022 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
22 May 2022	16 June 2022	$0.04260	$50 million	Ref.: 2022-01-062296
17 August 2022	22 September 2022	$0.04260	$50 million	Ref.: 2022-01-104986
23 November 2022	19 January 2023	$0.04260	$50 million	Ref.: 2022-01-141307
27 March 2023	20 April 2023	$0.05112	$60 million	Ref.: 2023-01-033114
10 May 2023	15 June 2023	$0.04260	$50 million	Ref.: 2023-01-050355
20 August 2023	14 September 2023	$0.04260	$50 million	Ref.: 2023-01-095958
15 November 2023	21 December 2023	$0.04260	$50 million	Ref.: 2023-01-104098
18 March 2024	11 April 2024	$0.05112	$60 million	-

4.2. For details regarding the tax regime applicable to the Partnership, see Section 7.21 below.

4.3. As of 31 December 2023, the Partnership has profits available for distribution in the amount of approx. 1,328 million U.S. dollars ("**dollars**" or "**$**").

4.4. Other than restrictions set forth in financing agreements, as specified in Section 7.20 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. The provisions of the Partnership Agreement regarding a profit distribution and resolutions of general meetings thereon:

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.

4.5.2 On 30 December 2013, the general meeting of the Unit holders approved a decision resolving, *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 31 December 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 21 September 2022, the general meeting of the Unit holders approved a decision resolving, *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 6 September 2022 and 21 September 2022 (Ref.: 2022-01-092520 and 2022-01-120358, respectively), the information in which is incorporated herein by reference.

4.5.4 On 2 January 2023, the general meeting of the Unit holders approved a decision resolving, *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 12 December 2022 and 3 January 2023 (Ref.: 2022-01-150004 and 2023-01-002016, respectively), the information in which is incorporated herein by reference.

4.5.5 On 18 December 2023, the general meeting of the Unit holders approved a decision resolving, *inter alia*, to approve the Partnership's participation in oil and/or natural gas exploration and production activity in the area of the exploration licenses in Zone I in the area of Blocks 4, 5, 6, 7, 8 and 11, in the EEZ of the State of Israel (in this section: the "**New Licenses**"), and to approve refrainment from the distribution of profits (as defined in Section 9.4 of the Partnership Agreement) for the purpose of investment in actions in the area of the New Licenses, in accordance with the work plans as shall be approved by the partners in the New Licenses from time to time. For further details, see the Partnership's immediate reports of 22 November 2023 and 18 December 2023 (Ref.: 2023-01-105883 and 2023-01-137334, respectively), the information appearing in which is incorporated herein by reference.

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

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

5.2. For details with respect to the total assets and liabilities of the Partnership as of 31 December 2023 and 31 December 2022, 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

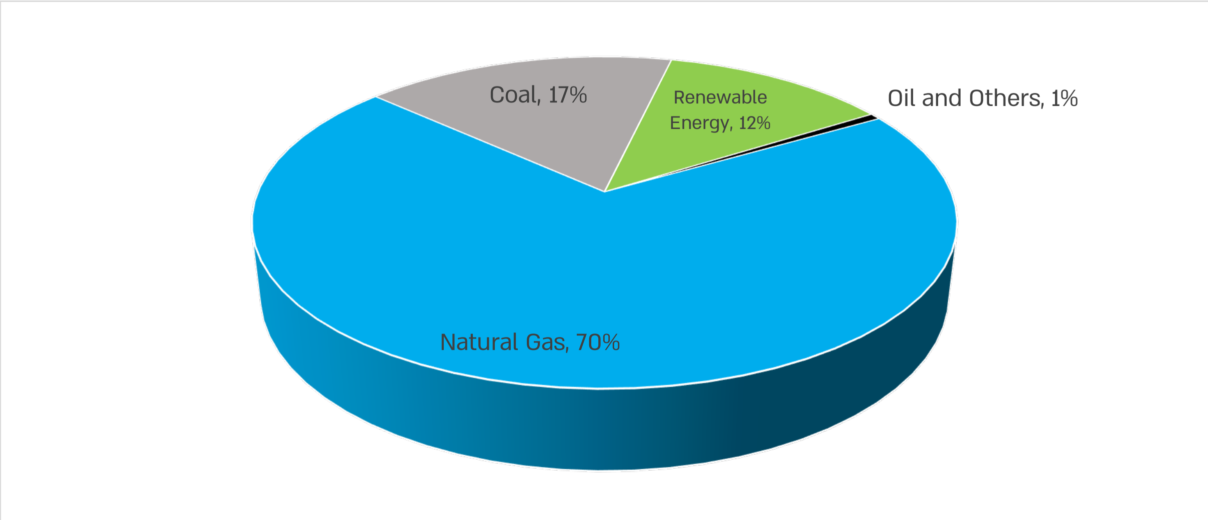
6.1. The Petroleum Law, 5712-1952 (the "**Petroleum Law**") governs the regulation in the sector of oil and natural gas exploration, development and production in Israel and determines, *inter alia*, provisions in relation to payment of royalties to the State and that oil and gas exploration activities 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 7.23.4, 7.23.5 and 7.21.2 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). The ability to export natural gas requires, *inter alia*, gas resources of considerable volumes, the grant of export permits by the Ministry of Energy and Infrastructures (the "**Ministry of Energy**") and engagement 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. The Partnership participated 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 from the Leviathan project began. In October 2022, Energean Oil and Gas Plc ("**Energean**") reported that the piping of gas from the Karish reservoir had begun. In May 2023, Energean received approval for the discovery of the Katlan natural gas reservoir, which was discovered in exploration license 12, which was granted to Energean in 2018. The Katlan reservoir is located in-between the Karish and Tanin reservoirs, and according to Energean's reports, around 68 BCM of natural gas is attributed thereto[13].

6.4. In the past two decades, the natural gas sector in Israel has undergone significant changes, which include, *inter alia*, regulatory, economic, commercial, fiscal and environmental changes. Thanks to the natural gas discoveries, the Israeli economy has become an independent economy in terms of energy. 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.



*Data Source: Analysis by BDO Consulting Group of data from Noga – Israel Independent System Operator Ltd. and the PUA-E.

6.5. According to the data of the Ministry of Energy, the volume of natural gas consumption in Israel increased from approx. 6.8 BCM in 2013 to approx. 13.7 BCM in 2023. In 2017, natural gas began to be exported, for the first time, from the Tamar reservoir to Jordan, in a limited volume, and 2020 saw commencement of the export of natural gas to Egypt from the Leviathan and Tamar reservoirs as well as the export of natural gas from the Leviathan reservoir to Jordan. According to the Ministry of Energy's publications, the export quantity has risen from 4.25 BCM in 2020 to approx. 11.6 BCM in 2023. Below is a chart presenting the growth in the gas quantities consumed in the

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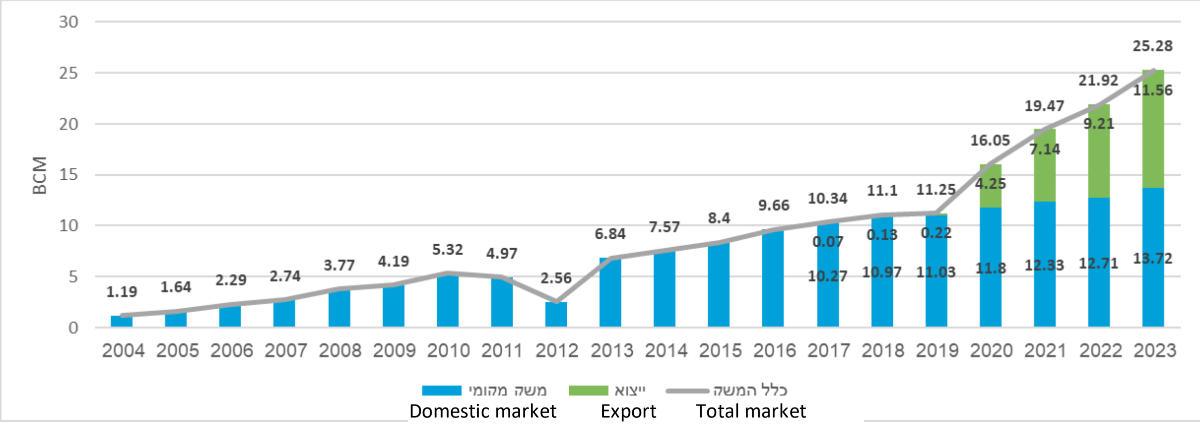
[13] The Ministry of Energy, new natural gas discovery Katlan in Israel's waters, 31 May 2023, https://www.gov.il/he/departments/news/news-310523.

domestic market and the gas quantities supplied for export, based on Ministry of Energy reports[14].



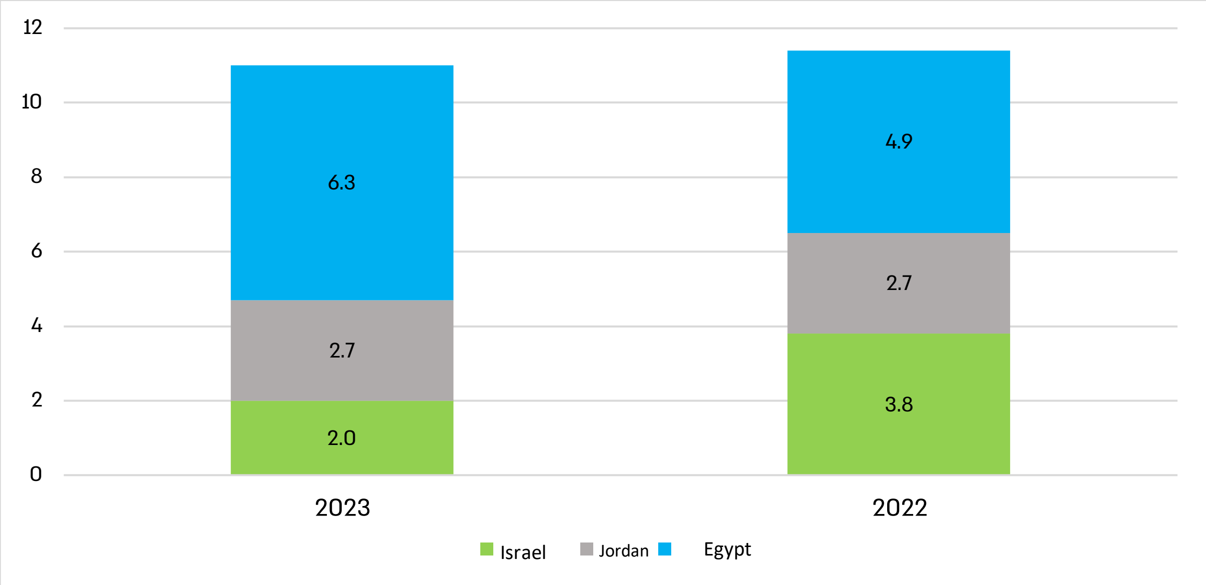
6.6. The following table presents the sales figures for the years 2022-2023, broken down by the various gas suppliers and categorizing sales under domestic market and export, based on Ministry of Energy reports[15] summed up and computed based on Ministry of Energy data and methodology due to which there may be differences between the figures in the following table and the figures reported by the various gas suppliers, including the Partnership:

	2023			**2022**		
	Domestic Market	Export	Total	Domestic Market	Export	Total
Leviathan	2.19	9.00	11.19	3.80	7.66	11.46
Tamar	6.61	2.56	9.17	8.60	1.56	10.16
Karish-Tanin	4.92	-	4.92	0.29	-	0.29
Offshore Buoy *(as specified in Section 7.14.3 below)*	-	-	-	0.05	-	0.05

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, and in 2023, approx. 2 BCM of natural gas was supplied from the Leviathan reservoir to the domestic market and approx. 2.7 BCM and approx. 6.3 BCM to Jordan and Egypt, respectively, as specified in the graph below.

[14] https://www.gov.il/he/departments/publications/reports/ng-overview
https://www.gov.il/he/departments/publications/reports/income_reporte

[15] See Footnote 14, *supra*.



6.7. A report released by the Ministry of Energy on 24 January 2024, which reviews developments in the natural gas market and provides a summary for 2022, presented a breakdown of consumption of natural gas produced in 2022 (in BCM) between the domestic market and the export markets, and according to the different uses:

Export to Egypt*	Export to Jordan*	Export	Distribution Network Only	Industry (incl. Distribution)	Electricity Production	Domestic Market	Economy-Wide	Years
5.81	3.40	9.21	0.353	2.61	10.10	12.71	21.92	**2022**
4.23	2.91	7.14	0.299	2.62	9.71	12.33	19.50	**2021**
2.16	2.09	4.25	0.254	2.51	9.29	11.8	16.11	**2020**
0	0.22	0.22	0.262	2.22	8.81	11.03	11.28	**2019**
0	0.13	0.13	0.194	1.89	9.08	10.97	11.13	**2018**
0	0.07	0.07	0.160	1.73	8.54	10.27	10.35	**2017**
0	0	0	0.106	1.62	8.04	9.66	9.66	**2016**

6.8. 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 nearly double, *inter alia*, given the connection of future gas suppliers to the national transmission system, the Government’s policy with regard to a gradual discontinuation of electricity production using coal by the middle of the current decade, 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), increased use of compressed natural gas ("**CNG**") 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 function of the distribution system, 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 7.23.10 below.

6.9. **<u>The Iron Swords War</u>**

6.9.1. Since the War broke out on 7 October 2023, thousands of rockets have been fired from the Gaza Strip mainly into the south and center of the State of Israel. At the same time, as the fighting has progressed, the terrorist organization Hezbollah has escalated the tension on the Israel-Lebanon border and initiated combat operations against Israel. Consequently, and in view of the possibility of expansion of the War on the northern border and other fronts, the IDF mobilized hundreds of thousands of reservists, communities located close to the frontlines on the southern and northern borders were evacuated, and the Home Front Command is periodically limiting the activity of workplaces and educational institutions. As of the report approval date, the Israeli economy has resumed normal operations under the shadow of war, most of the restrictions imposed by the Homefront Command upon the breakout of war have been lifted, and most of the people called for reserve duty by emergency decrees have been discharged and gone back to their homes.

6.9.2. Shortly after the War broke out, the Houthi rebel movement, which controls parts of Yemen and is supported by Iran, began attacking and launching missiles and UAVs at Israel and at vessels and tankers sailing near the shores of Yemen in the Red Sea. The Houthi rebels' said hostile activity is causing disruptions to the maritime trade routes to Israel and other countries, and is impacting maritime shipping prices and may also impact energy product prices.

6.9.3. Following the War, in October 2023, the credit rating agencies Moody's and Fitch announced that they were considering a possible downgrade of the credit rating of the State of Israel. The credit rating agency S&P

Global Ratings also announced a downgrade of the credit rating outlook of the State of Israel from stable to negative, while leaving the current credit rating unchanged. Further thereto, on 10 February 2024, the credit rating agency Moody's announced a downgrade of the State of Israel's credit rating by one notch to A2, stating that Israel's credit rating had been placed on an additional Negative Rating Watch, and that the main motive for the downgrade is Moody's estimations that the continued war, its extensive effects and ramifications, materially increase the political risk in Israel and weaken the executive branch and the legislature, and the financial robustness in the foreseeable future, adding that the negative forecast derives from the additional existing risks, particularly the risk of escalation vis-à-vis the Hezbollah terrorist organization in the north which could potentially harm the economy much more significantly than now. Further thereto, other rating agencies may possibly also publicize negative rating actions about the Israeli economy in the future.

6.9.4. With the outbreak of the War on 7 October 2023, as aforesaid, the Tamar Partners halted gas production from the Tamar reservoir following an order received by the operator from the Ministry of Energy. Gas production from the Tamar reservoir was resumed on 13 November 2023. Production from the Leviathan and Karish reservoirs continued as usual, without interruption. However, as a result of the halting of production from the Tamar reservoir as aforesaid, the Leviathan Partners supplied natural gas also to a number of customers of the Tamar reservoir in the domestic market, and mainly to the IEC, and as a result, the quantity of natural gas allocated for export to Egypt was reduced. At the same time, due to the War, the transmission of gas through the EMG pipeline had been discontinued, and was resumed on 14 November 2023. During this period, the entire gas supply to Egypt was piped via the Jordan-North Export Pipeline and the Jordanian transmission system. Transmission of the gas to Egypt in this manner entails additional transmission costs. As a consequence of the aforesaid, the total gas quantity supplied to Egypt in October and November 2023 was around 84% of the contract quantity of gas that the Leviathan Partners were obligated to supply according to the export agreement.

6.9.5. Since the outbreak of the War, and until the report approval date, production from the Leviathan reservoir has continued as usual, such that the Partnership's revenues and profitability have not suffered a material adverse effect. However, as a result of the War, the operating expenses entailed by gas production have increased by an immaterial rate, mainly due to the difficulty experienced by foreign companies in sending work teams to the region, which has led to a rise in the rates paid and to a need for additional logistics to transport manpower and equipment. In addition, scheduled maintenance actions have been delayed, changed and adapted.

6.9.6. In addition, as a result of the War, there has been a delay in several projects being promoted by the Leviathan Partners, as follows:

(a) Work on the laying of the Ashdod-Ashkelon offshore pipeline, part of the Combined Section project. For further details, see Section 7.12.2(b)(1) below.

(b) Commencement of the piping of the condensate to Ashdod Refinery Ltd. via the pipeline of Energy Infrastructures Ltd. (PEI). For further details, see Section 7.11.4(d) below.

6.9.7. As of the report approval date, significant uncertainty exists, making it impossible to estimate how the War will develop and whether it will expand to additional fronts, how long it will be, and what its results and repercussions will be. Under these circumstances, it is impossible to estimate the chances of materialization of the risk factors arising from the War and their possible effect, including the specific risk factors specified in Section 7.29.1 below, whose materialization could have a material adverse effect on the Partnership, its assets and its business.

Caution concerning forward-looking information - The Partnership's estimates specified above, including in relation to the potential impact of the War on the Partnership, are forward-looking information as defined in the Securities Law. These estimates may not materialize, in whole or in part, or may materialize differently, including significantly differently than expected, mainly due to the considerable uncertainty at this time, including with respect to the War's duration, scope, and its repercussions for the Israeli economy, and also due to the occurrence of events beyond the Partnership's control.

For further details regarding the demand for natural gas and other energy products, see Section 7.1.4 below.

6.10. **<u>The principal external factors that affect this sector are</u>**:

6.10.1. <u>Fluctuations in linkage components in the formulas of natural gas prices</u>

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**")[16]. Natural gas sale agreements include floor prices, with the exception of agreements in which the price is fixed. Therefore, the Partnership's exposure to fluctuations in the Linkage Components in such agreements is primarily 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 7.29.3 below.

6.10.2. Regulation

The sector of exploration, development, production, transportation and decommissioning of oil and natural gas assets 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, competition law, 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 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 7.23 below.

6.10.3. 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, 7.12 and 7.15 below.

[16] 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.

7. Description of the Partnership's Business by 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

Operations of exploration, development, production, transportation and decommissioning of natural gas and oil facilities and reservoirs (in this section: the "**Operations**") are complex and dynamic operations, entailing substantial costs and considerable uncertainty with respect to costs, timetables, the presence of and the ability to produce oil or natural gas while protecting the environment and maintaining cost effectiveness. As a result, despite considerable investments, exploration activities, including exploration and appraisal wells, often fail to achieve positive results and fail to generate any revenues and may lead to the loss of most or all of the investment within a relatively short amount of time.

The Operations 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 7.25.6 below).

The Operations 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 adoption of 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 of the field facilities after the reservoir is depleted, and after weighing various technical, economic and regulatory parameters. Decommissioning actions 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 aforesaid stages are not necessarily exhaustive of all of the stages of the Operations in a specific project, which may include, due to its quality and nature only some of the these 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 in the target markets. There is great difficulty in developing a project of significant scope when the demand for and prices of natural gas do not economically justify the costs of development of the project, as stated below, and/or 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, *inter alia*, since 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, due to material changes in the regulation and market conditions, commercial reservoirs, and vice versa.

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

For details, see Section 7.23 below.

7.1.3. 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 7.11.3 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 LNG markets in Europe and in Asia, subject to restrictions on gas export, as specified in Section 7.23.8 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 7.12.2(k) and 7.12.2(l) below. It is noted in this context that on 15 June 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**").[17] 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.

The Partnership is also examining and promoting possibilities for investing in renewable energy projects, in the context of the collaboration with Enlight, as specified in Section 7.9 below. In addition, the Partnership is conducting an initial examination of hydrogen production options and, *inter alia*, blue hydrogen produced from natural gas.

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

7.1.4. Factors affecting the price of and demand for natural gas and other energy products

General

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 closure and/or conversion to natural gas use of coal-fired power plants.

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 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 by pipeline from Russia to the European market and replacement thereof by LNG cargos.

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 2023, the increase in the levels of global demand for LNG continued and according to estimations amounted to approx. 404 million tons (approx. 557 BCM), reflecting an increase of approx. 1.7% versus the consumption in 2022. According to estimations, LNG demand is expected to grow by more than 50% until 2040, as a result, *inter alia*, of a transition to use of natural gas instead of coal in China and in South Asian countries, and increased demand for LNG in Europe and in South-East Asian countries.[18]

At present, Australia, Qatar and the United States are the world's largest LNG exporters, and in 2023 they provided approx. 60% of the global LNG supply.

The volatility in energy prices in recent years

Energy prices have been characterized, in recent years, by high volatility, mainly as a result of global changes and events. Following the outbreak of the Covid pandemic, which led, in H1/2020, to a decline in economic activity, a decrease was recorded in this period 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. In 2021, with the global recovery of the economic activity, the global energy sector experienced 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. This increase derived, *inter alia*, from growth in the demand in Europe and the European reliance on increased natural gas import, with an emphasis on LNG import, and from China’s entry into the global 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 onshore production capacity in Europe.

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

[18] The figures are based on a report published by Shell in February 2024 - https://www.shell.com/energy-and-innovation/natural-gas/liquefied-natural-gas-lng/lng-outlook-2024.html

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.

Following the Russian army's invasion of Ukraine in early 2022, 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, concurrently with the existing Nord Stream 1 pipeline, discontinuation of some collaborations 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 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.

In 2022, the war in Ukraine led to a steep and exceptional increase in the global oil and natural gas prices, with the Brent oil price peaking at over $120 per barrel in June 2022, a price significantly higher than the price environment to which the world had grown accustomed in the preceding years.

From mid-2022, a decline was recorded in the energy prices in the global markets, which 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 the effect of the weather, which was relatively mild in the winter months in Europe.

In 2023, relative stability was recorded in the Brent price fluctuations, and it is traded in a range of $70-$95 per barrel.

Below is a graph showing the Brent price in dollars from 2020:

*Graph source: Bloomberg.

The monetary policy and the inflation rate in Israel

The inflation rate in 2022 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. The price increases in Israel in the said period 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 rates.

With the aim of curbing inflation, the central banks began to increase the interest rates, including the Bank of Israel, which raised the base interest rate incrementally, from 0.1% in April 2022 to a maximum rate of 4.75% determined on 25 April 2023. At the start of 2024, the Bank of Israel, for the first time in a long time, reduced the base interest rate in the economy to 4.5%, which is the Bank of Israel interest rate as of the report approval date.

The first half of 2023 was characterized by an inflation environment that was still relatively high and exceeded the upper limit of the price stability target. However, the inflation rate subsided and inflation in Israel remained low compared with most developed economies around the world. In the second half of 2023, the inflation rate continued to subside, entering the range of the price stability target set forth in the Bank of Israel Law, against the backdrop of the restrictive monetary policy. The inflation rate in Israel in 2023 totaled approx. 3% compared with inflation of approx. 5.3% in 2022.

According to the macroeconomic forecast document released by the Bank of Israel's Research Department in January 2024,[19] the inflation rate in 2024 is expected to be 2.4%. This forecast expresses the subsiding of inflation compared with 2023, and reflects a trend which began prior to the War, impacted by global developments and the domestic monetary policy and a decline in the demand for consumption. Conversely, there may be supply interruptions as a result of the War, which may be reflected in rising prices of products and services. These restrictions include a reduced labor supply in view of the mobilization of reservists for the War, and reduced production capacity in border areas and disruptions to the supply chains. In the financial stability report for Q2/2023 published by the Bank of Israel on 31 January 2024 which focuses on an analysis of the ramifications on and risks to the Israeli economy deriving from the War, the authors stated, *inter alia*, that the scenario of the central risk to the global financial stability is that of a renewed global inflationary surge which would result in an additional monetary cutback by the central banks and possibly even in stagflation. In the aforesaid scenario, banks, including banks which are deemed as occupying key positions in many key countries, may encounter difficulties, which may also have an impact the local bank system.

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. 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.

[19] https://www.boi.org.il/73174.

7.1.5. Material technological changes

Recent decades have seen technological changes in the exploration, development, production, transportation and decommissioning of oil and natural gas facilities and reservoirs, both in the field of monitoring, collection and analysis of information, and in the drilling, development 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, and in this context invest considerable resources in reprocessing and reanalyzing 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 the resources therein, update the development plans and define new prospects. Furthermore, technologies defined as best available technologies are used, insofar as possible, in the Leviathan project in order to streamline the production system, enhance the facilities' safety and reduce their impact on the environment.

Technological changes in the natural gas production and transportation segment, such as newer and more efficient technologies for converting natural gas into LNG through an onshore or offshore liquefaction (FLNG) facility, compression into CNG and conversion of gas to liquid (GTL), may facilitate more efficient transportation and commercialization of natural gas. In this context it is noted that the Partnership is continuing to explore the possibility of building an offshore liquefaction (FLNG) facility for converting natural gas into LNG as aforesaid, as specified in Section 7.2.5(e) below.

7.1.6. Critical success factors in the field of business

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

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

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

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

(e) Success of the exploration activity.

(f) In the event of a natural gas 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 7.17 below.

7.1.8. Barriers to entry and exit

The main barriers to entry into the business sector are the need for permits and licenses for the performance of oil and natural gas exploration, development production and transmission, 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 the business sector 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 decommission all production facilities before returning the lease areas to the state, as specified in the lease deeds, the PSC in Cyprus and the relevant provisions of the law.

Furthermore, 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 alternative energy production methods have advantages and disadvantages, and they are subject to fluctuations in prices, availability, technical constraints, availability of land, etc. The transition from using one energy source to another energy source 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 7.23.10 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 7.14 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 asset:	Leviathan North. Leviathan South.
Location:	Offshore assets situated approx. 130-140 km west of the shores of Haifa.
Area:	The overall area of the two leases combined is approx. 500 km^2.
Type of petroleum asset and description of the activities permitted for such type:	Lease; Permitted activities under the Petroleum Law – exploration and production.
Original grant date of the petroleum asset:	27 March 2014
Original expiration date of the petroleum asset:	13 February 2044
Dates on which an extension of the term of the petroleum asset was decided:	-
Current expiration date of the petroleum asset:	13 February 2044
Is there an additional option to extend the term of the petroleum asset; if so – what is the possible extension period:	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 control holders 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 General Partner Ltd., is a company 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[20].
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%.

[20] To the best of the Partnership's knowledge, as of the report approval date, the rate of holdings of all of Ratio's interested parties (except holdings of institutional bodies, mutual funds and provident funds) is approx. 23.63%.

General Details with respect to the Petroleum Asset	
The total share of the holders of the equity interests of the Partnership in the aggregate investment in the petroleum asset during the five years preceding the last day of the year of the report (whether recognized as an expense or as an asset in the financial statements):	Approx. $1,374,819 thousand[21].

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

[21] The costs in the table do not include costs in respect of Leviathan's Participation (as specified in Section 7.25.5(d) below), the Combined Section (as specified in Sections 7.12.2(e)3(e), 7.12.2(e)3(f) and 7.12.2(e)3(g) below), the EMG Transaction (as specified in Section 7.25.5 below), and the construction of the Israeli transmission system up to the border between Israel and Jordan (as specified in Section 7.11.3(b) below).

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 500 BCM will be available to the domestic market in accordance with the provisions of the government resolution.[22]
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 27 March 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.

[22] For details regarding the government resolutions on export, see Section 7.23.8 below.

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

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

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

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) <u>The development plan</u>

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.

   For details regarding a draft policy document on the decommissioning of offshore exploration and production infrastructures released by the Ministry of Energy for public comment, see Section 7.23.9 below.

(n) Guarantees[23]

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

[23] 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.

guarantee in favor of the State of Israel in the amount of $50 million for each of the Leviathan Leases (and in total $100 million, while the Partnership's share is approx. $45 million) in accordance with timetables determined in advance (in this section: the "**Guarantee**"). As of the report approval date, each one of the holders of the Leviathan Leases has provided its share in the said Guarantee.

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

3. The Guarantee will serve to ensure compliance with the provisions of the lease deed and the Letters of Approval by the lease holder, to ensure payments due according to any law by the lease holder to the State for compensation and indemnification of the State and any authority thereof, for any damage, payment, loss, or expense incurred thereby, directly or indirectly, following non-compliance with the provisions of the lease deed or Letters of Approval, on time and in full, or following the revocation of a condition in the lease, its limitation or its suspension or following any action or omission of the lease holder in connection with the lease and the compliance with the conditions of the lease deed, and ensuring the payment of pecuniary 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 1 January 2021 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 ($ in thousands)[24]**	**Amount of Actual Participation in the Budget by the Holders of the Equity Interests of the Partnership ($ in thousands)**
2021[25]	• Costs in connection with the completion of Phase 1A, including activities related to asset integrity and improvement of production systems and safety. In addition, operation of the onshore condensate system, including operation of the entire Hagit site.	Approx. 35,546	Approx. 16,117
	• Planning and preliminary procurement of equipment for the Leviathan-8 well in the area of the I/14 Leviathan South lease ("**Leviathan-8**")[26].	Approx. 19,092	Approx. 8,656

[24] The amounts for the years 2021-2023 are amounts actually expended and audited in the framework of the financial statements.

[25] The costs, budgets and actions specified from 2021 do not include authorized budgets and costs in respect of (a) addition of the additional compressor (as specified in Section 7.11.3(c) below) in the sum of approx. $39.9 million (100%; the Leviathan Partners' share – approx. $27.6 million, the Partnership's share – approx. $12.5 million); (b) construction of the Combined Section (as specified in Section 7.12.2(b)(1) below) in the sum of approx. $140 million (100%; the Leviathan Partners' share – approx. $96.6 million, the Partnership's share – approx. $43.8 million); (c) construction of the Nitzana Pipeline (as specified in Section 7.12.2(b)(4) below) in the sum of approx. $29 million (100%; the Leviathan Partners' share – approx. $14.5 million, the Partnership's share – approx. $6.6 million); (d) conversion of the PEI pipeline for condensate piping (as specified in Section 7.11.4(c) below) in the sum of approx. $26.6 million (100%; the Partnership's share – approx. $12 million); (e) the FAJR+ Project (as specified in Section 7.12.2(b)(2) below) in the sum of approx. $75 million (100%; the Leviathan Partners' share – approx. $37.5 million, the Partnership's share – approx. $17 million); and (f) reservoir decommissioning costs and G&A and insurance costs.

[26] On 12 July 2021, the Leviathan Partners adopted a resolution regarding the drilling of the Leviathan-8 development and production well in the area of the I/15 Leviathan North lease. The approved budget for this project was approx. $248 million (100%; including completion and connection to the Leviathan reservoir's production system). The project ended in June 2023 upon connection of the well to the production system and commencement of gas piping therefrom, on schedule and under 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 ($ in thousands)[24]**	**Amount of Actual Participation in the Budget by the Holders of the Equity Interests of the Partnership ($ in thousands)**
	• Planning maintenance work and improvements in the subsea electricity and control systems.	Approx. 6,480	Approx. 2,938
	• (a) Examination of the development of Phase 1B and/or additional development options, insofar as required; (b) Examination of additional condensate transmission options, 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 engagement for receipt of engineering services for the performance of FEED (Front End Engineering Design).	Approx. 8,072	Approx. 3,660
	• Various additional actions, including: Continued production from the Leviathan reservoir, ongoing operation and maintenance[27], monitoring actions, update of the geological model and the flow model and formulation of a prospect for the deep targets.	Approx. 211	Approx. 96
2022	• Continued improvement of the systems and production processes, *inter alia*, by taking the necessary actions to reduce 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
	• Completion of engineering actions related to the development of Phase 1A.	Approx. 11,056	Approx. 5,014
	• Performance of maintenance work and improvements in the subsea electricity and control systems.	Approx. 6,482	Approx. 2,939
	• Drilling the Leviathan 8	Approx. 121,026	Approx. 54,873

[27] For details regarding operating costs in the Leviathan project which are attributed to the Partnership, see data on discounted cash flow attributed to the Partnership's share, as specified in the report on the resources in the Leviathan project, as defined in Section 7.2.10(a) 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 ($ in thousands)[24]**	**Amount of Actual Participation in the Budget by the Holders of the Equity Interests of the Partnership ($ in thousands)**
	development and production well and performance of subsea work as preparation for connection of the well to the production system.		
	• Continued update of the geological model and the flow model, *inter alia* according to the production and well data, and planning and preparations for drilling wells and additional supplementations, insofar as required.	Approx. 102	Approx. 46
	• Continued examination of the development of Phase 1B and/or additional development options, insofar as required, including an alternative to the export of natural gas via a subsea pipeline and/or liquefaction (including via an FLNG), *inter alia* through preparations for the performance of FEED and preparations for execution.	Approx. 13,472	Approx. 6,108
	• Examination of options for increasing the volumes of natural gas export to Egypt through onshore transmission systems. For further details, see Section 7.12.2(b) below.	Approx. 2,667	Approx. 1,209
	• Various additional actions, including: Continued production from the Leviathan reservoir, ongoing operation and maintenance[28], performance of monitoring actions, surveys, tests and review of options for specification, drilling and development of the deep exploration targets.	Approx. 102	Approx. 46

[28] For details regarding operating costs in the Leviathan project which are attributed to the Partnership, see data on discounted cash flow attributed to the Partnership's share, as specified in the report on the resources in the Leviathan project, as defined in Section 7.2.10(a) 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 ($ in thousands)[24]**	**Amount of Actual Participation in the Budget by the Holders of the Equity Interests of the Partnership ($ in thousands)**
2023	• Continued improvement of the production system on the Leviathan platform and the onshore facilities, and improvement of support systems and environmental systems, in accordance with operational and regulatory requirements.	Approx. 23,530	Approx. 10,665
	• Continued performance of maintenance work and improvements in the subsea electricity and control systems.	Approx. 6,412	Approx. 2,907
	• Completion of the Leviathan-8 well and connection thereof to the existing production system.	Approx. 54,983	Approx. 24,929
	• Conduct of Pre-FEED in a competitive process between international groups specializing in the design and construction of FLNG facilities, in the context of promoting the options for development of Phase 1B.	Approx. 36,165	Approx. 16,397
	• Conduct and completion of Pre-FEED for expansion of the production system of the Leviathan reservoir, including the setup of subsea infrastructures and incorporation of the required changes into the platform, in the context of promoting the options for the development of Phase 1B.	Approx. 21,981	Approx. 9,966
	• Conduct of surveys, design and procurement for the Third Pipeline Project (as defined in Section 7.2.5(b) below), including changes and adjustments on the platform.	Approx. 144,706	Approx. 65,610
	• Various additional actions, including: Continued production from the Leviathan reservoir, ongoing operation and maintenance[29], performance of monitoring actions, surveys, tests and review of options for specification, drilling and development of the deep	Approx. 102	Approx. 46

[29] For details regarding operating costs in the Leviathan project which are attributed to the Partnership, see data on discounted cash flow attributed to the Partnership's share, as specified in the report on the resources in the Leviathan project, as defined in Section 7.2.10(a) 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 ($ in thousands)[24]**	**Amount of Actual Participation in the Budget by the Holders of the Equity Interests of the Partnership ($ in thousands)**
	exploration targets.		
2024 forth	• Continued improvement of the production system on the Leviathan platform and the onshore facilities, and improvement of support systems and environmental systems, in accordance with operational and regulatory requirements.	Approx. 932	Approx. 423
	• Improvement of the MEG systems and produced water processing.	Approx. 13,520	Approx. 6,130
	• Conduct of a baseline gravity survey above the area of the reservoir to optimize production forecasts and assist development decision-making in the project.	Approx. 16,148[30]	Approx. 7,322
	• Completion of Pre-FEED for FLNG facility.	Approx. 11,350	Approx. 5,146
	• Completion of the Third Pipeline Project as defined in Section 7.2.5(b) below.	Approx. 426,430	Approx. 193,343
	• Continued implementation of measures to reduce pressure drops in the systems	Approx. 3,023	Approx. 1,370
	• Preparations for the conduct of FEED for expansion of the production system of the Leviathan reservoir, including the setup of subsea infrastructures and incorporation of the required changes into the platform, in the context of promoting the options for the development of Phase 1B, and execution thereof.	Approx. 69,913[31]	Approx. 31,698
	• Various additional actions, including: Continued production from the Leviathan reservoir, ongoing operation and maintenance[32], performance of monitoring actions, surveys, tests and review of options for	Approx. 102	Approx. 46

[30] As of the report approval date, the Leviathan Partners have authorized approx. $6 million out of this budget (100%; the Partnership's share - approx. $2.7 million).
[31] As of the report approval date, the Leviathan Partners have authorized approx. $19.9 million out of this budget (100%; the Partnership's share - approx. $9 million).
[32] For details regarding operating costs in the Leviathan project which are attributed to the Partnership, see data on discounted cash flow attributed to the Partnership's share, as specified in the report on the resources in the Leviathan project, as defined in Section 7.2.10(a) 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 ($ in thousands)[24]**	**Amount of Actual Participation in the Budget by the Holders of the Equity Interests of the Partnership ($ in thousands)**
	specification, drilling and development of the deep exploration targets.		
	• Adoption of a final investment decision (FID) by the Leviathan Partners for the development of Phase 1B[33].		

7.2.5. Plan for development of the Leviathan reservoir

(a) On 2 June 2016, the Leviathan field development plan was approved by the Petroleum Commissioner. This plan, which is divided into two phases (Phase 1A and Phase 1B), includes the supply of natural gas to the domestic market and for export of a total volume of up to approx. 21 BCM per year, and the supply of condensate to the domestic market (in this section: the "**Development Plan**" or the "**Plan**"). According to the Plan, a production system will be built 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 the gas and condensate processing systems will be installed. Gas will be piped from the Platform to the shore to the northern 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 will be connected to an existing fuel pipeline of Europe Asia Pipeline Co. ("**EAPC**"), which leads to the container site of PEI and from there to 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 the piping of condensate to ORL is not possible. For further details with respect to an agreement for piping condensate through the PEI pipeline to ARF, see Section 7.11.4(c) below. For further details regarding the approval of NOP 37/H and the provisions thereof as aforesaid, see Section 7.23.12 below, for further details regarding the production system of the Leviathan project and the Hagit site which includes a container for temporary storage of condensate, see Section 7.16.1 below.

[33] For further details, see Section 7.2.5 below.

(b) The Development Plan is implemented in two main phases, according to the maturity of the relevant markets, as specified below:

1. <u>Phase 1A</u> – the current stage, in which 4 first subsea production wells were drilled, a subsea production system was built, which connects the production wells with the platform, and a transmission system to the shore and related onshore facilities were built. At this point, the gas production capacity is approx. 12 BCM per year.

   On 23 February 2017, the Leviathan Partners adopted the final investment decision (FID) for the development of Phase 1A, with a budget of approx. $3.75 billion (100%). The total cost invested in the development of Phase 1A, as of 31 December 2023, is approx. $4.1 billion (100%). After a preliminary running-in period, on 31 December 2019, the piping of natural gas from the Leviathan reservoir commenced. On 1 January 2020, the sale of natural gas from the Leviathan reservoir to Jordan began, under the agreement with NEPCO (as specified in Section 7.11.3(b)1 below). On 15 January 2020, the piping of natural gas from the Leviathan reservoir to Egypt began under the agreement with Blue Ocean (as specified in Section 7.11.3(c) below).

   In June 2023, an additional fifth production well, Leviathan-8, was connected to the existing subsea production system of the Leviathan project and production began therefrom, on schedule and on budget.

   In addition, to increase the gas production capacity to approx. 14 BCM per year from mid-2025, the partners in the Leviathan project adopted a final investment decision (FID) on 29 June 2023 to carry out a project in which a third subsea transmission pipeline will be laid from the field to the platform and systems on the platform will be upgraded (the "**Third Pipeline Project**") with a total budget of approx. $568 million (100%, the Partnership's share – approx. $258 million). The Partnership intends to finance its share in the Third Pipeline project's budget from its own resources and its current cash flows.

2. <u>Phase 1B</u> – expected to include, *inter alia*, 3 additional production wells, insofar as required, related subsea systems and expansion of the platform's processing facilities to increase the system's total gas production capacity to a total of up to approx. 21 BCM per year.

As of the report approval date, the Leviathan Partners are promoting the development of Phase 1B as aforesaid, with the aim of adopting a final investment decision (FID). This plan includes the modular expansion of infrastructures for piping natural gas from the Leviathan reservoir, as aforesaid, and may also include the laying of a fourth subsea transmission pipeline from the field to the platform (the "**Fourth Pipeline**"), to allow for a maximum daily production capacity of approx. 2,350 MMCF (approx. 21 BCM per year) and supply to consumers in the domestic market and in the regional market, headed by the Egyptian and the LNG markets (for details, see Section 7.16.2 below).

(c) In the letter of approval of the Development Plan, 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 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 provided and does provide the Petroleum Commissioner with a comprehensive database that is updated from time to time, which includes, *inter alia*, data from wells, seismic products, and *inter alia* seismic surveys' reprocessing products, products of mapping and analysis of the scope and features of the reservoir , among other things, based on the seismic inversion method, reservoir models 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 and its advisors 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 resolutions with respect to natural gas export, the recoverable quantity according to the opinion of the Petroleum Commissioner is also sufficient for entry into additional export agreements required for implementation of the Leviathan project expansion plan and engagement in additional export agreements.

(d) On 21 June 2023 and 21 December 2023, the partners in the Leviathan project submitted an in-principle application to the Petroleum Commissioner to approve an increase of the volume of export of natural gas produced from the Leviathan project, according to the government resolution applicable to the export of gas from the Leviathan reservoir, via an existing and future regional pipeline or via an FLNG facility, along with an increase in the volumes of natural gas which will be piped from the Leviathan project to the domestic market. As of the report approval date, no official response to the Partnership's application has been received from the Ministry of Energy, and there is no certainty that it will be granted, and if so – on what terms.

(e) In the context of promotion of Phase 1B, the Leviathan Partners approved, in 2023 and 2024, in accordance with the Joint Operating Agreement, budgets in the sum total of approx. $44.9 million and approx. $19.9 million (100%), respectively, for performance and completion of pre-FEED of the alternatives for expansion of the Leviathan reservoir's production system, including the construction of subsea infrastructures, connection of additional production wells, and performance of the required changes on the platform. As of the report approval date, the pre-FEED stage has been completed and in the operator's estimation, the FEED is expected to commence in mid-2024.

In addition, in the said years, the Leviathan Partners approved budgets in the sum total of approx. $51.5 million and approx. $11.4 million (100%), respectively, for the performance of pre-FEED to examine the various alternatives for the export of natural gas, *inter alia*, through the construction of an FLNG facility. In this regard it is noted that in the context of exploring the option of constructing an FLNG facility, indications have been received that point to a substantial change in the estimated costs of constructing an FLNG facility, and therefore, in 2024, the Leviathan Partners intend to review additional options for constructing an FLNG facility, *inter alia*, given the possibility of modular expansion of the Leviathan project.

(f) In the estimation of the operator in the Leviathan project, before performance of the FEED, the estimated cost of Phase 1B (excluding the costs of the Fourth Pipeline and an FLNG facility, insofar as it is decided to approve the same) is approx. $2.4 billion (100%). insofar as a FID is adopted for the development of Phase 1 - Second Stage during H1/2025, the estimated timeframe for first gas production is expected between mid-2028 and mid-2029.

(g) Additional production wells will be required during the years of operation 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.

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 and the dates of completion of the engineering design phases, costs of laying the third pipeline, the estimated cost of Phase 1B and the possible start-up date of the Third Pipeline Project, 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 which are beyond the Partnership's control or which may change, 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, the possibility of 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 7.29 below.

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

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

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

Item	Percentage Pre Investment-Recovery	Percentage Post Investment-Recovery	Concise Explanation as to How Royalties or Payments are Calculated
Projected annual revenues of petroleum asset	100%	100%	
Specification of the royalties or payment (deriving from revenues post-finding) at the petroleum asset level:			
The State	(12.50%)	(12.50%)	As prescribed by the Petroleum Law, royalties are calculated according to market value at the wellhead. The actual royalty rate may be lower, as a result of the deduction of expenses in respect of the systems of gas processing and transmission up to the onshore gas delivery point. For further details, including with respect to the publication of directives on the method of calculation of the royalty value at the wellhead with respect to offshore petroleum interests, see Section 7.23.7(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[34]. 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 7.25.8(b) below.

[34] 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
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 level)	45.79%-47.15%	
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 thousands)

Item	Total share of the holders of the equity interests of the Partnership in the investment in the petroleum asset in this period (including costs for which no payments are made to the Operator)	Out of which, the share of the holders of the equity interests of the Partnership in payments to the General Partner	Out of which, the share of the holders of the equity interests of the Partnership in payments to the Operator (in addition to the reimbursement of its direct expenses)
Budget actually invested in 2021	Approx. 114,614	-	Approx. 867
Budget actually invested in 2022	Approx. 179,458	-	Approx. 1,273
Budget actually invested in 2023	Approx. 248,111		Approx. 1,744

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 31 December 2023, see current reserves, contingent resources and DCF figures report for the Leviathan Leases attached as **Annex B** to this chapter (the "**Leviathan Project Resource Report**"). 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 31 December 2019, see Section 7.2.10 of the Partnership's 2019 periodic report (the "**2019 Periodic Report**"), as released on 30 March 2020 (Ref.: 2020-01-032010), the information appearing therein is hereby included by reference. As of 31 December 2023, 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 11 February 2013 the authorities in Cyprus approved transfer to the Partnership of 30% of the rights of Chevron Cyprus in a production sharing contract dated 24 October 2008 (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 7 November 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 this section: the “**Development Plan**”), as specified in Section 7.3.11 below. In the First Amendment to the PSC, additional modifications and updates were made, *inter alia* with respect to the transfer of rights by the parties, approval of work plans and annual budgets, the method of approval of changes to plans and budgets, the method of calculation of the various expenses, changes in connection with grounds for termination of the PSC, arrangements with respect to ensuring the plugging, decommissioning and disposal of wells and facilities at the end of the term of the PSC, and more.

Further thereto, on 9 November 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. For details regarding the drilling of the A-3 Well, which was completed in July 2023, see Section 7.3.3(b) below.

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

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, 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 7.29.37 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[35].
Area	Approx. 386 km^2.
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:	7 November 2019.
Original expiration date of the petroleum asset:	7 November 2044.
Dates on which an extension of the term of the petroleum asset was decided:	-
Current date for expiration of the petroleum asset:	7 November 2044 (25 years from the date on which the license was granted).
Is there an additional option to extend the term of the petroleum asset; if so – what is the possible extension period:	Extendable by 10 more years.
The operator's name:	Chevron Cyprus
The names of the direct partners in the petroleum asset, and their direct share in the petroleum asset, and, to the best of the Partnership's knowledge, the names of the control holders of such 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

[35] The vast majority of the Aphrodite reservoir is in the area of the EEZ of Cyprus, and a few percent of its area is in the area of the 370/Ishai license (the "**Ishai 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 Ishai 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 9 March 2021, the aforesaid governments signed an MOU instructing the partners in the Aphrodite reservoir and the holders of the interests in the Ishai License to conduct direct negotiations to regulate the issue of the overflow of the Aphrodite reservoir, which includes principles and timetables for the conduct of the negotiations. Since the parties failed to reach agreements and the date determined by the then Minister of Energy of the State of Israel for the signing of an agreement lapsed, the governments of Israel and Cyprus began negotiations for the distribution of the profits between the parties and between the countries. On 11 April 2022, the Israeli Ministry of Energy announced that the Israeli and Cypriot ministers of energy had agreed on the appointment of an external expert to examine the quantity of natural gas in the reservoir and determine the division between the EEZs of Israel and Cyprus. See: https://www.gov.il/he/departments/news/press_110422. To the best of the Partnership's knowledge, on 29 January 2024, talks were held between the Israeli and Cypriot ministers of energy, in which it was agreed to intensify the inter-government efforts to resolve the issue as soon as possible.

General details about the petroleum asset	
	energy company engaged in all fields of activity of the gas and oil industry, which is active in more than 70 countries worldwide[36]. ▪ 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:	22 January 2009. On 11 February 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.
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. $47,228 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:

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 complete the drilling was deferred as aforesaid until August 2023. For details regarding the drilling of the A-3 Well, see paragraph (b) below.

2. Completion of the 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).

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

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 deadline for adoption of a final investment decision (FID) being 6 years from the date of receipt of the Production License, namely by November 2025. For further details regarding the milestone for execution of the FEED (the "**FEED Execution Milestone**"), see Section 7.3.11 below.

Failure to comply with the milestones defined in the PSC will be grounds for termination of the PSC, unless resulting from "*force majeure*" (as defined in the PSC).

(b) The A-3 Well

In accordance with the terms and conditions of the PSC, on 15 September 2022, the partners approved a budget for the drilling of the A-3 Well in the sum of $130 million (100%). The A-3 Well is an appraisal well whose purpose is to corroborate the estimates of the operator and the Partnership regarding the nature and scope of the reservoir, and which is designed to be used in the future as a production well. For further details regarding the decision to drill the well, see the Partnership's immediate report of 18 September 2022 (Ref.: 2022-01-118267), the information appearing in which is incorporated herein by reference. The drilling of the A-3 Well began in May 2023 and was completed in July 2023, on schedule and on budget. For details regarding an updated report on the resources attributed to the Aphrodite reservoir, which was released after completion of the A-3 Well, see Section 7.3.12 below.

(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. The Republic of Cyprus is entitled to receive its share of the produced natural gas or oil, in whole or in part, in kind.

(d) Oil sharing

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[37]:

Average daily production (in barrels)[38]	**Price per barrel ($)**		
	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%

(e) Natural gas sharing

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 24 March 2019 (Ref.: 2019-01-023982).

2. After 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 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

[37] The oil sharing mechanism was not amended in the amendments to the PSC.

[38] The calculation is made progressively according to the brackets specified in the table.

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 (28 October 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.

(f) 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**")[39] at a rate of up to 55% of the total revenues from the gas produced and up to 49% of the total revenues from the oil produced ("**Output Designated for Expense Reimbursement Coverage**"). In case that the expenses will be higher than the **Output** Designated for Expense Reimbursement Coverage, any surplus will be carried forward to the following year until full coverage of the expenses or until termination of the PSC. An expense not covered on the PSC termination date will not be recovered.

(g) 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

[39] 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 its approval as part of the process of approval of the annual work plan under the PSC.

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.

(h) The bonuses as specified in Section 7.3.3(c) above are not included in the expenses which may be offset as aforesaid.

(i) 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.

(j) 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.

(k) 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.

(l) Termination of the PSC

Subject to specific conditions which include, *inter alia*, circumstances of force majeure, the Republic of Cyprus may terminate the PSC (and with it also the license) upon the occurrence of one of the following causes for termination: (1) Violation of the provisions of the Cypriot law and regulations promulgated thereunder; (2) Arrearage in payment to the Republic of Cyprus for 3 consecutive months; (3) after the FID milestone is reached, cessation of the development work for 6 consecutive months; (4) After production commences, 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; (5) The PSC contractor does not fulfill an arbitration decision or an expert determination issued pursuant to the provisions of the PSC; (6) An event of bankruptcy, composition with creditors, receivership of any of the partners or its parent company or any other event which will result in harm to the financial or technical abilities of any of the partners to fulfill its undertakings pursuant to the PSC; (7) Any and all other events not included in paragraph (6) above which materially derogate from the financial or technical abilities of the PSC contractor in comparison to the abilities it had on the PSC grant date and expected to result in the PSC contractor no longer having the technical of financial abilities to fulfill its undertakings pursuant to the PSC; (8) Failure to meet a milestone determined in the terms and conditions of the PSC; and (9) Non-compliance with the duty to provide the guarantees required under the terms and conditions of the PSC.

According to the PSC, upon the occurrence of one of the aforesaid causes for termination, the Cypriot government may give the PSC contractor notice of termination of the PSC, provided that the PSC contractor was given formal notice and the PSC contractor failed to remedy the breach within a 3- or 6-month remedial period in respect of causes (3) and (4) above, or seven days in respect of cause (9) above, from the notice receipt date, and other than termination pursuant to cause (6) which will take effect immediately on the notice receipt date.

The PSC sets provisions regarding the PSC contractor's right to give the Cypriot government notice with regard to disagreements pertaining to the PSC, and provisions regulating the method of settlement of disagreements in the framework of an international arbitration proceeding or, in specific cases, by way of appointment of an expert who will decide. It further sets forth that disagreements with regard to the establishment of a cause for termination of the PSC announced by the Cypriot government will be decided in the arbitration proceeding and in such case, the PSC will remain valid until a decision is issued in the arbitration proceeding.

(m) 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.

(n) 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 Regulation 22(c) 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[40].	-

7.3.5 Compliance with the binding work plan for Block 12

Up to the report approval date, the binding work plan for Block 12 was fulfilled in full, except in connection with the FEED Execution Milestone, as specified in Section 7.3.11 below.

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 1 January 2021 and the report approval date, as well as a concise description of planned activities:

Block 12 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 ($ in thousands)[41]	Amount of Actual Participation in the Budget by the Holders of the Equity Interests of the Partnership ($ in thousands)
2021	• Planning of an appraisal well which will be converted, insofar as required, into a production well.	Approx. 2,013	Approx. 604
	• Examination of options for commercialization of the natural gas from the Aphrodite reservoir.	Approx. 6,935	Approx. 2,080
	• Various additional actions, including: Geological analysis of data and update of the geological model, technical and economic analysis of the prospects in the license area.	Approx. 221	Approx. 66
2022	• Preparations for the drilling of the A-3 Well.	Approx. 11,722	Approx. 3,517
	• Examination of the possibility of	Approx. 7,076	Approx. 2,123

[40] On 2 October 2013, the Aphrodite A-2 appraisal well, which was started on 7 June 2013, was completed.
[41] The amounts for the years 2021-2023 are amounts actually expended and audited in the framework of the financial statements.

Block 12 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 ($ in thousands)[41]**	**Amount of Actual Participation in the Budget by the Holders of the Equity Interests of the Partnership ($ in thousands)**
	adopting an investment decision in relation to alternatives for the development of the Aphrodite reservoir.		
	• Various additional actions, including: Geological analysis of data and update of the geological model, technical and economic analysis of the prospects in the license area and alternatives for commercialization of the natural gas produced from the reservoir.	Approx. 195	Approx. 58
2023	• Drilling of the A-3 Well.	Approx. 85,871	Approx. 25,761
	• Update of the development plan and promotion of actions for receipt of approval from the Cypriot government.	Approx. 11,042	Approx. 3,313
	• Various additional actions, including: Geological analysis of data and update of the geological model, technical and economic analysis of the prospects in the license area and alternatives for commercialization of the natural gas produced from the reservoir.	Approx. 200	Approx. 60
2024 forth[42]	• Continued examination of alternatives for development of the Aphrodite reservoir, update and approval of the development plan, performance of pre-FEED and FEED, in preparation for FID adoption.	Approx. 20,118	Approx. 6,035
	• Various additional actions, including: Geological analysis of data and update of the geological model and technical and economic analysis of the prospects in the license area.		

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

[42] As of the report approval date, out of the said budgets, the partners in Block 12 have approved a temporary budget for 2024 in the sum of approx. $29 million (100%), that shall subsequently be updated according to agreements that shall be reached between the partners in the Aphrodite reservoir and the Cypriot government. For further details, see Section 7.3.11 below.

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. 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%	1.40%	0.93%	The parties entitled to royalties are Delek Energy, Delek Group and others that are not related parties. For further details see Section 7.25.8 below. The figures specified in this table were calculated according to the Partnership's position, whereby the

	R-factor 1	R-factor 1.5	R-factor 2	R-factor 2.5	Notes
					overriding royalties in respect of Block 12 apply to the Partnership's share in the natural gas output, i.e., after deduction of the State's share in the output (as opposed to the overriding royalties in respect of petroleum assets in Israel, which apply to the Partnership's share in the output before payment of the State's royalties under the Petroleum Law).
Rate of the effective participation of the holders of the equity interests in the Partnership, in the revenues from natural gas production	24.14%	21.25%	13.38%	8.82%	

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

7.3.9 <u>Participation rate of the holders of the equity interests of the Partnership in the exploration, development and production expenses in Block 12</u>

<u>Item</u>	**<u>Percentage</u>**	**<u>Summary explanation of how the royalties or payments are calculated</u>**
Theoretical expenses within the framework of a petroleum asset (without the said royalties)	100%	
<u>Specification of the payments (derived from the expenses) on the petroleum asset level:</u>		

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,[43] subject to certain exclusions, such as marketing activity. The 1%-4% rate pertains to exploration expenses. Such sums are for payment of the operator's indirect expenses and are in addition to the reimbursement of direct expenses paid thereto. The rate of payment to the operator decreases as exploration expenses increase.
Total actual expense rate on the petroleum asset level	101%-104%	
The share of the holders of equity interests of the Partnership in the petroleum asset expenses (indirect holdings)	30%	
Total actual share of the holders of the equity interests of the Partnership, in the expenses, on the petroleum asset level (and prior to other payments on the Partnership level)	30.3%-31.2%	
Specification of payments (derived from the expenses) in respect of the petroleum asset and on the Partnership level (the following percentage will be calculated according to the share of the holders of the equity interests of the Partnership in the petroleum asset):		
The rate actually attributed to the holders of the equity interests of the Partnership in expenses involved in the exploration, development or production activity at the petroleum asset.	30.3%-31.2%	

[43] As of the report approval date, such rate has not yet been agreed in connection with the production actions.

7.3.10 Fees and payments paid during exploration and development activity at Block 12 ($ 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[44]	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 2021	Approx. 3,678	-	Approx. 55
Budget actually invested in 2022	Approx. 6,597	-	Approx. 100
Budget actually invested in 2023	Approx. 30,370	-	Approx. 448

7.3.11 Plan for the development of the Aphrodite reservoir and the FEED Execution Milestone

The Aphrodite reservoir development plan, as approved by the Cypriot government on 7 November 2019, 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 (the "**Floating Production Facility**"), through 5 first production wells, and a subsea system for transmission to the Egyptian market (the "**Approved Plan**").

Further to the partners in the Aphrodite reservoir exploring additional development alternatives, with the aim of reducing the development costs and shortening the timeframe to commencement of production of gas from the reservoir, *inter alia* by integration with existing facilities and/or development plans of nearby assets in Egypt, on 31 May 2023 the partners submitted, for the Cypriot government's approval, an updated plan for the development of the reservoir, which includes a change to the outline of the approved development and production plan, according to which the production and processing of natural gas from the Aphrodite reservoir will be performed through the construction of a subsea pipeline and connection thereof to existing offshore and onshore infrastructure in Egypt, in lieu of the construction of a floating production facility over the reservoir, which was included in the Approved Plan (the "**Changes Plan**"). However, the Cypriot government decided not to approve the Changes Plan, *inter alia* because it is expected, according to the Cypriot government, to increase the technical and commercial complexity of development of the reservoir and is not expected to result in the advantages claimed in

[44] Including costs in respect of which no payments are made to the operator.

the Changes Plan. Therefore, the partners were required to meet the FEED Execution Milestone which was scheduled in the PSC for 7 November 2023, in accordance with the Approved Plan, including the construction of the Floating Production Facility in the area of the reservoir.

In meetings and letters exchanged with the Cypriot government, the Minister of Energy at the Cypriot government authorized the partners to submit a proposal for an optimal development plan, for his approval, by 31 March 2024, such that if and insofar as the minister approves the same, the date for meeting the milestone will be postponed, in the minister's discretion. The minister also clarified to the partners that the Republic of Cyprus reserves all of its rights under the PSC in relation to missing the Feed Execution Milestone as specified in Section 7.3.3 above. Failure to reach a milestone set in the conditions of the PSC may, subject to specific terms and conditions, confer on the Cypriot government a cause for termination of the PSC and the license.

As of the report approval date, the operator is continuing to hold discussions with the Cypriot government regarding an optimal development plan for the reservoir, including in connection with re-examination of the Cypriot government's demand to build the Floating Production Facility and in connection with the timetable for meeting the Feed Execution Milestone however, there is no guarantee that the Cypriot government will approve any changes to the details of the Approved Plan and in such a case, the government may impose sanctions against the partners in accordance with the provisions of the PSC. See Section 7.3.3(l) above for details about conditions pertaining to termination of the PSC.

In accordance with the operator’s estimation, which was provided to the Partnership and the Cypriot government, and before completion of technical-financial feasibility studies, including execution of the FEED, the estimated cost of the approved development plan, which includes the construction of a floating production facility over the reservoir, including the cost of installing the pipelines to the target markets, was estimated in 2022 at approx. $3.6 billion (100%). It is emphasized that formulating the development plan and adopting a final investment decision for development of the Aphrodite reservoir are subject, *inter alia*, to the update of the approved development plan, FEED execution, 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 precedent are fulfilled, the supply of natural gas from the Aphrodite reservoir may begin in 2028 at the earliest.

7.3.12 <u>Contingent and prospective resources attributed to the Block 12 petroleum asset in Cyprus</u>

Following completion of the drilling of the A-3 appraisal well, on 5 September 2023, the Partnership released (Ref.: 2023-01-102990) a contingent and prospective resources evaluation report, which was prepared by NSAI in accordance with the rules of the Petroleum Resources Management System (SPE-PRMS) (in this section: the "**Resource Report**"). The Resource Report relates to resources located in the area of the EEZ of Cyprus only. According to the Resource Report, as of 31 August 2023, most of the natural gas and condensate resources attributed to the Aphrodite reservoir in the area of Block 12 were proven by the A-3 Well and previous wells in the reservoir , and were therefore classified as development-pending contingent resources, while a small part of the natural gas and condensate resources attributed to the petroleum asset were not proven and were therefore classified as prospective resources. For details regarding the resources attributed to the Block 12 petroleum asset, see the Resource Report, the information appearing in which is incorporated herein by reference. Attached to this chapter as **<u>Annex C</u>** is NSAI's consent to the inclusion of the said report herein, including by way of reference, and a letter from NSAI on the absence of material changes in the said resources.

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 <u>The Yam Tethys project</u>

7.4.1 <u>Background</u>

The Yam Tethys project includes the Noa Lease, in the area of which the Noa natural gas reservoir was discovered in 1999, and the Ashkelon Lease, in the area of which the Mari B and Pinnacles reservoirs were discovered in 2000 and 2012 respectively. The production of natural gas in the Yam Tethys project began in March 2004 and was discontinued in May 2019 due to a depletion of the reservoirs.

As of the report approval date, the project's assets serve mainly for the provision of infrastructure services to the Tamar Reservoir, in accordance with an agreement signed on 23 July 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. [45]

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 are 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.

Upon receipt of all the required approvals, in 2021 the operator began decommissioning all of the project's facilities, with the exception of the platform. At the same time, a discussion is being held on possible future uses and/or the decommissioning 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 decommissioning of the facilities of the Yam Tethys project, except for the platform and the onshore terminal, as approved by the Yam Tethys partners, as of the report approval date, is in the sum of approx. $277 million (100%).

For details regarding a draft policy document regarding the decommissioning of offshore exploration and production infrastructures released by the Ministry of Energy for public comment, see Section 7.23.9 below.

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

In view of the 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 grant date of the petroleum asset:	Ashkelon Lease – 11 June 2002. Noa Lease – 10 February 2000.
Original expiration date of the petroleum asset:	Ashkelon Lease – 10 June 2032. Noa Lease – 31 January 2030.
Dates on which an extension of the term of the petroleum asset was decided:	-
Current expiration date of the petroleum asset:	Ashkelon Lease – 10 June 2032. Noa Lease – 31 January 2030.
Is there an additional option to extend the term of the petroleum asset; if so – what is the possible extension period:	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 control holders 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 1 January 2021 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 ($ in thousands)[46]**	**Amount of Actual Participation in the Budget by the Holders of the Equity Interests of the Partnership ($ in thousands)**
2021	• Commencement of plugging and abandonment of the project's production wells, and decommissioning of subsea facilities, in accordance with standards and the directives of the Petroleum Commissioner.	Approx. 141,470	Approx. 68,613
	• Various additional actions, including: Ongoing operation and maintenance, including consideration of possible uses for the existing infrastructures of the project.		
2022	• Continued plugging and abandonment of the project's production wells, and decommissioning of subsea facilities, in accordance with standards and the directives of the Petroleum Commissioner.	Approx. 106,550	Approx. 51,677
	• Various additional actions, including examination of possible uses of existing project infrastructures.		
2023	• Completion of plugging and abandonment of the project's production wells and continued decommissioning of subsea facilities, in accordance with standards and directives of the Petroleum Commissioner.	Approx. 15,906	Approx. 7,715
	• Various additional actions, including examination of possible uses of existing project infrastructures.		
2024 forth[47]	• Completion of decommissioning of subsea facilities, in accordance with standards and directives of the Petroleum Commissioner.	Approx. 3,460	Approx. 1,678
	• Conduct of asset integrity surveys in accordance with directives of the Petroleum Commissioner by 2029.	Approx. 1,500	Approx. 728
	• Decommissioning of the platform and subsea pipeline upon termination of use thereof, in accordance with standards and directives of the Petroleum Commissioner.	Approx. 109,002	Approx. 52,866
	• Decommissioning of the onshore terminal upon termination of use thereof, in accordance with standards and directives of the Petroleum Commissioner.	Approx. 8,843	Approx. 4,288

[46] The amounts for the years 2021-2023 are amounts actually expended and audited in the framework of the financial statements.
[47] As of the report approval date, out of the said budgets, the Yam Tethys partners have approved a budget for completion of the decommissioning of subsea facilities, as specified in the above table.

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 ($ in thousands)[46]**	**Amount of Actual Participation in the Budget by the Holders of the Equity Interests of the Partnership ($ in thousands)**
	• Various additional actions, including examination of possible uses of existing project infrastructures.		

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 16 August 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 26 December 2016, the transaction was closed and all of the interests (except in relation to the export of natural gas from Israel) in the leases were transferred to Energean Israel. For details regarding the aforesaid agreement, see Section 7.25.9 below.

As of 31 December 2023, 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.[48] 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 km².
Type of petroleum asset and description of actions permitted according to this type:	Lease; Actions permitted under the Petroleum Law – exploration and production.
Original grant date of the petroleum asset:	24 December 2015, valid since 11 August 2014 (amended on 25 April 2017)
Original expiration date of the petroleum asset:	10 August 2044
Dates on which an extension of the term of the petroleum asset was decided:	-
Current date for expiration of the petroleum asset:	10 August 2044
Is there an additional option to extend the term of the petroleum asset; if so – what is the possible extension period:	By 20 additional years, subject to the Petroleum Law.
The operator's name:	Energean Israel.
The names of the direct partners in the petroleum asset,	Energean Israel (100%).

[48] 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%; the Aphrodite project – 13.6%; overriding royalty from the Tanin and Karish Leases – 10.88% (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	
and their direct share in the petroleum asset, and, to the best of the Partnership's knowledge, the names of the control holders of such partners :	

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.
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.[49]

In 2018, Energean adopted a Final Investment Decision for development of the Karish reservoir through a floating production storage facility (FPSO). On 26 October 2022, Energean reported production of first gas from the Karish reservoir and on 28 October 2022 began to sell gas to its customers.

According to data released by the Ministry of Energy, in 2022, Energean marketed 0.29 BCM of natural gas produced from the Karish field. According to Energean's report of January 2024, in 2023, the Karish

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

reservoir produced approx. 4.4 BCM. Energean also reported that production of first gas from the Karish North reservoir started at the end of February 2024.[50]

Furthermore, to the best of the Partnership's knowledge, the current data on the resources attributed to the Tanin, Karish and Karish North reservoirs were reported by Energean in March 2023[51]. According to this report, the said reservoirs contain approx. 99.6 BCM of natural gas reserves (2P) and approx. 95.6 million barrels of hydrocarbon liquids.

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 Disputes with Energean

(a) For details regarding a dispute with Energean which ended in November 2023 regarding payment of the balance of the consideration for the sale of the rights to Energean, see Section 7.26.8 below.

(b) Letters have been exchanged between Energean and the Partnership regarding claims raised by Energean with respect to the Partnership's rights 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. By the report approval date, Energean had paid the Partnership royalties for the condensate produced from the Karish Lease, under protest.

[50] www.energean.com/media/5742/karish-north-and-second-gas-export-riser-online-and-new-gspa-signed.pdf.

[51] Link to Energean's notice: https://www.energean.com/media/5400/dm-final-report-energean-israel-2022ye.pdf.

According to Energean's reports, production of first gas from the Karish North reservoir began at the end of February 2024.

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 1 January 2021 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 Activities Actually Performed for the Period or of the Planned Work Plan	Total Estimated Budget for Activity at the Petroleum Asset Level ($ in thousands)	Amount of Actual Participation in the Budget by the Holders of the Equity Interests of the Partnership ($ in thousands)
2021	• Adoption of an FID for development of the Karish North reservoir and for production and installation of a second export riser, and a second fluid processing facility.		
	• Continued work on installation of 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 processing systems on the FPSO hull in Singapore.		
	• Departure of the FPSO, with its systems, to Israel.		
	• Completion of the connection and running-in of the production systems.		
	• Commencement of commercial production from the Karish Lease, ongoing operation and maintenance.		
	• Drilling of appraisal and development well in the Karish Lease and completion of the Karish North-1 well.		

Tanin and Karish 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 ($ in thousands)**	**Amount of Actual Participation in the Budget by the Holders of the Equity Interests of the Partnership ($ in thousands)**
2023	• Installation of a second export riser which connects the production facility to the export pipeline.		
	• Continued commercial production from the Karish Lease, ongoing operation and maintenance.		
	• Connection of the production well in Karish North to the FPSO.		
2024 forth	• Commencement of Production from the Karish North well.		
	• Continued operating activities and production from the Karish lease.		
	• Installation and running-in of a second fluid processing facility.		
	• Drilling of additional production wells in the Karish Lease, insofar as required.		
	• 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 Energean's reports, 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 6 December 2022, the Partnership, jointly with Adarco Energy Limited[52] ("**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**"),[53] 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, at a rate of 25%, being granted to ONHYM in accordance with the current regulation in Morocco. On 1 June 2023, NewMed Energy UK Limited (formerly Delek Energy

[52] As the Partnership has been informed by Adarco, Adarco is a company controlled by Mr. Yariv Elbaz (a Moroccan investor) and his family members.

[53] In practice, the License includes the areas of 17 different licenses.

Limited), a subsidiary incorporated in England, wholly-owned by the Partnership ("**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 years, subject to compliance with a work plan, which may be extended in the event of a 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 existing 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 2 January 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.

In December 2022, the Partnership provided a bank guarantee in the sum of approx. $1.75 million (100%) in favor of ONHYM.

The License is situated 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.

In the event that the Agreements are approved by Government of Morrocco 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, assuming that the Agreements are approved and the interests in the petroleum asset are granted.

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.
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 an extension of the term of the petroleum asset was decided:	-
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;
Is there an additional option to extend the term of the petroleum asset; if so – what is the possible extension period:	There is a possibility of applying for a special extension in a case where hydrocarbons are found and additional time is needed to examine economic viability.
The name of the operator:	The Partnership.
The names of the 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 purchased petroleum asset – the purchase 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.
The actual share of the revenues from the Petroleum Asset attributed to the holders of the Partnership's equity interests:[54]	Pre investment recovery date – 34.5%. Post investment recovery date – 32.63%.
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 (whether recognized as	-

[54] 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 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).

General Details with respect to the Partnership's Share in the Petroleum Asset	
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:

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 2D+3D seismic data and environment, social and government ("**ESG**") work.	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 Boujdour 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. Grant of the Boujdour license is subject to approval from the Ministry of Energy and Sustainable Development and the Ministry of Finance of Morocco, as specified above.

7.7 **Exploration licenses in Zone I in the area of Blocks 4, 5, 6, 7, 8 and 11 in the EEZ of the State of Israel (the "Zone I Licenses")**

7.7.1 Background

On 29 October 2023, the Petroleum Commissioner gave the Partnership, the State Oil Company of Azerbaijan Republic ("**SOCAR**"), and BP (in this section, collectively, the "**Partners**"), a notice of winning of the bid they submitted in connection with the Zone I Licenses, as part of the fourth competitive process for natural gas exploration in the northwest area of Israel's EEZ, entitling them to receive 6 exploration licenses in blocks 4, 5, 6, 7, 8, and 11, located in the Mediterranean Sea, in the area of Israel's EEZ (in this section: the "**Licenses**").

The Partners are continuing to comply with the terms and conditions of an agreement which regulated, *inter alia*, the terms of the said bid and also determined principles for the joint operating agreement which is expected to be signed after the Licenses are granted.

Completion of the process of issuance of the Licenses to the Partners, in accordance with the provisions of the Petroleum Law, the regulations and the terms and conditions of the competitive process, is subject, *inter alia*, to the provision of a guarantee in the sum of $5 million (100%) and payment of a signature bonus to the Ministry of Energy in the sum of approx. $5 million (100%), by 28 December 2023.

On 18 December 2023, the general meeting of the Unit holders approved the Partnership's participation in oil and/or natural gas exploration and production in the area of the Licenses.

Accordingly, in December 2023, the Partners provided the guarantee and paid the signature bonus, as aforesaid.

In the Partnership's estimation, the process of issuance of the Licenses to the Partners is expected to be completed during Q2/2024.

Presented below are further details regarding the Licenses. As of the report approval date, the Partnership deems the Licenses as a negligible petroleum asset relative to all of the Partnership's operations and assets, and therefore a brief description of the Licenses is presented below, in accordance with the disclosure format required with respect to a negligible petroleum asset. It is further noted that the description below is based on the assumption that the Licenses will be issued to the Partners, as stated in the notice of the win.

7.7.2 General Details

General Details with respect to the Petroleum Asset	
Name of the petroleum asset:	Zone I (Blocks 4, 5, 6, 7, 8, and 11).
Location:	The northwest area of Israel's EEZ in the Mediterranean Sea.
Area:	The total area of the License zone is 1,677 km^2.
Type of petroleum asset and description of the permitted activities according to such type:	The petroleum asset includes 6 licenses, in accordance with the provisions of the Petroleum Law. A license grants its holder, subject to the provisions of the Petroleum Law: (1) A right to explore for petroleum in the license area; (2) A right to conduct, to the extent and under the conditions determined by the Director, exploration activities outside of the

General Details with respect to the Petroleum Asset	
	license area, which establish the prospects of finding petroleum within the license area; and with regards to such right, the license holder will be deemed as a preliminary permit holder; (3) A unique right to drill exploration wells and development wells in the license area and to extract petroleum therefrom; and (4) A right to receive a lease after making a discovery in the license area.
Original grant date of the petroleum asset:	Not yet granted.
Original expiration date of the petroleum asset:	3 years from the grant date.
Dates on which an extension of the term of the petroleum asset was decided:	-
Current expiration date of the petroleum asset:	3 years from the grant date.
Is there an additional option to extend the term of the petroleum asset; if so – what is the possible extension period:	In accordance with the provisions of the Petroleum Law, the license may be extended up to 7 years from the original grant date, with the possibility of an extension of up to two additional years in the event of a discovery.
The name of the operator:	SOCAR.
The names of the 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 – 33.33%; ▪ SOCAR – 33.34%, to the best of the Partnership's knowledge, the control holder of SOCAR is the government of the Republic of Azerbaijan; ▪ BP – 33.33%, to the best of the Partnership's knowledge, BP's indirect control holder is BP plc., which is a public company whose shares are traded on the London Stock Exchange as well as on the stock exchanges in Frankfurt and New York, and it has no controlling shareholder.

General Details with respect to the Partnership's Share in the Petroleum Asset	
For a holding in a purchased petroleum asset – the purchase date:	A proportionate share (33.33%) of the signature bonus which will be paid to the State in the sum total of approx. $5 million (100%).
Description of the nature and manner of holding of the petroleum asset by the Partnership:	The Partnership will directly hold 33.33% of the rights in the license.
The actual share of the revenues from the petroleum asset attributed to the holders of the Partnership's equity interests:	The interests of the Partnership in the petroleum asset are subject to the payment of royalties to the State of Israel and to royalty interest owners which include, *inter alia*, Delek Group, as specified in Section 7.25.8 below. Below is the actual share attributed to the holders of the Partnership's equity interests in the revenues from the petroleum asset, net of the royalties: Before the investment recovery date – 27.66%; After the investment recovery date – 26.00%.
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 (whether recognized as an expense or as an asset in the financial statements):	-

7.7.3 Actual and planned work plan for the Licenses

Below are details regarding the planned actions in the petroleum asset and the costs in respect thereof (100%), as included in the bid submitted by the Partners in the competitive process. According to the terms and conditions of the said process, these actions constitute the binding work plan for the petroleum asset:

The Licenses			
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 ($ in thousands)**	**Amount of Actual Participation in the Budget by the Holders of the Equity Interests of the Partnership ($ in thousands)**
2024-2026	• Purchase, performance and processing of seismic surveys and additional work.	Approx. 25,000	Approx. 8,333

Caution regarding forward-looking information – The Partnership's estimate regarding the planned actions, including regarding the estimated costs, the timetables and the mere performance thereof, constitutes forward-looking information within the meaning thereof in the Securities Law, which is based, *inter alia*, on estimations of the Partnership with respect to components of the work plan, as agreed between the Partners prior to submission of the bid in the competitive process. The actual execution of the work plan, including the timetables and the costs, may be materially different to the estimates specified above, and is contingent, *inter alia*, on market conditions, regulation, many external circumstances, technical needs, technical capability, and economic merit.

7.8 Discontinued operations

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

7.8.1 Eran License

In the past, the Partnership held approx. 22.67% of the interests in the Eran License, which expired on 14 June 2013. Following the decision of the Petroleum Commissioner not to extend the Eran License, on 3 October 2013, the Partnership and the other interest holders in the Eran License submitted an appeal to the Minister of Energy from the decision of the Petroleum Commissioner as aforesaid. On 10 August 2014, the Minister of Energy denied the appeal. On 17 November 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 2 June 2016, the High Court of Justice entered a decision on the parties' agreement to defer to a mediation proceeding as proposed thereby. With the parties' consent, (Ret.) Chief Justice of the Supreme Court, A. Grunis, was appointed as mediator. At the end of the mediation proceeding, the parties reached agreements that were established in a mediation arrangement. On 20 March 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 holding rate in the license). On 11 April 2019, a judgment was entered on the mediation arrangement agreed to by the parties, as aforesaid. Negotiations are conducted between the Tamar Partners and the State of Israel and the holders of the interests in the Eran License, regarding the manner of regulation of the rights of the State and the holders of the interests in the Eran License on other 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.

7.8.2 **Alon D license**

In the past, the Partnership held approx. 53% of the interests in the Alon D license, which expired on 21 June 2020, after the partners' applications for extension thereof were denied by the Petroleum Commissioner. On 26 November 2023, the Supreme Court, sitting as the High Court of Justice, dismissed a petition filed by the partners in the license against the Minister of Energy and others in connection with their interests in the Alon D license, ruling that the petitioners were not entitled to extension or renewal of the license.

Against the backdrop of the expiration of the Alon D license, the Partnership and Chevron (in this section: the "**Bidders**"), which were the partners in the license, submitted a bid in a competitive process announced by the Ministry of Energy on 23 June 2020 for the grant of a natural gas and oil exploration license in Block 72 the area of which shares a significant overlap with the area where the Alon D license extended ("**Block 72**"), which scored the highest. Further thereto, on 10 January 2021, the Concentration Committee announced its recommendation not to allow the Bidders to win the competitive process in view of competition in the natural gas sector and economy-wide concentration considerations. Consequently, the Bidders applied to the Petroleum Commissioner requesting that the recommendation of the Concentration Committee not be taken into account as it is deficient, inaccurate and disregards material facts. As of the report approval date, the Commissioner's decision on the competitive process with respect to Block 72 has not yet been received. Part of Block 72 is located in an area in which the exploration rights have been transferred to Lebanon in the context of the Maritime Agreement with Lebanon, as specified below.

The Maritime Agreement with Lebanon

On 27 October 2022, Government Resolution no. 1906, ratifying the agreement for regulation of the maritime border between Israel and Lebanon (the "**Maritime Agreement**"), was published. On the same date, 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 Block 72. Further thereto, the State of Israel and the consortium of international companies that hold the exploration license in block 9 in Lebanon, which borders Block 72 in Israel, signed an MOU relating to Israel's economic interests in the event of a discovery in block 9. To the best of the Partnership's knowledge, in October 2023, the consortium reported that in the first well that was drilled in the area of block 9, no commercial discovery was made.

7.8.3 **Tamar project (Tamar Lease (I/12) and Dalit Lease (I/13))**

In accordance with the Gas Framework, on 9 December 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 of Chapter A of the Partnership's 2022 periodic report, which was released on 28 March 2023 (Ref.: 2023-01-033096) (the "**2022 Periodic Report**"). For further details regarding the closing of the transaction, see the Partnership's immediate reports of 6 December 2021 and 9 December 2021 (Ref.: 2021-01-176682 and 2021-01-178137, respectively), the information in which is incorporated herein by reference. See also Notes 7C1 and 10E to the financial statements, which were attached to the 2022 Periodic Report.

7.8.4 **New Ofek and New Yahel licenses**

On 19 March 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"). The Partnership's interests in the New Ofek and New Yahel licenses were classified by the Partnership as negligible petroleum assets compared with all of the Partnership's operations and assets.

The New Ofek and New Yahel licenses expired on 20 June 2022. On 12 March 2024, the partners in the New Ofek License received a letter from the Petroleum Commissioner, according to which SOA is required to complete abandonment of the well by: (a) three months after expiry of the declaration of special home front conditions; or (b) 31 August 2024, whichever is earlier.

7.9 **Renewable energies**

On 13 March 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 13 March 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 21 September 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 6 September 2022 and 21 September 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.

7.10 **Products**

7.10.1 Natural Gas

The vast majority of the natural gas discovered in the reservoirs held by the Partnership is comprised of methane gas and is therefore defined as "dry", even though upon production and processing, small quantities of 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 7.12.2 below.

7.10.2 Condensate

The process of production and treatment of natural gas also produces condensate as a byproduct, 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 7.11.4 below.

7.11 **Customers**

7.11.1 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 its 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.

7.11.2 Key customers

In 2023, 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 2023 to NEPCO and Blue Ocean were approx. 27% and 58%, 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-fulfilment thereof may materially affect the Partnership's business and future revenues. The Partnership's other revenues from the Leviathan reservoir in 2023 originated from sales in Israel to independent power producers, industrial customers and natural gas marketing companies.

7.11.3 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[55].

[55] The figures in the table do not include agreements for the supply of natural gas from the Leviathan project that are on an interruptible basis.

Customer	Supply commencement year	Agreement period[56]	Total maximum contract quantity for supply (100%) (BCM)	Quantity supplied until 31 December 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. 19.1	Approx. 2.3	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. In most of the agreements the parties are not granted an option to extend the agreement period.	Approx. 4.2	Approx. 0.9	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. 10	The linkage formula is based on linkage to the Brent prices and includes a "floor price".
Blue Ocean export agreement (described in Subsection (e) below)	2020	15 years. The agreement stipulates that in the event that the purchaser does not buy the total contract quantity, the period of the supply will be extended by another two years.	Approx. 60	Approx. 16.4	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

[56] 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.

Customer	Supply commencement year	Agreement period[56]	Total maximum contract quantity for supply (100%) (BCM)	Quantity supplied until 31 December 2022 (100%) (BCM)	Main linkage basis of the gas price
					conditions determined in the agreement.
Total			**Approx. 128**	**Approx. 30[57]**	

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.

The following table includes a breakdown of the Partnership's revenues from the Leviathan reservoir in 2022-2023:

	Y2023		Y2022	
Name of Customer	**Total Revenues ($ in million)**	**% of Total Revenues**	**Total Revenues ($ in million)**	**% of Total Revenues**
Independent Power Producers				
Other	Approx. 125	Approx. 11	Approx. 217	Approx. 19
Industrial Customers and Marketing Companies				
Other	Approx. 43	Approx. 4	Approx. 69	Approx. 6
Natural Gas Export				
NEPCO	Approx. 296	Approx. 27	Approx. 325	Approx. 28
Blue Ocean	Approx. 630	Approx. 58	Approx. 533	Approx. 47

[57] The total quantity supplied from the Leviathan project until 31 December 2023 (100%) (under the agreements specified in the table, under spot agreements and under agreements that have expired) is approx. 40 BCM.

(a) <u>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</u>

1. In 2023 and until the report approval date, the Partnership signed several spot agreements for the sale of natural gas from the Leviathan project with various customers in the Israeli market. During Q4/2023, with the temporary halting of production from the Tamar reservoir following the outbreak of the Iron Swords War, the Leviathan Partners took action to sign spot agreements with all of the relevant customers in the Israeli market to ensure that there would be no shortage of natural gas on the market by means of supplying natural gas to such customers, as required.

2. 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**”). 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.

3. 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.

4. In accordance with the terms and conditions of the Gas Framework, each of the buyers under Agreements signed by 13 June 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 26 September 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 1 January 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 9 November 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.

3. On 14 April 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.

4. On 3 July 2023, the parties agreed to increase the natural gas quantities that would be supplied to NEPCO on a firm basis, temporarily and in relation to a number of months in 2023-2024, and that the minimum annual quantity that NEPCO had undertaken to take or pay for during 2023-2024 would increase accordingly. The aforesaid does not change the total supply volume under the Export to Jordan Agreement (approx. 45 BCM), as specified above.

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 26 September 2019, an agreement for the 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 transmission system from Israel to Egypt and the bearing of the investments entailed by the purchase and refurbishment of this pipeline (for further details, see Section 7.25.5(d) below). The supply of natural gas to Egypt from the Leviathan reservoir according to the agreement began on 15 January 2020.

2. Below is a concise description of the main 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 15 January 2020, will continue until 31 December 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 daily gas quantities as follows: (1) in the period commencing 15 January 2020 and ending 30 June 2020 – 200 MMCF per day (approx. 2.1 BCM per year); (2) in the period commencing 1 July 2020 and ending 30 June 2022 – 350 MMCF per day (approx. 3.6 BCM per year); and (3) in the period commencing 1 July 2022 and ending upon the conclusion of the Supply Period – 450 MMCF per day (approx. 4.7 BCM per year). Furthermore, the agreement includes provisions with respect to the possibility of piping additional gas quantities, over and above the aforesaid daily quantities, on a spot basis. For details regarding the export of gas to Egypt via the EMG pipeline and through Jordan via the Jordan-North Export Pipeline and the Jordanian transmission system, see Section 7.12.2(b) below. The export agreement prescribes provisions whereby in cases of a shortfall in the supply of the daily gas quantities in a certain month, the buyer is entitled, under certain conditions, to compensation in the form of a discount on the gas that shall be supplied thereto in the following month, at a rate determined, *inter alia*, as a function of the rate of the supply shortfall in the current month.

(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. The average Brent price in 2023, and the Brent barrel price in proximity to the report approval date, were around $80.

(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. 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. For details regarding the engagement between the Tamar Partners and Blue Ocean for export of natural gas to Egypt, see Section 7.14.1(d) below.

3. Up to 31 December 2023, the Leviathan Partners supplied the buyer with approx. 16.45 BCM for total monetary consideration of approx. $3.54 billion. On the date of signing of the Export to Egypt Agreement, the Partnership estimated that the total amount of the contract (with respect to all of the Leviathan Partners) could total approx. $12.5 billion. This estimate is based, *inter alia*, on the assumption that the buyer will 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 the actual revenues will be derived from a gamut of factors, the majority of which are beyond the Partnership's control.

4. To facilitate an increase in the export quantities to Egypt, and in view of the delay in completion of the Ashdod-Ashkelon Combined Section project, as specified in Section 7.12.2 below, the Leviathan Partners and Blue Ocean signed an amendment to the Export to Egypt Agreement, in which it was agreed, *inter alia*, to define an additional gas delivery point in Aqaba, Jordan, under the Export to Egypt Agreement, in which a certain price discount was determined as compensation to Blue Ocean for the additional transmission expenses entailed by transmission of the gas from the additional delivery point, which are borne thereby. The piping of gas to Egypt to the delivery point in Aqaba began in March 2022, and is performed through the Jordan-North Export Pipeline, as specified in Section 7.12.2 below.

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.

7.11.4 Agreements for the supply of condensate from the Leviathan reservoir

(a) General

As described in Section 7.10.2 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 15 December 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. Following the signing of the agreement with ARF (as defined below), ORL sent a letter to the Leviathan Partners whereby the engagement with ARF constitutes a breach of the agreement with ORL, an anticipated breach of the agreement and conduct in bad faith. Later, on 4 February 2024, the Leviathan Partners notified ORL that the piping of the condensate to ARF was expected to commence in March 2024, and that from that date the quantities delivered to ORL would be significantly reduced. In response to this notice, ORL sent a letter to the Leviathan Partners, according to which the Leviathan Partners' said notice constitutes a breach of the agreement with ORL. In its said letter, ORL also demanded that the Leviathan Partners provide clarification on the condensate quantities they intend to pipe to ORL. It is the Partnership's position that ORL's said claims and demands are groundless.

(c) Agreement with PEI

On 1 September 2022, Chevron (on behalf of the Leviathan Partners) and PEI signed an agreement designed to regulate an alternative mechanism for the piping of condensate from the Leviathan project via an existing pipeline with a 6-inch diameter of PEI and the systems related thereto (in this section: the "**Pipeline**"). The agreement will be in effect for 20 years from the date of commencement of the piping, subject to provisions that confer on the parties the possibility of terminating it before the end of the term, under certain conditions. According to the agreement, PEI will be responsible for planning and carrying out the work for connection and adjustment of the Pipeline for the purpose of transmission of the condensate as aforesaid (the "**Connection Work**"), and for obtaining all the approvals for the piping of condensate in the Pipeline and for the ongoing operation and maintenance of the Pipeline. Chevron (through the Leviathan Partners, according to their share in the Leviathan Leases) has undertaken to bear the costs entailed by the Connection Work in accordance with the scope and the mechanism stipulated in the agreement, in amounts that shall be agreed by the parties in advance.

Each of the parties may terminate the agreement if the closing conditions are not met within 12 months from the date of signing or if the date of commencement of the piping is not within 12 months from the date the agreement takes effect.

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

In November 2022, the Leviathan Partners approved a budget of approx. $27 million (100%) for the implementation of the agreement as aforesaid.

(d) On 1 February 2024, the Partnership was informed that all of the conditions precedent for the agreement to take effect had been satisfied, and subsequently thereto, on 7 March 2024, condensate transmission through the Pipeline commenced, in the framework of the budget, as noted above.

(e) Agreement with Ashdod Refinery Ltd. ("**ARF**")

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

1. According to the Agreement, the Sellers undertook to supply ARF with condensate produced from the Leviathan reservoir, to be piped through PEI's pipeline.

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

3. Piping of the condensate to ARF will begin on the date of commencement of piping in PEI's pipeline (in this section: the “**Piping Commencement Date**”) and continue for a period of 4 years. It is noted that condensate piping to ARF began on 7 March 2024.

4. The price payable to the Sellers is determined according to the Brent oil barrel price, net of a staggered margin, as specified in the Agreement.

5. The Sellers estimate that the total revenues that the Sellers shall derive from the Agreement could total 104approx. $200-

300 million (100%, the Partnership’s share is approx. $90-135 million), based on the Brent price level on the report approval date. It is clarified that there is no certainty with regards to the Piping Commencement Date and the scope of the revenues that the Partnership may derive from performance of the Agreement, and that the actual revenues will be derived from a gamut of factors, including the condensate quantities actually produced and sold to ARF, and the Brent prices.

Caution regarding forward-looking information – the information provided above in relation to the agreement, including in respect of 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 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.

7.12 <u>Marketing and Distribution</u>

7.12.1 <u>Supply to the domestic market</u>

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 7.11.3 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 17 December 2015 by the Prime Minister in his then-capacity as Minister of the Economy, and according to supply agreements that were signed between the customers and all of the Leviathan Partners.

7.12.2 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 7.11.3 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 an FLNG facility), as specified above and below.

(b) Export via pipeline to Egypt and Jordan

As of the report approval date, the pipeline infrastructure for export to the Partnership's customers in Egypt and Jordan includes the main systems specified below. As specified below, the gas supply capacity for Egypt via the said systems is divided between the Tamar Partners and the Leviathan Partners.

(1) The EMG pipeline, which connects between the Israeli transmission system in the Ashkelon area and the Egyptian transmission system in the el-'Arīsh area, which has served as the main export pipeline to Egypt since commencement of production from the Leviathan reservoir. For details regarding the EMG Transaction which allows the piping of natural gas to Egypt via the EMG pipeline, see Section 7.25.5 below.

In July 2020, with the operation of a compressor at the entry to the EMG system in Ashkelon, the piping capacity in the EMG pipeline, under the restrictions of INGL's existing transmission system infrastructure, was approx. 500 MMCF per day (approx. 5 BCM per year). In March 2022, the additional compressor was installed in Ashkelon, which allowed the piping capacity in the EMG system to be increased to around 600 MMCF per day (approx. 6 BCM per year). Maximum use of this capacity is contingent on the conditions of INGL's national transmission system, which may change from time to time.

To increase the transmission capacity in the EMG pipeline to around 800 MMCF per day (approx. 8 BCM per year), INGL is carrying out a project to build a new 46-km-long offshore section between Ashdod and Ashkelon (above and below: the "**Combined Section**"). The expected completion date of the project for construction of the Combined Section has been postponed several times.

For further details and for details on the transmission agreements signed with INGL, see paragraph (e) below.

For details regarding an agreement for allocation of capacity in the EMG pipeline between the Leviathan Partners and the Tamar Partners, see Section 7.25.5 below.

(2) The Jordan-North export pipeline, which connects between the Israeli transmission system and the Jordanian transmission system near the Sheikh Hussein Bridge. The construction of this export pipeline was completed in December 2019, *inter alia* through the construction of a natural gas pipeline by INGL from the Tel Kashish station to the border with Jordan, including the construction of a station near the border whose purpose is to measure the gas exported to Jordan. The follow-on pipeline on the Jordanian side was built by FAJR, the Jordanian transmission company (which is Egyptian-owned), which connects the Israeli transmission system to the existing transmission pipeline in Jordan and the Arab Gas Pipeline, and connects to the Egyptian transmission system in the area of Aqaba (above and below: the "**Jordan-North Export Pipeline**"). As of the report approval date, the total maximum gas supply capacity in the Jordan-North Export Pipeline is approx. 7 BCM per year, of which around 3.5 BCM is allocated for the NEPCO agreement. For details regarding the supply of gas to Egypt under the export agreement via the Jordan-North Export Pipeline from March 2022, see paragraph (f) below.

To increase the transmission capacity to Egypt via the Jordan-North Export Pipeline, the Leviathan Partners approved, by the report approval date, preliminary budgets prior to the adoption of a final investment decision (insofar as shall be adopted) in the sum total of approx. $37.5 million (100%), for the construction of a compressor station and additional related work in the Jordanian transmission system (the "**FAJR+ Project**"). In the operator's estimation, the FAJR+ Project's budget is estimated at approx. $335 million (in equal shares between the Leviathan Partners and the Tamar Partners, the Partnership's share is approx. $76 million). The FAJR+ Project is expected to increase the total transmission capacity in the Jordan-North Export Pipeline to approx. 10.5 BCM per year during the first half of 2026. As of the report approval date, the Leviathan Partners are acting for adoption of a final investment decision for the FAJR+ Project, which is expected to be adopted by the end of H1/2024.

(3) The Jordan-south export pipeline, which connects the Israeli transmission system in the southern area of the Dead Sea to Jordanian industrial plants.

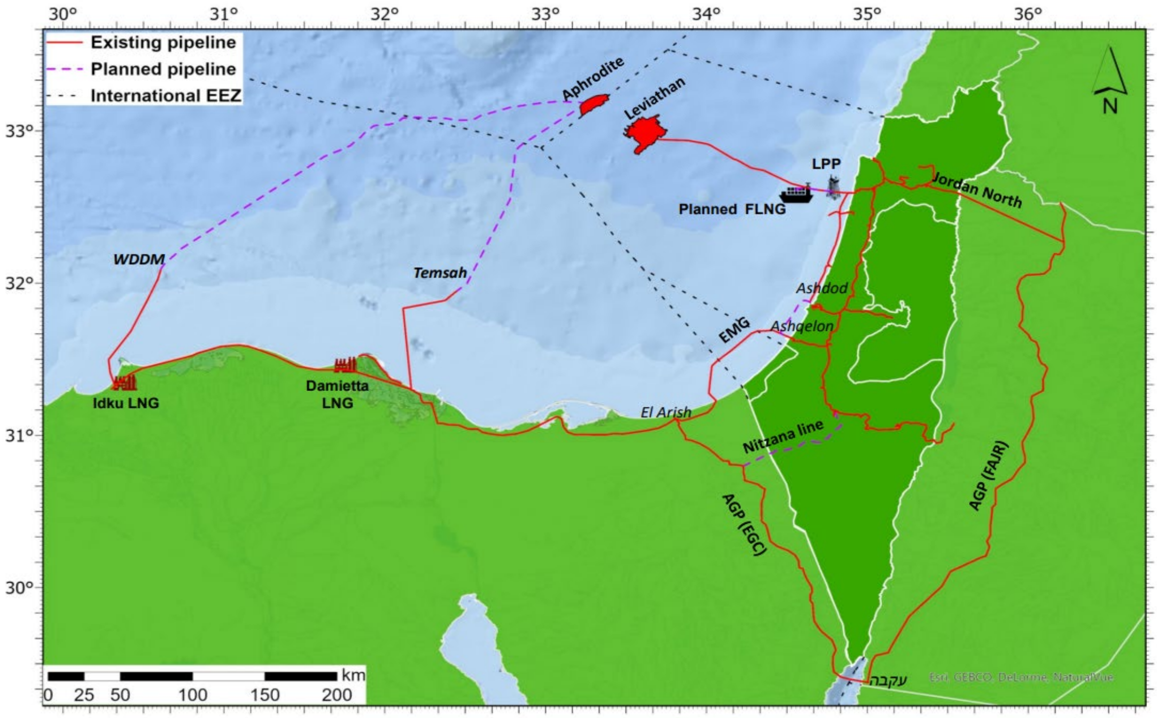
(4) As of the report approval date, the operator on behalf of the Leviathan Partners and the Tamar Partners is examining the possibility of participating in the construction of a project for a new onshore connection between the Israeli transmission system and the Egyptian transmission system in the area of Nitzana (the "**Nitzana Pipeline**"), which includes a pipeline and the construction of a compressor station in the area of Ramat Hovav. The Nitzana Pipeline (if built) will constitute part of INGL's transmission system and is expected to increase the transmission capacity to Egypt by around 6 BCM per year. For details with respect to the decision of 9 August 2023 by the Natural Gas Commission on the matter, see Section 7.23.5(f) below.

For promotion of the construction of the Nitzana Pipeline, the Leviathan Partners approved, by the report approval date, preliminary budgets prior to a commitment to participate in the funding of the Nitzana Pipeline, in accordance with the decision of the Natural Gas Commission on the matter, and prior to the adoption of a final investment decision (insofar as shall be adopted) in the sum total of approx. $14.5 million (100%). In the operator's estimation, the Nitzana Pipeline project's budget is estimated at approx. $360 million (in equal shares between the gas exporters participating in the funding; the Partnership's share is approx. $82 million). As of the date of approval of the report, the Partnership, together with the other Leviathan partners, is examining all of the commercial conditions in this project in comparison with the alternatives of other projects to increase the capacity for export to Egypt, and accordingly, will make a decision on whether and how to participate in the Nitzana project.

Below is a table summarizing the estimates of the current and possible transmission capacity of each of the transmission systems for export, and the total current and possible export capacity from the Leviathan reservoir, in BCM:

Infrastructure	Current transmission capacity	Possible additional transmission capacity	Total possible transmission capacity	Total current and possible export capacity from the Leviathan reservoir	Additional transmission capacity is contingent on:
EMG	Approx. 6	Approx. 2	Approx. 8	Approx. 6	Completion of the Combined Section
Jordan-North Export Pipeline	Approx. 7 (Approx. 3.5 to Egypt and 3.5 to Jordan)	Approx. 4 to Egypt	Approx. 11 (Approx. 7.5 to Egypt and 3.5 to Jordan)	Approx. 7.25 (Approx. 3.75 to Egypt and 3.5 to Jordan)[58]	The FAJR+ Project
Nitzana Pipeline	-	Approx. 6	Approx. 6	Approx. 3 (estimated)[59]	The Nitzana Pipeline project
Total	Approx. 13	Approx. 12	Approx. 25	Approx. 16.25	

The following map shows the system of existing and future export pipelines:



[58] The possible capacity for export from the Leviathan reservoir as noted above is in accordance with the Partnership's assessment of the estimated rate of allocation for the Leviathan project from the potential export capacity of the FAJR+ project.

[59] The possible capacity for export from the Leviathan reservoir as noted above is in accordance with the Partnership's assessment of the estimated rate of allocation for the Leviathan project from the potential export capacity of the Nitzana Pipeline project. See Sections 7.12.2(b)(4) and 7.23.5(f) below for details.

(c) The natural gas market in Jordan[60]

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. 3.9 BCM in 2023, slightly higher than in 2022. Natural gas is the main energy source for electricity production in Jordan, such that it is estimated that in 2024, approx. 70% of the electricity in Jordan will be produced by using natural gas, and approx. 30% will be produced by using renewable energies. In the Partnership's estimation, in 2024 natural gas consumption in Jordan is expected to slightly increase to approx. 4 BCM and in the next decade it is expected to range between 4 and 4.3 BCM. 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 production of electricity from the Attarat Power Plant as aforesaid. 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. 0.5 BCM in 2023 from Egypt 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. Despite Jordan's ability to import LNG, to the best of the Partnership's knowledge, no such import was conducted in 2023, *inter alia*, due to LNG prices.

(d) The natural gas market in Egypt

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 2023, approx. 90% of the electricity in Egypt was produced by using natural gas while the remaining electricity was produced using fuel oil and renewable energies. In 2023, local production in Egypt was approx. 59 BCM, a decrease of approx. 11% compared with 2022, and local demand for natural gas in Egypt in 2023 was approx. 63 BCM, an increase of approx. 3% compared with 2022. The increase in demand occurred despite a sharp drop in the local gas production ability, which, according to media

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

reports, led to deliberate power outages lasting several hours a day, which has endured since the summer of 2023, in order to cope with the shortage in natural gas for the domestic market.

In addition to the domestic demand, 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. Their operation at full capacity corresponds to natural gas quantities of approx. 19 BCM=. As of the report approval date, natural gas production in Egypt is not sufficient to fulfill the needs of the domestic market, and therefore is not sufficient for the operation of the two liquefaction facilities.

Regular LNG export is made possible by means of importing gas from Israel, as a second priority to meeting the demand in the domestic market as specified above.

According to the reports of independent consulting firms, demand forecasts for the domestic Egyptian market (excluding the liquefaction facilities) for 2024, 2025 and 2026 are approx. 62 BCM, approx. 60 BCM and approx. 64 BCM, respectively. The production of gas for Egypt has seen significant drops during the past year, over and above forecasts from previous years. The main cause is a drop in the output of significant gas fields in the Mediterranean, headed by the Zohr field, which represents approx. 35%-40% of all gas production for Egypt. Another cause for the said decrease in gas production is the prioritization of companies operating onshore for the production of oil over gas as a result of low gas prices. Local production from producing fields, either at development stages or with a high probability of production commencement, is expected to be approx. 59 BCM, approx. 56 BCM and approx. 51 BCM in 2024, 2025 and 2026, respectively. Therefore, 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. Egypt is the global leader in terms of exploration activity carried out by the industry majors, including Chevron, ExxonMobil, BP, ENI, Shell and more. 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.

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 28 May 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 via the EMG pipeline (in this section: the "**2019 Agreement**"). The payment pursuant to the 2019 Agreement was made based on the gas quantity actually 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 7.11.3(c) above, the additional compressor was installed in Ashkelon, which allowed the flow capacity in the EMG system to be increased to approx. 600 MMCF per day (approx. 6 BCM per year). Upon completion of the Combined Section, it will be possible to increase the flow capacity in the EMG system to approx. 800 MMCF per day (approx. 8 BCM per year), and given certain conditions in the Israeli and Egyptian transmission systems, even more.

3. On 18 January 2021, Chevron engaged with INGL in an agreement for the provision of transmission services on a firm

basis, which will replace the 2019 Agreement, 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 14 February 2021 (above and below: the "**Transmission Agreement**" or, in this section: the "**Agreement**"). Below is a concise description of the main terms of the Agreement, as amended from time to time:

(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.[61] 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.

(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) Under the Transmission Agreement, INGL has undertaken to construct the Combined Section, which is being carried out in accordance with the provisions of the decision of the Natural Gas Commission 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 7.23.5(e) below (in this section: the "**Commission's Decision**"), in a manner which

[61] As of the report approval date, the capacity fee and the throughput fee that INGL charges its customers total approx. ILS 0.67 and ILS 0.115 per MMBTU, respectively, according to Decision no. 2/2022 of the Natural Gas Commission dated 1 January 2024.

will allow the piping of the full quantities under the Transmission Agreement.

Piping gas under the Transmission Agreement will commence on a date to be coordinated and agreed between the parties, but no earlier than 1 July 2022 and no later than 1 April 2023 (in this section: the "**Piping Commencement Date**"), and subject to INGL's right to defer the Piping Commencement Date in the event of delay in the approval of the NOP under which the Combined Section is being constructed.

In February 2023, Chevron received a letter from INGL whereby, due to a malfunction in the vessel performing the infrastructure work for laying of the Combined Section (in this section: the "**Work**"), and further to a preliminary assessment received by INGL from the contractor performing the Work, a delay of at least 6 months was expected in completion thereof, such that the possible time frame for the Date of Commencement of Transmission had been postponed to the period from 1 October 2023 to 1 April 2024. This notice by INGL was given as a notice of force majeure under the transmission agreement, stating that its full implications were not yet known thereto at that time. In a letter of 9 March 2023 Chevron rejected INGL's claim of force majeure, until such time as information was provided about the malfunction and its effect on INGL's ability to fulfill its undertakings under the transmission agreement.

In October 2023, Chevron informed the Partnership that it had received notice from INGL whereby following the outbreak of the Swords of Iron war, the Work on the project had been suspended, and the forecast for the Date of Commencement of Transmission was about four months from the date of resumption of the Work. In February 2024, Chevron informed the Partnership that it had received notice from INGL whereby the foreign contractor performing the Work for construction of the Combined Section did not intend to continue maintaining its availability for resumption of the Work, and intended to return in August-September 2024 to complete its undertakings in the project. In view of the aforesaid, the Leviathan partners are considering the implications resulting therefrom and the possibilities available to them.

In February 2024, Chevron sent INGL a letter stating that, according to Chevron's position, the Date of Commencement of Transmission occurred on 30 April 2023 at the latest, and therefore, inter alia INGL is required to provide transmission services according to the transmission agreement starting from such date, and to reimburse Chevron for the excess transmission fees it collected from such date forth. On 26 February 2024, Chevron received a letter of reply from INGL, in which INGL rejected all of Chevron's claims and whereby the Date of Commencement of Transmission will only be possible after completion of the Combined Section. According to the position of Chevron and the Leviathan partners, this position of INGL's is contrary to the provisions of the transmission agreement. As of the date of approval of the financial statements, the parties are holding discussions in an attempt to resolve the said dispute.

(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.

(e) In accordance with the principles determined in the Commission’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 2 May 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 Commission’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 152 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 the date of expiration of the 2019 Agreement according to the terms and conditions thereof or by 1 January 2025 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 7.25.5(c) 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.

For further details regarding the Combined Section project, see Section 7.12.2(b) above.

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,[62] 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 via the Jordan-North Export Pipeline

In view of the delay in completion of the project for construction of the Ashdod-Ashkelon Combined Section, the Leviathan Partners have signed a set of agreements intended to allow the piping of quantities of natural gas to Egypt under the Export to Egypt Agreement, through Jordan, using the Jordan-North Export Pipeline. In accordance with the said set of agreements, in March 2022, natural gas piping to Egypt through Jordan began, 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

[62] For details regarding the piping of natural gas pursuant to the Export to Egypt Agreement, through Jordan, mainly until completion of the Combined Section, see Section 7.11.3(c) above and Section 7.12.2(f) below.

Ministry of Energy authorized the Leviathan Partners to add a point of delivery of natural gas to Egypt in Aqaba, Jordan. It is further noted that transmission of the gas to Egypt via the Jordan-North Export Pipeline entails additional transmission costs compared with transmission of the gas via the EMG pipeline.

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 via the Jordan-North Export Pipeline to the point of connection to the FAJR transmission system at the border between Israel and Jordan (the "**Jordan-North INGL Agreement**"). The payment pursuant to the Jordan-North 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 agreement. The term of the Jordan-North INGL Agreement was extended until 1 January 2025, unless the parties consensually extend it, subject to the decisions of the Natural Gas Authority at such time. Concurrently with the signing of the Jordan-North INGL Agreement, Chevron and the other Leviathan Partners engaged in a back-to-back services agreement in connection with the Jordan-North INGL Agreement.

4. The Leviathan and Blue Ocean partners signed an amendment to the Export to Egypt Agreement as specified in Section 7.11.3(c)4 above.

According to the Export to Egypt Agreement, the Leviathan Partners have been obligated, since July 2022, to supply Blue Ocean with 450 MMCF of natural gas per day. The piping of this full quantity via the EMG pipeline will only be possible after completion of the Combined Section, whose construction, as aforesaid, is delayed. It is noted that despite the fact that until the report approval date the piping of gas through Jordan has been conducted as planned, as the transmission agreements with INGL effective on the report approval date are for the provision of interruptible transmission services, it is not certain on the report approval date that it will be possible at all times to pipe via Jordan the full quantities that the Leviathan Partners are obligated as aforesaid to supply to Blue Ocean.

As specified in paragraph (b)(2) above, as of the report approval date, Chevron is promoting, for the Tamar and Leviathan Partners, the FAJR+ project which is designed to enable the increase of the capacity of transmission to Egypt through the Jordan-North export line.

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 the transmission agreements will allow to transmit, the estimate regarding the possibility of extending the Transmission Agreement, and the quantities that may be transmitted to Egypt, through Jordan, as well as the possibility of increasing the capacity of transmission to Egypt through the FAJR+ project, 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) <u>The natural gas market in the area of the Palestinian Authority and the Gaza strip</u>

Israel is the main source of electricity in the area of the Palestinian Authority 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 the existing power plant in the Gaza strip will be approx. 0.25 BCM per year.

As of the report approval date, due to the Iron Swords War, the negotiations that were being held by the Partnership, together with its partners in the various projects, for the supply of natural gas to the power plant in the Gaza strip have been suspended, and at this stage, there is no certainty as to whether and when they will be resumed, and under what conditions.

(h) <u>The natural gas market in Cyprus</u>

As of the report approval date, 85% 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 7.14.6(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 possibilities for connection to existing infrastructures in the Mediterranean Basin for the supply of natural gas to be processed and liquefied at one of the existing liquefaction facilities in Egypt.

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) Natural gas market in Morocco

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%) was previously supplied by gas import from Algeria via the GME pipeline. On 1 November 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 re-gasified 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. 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 MMCF per day, 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. In December 2023, Energean announced the signing of an agreement for its entry into the offshore licenses of Chariot as operator.

(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 24 September 2021, Ratio Petroleum Energy – Limited Partnership signed the Dakhla Atlantique reconnaissance license agreement.

(k) <u>Liquefied Natural Gas (LNG)</u>

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.

In 2023, the Leviathan Partners continued to explore the possibility of building an FLNG facility owned thereby located offshore and used to produce and store LNG. The costs of building an FLNG facility are affected by a broad range of factors that are beyond the Partnership's control, which change from time to time, *inter alia* as a result of the supply and demand levels in the global market. Given the receipt of indications that point to a material change in the estimation of the costs of building an FLNG facility, the Leviathan Partners intend to consider in the course of 2024 additional options for the construction of an FLNG facility, *inter alia*, in view of the possibility of modular expansion of the Leviathan project.

7.13 **Order backlog**

7.13.1 Following are data regarding the Partnership's order backlog calculated on the basis of the minimum gas quantities (according to the Take or Pay 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 2024 under supply agreements on a SPOT and an interruptible basis. 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 7.11 above will 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 7.11 above.

Period	Order Backlog ($ in millions) as of 31 Dec. 2023[63]
Q1/2024*	Approx. 204
Q2/2024*	Approx. 202
Q3/2024*	Approx. 202
Q4/2024*	Approx. 202
2025	Approx. 758
2026	Approx. 732
2027	Approx. 744
2028	Approx. 756
2029	Approx. 754
2030	Approx. 729
2031	Approx. 739
2032	Approx. 749
2033	Approx. 758

[63] 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 1 January 2024 and the report approval date.

* 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 7.29 below.

7.13.2 The order backlog from the Leviathan project for 2023, as included in the 2022 Periodic Report, was approx. $800 million. The Partnership's actual revenues from the Leviathan project in 2023 totaled approx. $1.1 billion. The difference between the order backlog figures for 2023 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 and from sales to customers in accordance with spot-based supply agreements.

7.14 <u>**Competition**</u>

7.14.1 <u>Natural gas discoveries in Israel</u>

a. The supply of natural gas from the Leviathan project is currently performed via pipeline and is designated for the domestic market and the export markets in Egypt and Jordan. 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.

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

b. Production from the Karish reservoir began in October 2022. According to Energean's report of January 2024, in the entirety of 2023 Energean produced from the Karish reservoir 4.4 BCM of natural gas, and in its estimation, the quantity of natural gas production in 2024 will be between 5.7 and 6.4 BCM. In addition, in a series of wells drilled by Energean in several licenses granted thereto in the context of competitive processes of the Ministry of Energy, several natural gas discoveries were made according to Energean's reports. On 31 May 2023, the Minister of Energy granted Energean approval for a natural gas discovery in Block 12, in several reservoirs referred to jointly as the Katlan field, to which approx. 31 BCM of natural gas reserves are attributed according to the report, and which is located in-between the Karish and Tanin reservoirs. According to the provisions of the Gas Framework, the Energean-owned Tanin and Karish reservoirs are intended for the supply of gas to the domestic market only, but this restriction does not apply to new discoveries outside the Tanin and Karish Leases. Notwithstanding the aforesaid, to the best of the Partnership's knowledge, Energean is working on obtaining a permit for the export of natural gas from the Karish North reservoir, but no such permit has yet been approved.

c. According to reports of the Tamar Partners which were released up to the report approval date, the Tamar Partners have adopted a final investment decision (FID) for a development project for expansion of the production capacity from the Tamar reservoir to an annual quantity of approx. 16 BCM from 2027. Completion of the said expansion work may affect competition, in both the domestic and the export markets.

d. The Tamar Partners and Blue Ocean signed agreements for export of natural gas on a firm basis in the total volume of approx. 25 BCM (approx. 200 MMCF per day, or approx. 2 BCM per year) until 31 December 2034, or until the entire contractual quantity is supplied (in this section below, the "**Original Agreement**"). The supply of gas by the Tamar Partners under the Original Agreement commenced in July 2020. On 16 February 2024, the Tamar Partners reported their engagement in an amendment to the Original Agreement, pursuant to which the Tamar Partners undertook to supply Blue Ocean with a total contract gas quantity of approx. 43 BCM, over and above the quantity that was set forth in the Original Agreement, until the end of the term of the Original Agreement. The annual quantity that the Tamar Partners undertook to supply to the buyer is approx. 4 BCM (a daily quantity varying between periods of the year, ranging between 350 and 450 MMCF), in addition to the contract quantity set forth in the Original Agreement. The Amendment to the Original Agreement was made contingent on various conditions which are expected to be fulfilled by 1 July 2025 (except in the case of a delay due to circumstances of *force majeure*).

e. The Tamar Partners signed an agreement designed to enable separate marketing of natural gas, which agreement took effect in

May 2021. To the best of the Partnership's knowledge, as of the report approval date, no separate gas sale agreements were signed by any of the Tamar Partners. 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.

7.14.2 Oil and gas exploration in Israel in recent years

On 15 November 2016, the Ministry of Energy opened Israel's EEZ for oil and natural gas exploration. In the first competitive process, 5 exploration licenses had been granted to Energean, and an additional license had been granted to an Indian consortium that waived the license. Furthermore, Energean waived one of its licenses. In the second competitive process on 4 November 2018, 12 licenses had been granted, which were returned without drilling. The Partnership and Chevron were precluded from participating in the first two processes.

On 23 June 2020, the Ministry of Energy issued a third competitive process, offering a single license, Block 72, which covers extensive parts of the Alon D license that had been owned by Chevron and the Partnership before its expiration. As of the report approval date, the decision of the Ministry of Energy with respect to the result of the third competitive process has not yet been received. For details regarding this process, see Section 7.8.2 above.

On 13 December 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, in which 4 zones of exploration licenses were offered. On 16 July 2023, the Partnership submitted a bid in the fourth competitive process as aforesaid, together with the international companies BP and SOCAR (which was proposed as operator), and on 29 October 2023, the Petroleum Commissioner notified the Partnership and SOCAR and BP that their bid had won in relation to the Zone I Licenses. For further details regarding the said licenses, see Section 7.7 above. In addition, in the context of this competitive process, the Commissioner also declared that ENI East Med BV (as the operator company), Dana Petroleum (sns) Limited and Ratio had won six licenses included in Zone G. The results of the competitive process for the remaining zones, Zones E and H, have not yet been announced.

It is noted in this context that, to the best of the Partnership's knowledge, two petitions have been filed with the High Court of Justice, *inter alia*, against the Ministry of Energy, in connection with the fourth competitive process, by which petitions the High Court of Justice is moved to order that such competitive process be revoked, suspended or amended.

At the beginning of 2024 the Ministry of Energy announced its intention to launch another competitive process in 2024-2025. 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.

7.14.3 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. According to a report of the Ministry of Energy, upon the connection of the three natural gas reservoirs Leviathan, Tamar and Karish, it was decided at the end of 2022 that it was no longer viable to continue the permanent engagement with the regasification vessel, and there was no longer any need to continue operating it as a backup for the Israeli market in cases of natural gas shortages.

7.14.4 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 7.23.10(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, 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.

According to reports of the Ministry of Energy, the Natural Gas Authority is the various implications of the developments in the hydrogen market, globally and in Israel, and their repercussions on the natural gas sector, and is promoting regulation, standards and safety rules for the future integration of hydrogen in the natural gas sector’s infrastructures. In addition, the Natural Gas Authority has instructed INGL to move ahead with exploring entry into the field of low-emissions hydrogen transmission, and is simultaneously promoting the issuance of approval to INGL for the transmission of hydrogen in a pilot planned in the area of Yotvata for the production, transmission and use of green hydrogen produced from solar energy.

On 3 December 2023, the Ministry of Energy issued an international RFP to receive information regarding hydrogen valleys, aiming to formulate an outline for establishing a “hydrogen valley” in Israel, including information on the specification and proposed geographical location, production technologies, transmission and use by the end-users, all in accordance with the hydrogen value chain and regulatory and economic aspects in establishing the hydrogen valley. Further thereto, on 3 January 2024, INGL issued an RFP to explore collaborations in connection with the establishment of hydrogen valleys in Israel. The Partnership intends to explore possibilities of collaboration in relation to these initiatives.

7.14.5 Renewable energy sources

(a) 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 and wind energy, which compete with the natural gas sold by the Partnership for the production of electricity.

(b) According to a review report of February 2024, released by the Knesset Research and Information Center, in 2023, the breakdown of electricity production in Israel was as follows: renewable energies – 11.5%; coal – 17.2%; natural gas – 70.8%; and other fuels – 0.5%. According to a review report of July 2023 which was released by the Ministry of Energy[64], the breakdown of electricity production from renewable energy facilities in 2022, which totaled approx. 7,061 MWH and constituted approx. 10.1% of the total electricity consumption in that year, was as follows: photovoltaic facilities – around 83%; thermo-solar facilities – 11%; wind facilities – approx. 4%; and biogas, hydro, biomass and landfill facilities – approx. 2%. The electricity produced at these facilities in 2022 constituted approx. 10.1% of the total electricity consumed in that year. According to the report, in order to meet the target set by the Ministry of Energy for 2030, according to which 30% of electricity production in the market shall be from renewable energies, the installed production capacity as being at the end of 2022 will need to be increased x3.5.

7.14.6 Natural gas discoveries and exploration activity in neighboring countries

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[65].

[64] For further details, see a review report of July 2023: https://fs.knesset.gov.il/globaldocs/MMM/694b85d6-ab73-ed11-8155-005056aa4246/2_694b85d6-ab73-ed11-8155-005056aa4246_11_20199.pdf

[65] It is noted that the Partnership is unable to independently corroborate the information in this section, which originates from various public reports.

(a) <u>Egypt</u>

1. <u>Resources</u>: Approx. 28 TCF in reserves and approx. 11 TCF in contingent resources.

2. <u>Current gas production capacity</u>: Capacity allows for approx. 72 BCM, but the natural decline of the reservoirs brings the production capacity down to approx. 60 BCM.

3. <u>Domestic demand</u>: Domestic demand in 2023 totaled approx. 63 BCM. For details about the amount of domestic demand in Egypt in 2022 and 2023 and forecasts of the domestic demand in Egypt in the coming years, see Section 7.12.2(d) above.

4. <u>Key facilities</u>: 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. For further details about the LNG market in Egypt, see Section 7.12.2(d) above.

5. <u>Production</u>: In 2023 gas production in Egypt amounted to approx. 59 BCM, approx. 70% of which was produced from the reservoirs in the Mediterranean Sea. At the same time, the most prominent reservoir is Zohr, the production from which represents approx. 35%-40% of the total domestic gas production in Egypt. In 2023, production from the Zohr reservoir was approx. 20 BCM (approx. 2 BCF per day), which is approx. 63% of the field's maximum production capacity. To the best of the Partnership's knowledge, based on media reports, the Zohr reservoir is in decline and not expected to resume such production rates as in 2020-2022 (up to approx. 3.2 BCFD per day).

6. <u>Exploration activity</u>: In recent years, Egypt has offered exploration licenses of vast scope, *inter alia*, in tenders. Most of 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 15 January 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 2023 Eni began drilling the Orion-1 well. As of the report approval date, the results of this drilling have not yet been released. Other than the aforesaid wells, in 2023 several

exploration wells were drilled, among them Eni's Thuraya-1 well and Shell's Oud-1 well, which, according to media reports, have been found to be dry.

7. Import/export balance: Since the commencement of production from the Zohr reservoir in 2017, the gas quantities produced in the country exceeded domestic demand. However, since May 2023, Egypt has reverted to being a gas importer. According to forecasts, domestic demand is expected to exceed the domestic production capacity, *inter alia* as a result of population growth on the one hand, and a decrease in the production capacity on the other hand. 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. Insofar as no additional significant discoveries are made in its territory, it will be difficult for Egypt to return to being a significant gas exporter.

(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.[66] As of the report approval date, the results of an appraisal well drilled by ExxonMobil in 2023 in the Glaucus discovery have not been reported, 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. In February 2024, Eni announced a successful appraisal well in the Cronos reservoir, and according to media reports Eni is expected to enter a process of development of the reservoir based on the infrastructures of the Zohr field in Egypt, thereby piping the gas from Cronos to Egypt. To the best of the Partnership's knowledge, the development of these discoveries may be based on export to Egypt, which may impact the Partnership's activity in Cyprus and/or in Egypt.

2. Current gas production capacity: None.

[66] "In place" means the amount of gas in the reservoir. The amount that can actually be produced (recoverable) is significantly lower than the amount in place. It is clarified that reserves and resources, which are reported, *inter alia*, by the Partnership, are recoverable quantities.

3. Domestic demand: As of the report approval date, Cyprus does not consume natural gas. For further details about the Cypriot market, see Section 7.12.2(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. According to reports in the foreign media, although an FSRU facility is already ready for transportation to Cyprus, the gas infrastructures are not installed and it is accordingly doubtful whether the operation of the FSRU facility will begin 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 2023, these three companies performed exploration activity which included the conduct of seismic surveys and exploration and appraisal drillings, which trend is expected to continue in 2024. 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 7.29.37 below.

7. Import/export balance: As of the report approval date, completion of an FSRU facility for LNG import is expected at the end of 2024-the beginning of 2025. As pertains to future export, in the absence of relevant regulation of natural gas export facilities in Cyprus, it is difficult to assess what effect, if any, existing discoveries as well as 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: None 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 which132 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: As of the report approval date, Lebanon has granted only two licenses to a consortium headed by TotalEnergies that includes ENI and QatarEnergies,. In recent years, exploration wells have been drilled and found to be dry in each of the said two licenses. According to media reports, the most recent among them was drilled in 2023 in Block 9 which borders on Israel's EEZ, without resulting in the announcement of a discovery. The other areas in Lebanon's EEZ are presently offered in the third tender of the Lebanese government. For details on the Maritime Agreement signed between the Israeli and Lebanese governments, see Section 7.8.2 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 MMCF per day. However, to the best of the Partnership's knowledge, export of this type has not taken place.

(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 , 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. 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 7.12.2(c) above.

7.15 **Seasonality**

7.15.1 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.

7.15.2 Following is data on the breakdown of natural gas sales (100%) from the Leviathan project in the past two years:[67]

Period	Q1 (in BCM)	Q2 (in BCM)	Q3 (in BCM)	Q4 (in BCM)
2022	2.7	2.8	3.0	2.9
2023	2.8	2.5	2.9	2.8

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

7.16.1 Phase 1A of the Leviathan project development plan

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

(a) Production wells: As of the report approval date, the production system of the Leviathan project includes 5 subsea production wells designed for production of up to approx. 400 MMCF per day, including the Leviathan-8 production well, which was connected to the production system in June 2023. Natural gas and condensate from the Leviathan reservoir, which is at a depth of approx. 3 km below the seabed, is piped from the said production wells to the subsea production system.

(b) Subsea production system: Connects the production wells to the production platform and lies on the seabed. The subsea system comprises 14-inch infield pipes through which the natural gas, condensate and related fluids are transported from each well to the subsea manifold. Two 18-inch pipes and a third 20-inch pipe (under construction), approx. 120 km long, come out of the manifold, transmitting gas, condensate and related fluids 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

[67] 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.

from the production platform to the wells. 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 capacity of the platform can handle approx. 1,200 MMCF of gas per day and up to approx. 5,400 barrels of condensate per day. However, under certain operating conditions, production can slightly exceed such quantity.

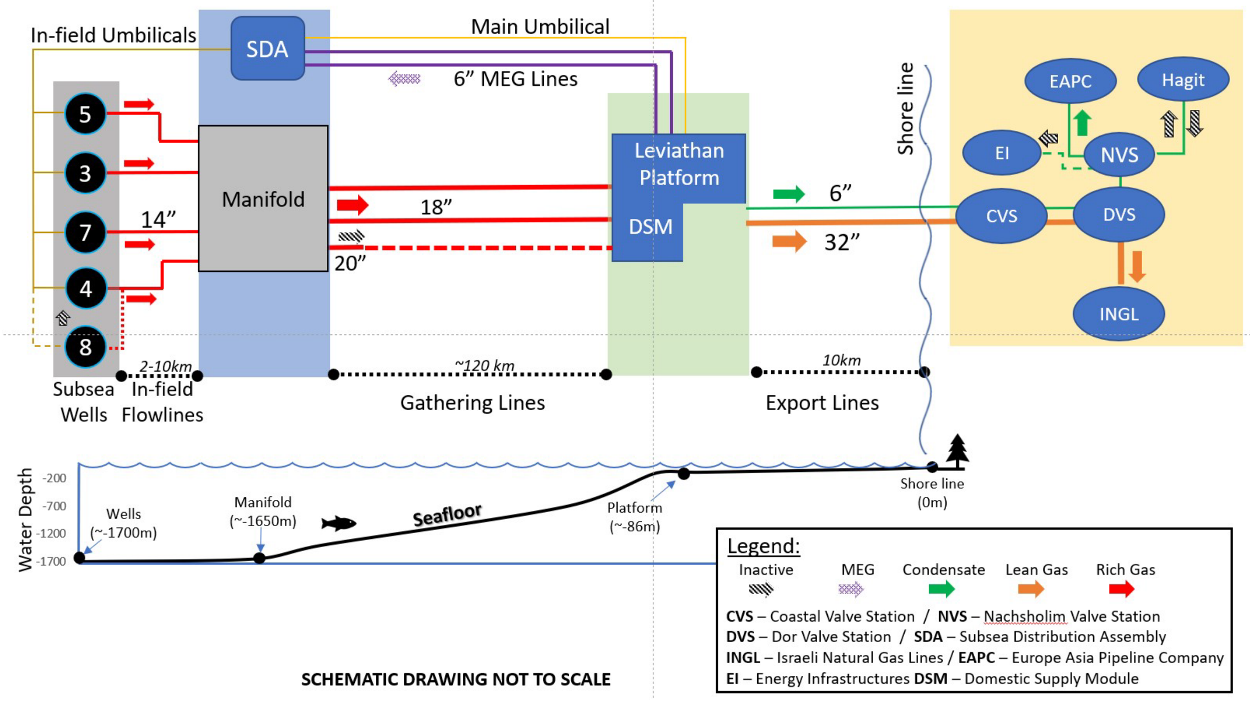
(d) Transmission system to the shore: The pipeline that comes out of the Leviathan platform to the shore comprises a 32-inch pipe for the transmission of natural gas[68] and a 6-inch pipe for the transmission of condensate. These pipes run under the shoreline, reach the coastal valve station and from there, the Dor valve station, which is situated near the INGL valve station, to which the natural gas is transferred. The condensate pipe connects at the Nahsholim Valve Station to the oil pipelines of EAPC and of PEI, as well as to the Hagit site.

(e) Hagit site: The Hagit site includes a tank for temporary storage of condensate, which includes the pipes, apparatus, equipment, pumps, command, control and operating systems, a tanker-filling facility, services and auxiliary facilities , as required for safe and operation of the site. The condensate reaches the Hagit site via a 6-inch pipe, as noted, and where there is no ability to immediately pipe the condensate to the customers of the Leviathan project, and in order to allow for continued regular production of natural gas, the site is intended to allow for transmission to and temporary

[68] For details regarding a license for the construction and operation of a transmission system, see Section 7.23.13(a) below.

storage of the condensate at the Hagit site, to be piped to the Partnership's customers when possible, or, to the extent necessary, to be removed from the site to the customers via tankers. As of the report approval date, condensate cannot be stored at the Hagit site due to damage caused to the storage tank by weather conditions. Further thereto, the operator is working to assess and remedy the damage, and in its estimation, given the available options in the absence of ability for transmission to ARF, this is not expected to affect the operations of the Leviathan project. For details regarding the agreements with the condensate customers, see Sections 7.11.4(b) and 7.11.4(e) above.

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

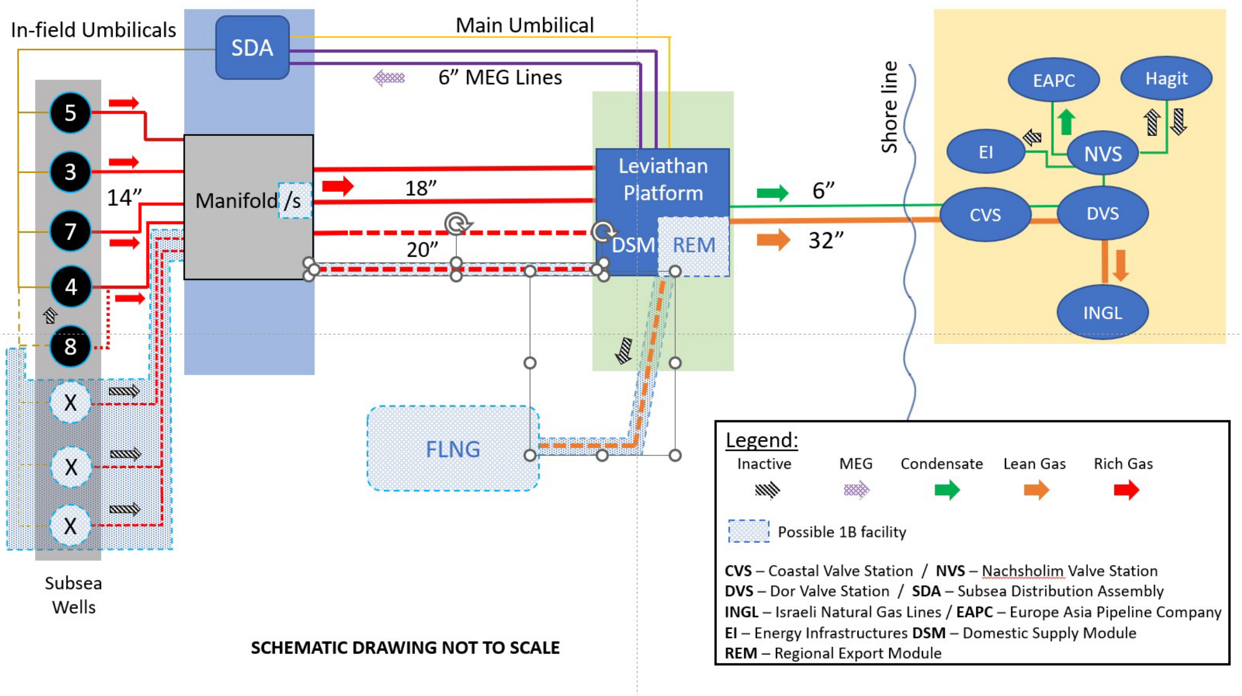


7.16.2 <u>Phase 1B of the Leviathan project development plan</u>

Phase 1B of the approved development plan is intended to increase the daily production capacity of the Leviathan project to approx. 2.1 BCF, and under certain operating conditions even above that. 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 up to approx. 400 MMCF per day, which shall be connected to the platform via a subsea pipeline and equipment which predominantly serves the existing production system. According to the plan, a processing system called 'Regional Export Module' (REM) that consists primarily of additional gas processing systems will be added to the platform. 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, including the fourth pipe and an FLNG facility, insofar as a decision is made to build them.

7.16.3 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.

Leviathan Project Phase 1A+1B– Schematic Diagram



7.17 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.

7.18 **Human capital**

7.18.1 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.

7.18.2 On 21 September 2022, the general meeting of the unit holders approved an arrangement regarding the Partnership's management expenses, whereby, from 1 January 2022, the Partnership bears all of the management expenses of the Partnership and the General Partner, including the cost of employment of the Active Chairman of the Board, the CEO and all the other officers and employees of the Partnership, with the exception of the compensation of directors appointed by Delek Group, the control holder of the Partnership. For further details regarding the said arrangement and the approval thereof, see the Partnership's immediate reports of 6 September 2022 and 21 September 2022 (Ref.: 2022-01-092520 and 2022-01-120358, respectively), the information appearing in which is incorporated herein by reference.

7.18.3 As of 31 December 2022 and 31 December 2023, the following employees were employed by the Partnership:

Department	Number of Employees as of 31 December 2022	Number of Employees as of 31 December 2023
Management, HQ and Finance	17 (including 7 officers)	16 (including 8 officers)
Professional departments	7 (including 2 officers)	7 (including 2 officers)
Total	**24**	**23**

7.18.4 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.

7.18.5 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 15 August 2011. The

Partnership updates the administrative enforcement plan from time to time, as needed.

7.19 **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).

7.20 **Financing**

7.20.1 General

As of the report approval date, the Partnership finances its activity mainly from income from the sale of natural gas to customers of the Leviathan project and from the issue of bonds to the institutional market in Israel and overseas.

7.20.2 Bonds of Leviathan Bond

On 18 August 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 totaling $500 million in par value, which were paid by 30 June 2023, and bore fixed annual interest at the rate of 5.75%.

(b) Bonds totaling $600 million in par value, payable on 30 June 2025 (in one installment), bearing fixed annual interest at the rate of 6.125%.

(c) Bonds totaling $600 million in par value, payable on 30 June 2027 (in one installment), bearing fixed annual interest at the rate of 6.5%.

(d) Bonds totaling $550 million in par value, payable on 30 June 2030 (in one installment) bearing fixed annual interest at the rate 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 5 August 2020 (Ref. 2020-01-084006), the information appearing in which is incorporated 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 31 December 2023 (net of capital raising costs) was approx. $1.74 billion.

1 May 2023 saw the partial prepayment of $280 million out of the first bond series (the series' total amount: $500 million), the original maturity date of which was 30 June 2023, in accordance with the terms and conditions of the bonds, and on 30 June 2023 the outstanding balance of the first bond series was repaid in full and on schedule, in accordance with the terms and conditions of the bonds.

On 22 January 2023, the board of directors of the General Partner approved the adoption of a plan for purchase of the bonds, in an aggregate amount of up to $100 million, for a period of two years (the "**Purchase Plan**"). On 15 November 2023, the board of directors of the General Partner authorized continued buybacks in accordance with the Purchase Plan, out of the bond series due and payable on 30 June 2025 and/or out of the bond series due and payable on 30 June 2027. By the report approval date, the Partnership has carried out buybacks in accordance with the Purchase Plan in the total amount of approx. $7.7 million. It is clarified that the aforesaid decision does not obligate the Partnership and/or Leviathan Bond to purchase the bonds and that the Partnership's management may decide not to purchase bonds at all.

For further details about the Purchase Plan, see the Partnership's immediate report of 23 January 2023 (Ref. 2023-01-010464), the information appearing in which is incorporated herein by reference, as well as Section 3E in Part One of the Board of Directors' Report (Chapter B of this report).

For further details about the bonds, see Part Five of the Board of Directors' Report (Chapter B of this report).

7.20.3 <u>Credit facility</u>

The Partnership has been provided a bank credit facility by an Israeli bank, which facility is intended to serve its operating activities. According to the terms and conditions of the credit facility, over a term beginning on 14 March 2024 and ending on 7 March 2025, the Partnership will be able, from time to time, to draw down dollar loans up to a total amount of U.S. $100 million, for a period until the final repayment date requested by the Partnership in the notice of its intention to take the loan or 15 April 2026, whichever is earlier (the "**Credit Facility**"). It is noted that the Credit Facility is *in lieu* of credit facilities formerly provided to the Partnership. For further details, see Note 10D to the financial statements (Chapter C of this report). As of the report approval date, the Partnership has drawn no amount of the Credit Facility.

7.20.4 Financial covenants

The Credit Facility prescribes 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.[69]

(b) The ratio between the surplus sources and the amount in the Credit Facility shall be no less than 1, and for the purpose of this calculation, an amount will be added to the sources which is equal to the balance of the Credit Facility not yet drawn down at such time, and it shall be deemed as part of the "surplus sources". A review of the coverage ratio shall be conducted every half-year according to the sources and uses report.[70] For further details,

[69] 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.
[70] For this purpose, "**surplus sources**" – the aggregate amount of sources by 30 June 2025 (as specified in an agreed form of sources and uses report) after deduction of the aggregate amount of uses (as defined in the sources and uses report) by 30 June 2025.

see Note 10D to the financial statements (Chapter C of this report).

As of the report approval date, the Partnership meets the said covenants.

7.21 **Taxation**

7.21.1 General

In accordance with an amendment to the Income Tax Regulations (Rules for the Calculation of Tax for the Holding and Sale of Participation Units in Oil Exploration Partnerships), 5749-1988 (the "**Income Tax Regulations**"), which amendment was approved on 3 August 2021, as of the tax yea" 2022, the Partnership has been governed by the tax regime that governs companies. 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).[71] For additional details in this regard, see Note 20A to the financial statements (Chapter C of this report).

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

For details regarding a legal proceeding conducted by the Partnership with respect to Section 19 of the Taxation of Profits from Natural Resources Law, and regarding an originating application that was filed by the Partnership and the General Partner with the District Court in connection with application of the provisions of Section 19, see Note 19C to the financial statements (Chapter C of this report).

7.21.3 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 19C to the financial statements (Chapter C of this report), respectively.

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

(b) 2 December 2020 saw the publication of the Taxation of Profits from Natural Resources Regulations (Advances due to the Oil Profit Levy), 5781-2020 (in this section: the "**Regulations**")[72] pursuant to Sections 10(b) and 51 of the Law, which are intended to regulate the issue of advance payments in respect of the Oil Profit Levy to be paid by holders of petroleum interests in a petroleum project, including the calculation method, payment dates and reporting of the advance payments. A summary of the principal provisions included in the Regulations follows.

1. The Regulations determine that a holder of a petroleum interest in a petroleum venture (in this section: the "**Petroleum Interest Holder**") shall pay advances on account of the Levy for that tax year, with 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 set payment date until payment of the amount of the advance.

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 Petroleum Interest Holder shall be obligated to pay the advances out of the ongoing receipts of the venture according to their proportionate share of the petroleum interest (in the case of joint marketing), or the ongoing receipts of the Petroleum Interest Holder (in the case of separate oil sale). It is further 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 area of the petroleum venture, from the receipts of the venture or from the oil profit of the venture, 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 owed by the Petroleum Interest Holder, and therefore, the Regulations determine that Petroleum Interest Holders are entitled to offset against their advance payments sums withheld by them from derivative payment recipients, pursuant to the provisions of Section 9(b)(1) of the Law, provided that all of the following are satisfied: (a) The Petroleum Interest Holder

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

transferred the amount of the Levy he has withheld to the assessing officer, no later than the date of payment of the advance for the effective month; (b) The transferred withheld amount has not been previously offset; and (c) The effective month due to which the setoff was required falls within 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 certain 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 10 November 2021 the Knesset approved Amendment No. 3 to the Law, which includes, *inter alia*, an amendment whereby, pursuant to the decision of an assessing officer, payment of 75% of the balance of the amount of a Levy that has been appealed may be compelled (before the dispute is resolved), and other amendments designed to confer powers on the assessing office to streamline the collection of the Levy. For further details, see Note 19C to the financial statements (Chapter C of this report).

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

(a) On 3 December 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 20 October 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 that had arisen between the Partnership and the Tax Authority and the disagreements on the amount of the Partnerships' taxable income in 2016, assessments to the best of judgment were received from the Tax Authority on 22 November 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**").

The disputes primarily pertain to the manner of recognition of finance expenses and other expenses that have been actually borne by the Partnerships and the manner of calculation of the capital gain from the sale of the Karish and Tanin Leases.

Further to an administrative objection to the Tax Assessment that had been filed by the Partnership, the Partnerships were issued tax assessment orders pursuant to Section 152(b) of the Income Tax Ordinance (the “**Orders**”).

According to the Orders, the taxable business income of the Partnership and of the Avner Partnership in 2016 was approx. $125.8 million and approx. $114 million, respectively (rather than approx. $107.2 million and approx. $95.4 million, respectively, as included in the Partnerships' tax reports as filed with the Tax Authority), and the capital gain of the Partnership and of the Avner Partnership in 2016 was approx. $49.3 million and approx. $67.1 million, respectively (rather than approx. $7.6 million and approx. $18.1 million, respectively, as included in the Partnerships' tax reports as filed with the Tax Authority). It is noted that the said amounts were converted from ILS to $ according to the dollar exchange rate known as of 31 December2023.

In the event that 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. $43.7 million.

On 15 September 2020, the Partnership filed a notice of appeal from the Orders with the Tel Aviv District Court. The grounds for the tax assessment in the appeal were submitted by the assessing officer on 21 December 2020, according to the Court’s decision. A notice of the grounds for the appeal on behalf of the Partnership was filed on 3 May 2021. A pretrial hearing on the appeal was held on 25 November 2021, and after several continuances due to talks with the assessing officer, another pretrial hearing has not yet been scheduled.

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.

7.21.5 The 2017 tax year

(a) On 8 November 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 Partnership's taxable income of the Partnership in 2017, on 23 July 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 losses formed in respect thereof 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 10 December 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 21 December 2022, the Assessing Officer issued an order for tax assessment for the 2017 tax year.

In accordance with the said order, the Partnership's taxable business income in 2017 was approx. \$344.2 million (rather than approx. \$205.4 million, as included in the Partnership's tax report as filed with the Tax Authority) and the Partnership's capital gain in 2017 was approx. \$654 million (rather than approx. \$593.5 million, as included in the Partnership's tax report as filed with the Tax Authority). It is noted that the said amounts were converted from ILS to \$ according to the dollar exchange rate known as of 31 December 2023.

It is further noted that on 22 January 2023, the Partnership filed a notice of appeal from the order with the Tel Aviv District Court. The grounds for the tax assessment were filed by the assessing officer on 30 May 2023. A notice of the grounds for the tax assessment on behalf of the Partnership was filed on 31 January 2024.

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. $105 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.

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

(a) On 19 February 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 24 March 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 business income in 2018 was approx. $179.5 million (rather than approx.

$137.8 million, as included in the Partnership's tax report as filed with the Tax Authority) and the Partnership's capital gain in 2018 was approx. $15.9 million, as stated in the report so filed thereby. It is noted that the said amounts were converted from ILS to $ according to the dollar exchange rate known as of 31 December 2023.

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 7.21.4(c) and 7.21.5(b) above, respectively.

As of the report approval date, pursuant to the Tax Assessment, and insofar as all the Tax Authority's arguments are accepted, the Partnership will be required to pay additional tax (including interest and linkage differentials), at the expense of the holders of Participation Units in the Partnership, in the amount of approx. $14.2 million.

On 10 June 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.

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

(a) On 14 July 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.

7.21.8 <u>The 2020 tax year</u>

(a) On 12 April 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.

7.21.9 <u>The 2021 tax year</u>

(a) On 30 April 2023, the Partnership released an immediate report, attaching thereto a temporary tax certificate for entitled holders and participation unit sellers in respect of participation unit-holding for the 2021 tax year (Ref. 2023-01-046137), the information appearing in which is incorporated herein by reference.

(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.

7.21.10 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 7.21.1 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.

7.21.11 It is clarified for each of the tax years from 2016 forth, for which court proceedings or administrative objection proceedings against the assessing officer are still conducted or the Tax Authority's audit of the

Partnership's tax reports is as yet uncompleted, that after a final decision on the disputes litigated in court or the conclusion of mutual agreements with the assessing officer or the completion of the Tax Authority's audit, it may transpire that there are assessment differences, such that the final tax assessment will 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 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 28 June 2021, as specified in Note 19B 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.

7.21.12 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.

7.21.13 For further details see Note 19B 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.

7.22 **Environmental risks and management thereof**

7.22.1 By nature, the activity of exploration, development, production and decommissioning 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.

7.22.2 <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) On 12 September 2023, the Ministerial Committee for Legislation authorized the Draft Climate Law, 5783-2023 (the "**Draft Climate Law**") toward a first reading in the Knesset. On 22 September 2023, Government Resolution No. 927 was adopted, whereby the Government authorized the Draft Climate Law, subject to certain modifications The Draft Climate Law establishes a national target for the reduction of greenhouse gas emissions in 2030, a 27% reduction, such that it total 73% of the amount of greenhouse gas emissions measured in 2015 (the base year). As of the report approval date, it is impossible to estimate when, if ever, the legislation proceedings of the Draft Climate Law will be promoted and what changes will be made therein.

(d) The 2024 Arrangements Law included the proposal to impose a carbon tax on waste fuels used for electricity production and industry as well as on waste disposal. According to the framework that has been released, tax will be gradually imposed from 2025 on coal, natural gas, fuel oil, LPG and petcoke, in order to encourage the transition to alternative energy sources. The framework that has been released is general, and so there is still uncertainty on the matter. However, the general framework has been approved by the Government and is now in the process of being approved. It is noted that the imposition of carbon tax is contingent on publication by government ministries of a procedure of budgetary support for fuel-consuming plants (otherwise the minister will suspend the imposition of the tax). In the Partnership's estimation, carbon tax, to the extent approved in the proposed form, shall have no material effect on its operations.

(e) On 2 May 2023, a policy document was released regarding the decommissioning of offshore petroleum and natural gas exploration and production infrastructures (policy of the Ministry of Environmental Protection and the Ministry of Energy). Chevron submitted a position regarding such document, as part of the public comments.

(f) On 27 March 2023, the Knesset approved the Enhanced Efficiency of Environmental Licensing Proceedings Bill (Legislative Amendments), 5782-2022 in the first reading, 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. As of the report approval date, the Bill, which was split and merged with another bill on 2 April 2023, is in preparation for the second and third reading.

(g) On 14 April 2022, a memorandum was released for a Bill on the Preparedness and Response to Incidents of Oil Pollution of the Sea and Coastal Environment, 5782-2022, which aims to implement the 1990 International Convention on Oil Pollution Preparedness, Response and Cooperation at Israeli-local level. According to the said bill, all entities that have a coastal strip within their scope or under their responsibility or that operate in the sea, including owners of facilities for the exploration and production of petroleum and natural gas, shall be prepared for incidents of oil pollution of the sea and the coastal environment. The bill includes the method of regulation of incidents of this type on several levels: preparedness – preparation of emergency plans, equipping and practicing. These entities are required to prepare plans to face incidents and be prepared to act on them if they occur; Response to the incident – reduction of damage in general and environmental in particular; Cleaning and restoration – cleaning what is polluted, returning the situation to its original state, and removing the waste that was created.

(h) Besides the regulation imposed by Israeli law, additional directives on environmental issues are also imposed by the terms of the lease deeds and licenses that have been granted to the Partnership, and by the various approvals required for the purpose of conducting the exploration and production activities and for the purpose of 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 7.23.7(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.

(i) <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.

(j) 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.

7.22.3 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.

7.22.4 <u>Events in connection with the environment</u>

According to information provided to the Partnership by the operator of the Leviathan project, in 2023 there was no event or matter relating to the Partnership's operations in connection with the environment which had a material effect on the Partnership. For details regarding material legal or administrative proceedings related to the environment, see Section 7.22.7 below.

7.22.5 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) Ober the course of 2019, the operator in the Leviathan project received a preliminary business license, air discharge permit, marine discharge permit and toxins 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 31 December 2029, the air discharge permit is valid until 5 November 2026, the marine discharge permit is valid until 31 March 2024, and the toxins permit is valid until 3 June 2024. A business license and toxins permit have also been obtained for the Hagit site, and their term is extended similarly.

7.22.6 Environmental costs and investments

The projected costs of actions relating to environmental protection are included in the budgets of the various projects and are updated from time to time according to the approved work plans. As of the report approval date, no additional material costs are expected.

7.22.7 Material legal or administrative proceedings in connection with the environment

As of the report approval date and to the best of the Partnership's knowledge, no material legal and/or administrative proceeding is being conducted against the Partnership and/or any of the officers of the General Partner and/or of the Partnership in connection with environmental protection, which is expected to have a material effect on the Partnership.

(a) Administrative monetary penalties

1. On 20 May 2020, Chevron received a notice from the Ministry of Environmental Protection of the intention to impose an administrative monetary 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 the 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 administrative 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.

   It is noted that, due to the passage of time since the process began and the response of the Ministry of Environmental Protection to the freedom of information request not yet being received, there is no certainty with respect to the completion of the process.

2. On 2 August 2023, Chevron received notice from the Ministry of Environmental Protection regarding its intention to impose thereon an administrative monetary penalty of approx. ILS 2.9 million (100%) for alleged violation of the marine discharge permit of the Leviathan project. Chevron has submitted its arguments with respect to such notice, and on 7 December 2023, the decision of the Ministry of Environmental Protection on the matter has been issued whereby it was decided to reject the claims of Chevron and that such administrative monetary penalty amount shall remain unchanged. Payment for such administrative monetary penalty was transferred on 26 December 2023.

(b) Hearings

On 6 August 2023, Chevron received a letter of notice and summons to a hearing before the Ministry of Environmental Protection for alleged violation of the marine discharge permit and the toxins permit of the Leviathan project, and in accordance with the Prevention of Sea Pollution and the Hazardous Substances Law. The hearing took place on 7 January 2024, and on 21 January 2024, the hearing summary was received, whereby 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 powers according to law.

It is not possible at this stage to estimate whether an administrative monetary penalty will be imposed for the violations and the amount of the administrative monetary penalty that will be imposed, if any.

(c) On 15 December 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 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.

7.22.8 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 holder of a license in Cyprus for exploration or production activities is obligated to act in accordance with an environmental assessment report prepared for the Cypriot Ministry of Energy and to conduct an environmental survey prior to the conduct of such activities in the area of the license.

7.22.9 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-ʻArīsh, is subject to Israeli and Egyptian regulation.

7.22.10 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.

7.23 **<u>Restrictions and supervision over the Partnership's activity</u>**

7.23.1 <u>The Gas Framework</u>

On 16 August 2015, Government Resolution No. 476 (readopted with certain changes in a Government Resolution of 22 May 2016) was adopted with respect to a framework for the increase of the natural gas quantity produced from the "Tamar" natural gas field[73] 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 17 December 2015, upon the grant of an exemption from certain provisions of the Economic Competition Law, 5748-1988[74] to the Partnership, Avner, Ratio and Chevron (in this section: the "**Parties**") by the Prime Minister, in his then-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**

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[73] 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".

[74] On 1 January 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".

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 1 January 2030.[75]

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 1 January 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. For details, see Section 7.23.2(a).

(b) The Exemption from the aforesaid Restrictive Arrangements had been contingent upon the satisfaction of certain conditions, including the transfer of all the interests of the Partnership and Chevron in the Tanin and Karish Leases, the transfer of all the interests of the Partnership in the Tamar project and the transfer

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

of some of the interests of Chevron (interests in excess of 25%) in the Tamar project, all of which were completed in accordance with the framework by December 2021.

(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:

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

2. The consumer will have the possibility of selling natural gas that it purchased in a secondary sale, in accordance with the conditions and provisions set forth in the Exemption.

3. The parties shall not apply any restriction to the sale price at which the consumer shall sell the natural gas in a secondary sale.
4. 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.

7.23.2 Economic competition laws

(a) The status of the Partnership as a monopoly

On 13 November 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 further sections have been implemented pursuant to the Products and Services Price Control Order in relation to 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 7.29.19 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 7.25.5 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 31 July 2019, the decision of the Competition Commissioner approving the merger was given[76], under the conditions whose summary is described below:

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

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

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 amount of the 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 party 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 party; (b) the other party 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 10 additional years (as specified in Section 7.25.5 below) without receiving prior permission from the Competition Commissioner.

On 8 September 2019, an appeal was filed with the Competition Court, challenging the merger approval decision issued by the Competition Commissioner. On 21 December 2022, the Competition Court handed down its judgment on the appeal, whereby it ruled that the appellants had failed to show that the merger gives rise to a reasonable concern of significant adverse effect on the competition and consequently denied the sought remedy of revocation of the approval granted to the merger transaction. However, the Competition Court ordered the Competition Commissioner to issue a supplemental decision with respect to the conditions imposed on the merger by the Commissioner, in view of the difficulties arising out of these conditions (in this section: "**Supplemental Decision**"). The judgment became peremptory on 5 February 2023. Further to the judgment, on 22 March 2023, the Competition Authority forwarded to the Partnership's counsel the "Written Arguments prior to Hearing on the Conditions for Approval of the EMED-EMG Merger" that had been filed by the appellants. On 9 July 2023, with the knowledge and consent of the Partnership and Chevron, EMED and EMG filed their response to appellant's arguments. As of the report approval date, a Supplemental Decision on behalf of the Competition Commissioner has not yet been received.

7.23.3 <u>The Promotion of Competition and Reduction of Concentration Law, 5774-2013 (the "**Anti-Concentration Law**")</u>

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 not to allocate to an entity listed on the published list of dominant enterprises, 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 dominant enterprise, 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 releases and updates from time to time a list of dominant enterprises in the economy, a list of significant financial entities and a list of significant non-financial corporations.

Delek Group, including the Partnership, was included in the list of dominant enterprises and in the list of significant non-financial corporations that was released on 10 August 2022.

On 28 March 2023, the Concentration Committee notified Delek Group that it would be taken off the list of significant non-financial corporations and the list of dominant enterprises when the lists would be updated in 2023. The Competition Authority further clarified that the Group's removal from the lists was subject to changes that may possibly occur in the infrastructure sectors or in the Group's financials.

As a result of changes that occurred since the last update to the lists on 10 August 2022, on 13 March 2024, the Concentration Committee released an updated list of dominant enterprises and an updated list of significant non-financial corporations.

Delek Group and the Partnership were removed both from the updated list of dominant enterprises and from the updated list of significant non-financial corporations, following the sale of the Partnership's holdings in the Tamar reservoir and because the credit amount taken by Delek Group was reduced and dropped below the effective threshold under the Anti-Concentration Law. Accordingly, Delek Group's controlling shareholder, Mr. Yitzhak Tshuva, was also removed from the said lists.

Therefore, the provisions of the Anti-Concentration Law no longer apply to Delek Group or the Partnership.

7.23.4 <u>The Petroleum Law and the regulations promulgated thereunder</u>

(a) <u>The Petroleum Law</u>

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 15 November 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.

7.23.5 <u>The Natural Gas Sector Law and the regulations promulgated thereunder</u>

(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 other than pursuant to a license issued by the Minister of Energy (in this section: the "**Minister**") and in accordance with its terms:

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

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

   (c) Construction and operation of an LNG facility.

   (d) Construction and operation of a storage facility.

   (e) Construction and operation of an export pipe by a person who is not a lease holder.

2. A transmission license will only be granted to a company incorporated in Israel under the Companies Law, 5759-1999 (the "**Companies Law**").

3. The holder of the transmission license, an electricity provider, or anyone who is a control holder or stakeholder thereof may not engage in the sale and marketing of natural gas.

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.

The definition of the term “Rates” in the Natural Gas Sector Law 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 definition may allow for the imposition of charges under the law on natural gas suppliers as well.

28 December 2023 saw the publication of Amendment No. 13 to the Natural Gas Sector Law, 5784-2023, under which the Minister of Energy may extend the term of INGL’s transmission license by an additional period of 15 years. It is further prescribed that the Minister of Energy may grant INGL a distribution license, including construction and operation of a distribution network, taking into account the considerations and the restrictions specified in the Amendment.

(b) The 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.

Furthermore, 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.

It is noted that following the outbreak of the Iron Swords War, and in accordance with Section 91(a) of the Natural Gas Sector Law, the State of Israel has adopted resolutions which are renewed from time to time, to authorize the Minister of Energy to announce a state of emergency in the natural gas sector, to the extent that there is need to exercise the powers specified in the Emergency Regulations in order to contend with the shortage of natural gas. As of the report approval date, the conditions requiring such an announcement have not been satisfied, and in accordance with Section 8 of the Emergency Regulations, in the event of announcement of a state of emergency in the natural gas sector, the Minister is authorized, *inter alia*, to order a different allocation of the natural gas quantities for supply. Therefore, in such a case, the Minister may order the Leviathan project partners to allocate natural gas quantities for the benefit of the domestic market at the expense of the gas supply to the export customers in Egypt and Jordan.

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

On 6 April 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 for the purpose of operation of the transmission system</u>

1. From time to time, the Natural Gas Commission adopts resolutions that update the rates of the various transmission services.

2. According to the Natural Gas Commission’s resolution of 3 January 2021 on criteria and rates for the purpose of operation of the transmission system in a flow control regime , the Commission determined that the costs in respect of unaccounted for gas (UFG) in the transmission system that derives from reasons that cannot be attributed to deficient operation of the transmission system, but rather to factors that can be neither prevented nor controlled, such as measurement timing, pressure differences and temperature differences, will be borne by the gas suppliers. The resolution further stipulates that UFG within the range of 0% and 0.5% (either positive or negative) is deemed to be within the reasonable range (Unaccounted for Gas Target, UFG-T). The costs in respect of UFG-T will be allocated equally between the gas suppliers and the gas consumers.

(e) <u>Resolutions of the Natural Gas Commission regarding the financing of export projects via the national transmission system</u>

The Natural Gas Commission has adopted several resolutions 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.

According to the Commission’s resolutions, on 23 June 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 2 May 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 7.12.2(e) above.

(f) 9 August 2023 saw the release of Resolution No. 3/2023 by the Natural Gas Commission on financing and allocation of capacity in all export lines, the key points of which are as follows:

1) Every exporter shall be allocated capacity according to a percentage to be calculated according to certain parameters, such as the annual production capacity of the exporter and the existing and potential export volumes of that exporter. According to the initial allocation, 54% of the total export capacity will be allocated to the Leviathan reservoir, 33% will be allocated to the Tamar reservoir and 13% will be allocated to the Karish reservoir. For the avoidance of doubt, it is clarified that preexisting transmission agreements will not be adversely affected.

2) In the event of construction of export infrastructure other than by the transmission license holder, the share of each exporter in that infrastructure shall be taken into account as part of its export allocation.

3) The Commission shall reexamine and redetermine the allocation upon the occurrence of a significant event in the natural gas sector, the discovery of additional significant reserves, the entry of a new exporter, the construction of additional natural gas export infrastructure or another material change in the natural gas sector as shall be determined by the Commission.

4) The Commission may determine that use shall be made of all or part of the export lines for the purpose of importing natural gas in case it determines that there is need to supply the demand in the domestic market.

5) As relating to the Ramat Hovav-Nitzana line, the following provisions have been determined:

   a. The allocation of capacity between the existing exporters shall be conducted on an equal basis, such that every existing exporter may request a third of the line's capacity and choose whether to use its allocation. The remaining capacity of an exporter that chooses not to use its allocation, or part thereof, shall be divided between the other exporters on an equal basis, subject to their respective total allocation limits.

   b. An exporter that has financed the line shall be entitled to a refund proportionate to its allocation in respect of use of the line by another entity during the term of the transmission agreement.

   c. An exporter that does not sign a transmission agreement within two months of receipt of the line allocation or fails to make up its share of the financing in accordance with the provisions of the transmission agreement shall be deemed to have waived its allocation. Accordingly, the allocation will be transferred to another exporter, and it shall receive reimbursement for the costs paid thereby.

   d. The costs of construction of the line (CAPEX) include the costs of the compressor and are estimated at over ILS 1 billion. The period of construction thereof is estimated at approx. 36 months. It is noted that operation of the compressor is expected to entail high annual operating costs in relation to the operation of the rest of the national transmission system, which are estimated at approx. ILS 20 million per annum.

6) As relating to the Jordan North line, it has been determined that after the transfer of payment to the parties that financed its construction (NBL Jordan Marketing Limited and INGL), an exporter may sign a transmission agreement for use thereof, according to the available capacity over and above preexisting uninterruptible transmission agreements as of 1 August 2023.

7) The uninterruptible transmission agreements of each exporter with respect to the Ramat Hovav-Nitzana line and the Jordan North line shall not exceed 70% of the exporter's allocation of that line, with the remaining capacity reserved for interruptible transmission.

8) The actual line financing cost, and consequently the cost of use per MMBTU, shall be determined by the Director of the Natural Gas Authority after construction of the export line is completed.

9) In the event of discovery of a new natural gas reservoir from which natural gas export is intended, the new exporter shall receive its full allocation of the Ramat Hovav-Nitzana line and its remaining allocation in the Jordan North line, provided that its allocation does not exceed 20% of the capacity of each line. Such allocation shall be made at the expense of the interruptible transmission agreements and subject to the signing of a transmission agreement within 24 months prior to the commencement of piping through the line.

10) An export mechanism by way of re-trade shall be allowed through interruptible transmission agreements, in a volume of up to 5% of the capacity of every export line.

It is noted that the Leviathan Partners have submitted to the Gas Authority their reservations in connection with the regulation pertaining to participation in the Nitzana Pipeline, and the parties are discussing the matter.

7.23.6 Regulation of Security in Public Entities Law, 5758-1998 (in this section: the "**Law**")

(a) The Law imposes various duties on a "public entity" (as defined in the Law), including: (1) 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; (2) Appointment of an officer in charge of the security of essential computerized systems; and (3) 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 the term of this confirmation has been extended until February 2026.

(e) As of the report approval date, and as the Partnership has been informed by the operator, 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.

7.23.7 Directives of the Petroleum Commissioner

(a) Provision of collateral in connection with petroleum interests

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, 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 Zone I Licenses and the New Ofek and New Yahel licenses.[77] The Partnership's total share in the said guarantees totals approx. $54.5 million.

[77] For details regarding additional guarantees the Partnership has 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 a

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

On 1 January 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 of oil at sea. As of the report approval date, the Directives have not yet been published.[78]

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

1. On 14 May 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.

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guarantee the Partnership has provided in respect of the Boujdour license, see Section 7.6.1 above. For details regarding guaranties the Partnership has provided in favor of 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).

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

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 24 July 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 from the Leviathan reservoir, and on 1 September 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).

   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.

3. 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 7.25.8(b) below.

(d) <u>The transfer and pledge of a petroleum asset interest and benefit in a petroleum asset interest</u>

On 28 December 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 7.11.3 above.

7.23.8 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 6 January 2019, by Resolution No. 4442, 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: "**Resolution 4442**").

(b) According to Resolution 4442, 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 Resolution 4442 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%

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 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.[79] 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) Resolution 4442 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) It is determined within Resolution 4442 that it will be examined by the Government at the expiration of five years from the date of approval thereof for the purpose of incorporating changes, to the extent required, with respect to the policy on discoveries to be recognized by the Commissioner five years after the date of approval of the resolution, in accordance with the needs of the domestic market and considering the natural gas supply, such that a further resolution on the matter is expected to be adopted in 2024.

(g) Further to Resolution 4442, on 28 December 2023, it was reported that the Minister of Energy instructed the Director of the Ministry to set out to appoint the interministerial committee for periodic

[79] 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 7.23.1(b) above.

examination of the natural gas sector policy. Further thereto, on 14 February 2024, the committee launched its discussions. The committee is expected to review the natural gas export policy in relation to new natural gas reservoirs, rather than in relation to producing reservoirs, as well as all relevant aspects – energetic, economic, environmental and security-related. The committee is expected to complete its work within a timeframe of several months and submit its conclusions to the Government still within 2024.

(h) In the months of August and December 2023, the Tamar Partners received authorization from the Petroleum Commissioner to export additional quantities from the Tamar project at a maximum volume of approx. 4 BCM per annum, subject to execution of the expansion of the production capacity of the Tamar project.

For details with respect to the Leviathan Partners' application to the Commissioner in connection with the approval of export of additional natural gas from the Leviathan project, see Section 7.2.5(d) above.

7.23.9 <u>Draft policy document with respect to the decommissioning of offshore exploration and production infrastructures</u>

On 2 May 2023, the Ministry of Energy published for public comment a draft policy document that specifies general principles with respect to the decommissioning of offshore oil and natural gas exploration and production infrastructures, without derogating from the provisions of law applicable to this issue and from the provisions of the lease deeds and operation authorizations. The draft policy document specifies, *inter alia*, rules, criteria and timeframes for the decommissioning of wells and production facilities as well as the abandonment of no-longer used subsea infrastructures and pipelines, *inter alia*, according to the location of such installations in the deep sea, on the seabed or under the seabed.

According to the Partnership's preliminary assessment, to the extent approved, the stringent requirements under the draft policy document are expected to increase the costs of decommissioning of the Partnership's assets.

7.23.10 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 3 June 2018, the government, in Resolution 3859, approved electricity sector reform and a restructuring of the IEC[80]. According to the resolution, the IEC will reduce its power production operations by selling 5 production sites with a total maximum capacity of approx. 4,500 MW, representing around 40% of its power production capacity, and the IEC will build two modern natural gas-fired production units in Orot Rabin, as part of the trend of reducing the use of coal in the power production process. According to the Minister of Energy's decision of 20 November 2019, two coal-fired production units at the Orot Rabin site in Hadera and the four coal-fired production units at the Rutenberg site in Ashkelon will be converted to natural gas by 2025, and no later than 2026, such that the era of coal use for power production in Israel will come to an end that year[81].

The aforesaid notwithstanding, according to IEC reports, on 18 May 2023, the IEC's board of directors decided to continue advancing the conversion of the two production units at the Rutenberg site only, but to suspend the project for the conversion of the four other production units at the Rutenberg site and at the Orot Rabin site until receipt of a decision of the Ministry of Energy for in-principle recognition of the costs of the project[82].

On 15 June 2023, the IEC's board of directors decided to cancel suspension of the project for the conversion of the two remaining production units at the Rutenberg site to prevent damage to the project that could result from a delay in the timetable for completion of the conversion. The suspension of the project for the conversion of the two production units at the Orot Rabin site shall remain in effect[83].

On 9 August 2023, adequacy testing was carried out on the first converted unit at the Rutenberg site which, as a result of the Iron Swords War, has not been completed in full. As of the report approval date, and based on current reports of the IEC, despite the declaration of the IEC that the chances of performance of the conversion of the six coal-fired production units on schedule were greater than the chances of non-performance of the conversion in

[80] https://www.gov.il/he/departments/policies/dec3859_2018.
[81] https://www.gov.il/he/departments/policies/electricity_nov_2019.
[82] Q1/2023 report, TASE, May 2023.
[83] Q3/2023 report, TASE, November 2023.

full, there is partial certainty regarding the continuation of the conversion project and the date of completion thereof. The current estimated timetable for completion of the project in full has not yet been released[84].

(b) Government Resolution 1261 on the pricing of local pollutants and greenhouse gas emissions

14 January 2024 saw the adoption of Government Resolution No. 1261 (“**Resolution 1261**”), whereby the Minister of Finance was tasked with amendment of the Fuel Excise Tax 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 and local pollutant emissions. Natural gas-related taxation will be imposed gradually as of 2025, as follows: In 2025, the amount of the excise tax and purchase tax on natural gas shall be approx. ILS 33 per ton; in 2026, it shall be approx. ILS 54 per ton; in 2027, it shall be approx. ILS 80 per ton; in 2028, it shall be approx. ILS 114 per ton; in 2029, it shall be approx. ILS 149 per ton; in 2030 it shall be approx. ILS 192 per ton, and so on and so forth. As part of the resolution, it was decided: (1) To task the Ministry of Finance, the Ministry of Energy, the Ministry of Economy and Industry and the Ministry of Environmental Protection to set in place a procedure for budgetary support for fuel-consuming plants, which support shall emulate the consideration that they would be entitled to receive in the context of emission quotas within the European Emissions Trading System (EU ETS) if they were subject to such mechanism, while retaining incentives for efficiency of the plants, and considering the changes required for the market features and the Israeli carbon tax structure and the principles determined in the Government’s resolution; (2) For the purpose of reducing the use of polluting fuels, such as mazut and LPG, a plan will be implemented for acceleration of the natural gas network by the Natural Gas Authority; (3) To instruct the Ministry of Environmental Protection to request the Cleanliness Fund to allocate a budget for support of the conversion of fuels for waste use; (4) If, every year until the end of 2029, the average electricity price for household consumers at the date of update of the annual electricity tariff shall have increased over and above the Consumer Price Index (CPI) due to a change in the indicators: interest prices, fuel costs and exchange rates, the Minister of Finance shall present and order for suspension or reduction of the increase of the excise tax on natural gas for one year, so as to prevent an increase of electricity prices over and above the rate of increase of the CPI, and all subject to Sections 40 and 40A of the Budget Fundamentals Law; (5) The Ministry of Finance shall publish an outline for aid to the

[84] Investor presentation of the Israel Electric Corp. Ltd., the IEC, February 2024.

weaker demographics to assist them in dealing with the increase in energy prices, if any; (6) 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; (7) Revocation of Government Resolution No. 286 of 1 August 2021 on the pricing of greenhouse gas emissions.

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

On 14 March 2022, Government Resolution No. 1282 was adopted, which presents a multi-annual national plan for the prevention and reduction of air pollution and greenhouse gas emissions in Israel (in this section - the "**Plan**").[85] The resolution stipulates that the Plan will constitute part of the State of Israel's response to the climate crisis and is intended, *inter alia*, to fulfill some of the obligations of the State of Israel under the Paris Agreement and the Glasgow Climate Change Conference. As part of the resolution, quantitative targets were set for reduction by 2030 of air pollutants and greenhouse gases from industry, power production, transport, agriculture and waste, as well as promotion of the environmental and health-related information pertaining to air pollutants and the promotion of environment- and climate-related technologies, including ratification of a national target for the introduction of renewable energy at the rate of 30% in 2030 and a 30% reduction by 2030 of greenhouse gas emissions from the electricity sector relative to the electricity sector emissions in 2015.

As part of a report on the implementation of the Plan released by the Ministry of Environmental Protection on 11 July 2023[86], the Ministry of Environmental Protection cautioned of the concern that the Plan's targets would not be achieved, primarily due to suspension of the plan for conversion of the coal-fired units pursuant to the IEC's decision of 18 May 2023, as specified in paragraph (a) above.

(d) 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

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

[86] https://www.gov.il/he/Departments/news/status_report_regarding_the_national_plan_to_reduce_airpollution

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.

7.23.11 <u>The incorporation of hydrogen into the Israeli energy sector</u>

(a) On 15 May 2023, the Ministry of Energy released a strategy document for the incorporation of hydrogen into the Israeli energy sector. The document reviews the features of hydrogen production, transportation, storage and accumulation, and examines the hydrogen use manner, its incorporation around the world and the possibilities for its incorporation in Israel. In the document, it is proposed to formulate, by 2030, policy measures that would lay the initial groundwork for hydrogen use, including the mapping of areas that are suitable for hydrogen accumulation, promotion of experimentation areas, formation of hydrogen valleys, support of projects and pilots in the market, promotion of safety standardization and promotion of regulatory outlines for experimentation.

(b) On 3 May 2023, Government Resolution No. 482 was released, which determines that the ‘Objectives’ section in the articles of association of INGL would be amended to allow INGL to engage in the construction and operation of hydrogen gas pipelines including facilities related thereto as well as the construction and operation of a pipeline for the removal of carbon dioxide that is related to or created by the production of hydrogen, subject to the permit, insofar as granted, and the details specified therein and all in accordance with the provisions of Section 14(b) if the Natural Gas Sector, 5762-2002. On 21 December 2023, the Minister of Energy granted INGL an additional business permit for engagement in the hydrogen segment.

7.23.12 <u>National Outline Plan 37/H for the Reception and Processing of Natural Gas</u>

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.

7.23.13 <u>Permits and licenses for the facilities of the Yam Tethys project and the Leviathan project</u>

(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 21 February 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.

7.23.14 <u>Applicability of Cypriot legislation to the Partnership's activity</u>

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.

7.24 **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).

7.25 **Material Agreements**

The Partnership has entered into material agreements that were in effect during the period from 1 January 2022 until the report approval date, as specified below:

7.25.1 The main agreements for the sale of natural gas from the Leviathan project to the domestic market and for export as specified in Section 7.11.3 above.

7.25.2 Financing documents of the bonds issued by Leviathan Bond, as specified in Section 7.20.2 above.

7.25.3 Production Sharing Contract in respect of Block 12 (as specified in Section 7.3.3 above).

7.25.4 Agreements with respect to entry into the renewable energy sector, in collaboration with Enlight and the CEO of the Partnership, as specified in Section 7.9 above.

7.25.5 <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 7.11.3(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 (hereinbefore and hereinafter, collectively: the "**EMG Pipeline**", and the "**EMG Transaction**", respectively).

The EMG Transaction was closed on 6 November 2019, and natural gas flow from the Leviathan reservoir to Egypt through the EMG Pipeline began on 15 January 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 26 September 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) <u>Capacity Lease & Operatorship Agreement (CLOA)</u>

In the CLOA signed on 30 June 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 31 December 2023, 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) <u>Agreement for allocation of capacity in the transmission to Egypt system</u>

Concurrently with the signing of the Export to Egypt Agreement, on 26 September 2019 (as amended on 21 August 2023), 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 MMSCF per day will be allocated to the Leviathan Partners.

2. Second layer – the capacity above the first layer, up to 150 MMSCF per day until 30 June 2022 (the "**Capacity Increase Date**"), and up to 200 MMSCF 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 1 January 2022 and 30 June 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 30 June 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 30 June 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 the extension of the Capacity Lease and Operatorship Agreement according to the decision of the Competition Commissioner, as specified in Section 7.23.2 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) <u>EMED's shareholders' agreement</u>

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) <u>Term sheet for use of additional infrastructures</u>

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 7.12.2(e) above.

(g) <u>Agreement between EMG and EAPC and Eilat-Ashkelon Infrastructure Services Ltd.</u>

On 1 July 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 6 November 2019, together with the closing of the EMG Transaction, and will be in effect until 10 June 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 6 October 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: (1) all of EMG's undertakings vis-à-vis the EAPC Companies shall have been cancelled; (2) the EAPC Companies shall have received payment in the sum of the Guaranty Amount due to enforcement of the Bank Guaranties; (3) the Bank Guaranties shall have been replaced with a bank guaranty provided by EMG; or (4) 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 7.12.2(e)3 above.

7.25.6 <u>The Joint Operating Agreement in respect of the Leviathan Leases</u>[87]

(a) <u>General</u>

The activity in the framework of the Leviathan Leases is carried out under a joint operating agreement of 31 August 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) <u>Manner of accounting</u>

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

[87] It is noted that until 1 January 2012, the activity in the Leviathan Leases was carried out in the framework of a single joint operating agreement.

and all the liabilities and expenses incurred or undertaken by the operator in connection with the joint activity,[88] and all the credits to the joint account,[89] 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 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 30 June 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

[88] 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.

[89] 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.

companies/affiliates of the operator[90] 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. 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

[90] 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.

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) Operating committee

In the framework of the JOA the parties established an operating committee, which has the authority and responsibility to approve and supervise the joint activities required or necessary to meet the conditions of the Petroleum Asset and the JOA, for exploration and exploitation of Petroleum Asset areas in accordance with the JOA and in an appropriate manner according to the circumstances. The operating committee is made up of representatives of the parties (and their alternates) and each representative of a said party will have the right to an opinion equal to the working interest which it represents. The JOA determines the order of processes and proceedings for convening meetings of the operating committee and the discussion at them and includes processes and arrangements for making decisions in writing.

Unless otherwise provided for specifically in the JOA, all decisions, approvals and other activities of the operating committee with regard to the proposals presented before it, will be decided by the vote in favor of at least 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: (1) if it becomes insolvent, bankrupt or if it has made an arrangement with its creditors; (2) if a notice was provided by a party to an agreement in the event of a court order or valid decision for reorganization under the insolvency laws; (3) if a receiver is appointed to a significant portion of its assets; or (4) if the operator is liquidated or ceases to exist in another manner.

Furthermore, the operator may be removed from its position by a decision of other parties to the JOA (that are not the operator) if it materially breached the JOA and did not commence the remedy of said breach within 30 days from the date upon which it received notice detailing said breach, or if it did not act to complete the remedy of the breach. Any decision of other parties to the JOA (that are not the operator) to give a notice of breach to the operator or to remove the operator will require an affirmative vote in favor of the decision of one or more of the parties that are not the operator (or that are not a related party or an affiliate of the operator) that represent collectively at least 65% of the total working interests of the parties that are not an operator.

When there is a change in the identity of the operator as aforesaid, then the operating committee will convene as soon as possible in order to appoint an operator, however no party to the JOA will be appointed as operator against its will. The operator that was removed from office against its will or the related party/affiliate will not be permitted to vote in favor of itself or to be a candidate for the position of operator.

(h) 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: (1) all of the required governmental approvals, as well as the guarantees required by the government; and (2) 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 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).

7.25.7 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 7.25.6 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. However, it is noted that in the joint operating agreement that applies to Block 12, the parties do not have a right of first refusal in the case of transfer of rights in the petroleum asset.

7.25.8 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 7.25.8(c)2 below, and undertakings originating from Avner's Limited Partnership Agreement as specified in Section 7.25.8(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. <u>The Effective Rate of the royalties in the Tamar project</u>.

   Since commencement of production in 2013, a dispute has arisen 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 taking action to resolve this dispute vis-à-vis the Ministry of Energy. Further to the draft royalty audit reports for 2013-2018 that were received from the Ministry of Energy, and based on the understandings that are being finalized vis-à-vis the Ministry of Energy following discussions that were recently held in connection with the draft audit reports as aforesaid, the Partnership has updated non-material gaps in the aggregate amounts carried to the Statement of Comprehensive Income in the "expenses of royalties to the State" item (in 2013-2018). In the Partnership's estimation, and based on the understandings that are being finalized as aforesaid, the Partnership will be entitled to receive from the State (by way of setoff against future royalty payments in 2024) a sum of approx. $17.2 million for the years 2013-2018. The Partnership will also be entitled to receive from the royalty interest owners a total sum of approx. $8.3 million in respect of the said years. For further details, see Note 15B4 to the financial statements (Chapter C of this report).

   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. <u>The Effective Rate of the royalties in the Leviathan project</u>

   According to a demand letters received from the Ministry of Energy in October 2023 and January 2024, the Leviathan Partners are required to make advance payments to the State on account of the State Royalties in respect of the revenues from the Leviathan project in 2023 and 2024 at the rate of 11.06%, *in lieu* of 11.26% as paid by the Leviathan Partners since the date of commencement of the gas supply from the Leviathan reservoir in accordance with a demand letter 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 rate of the State Royalties in the Leviathan project should be approx. 9.58%. Accordingly, the rate of the royalties on which the Partnership relied was approx. 10.9% its financial statements for 2022, and approx. 10.73% in its financial statements for 2023.[91] The difference between the royalties actually paid to the State by the Partnership in the Leviathan project and the Effective Rate of royalties on which the Partnership based its financial statements for the years 2019 to 2023 is approx. $15 million. For further details see Note 15 to the financial statements (Chapter C of this report).

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) Royalty payment obligations to the Royalty Interest Owners [92]

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.[93] ("**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

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[91] It is noted that in the discounted cash flow figures for the Leviathan project, the Partnership assumed that the Effective Rate of the State Royalties was 11.06%.

[92] 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.

[93] Following the reorganization that was carried out in the past, the royalty right as aforesaid of Delek Israel was transferred to Delek Group.

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), 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.

With respect to determining the Investment Recovery Date, the following provisions were determined in conditions of the royalties:

1. The term "**Investment Recovery Date**" means – The date after the signing of the Interest Transfer Agreement in which the (Net) Revenues Value (as defined below) that the Partnership received or is entitled to receive in respect of petroleum and/or gas and/or other valuable materials produced and used from the Petroleum Asset (i.e. – license or lease) where the finding is located, calculated in dollars (according to the representative exchange rate published by the Bank of Israel) will reach an amount equal to the full Value of All of the Partnership's Expenses in such Petroleum Asset (as defined below), calculated in dollars (according to such representative exchange rate).

2. The term "(Net) Revenues Value" means – The value of all revenues as shall be approved by the Partnership's accountants in respect of petroleum and/or gas and/or other valuable materials produced and used from the Petroleum Asset (i.e. - license or lease) (the "**(Gross) Revenues Value**") after deduction of all expenses for production thereof and royalties paid therefor.

3. The term "Value of All of the Partnership's Expenses" means – any and all expenses that the Partnership

incurred in the Petroleum Asset (i.e. – license or lease) where the petroleum and/or gas and/or other valuable materials are extracted, but with the exception of expenses (up to the (Net) Revenues Value) deducted from the (Gross) Revenues Value for the purpose of determining the sum of all of the (Net) Revenues Value and as approved by the Partnership's accountants.

For details on a legal proceeding being conducted in connection with the Investment Recovery Date in the Tamar Project, see Section 7.26.5 below.

(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**").[94] Delek Group and Delek Energy are entitled to Delek Group Royalties with respect to all the remaining petroleum 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.

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 Agreement[95] (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.

[94] 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.

[95] 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**").

4. Terms and conditions of the royalties

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 Interest 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 Interest Owner. Such payment shall be made once every month. The measurement of the quantities of oil and/or gas and/or other valuable substances that shall be produced and exploited from the petroleum assets, for the purpose of calculating the royalties due to the Royalty Interest Owners, shall be made in accordance with accepted principles in the petroleum industry.

(b) The Partnership shall keep full and accurate records concerning its share in the oil and/or gas and/or other valuable substances that shall be produced and exploited from the petroleum assets in which it has an interest. Each of the Royalty Interest Owners shall be entitled to appoint an accountant who shall be entitled to inspect, examine and copy, during normal work hours, the Partnership's books and other documents and records regarding the Transferors' right to the royalties under the Interest Transfer Agreement.

(c) The aforesaid right to royalties shall be linked to the Partnership's share in each of the petroleum assets in which it has an interest. Should the Partnership transfer its rights in a petroleum asset in which it has an interest, the Partnership shall ensure that the transferee assume all of the undertakings to pay the royalties as aforesaid. The aforesaid shall not apply at the event of asset forfeiture due to the Partnership being behind on payments. Regarding the Royalties by Virtue of the Avner Partnership Agreement, the aforesaid shall also not apply in the event of a transfer to partners who are continuing operations by some of the participants (sole risk).

5. 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 7.25.8(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 7.26.1 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 Royalty Interest 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. For details about the legal proceeding that the Partnership is conducting vis-à-vis the State regarding the Yam Tethys Dispute, see Section 7.26.1 below.

7.25.9 Agreement for the sale of the Partnership's interests in the Tanin and Karish Leases

Following the Government decision to approve the Gas Framework, on 16 August 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.

7.25.10 The agreement for the sale of 9.25% of the interests in the Tamar and Dalit Leases to Tamar Petroleum

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 2 July 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.

7.25.11 Agreement for the sale of the Partnership's remaining interests (22%) in the Tamar and Dalit leases

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 2 September 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.[96]

For further details regarding the agreement, see Section 7.24.12 of the 2021 Periodic Report.

7.26 **Legal proceedings**

7.26.1 On 12 March 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 31 December 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 31 December 2022, approx. $19.4 million, the Partnership’s share being approx. $9 million.

On 14 November 2022, the court handed down a judgement dismissing the claim, except as related to the Plaintiffs’ position regarding the restitution of interest amounts the defendant had collected from the Plaintiffs in an insignificant amount.

On 6 February 2023, the Plaintiffs filed an appeal from the judgement with the Supreme Court. On 13 August 2023, the Defendant filed its response to the appeal, and a hearing on the appeal has been scheduled for 15 July 2024.

In the Partnership’s estimation, based on the opinion of its legal counsel, the prospects of the Plaintiffs’ success in the appeal are difficult to assess, further to the issuance of the judgment and since the a hearing on the appeal has not yet been held.

The decision on this matter, when it becomes final and conclusive, shall also apply, *mutatis mutandis*, with respect to the overriding royalties that the Partnership paid over the years for the Tamar Project, in

[96] 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.

accordance with the agreements described in Section 7.25.8(c)5 above. Accordingly, insofar as the court's said decision of 14 November 2022 stands, the Partnership shall bear an additional payment to the Royalty Interest Owners 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. $6.2 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 Interest Owners.

For further details, see Note 7C9 to the financial statements (Chapter C of this report).

7.26.2 On 25 December 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 13 February 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 6 July 2017, the court ordered to add the Partnership as a respondent in accordance with the Partnership's motion. On 7 May 2023 the court handed down its judgment, which denied the Certification Motion.

On 6 July 2023, the Petitioners filed an appeal from the judgment with the Supreme Court, requesting the Supreme Court to accept the appeal and order the grant of the Certification Motion.

On 27 December 2023, PWC filed a counter appeal from the judgment, which is litigated within the aforesaid appeal, arguing that the District Court erred in that it failed to order costs in its favor (in this section: the "**Counter Appeal**").

According to the court's decisions, the parties are required to file their responses to the appeal and the Counter Appeal by 15 April 2024. A hearing on the appeal and the Counter Appeal has been scheduled for 2 January 2025.

In the Partnership’s estimation, based on the opinion of its legal counsel, the chances of the appeal’s being dismissed are greater than the chances of its being granted.

7.26.3 On 4 February 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: “**Leader**” and 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 12 July 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 13 August 2019, the court ordered the Petitioners to deliver the pleadings in the file to the Attorney General in order that he give notice by 15 September 2019 of whether he wishes to be joined to the proceeding, and on 6 February 2020, the Attorney General gave notice that at this stage he does not deem fit to join the proceeding. On 1

November 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 6 April 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 23 January 2022, an amended motion for class certification was filed, and on 21 August 2022 and 4 September 2022, the Respondents filed their response to such motion. On 20 December 2022, a pretrial hearing was conducted, and in accordance with the court's decision as part thereof, on 17 January 2023, the Petitioners filed an amended response to the Respondents' answers to the amended Certification Motion.

On 23 April 2023, the Petitioners filed a motion for a discovery order, and on 17 July 2023, the court denied the motion for discovery in relation to all the Respondents, except Leader, with respect to which the motion was partly granted. Furthermore, on 16 August 2023, the court approved an agreed procedural arrangement between the parties, whereby the cross-examination of witnesses in the context of the Certification Motion would be conducted in February-April 2024. As of the report approval date, the case is at the trial hearing stage, which is expected to be completed in 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%.

7.26.4 On 27 February 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 22 December 2020 the other holders of the Tamar project filed a motion for summary omission thereof, and on 9 September 2021 the Court approved their omission. Furthermore, on 17 November 2021, the court approved Ratio's stipulation to be omitted from the Certification Motion.

On 9 December 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 27 February 2022, the Court decided that this motion will be heard at the pretrial hearing set for 24 April 2022. On 28 February 2022, the Petitioner filed a response to the Respondents' response to the Certification Motion.

On 24 April 2022, in the context of a pretrial hearing, the court ordered as follows: (a) 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; (b) the Petitioner shall be given an opportunity until 24 May 2022 to file a motion to amend the Certification Motion; (c) 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 (d) on 25 May 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 25 May 2022, the partied filed a list of questions which will be directed to the regulator, and on 31 May 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 19 January 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 6 February 2024, the court granted the Petitioner's motion, with the consent of the Respondents, to cancel the trial hearings scheduled for March-April 2024, and no new dates have been scheduled therefor.

In the Partnership's estimation, based on the opinion of its legal counsel, the chances of the Certification Motion being granted are lower than 50%.

7.26.5 On 6 January 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,[97] 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 4 April 2019, the Royalty Interest Owners filed an answer and a counter-complaint against the Partnership, the General Partner and the

[97] On 13 June 2021, Delek Royalties (2012) Ltd. announced the change of its name to Tomer Energy Royalties (2012) Ltd. ("**Tomer Energy Royalties**").

supervisor (in this section: the "**Counterclaim**"). In the Counterclaim, the Royalty Interest Owners argue, *inter alia*, that the Partnership's calculation of the Investment Recovery Date in respect of the Tamar project included expenses that were "loaded" onto the calculation, and *inter alia*, financial expenses of the Partnership itself, future expenses of uncertain amount with respect to the retirement and disposal of facilities, headquarter expenses of the Partnership and any expense intended for stages of the project that are subsequent to the "wellhead". The Royalty Interest Owners argue that, discounting such expenses, the Investment Recovery Date in respect of the Tamar project had already occurred in August 2015, or alternatively – in 2016, or further alternatively – in 2017. Accordingly, the Royalty Interest Owners move the Court to declare which expenses should be taken into account in the calculation of the Investment Recovery Date, 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 2 October 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 5 April 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.

On 21 December 2023, at the parties' request, the court ordered the dismissal of the Supervisors' Claim and the Counterclaim, with no order for costs, in view of mutual agreements at which the parties had arrived, in the context of which, *inter alia*, the parties confirmed the original calculation that had been made by the Partnership (subject to the correction of an error with respect to abandonment costs attributed to the Partnership for which a provision of approx. $1.6 million had been made on the Partnership's books as early as 2018). Furthermore, the Royalty Interest Owners and the Partnership confirmed that the principles by which the investment recovery date had been calculated for the Tamar project would apply (after certain adjustments that are specified under the mutual agreements) also in relation to the calculation of the investment recovery date for the Leviathan project.

7.26.6 On 23 April 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 17 January 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 2 January 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. On 10 December 2023, the Petitioner filed written statements on his behalf, and according to the court's decision, the Respondents and the Plaintiff are required to file written statements and responding summations during 2024, and all by 7 June 2024.

In the Partnership’s estimation, based on an opinion of its legal counsel, the chances of the motion being granted are lower than 50%.

7.26.7 On 3 May 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 31 August 2021, and on 1 December 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 1 December 2021.

On 11 September 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. On 8 July 2023 and 18 July 2023, the court denied the motions the parties had filed with respect to the preliminary proceedings and scheduled a last pretrial hearing for 4 June 2024.

It is also noted that on 3 April 2023, Haifa Port filed a motion for summary dismissal of the counterclaim, arguing lack of controversy between itself and Chevron, because the invoices and mooring fees had been paid by an agent. Such motion was denied on 21 June 2023 and the court issued an order for costs against Haifa Port.

In the Partnership's estimation, based on the opinion of its legal counsel, the Primary Claim is more likely to be denied than accepted.

7.26.8 On 31 May 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 in cash in the sum of $108.5 million (the "**Balance of the Consideration**"). Therefore, in the opinion of the Partnership, Energean's notice of 30 April 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. On 19 April 2023, a pretrial hearing was held on the Claim, and according to a decision issued therein, the parties filed, on 10 May 2023, a joint motion with the court regarding their consent to defer to a mediation proceeding, without this delaying the litigation of the Claim. On 13 August 2023, the court approved an agreed procedural arrangement between the parties, whereby, *inter alia*, a pretrial hearing was scheduled for 7 December 2023. On 5 November 2023, mutual agreements at which the parties had arrived were entered as a judgment, whereby Energean will pay the Partnership, in two installments during 2024, a total amount of approx. $47.4 million, which constitutes the entire Balance of the Consideration plus agreed annual interest. This constitutes the full and final discharge of the parties' claims in relation to the disputes to which the legal proceeding pertained.

7.26.9 On 3 December 2023, a participation unit holder of the Partnership (in this section: the "**Petitioner**") filed a motion against the Partnership, in accordance with Section 65OO of the Partnerships Ordinance and Section 198A of the Companies Law, for the issuance of an order for the discovery and review of documents before filing a derivative claim against the General Partner; Mr. Yossi Abu, CEO of the General Partner; and the members of the General Partner's board of directors (including members of the compensation committee) in the relevant period (in this section: the "**Discovery Motion**"). In summary, the Discovery Motion is based on the claim that the approval of Mr. Abu's current terms of office and employment by the compensation committee and the board of directors, in the "overruling", against the position of the general meeting of the participation unit holders, was done in violation of the law, while breaching the duties of care and fiduciary duty applicable to the members of the board of directors and in violation of Mr. Abu's duty, as CEO of the General Partner, to act in the best interests of the Partnership. As part of the Discovery Motion, it was claimed that the approval of Mr. Abu's terms of office and employment in the overruling was done without the conditions required therefor being met pursuant to the Partnerships Ordinance; that there was no sufficient re-discussion of the terms of office and employment of Mr.

Abu and that no reference was made therein to the general meeting's objection; and that the reasons detailed by the board of directors did not refer to the mere rejection by the general meeting of the approval of Mr. Abu's terms of office and employment.

It is noted that in proximity to the filing of the Discovery Motion, the Petitioner filed with the court, a notice regarding additional motions for discovery and inspection of documents before the filing of the derivative action, which were filed by him or by his counsel, based, as he alleges, on a "similar factual matrix"; against other respondents: Delek Group Ltd. (D.A. 58205-11-23); Electra Ltd. (D.A. 50050-11-23), Matrix I.T. Ltd. (D.A. 60805-11-23); and Scope Metals Ltd. (D.A. 47021-11-23) (the "**Additional Proceedings**").

On 6 December 2023, the court ordered that the parties to the Additional Proceedings consider consolidating their hearings by choosing a lead case ("**Locomotive Case**") which shall govern the decisions in all of the Additional Proceedings; or in any other way (the "**Consolidation of the Hearing**"). On 8 January 2024, the Petitioner informed the court of his consent to the Consolidation of the Hearing, and on that date the Partnership filed its objection with the court to the Consolidation of the Hearing, since, *inter alia*, these are different and distinct proceedings, which concern other decisions, made by other entities, in relation to the terms of office of other officers and in other corporations; and that under these circumstances the consolidation of the proceedings is not expected to simplify and streamline the hearing thereof, and there is no concern of conflicting decisions between them, as required by law in order to consolidate the hearing in parallel proceedings. To the best of the Partnership's knowledge, the respondents in the Additional Proceedings also opposed the proposal for Consolidation of the Hearing.

In accordance with the court's decision, the Partnership is required to file its response to the Discovery Motion by 2 April 2024.

In the Partnership’s estimation, based on an opinion of its legal counsel, the chances of the Discovery Motion being granted are lower than 50%.

7.27 Goals and business strategy

7.27.1 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 while protecting sustainability values. 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, in accordance with the ESG policy adopted by the Partnership, in order to generate optimal value for the Partnership's stakeholders.

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 order to accomplish targets of reduction of greenhouse gas emissions from the Partnership's assets to zero, and 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, the Partnership is exploring possibilities for investment in the alternative energies sector. In this context, the Partnership has entered into an agreement with Enlight, as specified in Section 7.9 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.

7.27.2 **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. Ensuring natural gas and condensate supply 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 to various potential consumers in Israel and in counties in the region, chiefly Egypt and Jordan.

2. Promoting the development of Phase 1B and increasing the maximum daily production capacity to approx. 2,350 MMCF (up to approx. 21 BCM per year), as specified in Section 7.2.5(b)(2) above, with the purpose of making a final investment decision (FID), to consumers in the domestic market, to the regional market, chief of which - to the Egyptian market and LNG markets, by means of expanding the transmission capacity (as specified in Section 7.12.2 above).

3. Promoting the consideration of prospecting for oil 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 details regarding the possibilities of piping the gas to Egypt which are being examined by the Partnership, see Section 7.12.2(d) above.

(d) Oil and gas exploration

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 has signed agreements regarding exploration and production activities in the area of the Boujdour license in Morocco, and has also been granted the Zone I Licenses, in the area of Blocks 4, 5, 6, 7, 8 and 11 in the Mediterranean Sea, within Israel's exclusive economic zone (EEZ). For further details, see Section 7.6 and 7.7 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 natural gas use: 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 the termination of all coal-fired electricity generation in the interest of switching to power generation by natural gas, 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.

7.27.3 **Alternative energies**

(a) Renewable energies

The Partnership is exploring possibilities for investing in projects in the field of renewable energy as part of a collaboration with Enlight, as specified in Section 7.9 above.

(b) Hydrogen production

The Partnership is examining a blue hydrogen venture, in which natural gas is split into hydrogen and carbon dioxide (CO2), with the carbon dioxide being collected and stored in designated subsurface storage sites, or connected in various ways to rocks underground or in seawater or used for the manufacture of various products. It is noted that hydrogen is 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. For further details, see Section 7.14.4 above.

7.27.4 **ESG**

The Partnership strives to realize the potential of its primary assets, the Leviathan and Aphrodite reservoirs, responsibly and efficiently, in order to open up optimal value for stakeholders while actively protecting its ESG values.

The Partnership, in collaboration with the other Leviathan Partners, is holdings discussions with stakeholders, primarily the Government of Israel, on the optimal development plan, which balances technical, national, commercial, environmental and social considerations.

In this context, it is noted that although natural gas is a fossil fuel and perishable resource, the demand for natural gas is expected to grow in the coming decades, particularly in the Middle East.

The Partnership is expanding its operations in order to discover additional resources and meet the growing demand, both in the Mediterranean and on the coast of North Africa. The Partnership recognizes that natural gas is a transitional fuel and therefore acts to expand its renewable energy operations, as specified in Section 7.9 above, and also promotes abilities via clean energy technologies, such as hydrogen.

7.27.5 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 using 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 7.29 below. It is further clarified that realization of the goals and strategy specified above is subject to approvals by the Partnership's competent organs, some of which have not yet been obtained, including the general meeting of the unit holders, as well as third-party approvals.

7.28 **<u>Insurance coverage</u>**

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 aforesaid insurance policies have been taken out partly independently and partly in the framework of the operator's insurance system. Some of the insurance policies are subject to 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(n) 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 7.29.12 below.

7.29 <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.

7.29.1 <u>The Iron Swords War</u>

As of the report approval date, the Iron Swords War is ongoing in Gaza at varying levels of intensity against the Hamas terrorist organization, and clashes on the northern border with the Hezbollah terrorist organization are also ongoing, and there is considerable uncertainty as to the development and outcome of the war. There is risk of escalation on the northern border or escalation of the situation in additional fronts, and it is impossible to assess the impact of the war on the Partnership's operations, and primarily on continued regular production from the Leviathan reservoir and marketing of gas to export customers and the domestic market. For details with respect to the halt of production from the Tamar reservoir in the first stages of the war, see Section 6.9.4 above.

Natural gas platforms, the offshore and onshore production and transmission facilities, and other essential infrastructure systems in Israel and in the export countries may constitute targets for missile firing and acts of sabotage, and impact they suffer, if any, may cause extremely significant damage and disrupt or shut down the production and/or transmission activities for such amount of time and to such extent that may prove to be considerable. In such cases, the insurance policies that Chevron and the Partnership have acquired may possibly prove insufficient to cover the damage and loss suffered by the Partnership. In this context, it is noted that there is risk that at the renewal date of the insurance policies, chiefly in connection with war and terrorism, it will be impossible to acquire appropriate policies on reasonable commercial terms or at all. Another risk that arises from the war is for impact on the facilities for intake of condensate, a byproduct of the natural gas production from the Leviathan project. It is noted that, in the Partnership's estimation, the risk of events of this type is primarily relevant in relation to the eventuality of escalation on the northern front of the State of Israel. In such case of escalation of the war, the risk of imposition by the Government of restrictions on the regular production operations of the Leviathan reserve and/or the Tamar or Karish reservoirs may increase as well. Restriction or discontinuation of the production from the Tamar and/or Karish reservoirs is expected to compel the Leviathan Partners to increase the quantities of supply to the domestic market, predominantly at the expense of the export to Egypt.

Moreover, against the backdrop of the ongoing war, there is an increase in the geopolitical risk related to the export of natural gas from the Leviathan reserve pursuant to the export agreements, which accounted for most of the Partnership's revenue in 2023.

In addition to the foregoing, in the event of significant escalation of the security situation, which leads to the early termination of the export agreements or which results in physical damage to the Leviathan project which is not remedied or in other events that are reasonably expected to cause a material adverse effect, and subject to remedying periods, qualifications and conditions, there is a risk of breach of the terms and conditions of the bonds of Leviathan Bond, which are secured by the Partnership's interests in the Leviathan project and are traded on the TACT-Institutional system of Tel Aviv Stock Exchange Ltd. (in this section: the "**Bonds**"), which may provide the holders of the Bonds with a cause for acceleration and enforcement of the collateral. For further details with respect to the Bonds, see Section 7.20.2 above. It is further noted that an increase in the returns on the Bonds due to the development of the war may adversely affect the Partnership's ability to raise additional debt and increase the finance costs in respect of such additional debt raising.

7.29.2 Pandemic outbreaks

The Covid crisis, which started in 2020, impacted the global economy in general and the energy sector in particular. As of the report approval date, Covid morbidity rates are significantly lower than they were in the preceding years, and the effects of the pandemic on the economy and the energy sector are highly limited. Still, it is possible that a renewed outbreak of Covid or an outbreak of other pandemics will occur, which may have a significant effect on the financial markets, interest margins, currency exchange rates and the prices of commodities in the energy sector, thereby adversely affecting many industries, including the energy sector in which the Partnership operates, with the effects being similar to or even harsher than the effects of the Covid pandemic outbreak. As of the report approval date, it is impossible to assess the probability for materialization of risks of this type.

7.29.3 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.

7.29.4 Changes in demand and in the prices of the energy products

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.

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 wars, hostilities and local or regional armed conflicts, 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 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.

7.29.5 Global macroeconomic factors

The Partnership's ability to sell natural gas from its assets, and 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*, wars, hostilities and local or regional armed conflicts, 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, such as attacks on ships on their way to Israel by the Houthi rebels, 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, 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 2023, the Partnership’s operations and results were influenced by various factors, including the changes in energy prices due to 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.

7.29.6 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.

7.29.7 Difficulties in obtaining financing

For the promotion of additional development phases in the development plan of the Leviathan reservoir or the development of additional reservoirs in the future, such as the Aphrodite reservoir, if it is decided to drill the same, the Partnership will need additional significant financial sources, and the Partnership may be required to raise capital or additional financing, including through a future raising of bank debt or a private or public bond offering.

Raising of additional financing or withdrawal of credit from the Credit Facility as specified in Section 7.20.3 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.

7.29.8 Competition over gas supply

The Partnership is exposed to competition over the supply of natural gas to the domestic market and to export markets, 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 7.14 above.

7.29.9 Restrictions on export

The results of the Partnership's operations are highly dependent on the ability to export gas from the Leviathan reservoir and sell it in the regional and international market. The Government Resolutions with respect to export, as specified in Section 7.23.8 above, limit the quantity of gas that may be exported. Therefore, in the event that a decision is adopted regarding further restrictions in connection with 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 7.11.3(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.

7.29.10 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 or disruption in the Transmission Systems that are 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.

7.29.11 Operational risks

Operations of exploration, development, production and decommissioning of oil and natural gas assets, particularly in deep water, entail 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 aforesaid events may significantly reduce or completely put a stop to the ability to produce or supply the natural gas, undermine the schedule and budget of the operations, damage the quality of the sold hydrocarbons, and consequently lead to the imposition of fines for failure to comply with contractual terms and conditions and even to the termination of existing gas sale agreements of the Partnership.

In addition, operations of drilling, completion and sealing of deep water well require use of specifically-designated technologies and equipment, and usually take longer and cost more than their onshore counterparts, due to the considerable complexity of such operations and due to the need to sustain and maintain long supply systems. In view thereof, these operations are exposed to significant risks and challenges.

7.29.12 Lack of sufficient insurance coverage

Although 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 terrorism, war, cyber and loss of control of the well, and with respect to damage to any kind of property inside the well. The Partnership's insurance policies include, *inter alia*, specific coverage for the Partnership's holdings in the Leviathan project against physical damage and loss of profits related to physical damage, due to risks of political violence, including risks of war and terror. The policy covers property damage over and above the coverage to which the Partnership is entitled from the State under the Property Tax and Compensation Fund Law, 5721-1961, and specific coverage for loss of income for a certain period. The said coverage is renewed from time to time and is subject to its availability in the insurance market under reasonable terms and conditions. It is further noted that the insurance policies purchased by the Partnership do not cover an event of loss of income that results from the halting of production following receipt of a mandatory regulatory directive, as received by the Tamar Partners after the outbreak of the Iron Swords War. For further details regarding the impact of the Iron Swords War on the Partnership's insurance policies, see Section 7.29.1 above. 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 7.12.2(c) above) and in Egypt (as specified in Sections 7.12.2(d) and 7.25.5 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.

7.29.13 <u>Construction risks, dependence on contractors and on professional service and equipment suppliers</u>

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, and specifically the Iron Swords War. It is noted that the price of the services and costs of exploration, development, production and decommissioning operations is determined according to supply and demand on the markets, which are affected, *inter alia*, by commodity prices, regulation changes, the supply of alternative products and the level of activity in the industry.

7.29.14 <u>Risks of exploration activity and reliance on partial and estimated data, estimates and evaluations</u>

Operations of exploration for oil and gas reservoirs entail a high level of risk, mainly because the geological and geophysical means do not provide a precise picture of the location, form, characteristics or size of the subsurface, and therefore exploration operations 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.

It is noted that, given the aforesaid, the information included in the report with respect to 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 resources 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 fully 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**.

7.29.15 Merely estimated costs and timetables and the eventuality of lack of means

Estimated costs of and estimated timetables for the execution of exploration, development, operation and maintenance activities, are based on past experience and general estimates, and may thus entail considerable deviations, including in consequence of events that are not within the Partnership's control. In addition, exploration and development 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 may cause the timetable to be extended far beyond the plan, and the actual expenditure required for completion of the activities to be considerably higher than the costs planned therefor.

7.29.16 Forfeiture of the Partnership's interests in its petroleum assets and the financial strength of the partners in the petroleum assets

The activities of exploration, development and expansion/maintenance of the capability to supply gas in the Partnership's petroleum assets, entail considerable financial expenses, which the Partnership may not have the means to cover. According to the joint operation agreements, failing to pay on time the Partnership's share in an approved budget for the performance of an approved work plan constitutes a breach that may lead to the loss of the Partnership's share in the petroleum asset/s to which the operation agreement and/or agreements applies and/or apply.

In addition, in a situation where other parties to the joint operating agreements shall not have paid amounts that they were supposed to pay, the Partnership may be required to pay amounts that considerably exceed its proportionate share in such petroleum assets. Due to the especially high cost of development expenses and offshore drillings, these additional costs may lead to the Partnership's being unable to meet its financial obligations and as a result, it will lose its rights in the petroleum assets.

In view of the aforesaid, the financial strength of the partners in the petroleum assets held by the Partnership may have repercussions, *inter alia*, on its cash flow.

7.29.17 Dependence on obtaining regulatory and other approvals

Exploration, development, production and decommissioning activities 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 Energy, the Ministry of Environmental Protection, the Ministry of Defense, 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.

7.29.18 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 activities of exploration, development, production, marketing and decommissioning of gas and oil facilities and reservoirs, natural gas supply terms and conditions, natural gas export, taxation of oil and gas profits, rules for 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, they may cause the Partnership and/or its customers to be unable to comply with their obligations according to preexisting agreements.

For details regarding the main regulation that applies to the Partnership's operations as of the report approval date, see Sections 7.22.2 and 7.23 above.

7.29.19 <u>Potential control of natural gas prices</u>

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 7.23.2(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.

7.29.20 <u>Applicable environmental regulation</u>

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 seepage or leakage of oil, natural gas or other pollutants into the marine environment, discharge into the sea of pollutants and waste of various types (wastewater, operating fluids, cement, 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, activities of exploration, development, production and decommissioning of oil and natural gas assets in deep water entail various risks, all the more so due to activities in shallow water and onshore, including the discharge 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 7.22.2(i) 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.

7.29.21 Climate changes

Climate changes are a gamut of phenomena that have been extensively documented and researched in recent decades, which require mankind to prepare in terms of slowing down adverse changes (e.g., decreasing the temperature increase rate) and in terms of contending with the implications of the phenomena (e.g., dealing with the rising sea level). Climate changes affect 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 a stated government policy on dealing with climate changes, which is mainly prevalent among 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 carbon tax). For details regarding decisions and plans published on this issue on behalf of the Israeli government and government authorities, see Section 7.23.10 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 for investing in projects in the renewable energy sector, in the context of the collaboration with Enlight, as specified in Section 7.9 above, and in blue hydrogen projects, as specified in Section 7.27.3(b) above.

7.29.22 <u>Dependence on weather and sea conditions</u>

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) 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, see Section 7.1.4 above.

7.29.23 <u>Cyber and information security risks</u>

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 cyber threats worldwide in terms of their sophistication and complexity and the number of attacks against organizations in Israel, particularly during this time of the Iron Swords War, and following the changes in the labor market in view 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 General Partner'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. As part of its operations, the Partnership constantly improves its information security scheme, while adopting guidelines of various international standards.

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.

Moreover, from time to time, the Partnership conducts risk surveys and penetration tests 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 in charge of implementing the defense policy, and the Partnership is also assisted by the outsourced services of an information security manager and an IT company, and they act on an ongoing basis for constant reinforcement and improvement of the Partnership’s defense scheme. The responsibilities of the Partnership’s information security manager include, *inter alia*: (a) establishment of the defense policy and supporting procedures; (b) implementation of a work plan and ongoing control over compliance with regulation requirements, the defense policy and the procedures; (c) instruction in connection with the implementation of cyber defense measures in the Partnership and issuance of instructions prior to the incorporation of new business systems; (d) enhancement of the employees', management's and the board of directors' awareness of the changing cyber risks; (e) control over the managerial network's supply chain; and (f) instruction of the Partnership and the aforesaid 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.

It is noted that the Partnership allocates a specifically-designated budget to cyber risk management, in accordance with its needs.

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.

7.29.24 <u>Changes in investment trends due to ESG 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.

These trends may manifest 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 and 2023 in Q2/2024.

7.29.25 <u>Tax risks</u>

Tax issues related to the Partnership’s operations, including with 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 7.21 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 7.21.1 above.

7.29.26 Financing-related obligations

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 7.20 above. Furthermore, the Credit Facility prescribes financial covenants with which the Partnership is required to comply in the event that it makes a drawdown therefrom and noncompliance with which entitles the lender to immediate repayment, as specified in Section 7.20.4 above.

7.29.27 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 7.11.3 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.

7.29.28 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 operations in 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.

7.29.29 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.

7.29.30 Revocation or expiration of petroleum interests and assets

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 case of non-compliance with such terms, the petroleum interest may be revoked, subject to the Petroleum Law. Furthermore, noncompliance with the terms set forth in the Petroleum Law or with the terms and conditions of the PSC Agreement granted to the partners in the Aphrodite reservoir from the Government of Cyprus may lead to loss of the interests and all the money invested in such interests may be lost. For details with respect to noncompliance of the partners in the Aphrodite reservoir with the Milestone specified in the terms and conditions of the PSC Agreement in relation to the execution of the FEED for the development plan approved by the Government of Cyprus, see Section 7.3.11 above.

7.29.31 Overflow of reservoirs

Oil or natural gas reservoirs discovered or to be discovered in areas in which the Partnership holds interests may overflow (in terms of the span 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.

7.29.32 Security risks

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.[98] For further details with respect to security risk factors, see paragraph 7.29.1 above in relation to the Iron Swords War.

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.

7.29.33 <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 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.

[98] 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.

7.29.34 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.

7.29.35 The Partnership's status as a monopoly

As provided in Section 7.23.2(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).

7.29.36 *“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.

7.29.37 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			
Iron Swords War	X		
Outbreak of pandemics			X
Fluctuations in linkage components in the natural gas price formulas in the supply contracts		X	
Changes in demand and in energy product prices		X	
Global macroeconomic factors	X		
Geopolitics	X		
Industry Risks			
Difficulties in obtaining financing		X	
Competition over 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	
Merely estimated costs and timetables and the eventuality of lack of means		X	
Forfeiture of the Partnership's interests 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 over natural gas prices		X	
Applicable environmental regulation	X		
Climate changes		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			
Tax risks		X	
Financing-related obligations			X
Dependence on customers		X	

	Degree of Risk Factor's Effect on Partnership's Business		
	Significant Effect	**Medium Effect**	**Small Effect**
Reliance on the operator	X		
Risk in development and production in the case of 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 of Professional Terms

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.

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 in specifically-designated tanks 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**

<u>Abbreviations, partial list</u>

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

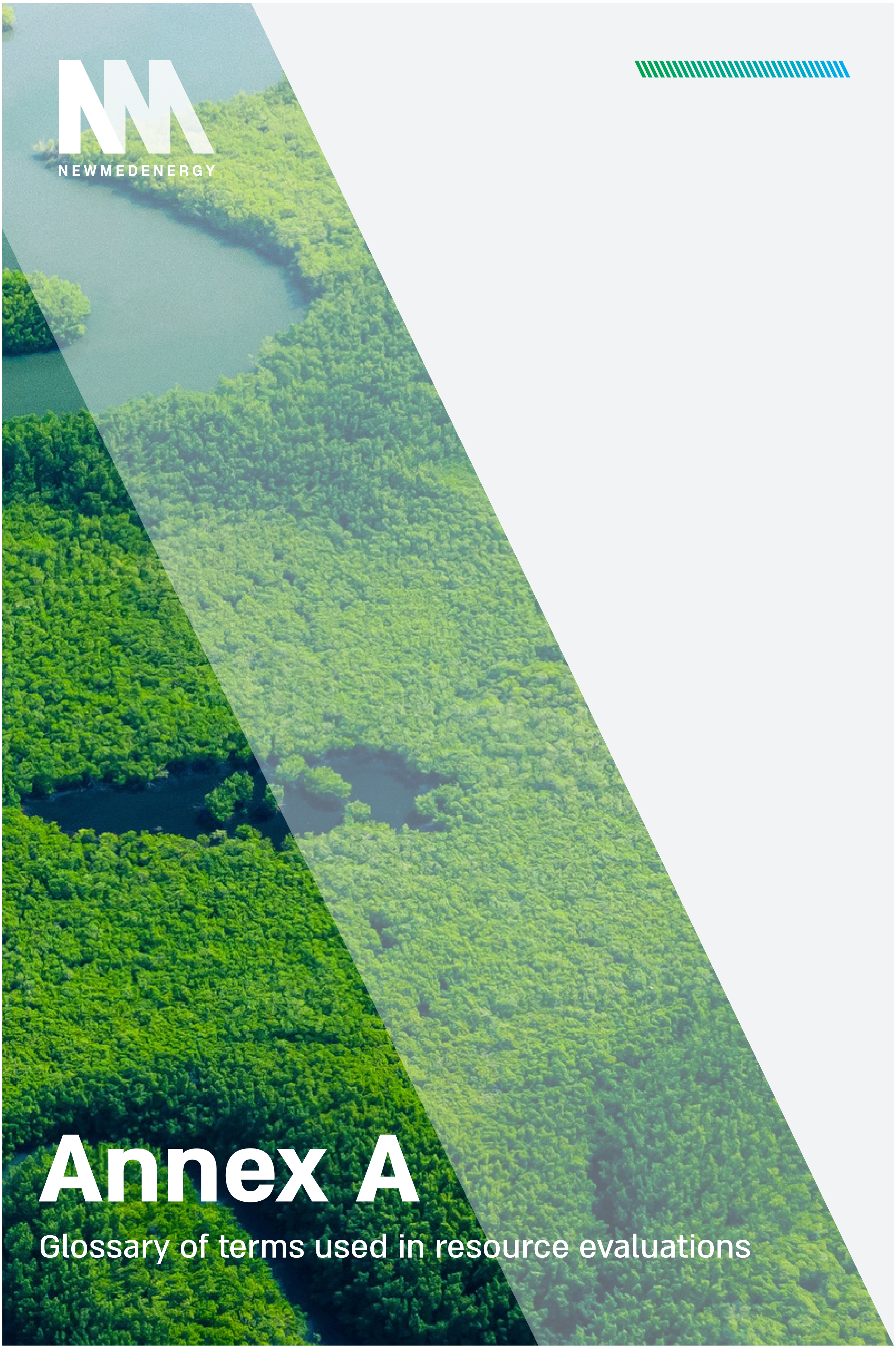
TCQ – Total Contract Quantity

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



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, Rs; produced gas/oil ratio, Rp; 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.

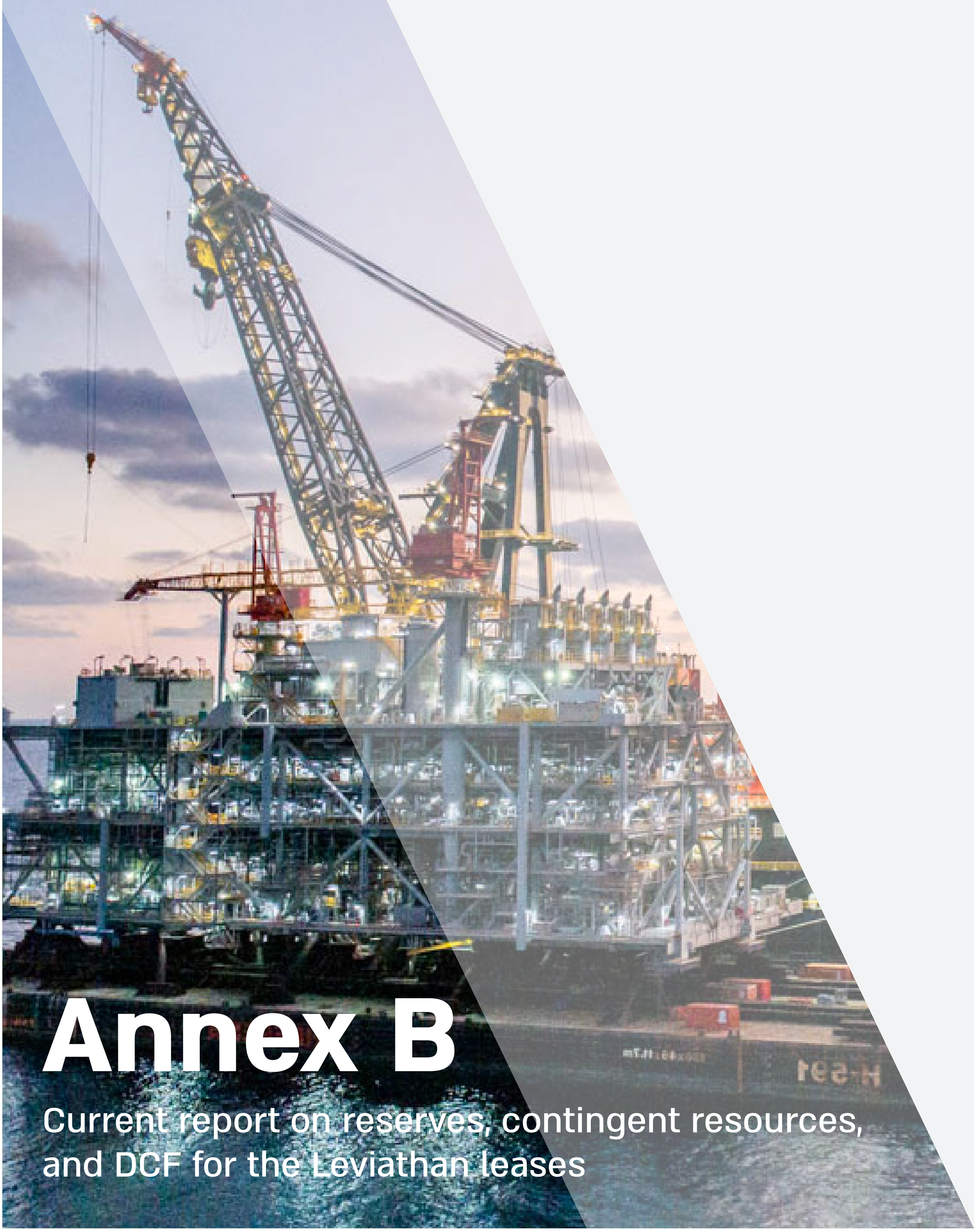
Proved Reserves	2.2.2 Table 3	An incremental category of estimated recoverable quantities associated with a defined degree of uncertainty. Proved Reserves are those quantities of petroleum that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially 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.



Annex B

Current report on reserves, contingent resources, and DCF for the Leviathan leases

NewMed Energy - Limited Partnership
(the "Partnership")

19 March 2024

Israel Securities Authority	Tel Aviv Stock Exchange Ltd.
22 Kanfei Nesharim St.	2 Ahuzat Bayit St.
Jerusalem	Tel Aviv
Via Magna	Via Magna

Dear Sir/Madam,

Re: **Report on Updated Discounted Cash Flow Figures, Reserves and Contingent Resources in the Leviathan Leases**

Further to the Partnership's immediate report of 19 March 2023 (Ref.: 2023-01-023806) regarding the evaluation of the reserves and the contingent resources in the Leviathan reservoir, which is located in the area of the I/14 "Leviathan South" and I/15 "Leviathan North" leases (the "**Previous Resources Report**", the "**Leviathan Reservoir**" or the "**Reservoir**" or the "**Field**" or the "**Leviathan Project**", and the "**Leviathan Leases**", respectively), and regarding the discounted cash flow figures from the reserves and from part of the contingent resources in the Leviathan Leases as of 31 December 2022 (the "**Previous Discounted Cash Flow**"), the Partnership respectfully provides a report on updated discounted cash flow figures, reserves and contingent resources, as of 31 December 2023, with respect to the Partnership's share in the Leviathan Leases (the "**Discounted Cash Flow**", the "**Current Discounted Cash Flow**" or the "**Cash Flow**" and the "**Resources Report**", respectively)[1].

1. Figures on reserves and contingent resources in the Leviathan Reservoir

As of the date of this report, the maximum daily gas production capacity from the Leviathan Reservoir is approx. 1.2 BCF. To increase the maximum daily gas production capacity in the context of Phase I – First Stage of the development plan for the Leviathan project ("**Phase I – First Stage**") to approx. 1.4 BCF, from H2/2025, on 29 June 2023 the partners in the Leviathan project adopted a final investment decision (FID) for the performance of a project, in the context of which a third subsea transmission pipeline will be laid from the Field to the platform, including changes and improvements on the platform (the "**Third Pipeline Project**"), with a total budget of approx. $568 million (100%, the Partnership's share is approx. $258 million). As specified below, the additional resources that it will be possible to produce upon completion of the Third Pipeline Project are included in the reserves attributed to Phase I – First Stage.

[1] For a glossary of the professional terms included herein, see the Glossary on page A-206 of Chapter A (Description of the General Development of the Partnership's Business) of the Partnership's periodic report as of 31 December 2022, as released on 28 March 2023 (Ref.: 2023-01-033096) (the "**Periodic Report**").

According to the Resources Report which the Partnership received from Netherland, Sewell & Associates Inc. ("**NSAI**" or the "**Evaluator**"), part of the resources in the Leviathan Reservoir are classified as reserves and part are classified as contingent resources. Therefore, the report that the Partnership received from NSAI includes two parts, as follows:

- A reserves report, which includes 'on production' reserves that shall be produced from the Leviathan Project's facilities, including from the Third Pipeline Project's facilities. Discounted Cash Flow figures with respect to the reserves, as of 31 December 2023, are presented in Section 1(a)(3) below.

- A contingent resources report, which includes resources which are classified as contingent at the 'development pending' phase, which are contingent on approval for the drilling of additional wells, approval for future developments, demonstration of the existence of a future market for the sale of natural gas, and a commitment to develop the resources. The contingent resources were divided into two groups, which relate to the stages of development of the Reservoir, as follows:

  (1) <u>Phase I – First Stage</u>: Resources attributed to Phase I – First Stage that are contingent, *inter alia*, on approval for the drilling of additional wells, as specified in Section 7.2.5(d) of the Periodic Report. Discounted Cash Flow figures with respect to contingent resources at this stage, as of 31 December 2023, are presented in Section 1(b)(4) below.

  (2) <u>Future Development</u>: Additional resources that are contingent, *inter alia*, on approval for the drilling of additional wells and approval for future development beyond Phase I – First Stage, and on a commitment to develop the resources.

  Below is a summary of the Current Discounted Cash Flow figures relative to the Previous Discounted Cash Flow figures. During 2023, the Leviathan partners sold approx. 11 BCM of natural gas for (gross) financial consideration of approx. U.S. $2.4 billion ("**Dollars**" or "**$**") (100%, the Partnership's share was approx. $1.1 billion)[2].

	31.12.2023 ($ in billions)		**31.12.2022 ($ in billions)**	
	Cap Rate 7.5%	**Cap Rate 10%**	**Cap Rate 7.5%**	**Cap Rate 10%**
2P reserves	6.2	5.09	6	4.9
2P+2C	6.63	5.34	6.3	5.1

[2] It is clarified that the revenue figures for 2023 are unaudited.

For further details regarding the changes in the Current Discounted Cash Flow compared with the Previous Discounted Cash Flow, see Section 1(a)(3) below.

(a) **Reserves in the Leviathan Reservoir**

(1) Quantity data

According to the report that the Partnership received from NSAI and which was prepared according to the SPE-PRMS guidelines, as of 31 December 2023, the reserves in the Leviathan Project are defined at the 'on production' maturity stage. These reserves are as specified below:

Reserve Category[3]	**Total (100%) in the Petroleum Asset (Gross)**		**Total Share Attributed to the Holders of the Equity Interests of the Partnership (Net)** [4]	
	Natural Gas BCF	**Condensate Million Barrels**	**Natural Gas BCF**	**Condensate Million Barrels**
1P (Proved) Reserves	13,472.1	29.6	4,815.4	10.6
Probable Reserves	1,699.3	3.7	601.0	1.3
Total 2P (Proved+Probable) Reserves	15,171.4	33.4	5,416.4	11.9
Possible Reserves	684.4	1.5	242.0	0.5
Total 3P (Proved+Probable+Possible) Reserves	15,855.8	34.9	5,658.4	12.5

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

(2) In the report received by the Partnership from NSAI, NSAI stated, *inter alia*, several assumptions and reservations, including that: (a) The evaluations, as customary in the evaluation of reserves according to the SPE-PRMS guidelines, are not adjusted to reflect risks, such as technical and commercial risks and development

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

[4] The report that the Partnership received from NSAI does not state the Partnership's net share but rather the Partnership's gross share. The Partnership's net share presented in the table is after payment of royalties to the State and to related and third parties and assuming that recovery of the investment will be achieved after the Investment Recovery Date, as defined in Paragraph 1(a)(3) below.

risks; (b) NSAI did not visit the Field, and did not check the mechanical operation of the facilities and the wells or the condition thereof; (c) NSAI did not examine possible exposure deriving from environmental matters. However, NSAI stated that as of the date of signing of the report that the Partnership received from NSAI, it was not aware of any potential liability regarding environmental matters which may materially affect the quantity of the reserves estimated in the report that the Partnership received from NSAI or the commerciality thereof; and (d) NSAI assumed that the Reservoir is being and shall be developed in accordance with the development plan, is reasonably operated, that no regulation will be instituted that will affect the ability of a holder of the petroleum interests to extract the reserves, and that its forecasts regarding future production will be similar to the functioning of the Reservoir in practice.

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

(3) <u>Discounted Cash Flow figures</u>

The Discounted Cash Flow figures are based on various estimates and assumptions provided to NSAI by the Partnership, and mainly:

(a) <u>The projected sale quantities</u>: The assumptions in the Cash Flow with respect to the quantities of natural gas and condensate that shall be sold by the Partnership from the Leviathan Reservoir are based on: (i) the Leviathan Reservoir's production capacity in Phase I – First Stage only, including expansion thereof through the Third Pipeline Project, from H2/2025[5]. It is noted that the actual production rate may be lower or higher than the production rate assumed in the Cash Flow; (ii) the Partnership's assumptions regarding the natural gas quantities that shall be sold to customers of the Partnership under the Existing Agreements, including the agreement for the export of natural gas to Egypt with Blue Ocean Energy, as specified in Section 7.10.3(c) of the Periodic Report (the "**Export to Egypt Agreement**"), taking into account, *inter alia*, forecasts with respect to the Brent oil barrel price (the "**Brent Price**") and its possible impact on the quantities that are sold to Egypt, the agreement for the export of gas to Jordan's national electricity company (NEPCO), as specified in Section 7.10.3(b) of the Periodic Report, and additional agreements for the supply of natural gas to the domestic market (collectively: the "**Existing Agreements**"); (iii) additional quantities of natural gas which, in the Partnership's estimation, will be sold on the regional export markets and on the domestic market in Israel, based, *inter alia*, on negotiations for the sale of natural gas from the Leviathan Project, being conducted by the Partnership, together with its partners in the Leviathan Project, a forecast of the demand for natural gas in the domestic market in Israel, prepared for the Partnership an outside consultant (BDO Consulting Group, "**BDO**")[6], and in relation to the estimate of

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[5] The sale quantities do not include sales of additional gas quantities which may be rendered possible as a result of the performance of additional development stages, which were classified in the Resources Report as contingent resources – future development, including additional sales to the domestic market and/or designated sales via other LNG facilities and/or FLNG facilities, if and insofar as such facilities are built, to additional target markets.

[6] The forecast of the demand for natural gas in the domestic market for the coming years on which the Partnership relied, is as follows (in BCM): 2024 – approx. 13.4; 2025 – approx. 15; 2026 – approx. 17.3; 2027 – approx. 18; and 2028 – approx. 18.8. The aforesaid forecast of the demand is primarily based on a forecast of demand for electricity, which is affected, *inter alia*, by the growth forecasts in Israel, and is also based on the mix of energy sources that will be used for electricity production that is affected by government policy regarding reduction of the use of coal as a source for electricity production until its complete phase-out, and regarding the use of renewable energies as a source for electricity production. The demand forecast is forward-looking information, which there is no certainty will materialize, in whole or in part, and may materialize in a materially different manner, due to various factors, and *inter alia* the development of growth in the Israeli economy, the climate conditions in Israel and worldwide, the rate of phasing out of the use of coal as a source in electricity production, the rate of entry of renewable energies as a source for electricity production, the rate of entry of electric

the expected supply from other gas sources in the domestic market, and mainly from the Tamar, Karish and Tanin leases; and (iv) additional quantities of natural gas, which, in the Partnership's estimation, will be sold in the regional markets, based, *inter alia*, on a forecast for completion of projects for increasing the natural gas quantities, as specified in Section 7 of the Q2/2023 report, as released on 21 August 2023 (Ref.: 2023-01-095937) (the "**Q2 Report**"), and Section 9 of the Q3/2023 report, as released on 16 November 2023 (Ref.: 2023-01-104080) (the "**Q3 Report**"), as well as on forecasts of the supply and demand in these markets, which were prepared by consultancy firms.

(b) <u>The sale prices of natural gas and condensate</u>: The assumptions in the Cash Flow with respect to the prices of natural gas that shall be sold from the Leviathan Reservoir are based, *inter alia*, on a weighted average of the natural gas prices which are stated in the Existing Agreements, according to the price formulas determined therein, and the Partnership's assumptions regarding the prices that shall be determined in future agreements, based, *inter alia*, on the demand forecast in the domestic market in the Cash Flow years, as estimated by BDO, and on the Partnership's estimate of the projected demand.

Most of the Existing Agreements include price formulas, and some of them include fixed prices. The price formulas set forth in the Existing Agreements may change over the years and include, *inter alia*, linkage to the Brent Price, partial or full linkage to the electricity production tariff and linkage to the ILS/dollar exchange rate. The dollar rate used is ILS 3.627 to the dollar throughout the Cash Flow period, which is based on the exchange rate as of 31 December 2023.

The electricity production tariff is supervised by the Electricity Authority and reflects the costs of the electricity production component of the Israel Electric Corp. Ltd., including the cost of its fuels, capital and operating costs attributed to the production component and the cost of purchasing electricity from independent power producers. The assumptions in the Cash Flow regarding the changes in the electricity production tariff over the Cash Flow years are based on a forecast that was prepared for the Partnership by

vehicles into the Israeli market and government policy in other areas which directly or indirectly pertain to growth in the demand for natural gas.

BDO, which does not include additional costs in respect of carbon tax.

The assumptions in the Cash Flow with respect to the Brent Price are based on long-term forecasts of third parties, as follows: The United States Department of Energy, the World Bank, IHS Global Insights and Wood Mackenzie. Accordingly, the Cash Flow assumes a Brent Price of approx. $85 in 2024, decreasing to approx. $83 in 2025, and gradually rising to approx. $93 in 2028, and to approx. $105 in 2033 until the end of the Cash Flow period.

Changes in the sale prices may occur, *inter alia*, due to regulatory intervention, price adjustment mechanisms (as determined in the Export to Egypt Agreement)[7] or changes in the indices that serve as the linkage bases in the price formulas, as specified above.

The assumptions in the Cash Flow with respect to the sale prices of condensate are based on the Brent Price[8].

(c) The operating expenses (OPEX) taken into account in the Cash Flow include direct costs at the project level, insurance costs, production well maintenance costs, payment of the costs of transmission to third parties and estimated overhead and general and administrative expenses of the Operator, which may be directly attributed to the project, and jointly constitute the operating expenses of the project. These expenses are represented at the Reservoir level and per production unit, and the operating expenses in the Cash Flow are not adjusted to inflation changes. NSAI confirmed that the operating expenses provided by the Partnership are reasonable, based, *inter alia*, on knowledge available thereto from similar projects.

(d) The capital expenditures ("CAPEX" or "Capital Expenditures") taken into account in the Cash Flow deriving from reserves include expenses that were approved by the Partnership and its partners in the Leviathan Project, including the costs of the Third Pipeline Project, expenses in respect of engineering work for improvement of the

[7] The Export to Egypt Agreement includes a mechanism for updating the price at a rate of up to 10% (up or down) after the fifth year and after the tenth year of the agreement upon fulfillment of certain conditions that are set forth in the agreement. No price update on such dates was assumed.

[8] For details regarding an agreement for the supply of condensate from the Leviathan Project to Ashdod Refinery Ltd. via a pipeline of Energy Infrastructures Ltd. and its related systems, see Sections 7.10.4(c) and 7.10.4(d) of the Periodic Report, and the Partnership's immediate reports of 4 February 2024 and 10 March 2024 (Ref.: 2024-01-012741 and 2024-01-023730).

production system and related systems, participation in the costs of construction of natural gas transmission infrastructures[9], an estimate of future Capital Expenditures not yet approved by the Partnership, and indirect costs paid to the Operator. The Capital Expenditures taken into account in the contingent resources Cash Flow (Phase 1 – First Stage) exceed the total costs approved by the Partnership, and include an estimate of future Capital Expenditures that may be required for the drilling of new wells, the installation of infrastructures, additional production equipment, and various engineering actions, which exceed the expenses which were included in the budget for the development of Phase I – First Stage, plus indirect costs paid to the Operator. The Capital Expenditures in the Cash Flow are not adjusted to inflation changes. NSAI has confirmed that the Capital Expenditures provided by the Partnership are reasonable, based, *inter alia*, on information in its possession.

(e) Decommissioning costs taken into account in the Cash Flow are costs that were provided to NSAI by the Partnership in accordance with estimates of expert consultants with respect to the cost of plugging and decommissioning of the wells, and the cost of decommissioning of the platform, the production facilities and the subsea equipment, assuming that the project will come to an end in 2064 and in accordance with the directives of the Petroleum Commissioner and with the current best industry standards. However, the project may come to an end before or after such year. In this context it is noted that the date of expiration of the Leviathan Leases is 13 February 2044, but, according to the provisions of the Petroleum Law, 5712-1952, it is possible to extend it by an additional 20 years. The decommissioning costs do not take into account the salvage value of the facilities in the Leviathan Leases and are not adjusted to inflation changes.

(f) The calculation of the Discounted Cash Flow assumed that the effective rate of the State's royalties in the Leviathan project will be 11.06% in accordance with the royalty rate determined as advances for 2023-2024, and accordingly, the effective rate of the royalties that will be paid to third and related parties will be 3.98% before, and 8.41% after the Investment Recovery Date. The actual rate of the said royalties is not final and may change. For details, see Section

[9] In order to increase the possible flow capacity via the EMG pipeline, it is necessary to expand the supply capacity in the INGL system and in the EMG systems in Israel and in Egypt. For details, see Sections 7.11.2(d) and 7.11.2(e) of the Periodic Report, and Section 9(b) of the Q3 Report.

7.22.8(c) of the Periodic Report and Section 14 of the Q3 Report.

The Cash Flow was calculated assuming that for purposes of payment of the royalties to related parties, the date of recovery of the investment will fall after the sale of a total quantity (in respect of 100% of the interests in the petroleum asset) of approx. 2,250 BCF and of approx. 5 million barrels of condensate from Phase I – First Stage (above and below: the "**Investment Recovery Date**"). Since the Investment Recovery Date is affected, *inter alia*, by the gas and/or condensate prices, the production rate, the production and development costs, and the rate of the royalties, and since additional agreements are expected to be signed for the sale of natural gas, the total quantity of natural gas and/or condensate that shall be sold by the Investment Recovery Date may be materially different than stated above. The rate attributed to the holders of the equity interests of the Partnership before and after the Investment Recovery Date is calculated in accordance with the rates set forth in Section 7.2.7 of the Periodic Report. For details regarding calculation of the Investment Recovery Date, see Sections 7.24.9 and 7.25.6 of the Periodic Report and the Partnership's immediate report of 24 December 2023 (Ref.: 2023-01-115693).

(g) The tax calculations took into account corporate tax at a rate of 23%.

(h) The calculation of the Discounted Cash Flow took into account the petroleum profit levy (the "**Levy**"), which shall apply to the Partnership according to the provisions of the Taxation of Profits from Natural Resources Law, 5771-2011 (the "**Law**"). The calculations of the Levy were made in accordance with the approval of the Tax Authority regarding the consolidation of the Leviathan North and Leviathan South leases for purposes of the Law (the "**Ventures**"). It is emphasized that the Levy calculations were made, *inter alia*, according to the definitions, the formulas and the mechanisms defined in the Law, to the best of the Partnership's understanding and interpretation, which were expressed in the Levy reports of the Ventures which were filed with the Tax Authority. However, in view of the novelty of the Law and the complexity of the calculation formulas and the various mechanisms defined therein, there is no assurance that this interpretation of the manner of calculation of the Levy will be the same as that which shall be adopted by the tax authorities and/or the same as the interpretation of the Law by the court. In addition, the calculation was made in Dollars at the choice of the holders of the interests in the Ventures pursuant to Section 13(b) of the Law and is based, *inter alia*, on the following assumptions: the payments attributed to the Ventures (the production costs, the main investments, the royalties, etc.) shall be recognized by the tax authorities for the purpose of the Levy calculation; and for purposes of calculation of the income attributed to the Ventures, the actual sale prices of the natural gas shall be taken into account.

(i) The calculation of the Discounted Cash Flow took into account expenses and investments which were actually paid from 1 January 2024 and which are expected to continue to be paid by the Partnership, as well as revenues deriving from sales of natural gas produced from 1 January 2024 and which is expected to continue to be produced.

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

<u>The changes in the Current Discounted Cash Flow versus the Previous Discounted Cash Flow</u>:

The changes in the Current Discounted Cash Flow relative to the Previous Discounted Cash Flow mainly derive from an update of the assumptions specified above, which are mainly as follows:

a. An update to the volume, timing and type of capital investments relating to the reserves and the contingent resources (Phase I – First Stage), including in connection with projects for increasing the natural gas quantities for export, as specified in Section 7 of the Q2 Report and Section 9 of the Q3 Report.

b. The natural gas quantities expected to be sold in 2024-2025 were reduced, *inter alia* due to an update to BDO's forecast of the demand for natural gas in the domestic market, and a delay in the anticipated completion date of the project for the laying of the Ashdod-Ashkelon offshore pipeline[10]. For details regarding this project, see Section 7.11.2(e)(5) of the Periodic Report and Sections 3(a)(6) and 9(b) of the Q3 Report.

c. The Brent price and electricity production tariff forecasts were raised, as specified in Section 1(a)(3)(b) above.

In accordance with various assumptions, which are primarily as specified above, presented below is the estimated Discounted Cash Flow, as of 31 December 2023, in Dollars in thousands, after levy and income tax, which is attributed to the Partnership's share of the reserves in the Leviathan Reservoir, for each one of the reserve categories specified above[11]:

[10] In February 2024, Chevron informed the Partnership that it had received notice from INGL whereby the foreign contractor performing the work on construction of the combined section has no intention of continuing to remain on standby to continue the work, and that it intends to return in August-September 2024 to complete its undertakings in the project. In view of the aforesaid, the Leviathan partners are reviewing the implications deriving therefrom and the options available to them.

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

Total Discounted Cash Flow from 1P (Proved) Reserves as of 31 December 2023 (in Dollars in thousands in relation to the Partnership's share)																	
Cash Flow components																	
										Taxes		Total Discounted Cash Flow after tax					
Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Gas sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Develop-ment costs	Abandon-ment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Levy	Income Tax	Discounted at 0%	Discounted at 5%	Discounted at 7.5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2024	825	10.6	1,099,444	165,374	-	150,842	262,580	-	520,648	-	130,883	389,765	380,372	375,923	371,626	363,458	355,805
31.12.2025	888	11.4	1,189,923	178,983	-	144,629	128,588	-	737,723	-	146,281	591,442	549,703	530,639	512,653	479,585	449,925
31.12.2026	976	12.6	1,308,306	245,023	-	134,606	32,585	-	896,092	-	158,090	738,002	653,257	615,937	581,535	520,371	467,848
31.12.2027	977	12.6	1,310,307	255,059	-	139,283	2,494	-	913,471	165,352	113,616	634,503	534,898	492,611	454,526	389,037	335,196
31.12.2028	977	12.6	1,339,669	260,775	-	137,642	2,026	-	939,226	303,536	87,881	547,809	439,822	395,632	356,748	292,071	241,165
31.12.2029	977	12.6	1,360,425	264,815	-	158,614	687	-	936,309	374,722	71,041	490,546	375,093	329,559	290,416	227,427	179,963
31.12.2030	977	12.6	1,386,751	269,939	-	138,929	-	-	977,883	449,084	102,814	425,985	310,216	266,219	229,267	171,735	130,232
31.12.2031	977	12.6	1,409,082	274,286	-	118,888	-	-	1,015,907	475,445	108,765	431,698	299,406	250,967	211,220	151,337	109,982
31.12.2032	977	12.6	1,457,146	283,642	-	119,717	-	-	1,053,786	493,172	113,665	446,949	295,222	241,705	198,802	136,247	94,889
31.12.2033	977	12.6	1,485,435	289,149	-	120,004	-	-	1,076,282	503,700	116,453	456,129	286,939	229,460	184,441	120,909	80,699
31.12.2034	976	12.6	1,485,887	289,237	-	140,835	-	-	1,055,815	494,121	116,811	444,883	266,537	208,188	163,539	102,546	65,591
31.12.2035	976	12.6	1,454,428	283,113	-	106,163	-	-	1,065,152	498,491	124,057	442,604	252,545	192,672	147,911	88,714	54,379
31.12.2036	976	12.6	1,454,401	283,108	-	106,193	-	-	1,065,100	498,467	126,706	439,927	239,064	178,146	133,651	76,676	45,042
31.12.2037	976	12.6	1,454,428	283,113	-	106,225	-	-	1,065,090	498,462	130,267	436,361	225,835	164,373	120,516	66,134	37,231
31.12.2038	973	12.5	1,450,349	282,319	-	106,239	-	-	1,061,791	496,918	129,882	434,991	214,405	152,426	109,216	57,327	30,928
31.12.2039	946	12.2	1,411,197	274,698	-	126,704	-	-	1,009,795	472,584	123,551	413,660	194,182	134,838	94,419	47,405	24,510
31.12.2040	908	11.7	1,356,427	264,037	-	105,886	-	-	986,504	461,684	120,709	404,112	180,667	122,535	83,854	40,270	19,953
31.12.2041	872	11.2	1,305,064	254,039	-	105,688	-	-	945,337	442,418	115,671	387,248	164,883	109,230	73,049	33,557	15,934
31.12.2042	838	10.8	1,255,886	244,466	-	105,499	-	-	905,921	423,971	110,849	371,102	150,484	97,372	63,640	27,963	12,724
31.12.2043	805	10.4	1,207,868	235,119	-	105,314	-	-	867,435	405,959	106,139	355,336	137,230	86,731	55,396	23,283	10,153
31.12.2044	773	10.0	1,162,035	226,197	-	125,746	-	-	810,092	379,123	99,123	331,846	122,055	75,347	47,031	18,907	7,902
31.12.2045	742	9.6	1,117,375	217,504	-	104,967	-	-	794,904	372,015	97,264	325,625	114,064	68,776	41,954	16,133	6,461
31.12.2046	713	9.2	1,076,018	209,453	-	104,809	-	-	761,755	356,501	93,208	312,045	104,102	61,309	36,550	13,444	5,160
31.12.2047	684	8.8	1,034,910	201,451	-	104,651	-	-	728,807	341,082	89,177	298,549	94,856	54,565	31,790	11,184	4,114
31.12.2048	657	8.5	998,093	194,285	-	104,507	-	-	699,301	327,273	85,566	286,462	86,682	48,703	27,730	9,332	3,289
31.12.2049	632	8.1	961,214	187,106	-	124,971	-	-	649,137	303,796	79,428	265,912	76,632	42,056	23,401	7,533	2,545
31.12.2050	607	7.8	925,062	180,069	-	103,549	-	-	641,444	300,196	78,487	262,761	72,118	38,658	21,021	6,472	2,095
31.12.2051	583	7.5	888,344	172,921	-	102,756	-	-	612,666	286,728	74,966	250,973	65,603	34,347	18,253	5,376	1,668
31.12.2052	559	7.2	852,810	166,005	-	101,999	-	-	584,807	273,690	71,557	239,560	59,638	30,498	15,839	4,462	1,327
31.12.2053	538	6.9	819,645	159,549	-	101,317	-	-	558,779	261,509	68,372	228,898	54,270	27,108	13,758	3,707	1,056
31.12.2054	517	6.7	787,665	153,324	-	121,268	-	-	513,073	240,118	62,780	210,175	47,458	23,154	11,484	2,960	808

Total Discounted Cash Flow from 1P (Proved) Reserves as of 31 December 2023 (in Dollars in thousands in relation to the Partnership's share)																	
Cash Flow components																	
										Taxes		Total Discounted Cash Flow after tax					
Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Gas sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Develop-ment costs	Abandon-ment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Levy	Income Tax	Discounted at 0%	Discounted at 5%	Discounted at 7.5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2055	496	6.4	756,869	147,329	-	100,032	-	-	509,508	238,450	62,343	208,715	44,884	21,389	10,368	2,556	669
31.12.2056	476	6.1	726,073	141,334	-	99,403	-	-	485,335	227,137	59,386	198,813	40,719	18,953	8,978	2,117	531
31.12.2057	458	5.9	697,646	135,801	-	98,826	-	-	463,019	216,693	56,655	189,671	36,996	16,820	7,787	1,756	422
31.12.2058	440	5.7	670,403	130,498	-	98,275	-	-	441,630	206,683	54,038	180,909	33,607	14,923	6,752	1,457	336
31.12.2059	423	5.4	644,345	125,426	-	118,357	-	-	400,562	187,463	46,368	166,731	29,498	12,794	5,657	1,167	258
31.12.2060	406	5.2	618,287	120,353	-	97,226	-	-	400,708	187,531	46,386	166,791	28,104	11,906	5,144	1,016	215
31.12.2061	390	5.0	594,598	115,742	-	96,754	-	-	382,102	178,824	44,109	159,169	25,542	10,569	4,463	843	171
31.12.2062	374	4.8	570,909	111,131	-	96,283	-	35,689	327,807	153,413	45,674	128,719	19,672	7,951	3,281	593	115
31.12.2063	360	4.6	548,404	106,750	-	95,838	-	35,689	310,128	145,140	43,511	121,477	17,681	6,980	2,815	486	91
31.12.2064	37	0.5	55,670	10,836	-	16,738	-	35,689	(7,594)	-	3,817	(11,411)	(1,582)	(610)	(240)	(40)	(7)
Total	**29,639**	**381.5**	**43,688,798**	**8,393,358**	**-**	**4,596,173**	**428,959**	**107,066**	**30,163,240**	**12,641,452**	**3,716,346**	**13,805,442**	**7,323,359**	**5,801,360**	**4,780,239**	**3,527,513**	**2,801,372**

Total Discounted Cash Flow from Probable Reserves as of 31 December 2023 (in Dollars in thousands in relation to the Partnership's share)

Cash Flow components

										Taxes		Total Discounted Cash Flow after tax					
Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Gas sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Develop-ment costs	Abandon-ment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Levy	Income Tax	Discounted at 0%	Discounted at 5%	Discounted at 7.5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2024	41	0.5	55,297	8,318	-	2,118	-	-	44,861	-	10,318	34,543	33,710	33,316	32,935	32,211	31,533
31.12.2025	65	0.8	86,457	13,005	-	2,945	-	-	70,508	-	16,217	54,291	50,460	48,710	47,059	44,023	41,301
31.12.2026	86	1.1	114,129	31,862	-	3,186	-	-	79,080	-	18,188	60,892	53,899	50,820	47,982	42,935	38,601
31.12.2027	76	1.0	129,770	25,260	-	6,143	-	-	98,366	95,328	699	2,340	1,972	1,816	1,676	1,435	1,236
31.12.2028	88	1.1	170,452	33,180	-	10,502	-	-	126,770	79,621	10,844	36,305	29,148	26,220	23,643	19,356	15,983
31.12.2029	76	1.0	157,578	30,674	-	10,470	-	-	116,435	88,019	6,536	21,881	16,731	14,700	12,954	10,144	8,027
31.12.2030	85	1.1	169,299	32,955	-	10,752	-	-	125,592	67,342	13,397	44,852	32,663	28,030	24,140	18,082	13,712
31.12.2031	76	1.0	145,767	28,374	-	9,708	-	-	107,685	50,397	13,176	44,112	30,594	25,644	21,583	15,464	11,238
31.12.2032	76	1.0	136,932	26,655	-	9,957	-	-	100,321	46,950	12,275	41,095	27,145	22,224	18,279	12,527	8,725
31.12.2033	55	0.7	104,391	20,320	-	9,881	-	-	74,189	34,721	9,078	30,391	19,118	15,288	12,289	8,056	5,377
31.12.2034	35	0.5	75,974	14,789	-	9,838	-	-	51,347	24,030	6,283	21,034	12,602	9,843	7,732	4,848	3,101
31.12.2035	15	0.2	25,688	5,000	-	13,785	-	-	6,903	3,230	845	2,828	1,613	1,231	945	567	347
31.12.2036	(4)	(0.1)	(2,076)	(404)	-	13,755	-	-	(15,427)	(7,220)	(1,888)	(6,319)	(3,434)	(2,559)	(1,920)	(1,101)	(647)
31.12.2037	(24)	(0.3)	(30,172)	(5,873)	-	13,539	-	-	(37,838)	(17,708)	(4,630)	(15,500)	(8,022)	(5,839)	(4,281)	(2,349)	(1,322)
31.12.2038	(40)	(0.5)	(52,785)	(10,275)	-	13,507	-	-	(56,018)	(26,216)	(6,854)	(22,947)	(11,311)	(8,041)	(5,761)	(3,024)	(1,632)
31.12.2039	(31)	(0.4)	(40,637)	(7,910)	-	13,491	-	-	(46,218)	(21,630)	(5,655)	(18,933)	(8,887)	(6,171)	(4,321)	(2,170)	(1,122)
31.12.2040	(11)	(0.1)	(11,423)	(2,224)	-	13,713	-	-	(22,913)	(10,723)	(2,804)	(9,386)	(4,196)	(2,846)	(1,948)	(935)	(463)
31.12.2041	7	0.1	14,106	2,746	-	13,735	-	-	(2,375)	(1,111)	(291)	(973)	(414)	(274)	(184)	(84)	(40)
31.12.2042	24	0.3	38,825	7,557	-	13,916	-	-	17,352	8,121	2,123	7,108	2,882	1,865	1,219	536	244
31.12.2043	40	0.5	62,145	12,097	-	13,952	-	-	36,096	16,893	4,417	14,786	5,710	3,609	2,305	969	423
31.12.2044	55	0.7	66,382	12,922	-	5,692	-	-	47,768	22,355	5,845	19,568	7,197	4,443	2,773	1,115	466
31.12.2045	70	0.9	86,690	16,875	-	5,343	-	-	64,472	30,173	7,889	26,410	9,251	5,578	3,403	1,308	524
31.12.2046	83	1.1	104,785	20,397	-	5,006	-	-	79,382	37,151	9,713	32,518	10,848	6,389	3,809	1,401	538
31.12.2047	96	1.2	122,894	23,922	-	4,669	-	-	94,303	44,134	11,539	38,630	12,274	7,060	4,113	1,447	532
31.12.2048	108	1.4	138,862	27,030	-	4,323	-	-	107,508	50,314	13,155	44,040	13,326	7,487	4,263	1,435	506
31.12.2049	118	1.5	152,522	29,689	-	3,972	-	-	118,861	55,627	14,544	48,690	14,032	7,701	4,285	1,379	466
31.12.2050	128	1.7	166,596	32,429	-	4,318	-	-	129,849	60,769	15,888	53,191	14,599	7,826	4,255	1,310	424
31.12.2051	138	1.8	182,416	35,508	-	4,668	-	-	142,239	66,568	17,404	58,267	15,231	7,974	4,238	1,248	387
31.12.2052	147	1.9	196,027	38,158	-	4,957	-	-	152,912	71,563	18,710	62,639	15,594	7,975	4,141	1,167	347
31.12.2053	155	2.0	209,576	40,795	-	5,222	-	-	163,559	76,545	20,013	67,000	15,885	7,935	4,027	1,085	309
31.12.2054	162	2.1	224,016	43,606	-	5,443	-	-	174,967	81,885	21,409	71,674	16,184	7,896	3,916	1,009	276
31.12.2055	169	2.2	235,197	45,782	-	5,656	-	-	183,758	85,999	22,485	75,275	16,188	7,714	3,739	922	241
31.12.2056	176	2.3	246,377	47,959	-	5,868	-	-	192,550	90,113	23,560	78,876	16,155	7,519	3,562	840	211
31.12.2057	182	2.3	275,351	53,599	-	6,073	-	-	215,679	100,938	26,390	88,351	17,233	7,835	3,627	818	197
31.12.2058	187	2.4	283,740	55,232	-	6,234	-	-	222,275	104,025	27,198	91,053	16,915	7,511	3,398	733	169
31.12.2059	192	2.5	290,945	56,634	-	6,368	-	-	227,943	106,677	27,891	93,375	16,520	7,165	3,168	654	144

Total Discounted Cash Flow from Probable Reserves as of 31 December 2023 (in Dollars in thousands in relation to the Partnership's share)																	
Cash Flow components																	
										Taxes		Total Discounted Cash Flow after tax					
Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Gas sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Develop-ment costs	Abandon-ment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Levy	Income Tax	Discounted at 0%	Discounted at 5%	Discounted at 7.5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2060	197	2.5	300,852	58,563	-	6,531	-	-	235,759	110,335	28,847	96,576	16,273	6,894	2,979	588	124
31.12.2061	201	2.6	306,775	59,716	-	6,639	-	-	240,421	112,517	29,418	98,486	15,804	6,540	2,762	521	106
31.12.2062	205	2.6	312,697	60,868	-	6,746	-	-	245,083	114,699	29,988	100,396	15,344	6,201	2,559	462	90
31.12.2063	208	2.7	317,435	61,791	-	6,826	-	-	248,818	116,447	30,445	101,926	14,836	5,857	2,362	408	76
31.12.2064	22	0.3	33,165	6,456	-	713	-	-	25,996	8,612	3,998	13,386	1,856	715	282	47	8
Total	**3,738**	**48.1**	**5,603,016**	**1,094,036**	**-**	**320,159**	**-**	**-**	**4,188,821**	**1,977,489**	**508,606**	**1,702,725**	**573,528**	**399,802**	**307,987**	**221,388**	**180,762**

Total Discounted Cash Flow from 2P (Proved + Probable Reserves) as of 31 December 2023 (in Dollars in thousands in relation to the Partnership's share)

Cash Flow components

Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Gas sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Develop-ment costs	Abandon-ment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Taxes: Levy	Taxes: Income Tax	Total Discounted Cash Flow after tax: Discounted at 0%	Discounted at 5%	Discounted at 7.5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2024	867	11.2	1,154,741	173,691	-	152,961	262,580	-	565,509	-	141,201	424,308	414,082	409,239	404,562	395,669	387,338
31.12.2025	953	12.3	1,276,381	191,988	-	147,574	128,588	-	808,231	-	162,498	645,733	600,163	579,349	559,711	523,608	491,226
31.12.2026	1,062	13.7	1,422,435	276,885	-	137,792	32,585	-	975,172	-	176,279	798,894	707,157	666,757	629,517	563,306	506,449
31.12.2027	1,053	13.6	1,440,076	280,319	-	145,425	2,494	-	1,011,838	260,680	114,315	636,842	536,870	494,427	456,202	390,472	336,432
31.12.2028	1,064	13.7	1,510,121	293,954	-	148,144	2,026	-	1,065,996	383,157	98,725	584,114	468,971	421,851	380,391	311,428	257,147
31.12.2029	1,053	13.6	1,518,003	295,488	-	169,083	687	-	1,052,744	462,741	77,577	512,427	391,824	344,259	303,370	237,571	187,990
31.12.2030	1,062	13.7	1,556,050	302,894	-	149,681	-	-	1,103,475	516,426	116,211	470,837	342,879	294,249	253,407	189,817	143,944
31.12.2031	1,053	13.6	1,554,849	302,661	-	128,596	-	-	1,123,592	525,841	121,941	475,810	330,000	276,611	232,803	166,801	121,220
31.12.2032	1,053	13.6	1,594,078	310,297	-	129,674	-	-	1,154,107	540,122	125,940	488,045	322,367	263,929	217,081	148,774	103,614
31.12.2033	1,032	13.3	1,589,826	309,469	-	129,885	-	-	1,150,472	538,421	125,531	486,520	306,057	244,749	196,730	128,965	86,075
31.12.2034	1,012	13.0	1,561,861	304,026	-	150,673	-	-	1,107,162	518,152	123,094	465,916	279,139	218,031	171,271	107,394	68,692
31.12.2035	991	12.8	1,480,116	288,113	-	119,948	-	-	1,072,055	501,722	124,901	445,432	254,158	193,903	148,856	89,280	54,726
31.12.2036	972	12.5	1,452,325	282,704	-	119,949	-	-	1,049,673	491,247	124,818	433,608	235,630	175,587	131,731	75,574	44,395
31.12.2037	953	12.3	1,424,256	277,240	-	119,764	-	-	1,027,252	480,754	125,637	420,861	217,813	158,535	116,235	63,785	35,908
31.12.2038	934	12.0	1,397,564	272,044	-	119,746	-	-	1,005,773	470,702	123,027	412,044	203,095	144,385	103,455	54,303	29,296
31.12.2039	915	11.8	1,370,561	266,788	-	140,196	-	-	963,577	450,954	117,895	394,728	185,295	128,667	90,097	45,236	23,388
31.12.2040	897	11.6	1,345,004	261,813	-	119,599	-	-	963,592	450,961	117,905	394,726	176,470	119,689	81,906	39,335	19,490
31.12.2041	879	11.3	1,319,170	256,784	-	119,423	-	-	942,962	441,306	115,381	386,275	164,469	108,955	72,866	33,472	15,894
31.12.2042	862	11.1	1,294,711	252,023	-	119,415	-	-	923,273	432,092	112,972	378,209	153,366	99,238	64,859	28,499	12,968
31.12.2043	845	10.9	1,270,013	247,216	-	119,267	-	-	903,531	422,852	110,556	370,122	142,940	90,340	57,702	24,251	10,576
31.12.2044	828	10.7	1,228,416	239,119	-	131,438	-	-	857,860	401,479	104,968	351,414	129,252	79,789	49,805	20,022	8,368
31.12.2045	812	10.5	1,204,065	234,378	-	110,310	-	-	859,377	402,188	105,153	352,035	123,315	74,354	45,357	17,441	6,985
31.12.2046	796	10.3	1,180,803	229,850	-	109,815	-	-	841,137	393,652	102,922	344,564	114,950	67,698	40,358	14,845	5,698
31.12.2047	781	10.1	1,157,804	225,374	-	109,321	-	-	823,110	385,216	100,716	337,179	107,130	61,626	35,903	12,632	4,646
31.12.2048	765	9.9	1,136,955	221,315	-	108,831	-	-	806,809	377,587	98,721	330,501	100,008	56,191	31,993	10,767	3,795
31.12.2049	750	9.7	1,113,736	216,795	-	128,943	-	-	767,998	359,423	93,972	314,603	90,664	49,756	27,685	8,912	3,011
31.12.2050	735	9.5	1,091,658	212,498	-	107,867	-	-	771,293	360,965	94,375	315,953	86,717	46,483	25,276	7,783	2,520
31.12.2051	721	9.3	1,070,760	208,430	-	107,424	-	-	754,906	353,296	92,370	309,240	80,833	42,322	22,490	6,624	2,055
31.12.2052	706	9.1	1,048,837	204,162	-	106,955	-	-	737,719	345,253	90,267	302,199	75,231	38,473	19,980	5,629	1,674
31.12.2053	693	8.9	1,029,222	200,344	-	106,539	-	-	722,338	338,054	88,385	295,899	70,155	35,042	17,785	4,792	1,366
31.12.2054	679	8.7	1,011,681	196,930	-	126,711	-	-	688,040	322,003	84,189	281,849	63,642	31,050	15,401	3,969	1,084
31.12.2055	666	8.6	992,066	193,112	-	105,688	-	-	693,266	324,449	84,828	283,990	61,072	29,103	14,107	3,478	910
31.12.2056	653	8.4	972,450	189,293	-	105,271	-	-	677,886	317,250	82,946	277,689	56,873	26,472	12,540	2,957	742
31.12.2057	639	8.2	972,997	189,400	-	104,899	-	-	678,698	317,631	83,045	278,022	54,230	24,654	11,414	2,575	619
31.12.2058	627	8.1	954,144	185,730	-	104,509	-	-	663,905	310,708	81,235	271,962	50,522	22,435	10,150	2,190	504
31.12.2059	615	7.9	935,290	182,060	-	124,725	-	-	628,506	294,141	74,259	260,106	46,018	19,959	8,825	1,821	402
31.12.2060	603	7.8	919,140	178,916	-	103,757	-	-	636,467	297,866	75,233	263,367	44,376	18,800	8,123	1,604	339
31.12.2061	591	7.6	901,373	175,458	-	103,393	-	-	622,522	291,340	73,527	257,655	41,347	17,109	7,225	1,364	277
31.12.2062	580	7.5	883,606	171,999	-	103,028	-	35,689	572,890	268,112	75,662	229,115	35,016	14,152	5,840	1,055	205
31.12.2063	568	7.3	865,839	168,541	-	102,664	-	35,689	558,946	261,587	73,956	223,403	32,517	12,837	5,177	894	167

Total Discounted Cash Flow from 2P (Proved + Probable Reserves) as of 31 December 2023 (in Dollars in thousands in relation to the Partnership's share)																	
Cash Flow components																	
										Taxes		Total Discounted Cash Flow after tax					
Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Gas sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Develop-ment costs	Abandon-ment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Levy	Income Tax	Discounted at 0%	Discounted at 5%	Discounted at 7.5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2064	58	0.8	88,834	17,292	-	17,451	-	35,689	18,403	8,612	7,815	1,975	274	106	42	7	1
Total	**33,377**	**429.6**	**49,291,813**	**9,487,394**	**-**	**4,916,332**	**428,959**	**107,066**	**34,352,061**	**14,618,941**	**4,224,953**	**15,508,168**	**7,896,887**	**6,201,161**	**5,088,227**	**3,748,901**	**2,982,134**

Total Discounted Cash Flow from Possible Reserves as of 31 December 2023 (in Dollars in thousands in relation to the Partnership's share)																	
Cash Flow components																	
										Taxes		Total Discounted Cash Flow after tax					
Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Develop-ment costs	Abandon-ment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Levy	Income Tax	Discounted at 0%	Discounted at 5%	Discounted at 7.5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2024	0	0.0	497	75	-	3	-	-	420	-	97	323	315	312	308	301	295
31.12.2025	30	0.4	60,807	14,076	-	2,777	-	-	43,954	-	10,109	33,845	31,456	30,365	29,336	27,444	25,747
31.12.2026	-	-	22,107	4,303	-	2,322	-	-	15,482	16,683	(276)	(924)	(818)	(772)	(728)	(652)	(586)
31.12.2027	-	-	23,720	4,617	-	2,176	-	-	16,927	11,894	1,157	3,875	3,267	3,008	2,776	2,376	2,047
31.12.2028	-	-	40,689	7,920	-	2,744	-	-	30,025	19,985	2,309	7,731	6,207	5,583	5,035	4,122	3,403
31.12.2029	-	-	39,923	7,771	-	2,730	-	-	29,422	21,483	1,826	6,113	4,674	4,107	3,619	2,834	2,243
31.12.2030	-	-	39,513	7,692	-	2,769	-	-	29,053	13,597	3,555	11,901	8,667	7,438	6,405	4,798	3,638
31.12.2031	-	-	16,341	3,181	-	1,679	-	-	11,481	5,373	1,405	4,703	3,262	2,734	2,301	1,649	1,198
31.12.2032	12	0.1	27,321	5,318	-	1,789	-	-	20,213	9,460	2,473	8,280	5,469	4,478	3,683	2,524	1,758
31.12.2033	21	0.3	39,388	7,667	-	1,858	-	-	29,862	13,976	3,654	12,233	7,695	6,154	4,946	3,243	2,164
31.12.2034	32	0.4	55,115	10,728	-	1,942	-	-	42,445	19,864	5,194	17,387	10,417	8,136	6,391	4,008	2,563
31.12.2035	34	0.4	53,476	10,410	-	2,350	-	-	40,717	19,055	4,982	16,679	9,517	7,261	5,574	3,343	2,049
31.12.2036	35	0.5	54,602	10,629	-	2,361	-	-	41,613	19,475	5,092	17,046	9,263	6,903	5,179	2,971	1,745
31.12.2037	37	0.5	57,945	11,279	-	2,371	-	-	44,294	20,730	5,420	18,145	9,391	6,835	5,011	2,750	1,548
31.12.2038	38	0.5	59,069	11,498	-	2,381	-	-	45,190	21,149	5,529	18,512	9,124	6,487	4,648	2,440	1,316
31.12.2039	40	0.5	62,414	12,149	-	2,393	-	-	47,872	22,404	5,858	19,610	9,206	6,392	4,476	2,247	1,162
31.12.2040	41	0.5	63,540	12,368	-	2,404	-	-	48,767	22,823	5,967	19,977	8,931	6,057	4,145	1,991	986
31.12.2041	43	0.5	65,766	12,802	-	2,410	-	-	50,554	23,659	6,186	20,709	8,817	5,841	3,906	1,795	852
31.12.2042	44	0.6	66,889	13,020	-	2,420	-	-	51,449	24,078	6,295	21,076	8,546	5,530	3,614	1,588	723
31.12.2043	45	0.6	68,883	13,408	-	2,316	-	-	53,158	24,878	6,504	21,776	8,410	5,315	3,395	1,427	622
31.12.2044	47	0.6	69,580	13,544	-	1,582	-	-	54,454	25,485	6,663	22,307	8,204	5,065	3,161	1,271	531
31.12.2045	47	0.6	70,744	13,771	-	1,609	-	-	55,363	25,910	6,774	22,679	7,944	4,790	2,922	1,124	450
31.12.2046	48	0.6	71,904	13,997	-	1,637	-	-	56,271	26,335	6,885	23,051	7,690	4,529	2,700	993	381
31.12.2047	49	0.6	73,079	14,225	-	1,665	-	-	57,189	26,764	6,998	23,427	7,443	4,282	2,495	878	323
31.12.2048	50	0.6	74,368	14,476	-	1,693	-	-	58,199	27,237	7,121	23,841	7,214	4,053	2,308	777	274
31.12.2049	51	0.7	76,692	14,929	-	1,748	-	-	60,016	28,087	7,344	24,585	7,085	3,888	2,163	696	235
31.12.2050	51	0.7	76,692	14,929	-	1,749	-	-	60,014	28,087	7,343	24,584	6,747	3,617	1,967	606	196
31.12.2051	52	0.7	77,836	15,151	-	1,777	-	-	60,908	28,505	7,453	24,950	6,522	3,415	1,815	534	166
31.12.2052	53	0.7	78,822	15,343	-	1,805	-	-	61,674	28,863	7,546	25,264	6,289	3,216	1,670	471	140
31.12.2053	53	0.7	78,704	15,320	-	1,807	-	-	61,577	28,818	7,535	25,225	5,981	2,987	1,516	409	116
31.12.2054	54	0.7	76,491	14,889	-	1,827	-	-	59,774	27,974	7,314	24,486	5,529	2,697	1,338	345	94

Total Discounted Cash Flow from Possible Reserves as of 31 December 2023 (in Dollars in thousands in relation to the Partnership's share)																	
Cash Flow components																	
										Taxes		Total Discounted Cash Flow after tax					
Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Develop-ment costs	Abandon-ment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Levy	Income Tax	Discounted at 0%	Discounted at 5%	Discounted at 7.5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2055	54	0.7	77,540	15,094	-	1,856	-	-	60,591	28,357	7,414	24,820	5,338	2,544	1,233	304	80
31.12.2056	55	0.7	78,694	15,318	-	1,884	-	-	61,492	28,778	7,524	25,189	5,159	2,401	1,138	268	67
31.12.2057	56	0.7	59,686	11,618	-	1,868	-	-	46,199	21,621	5,653	18,925	3,691	1,678	777	175	42
31.12.2058	56	0.7	63,306	12,323	-	1,878	-	-	49,105	22,981	6,008	20,115	3,737	1,659	751	162	37
31.12.2059	57	0.7	64,852	12,624	-	1,908	-	-	50,320	23,550	6,157	20,613	3,647	1,582	699	144	32
31.12.2060	57	0.7	63,695	12,399	-	1,908	-	-	49,389	23,114	6,043	20,232	3,409	1,444	624	123	26
31.12.2061	57	0.7	84,586	16,465	-	1,956	-	-	66,165	30,965	8,096	27,104	4,349	1,800	760	144	29
31.12.2062	57	0.7	84,678	16,483	-	1,958	-	-	66,237	30,999	8,105	27,133	4,147	1,676	692	125	24
31.12.2063	57	0.7	85,948	16,730	-	1,988	-	-	67,230	31,464	8,226	27,540	4,009	1,582	638	110	21
31.12.2064	(7)	(0.1)	(10,800)	(2,102)	-	(229)	-	-	(8,468)	(3,963)	(1,036)	(3,469)	(481)	(185)	(73)	(12)	(2)
Total	**1,506**	**19.4**	**2,395,102**	**468,439**	**-**	**80,067**	**-**	**-**	**1,846,597**	**870,496**	**224,503**	**751,597**	**275,471**	**186,886**	**135,315**	**82,844**	**58,738**

Total Discounted Cash Flow from 3P (Proved + Probable + Possible) Reserves as of 31 December 2023 (in Dollars in thousands in relation to the Partnership's share)

Cash Flow components

Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Gas sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Develop-ment costs	Abandon-ment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Taxes		Total Discounted Cash Flow after tax					
										Levy	Income Tax	Discounted at 0%	Discounted at 5%	Discounted at 7.5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2024	867	11.2	1,155,238	173,766	-	152,963	262,580	-	565,929	-	141,298	424,631	414,397	409,551	404,870	395,970	387,633
31.12.2025	983	12.7	1,337,188	206,064	-	150,351	128,588	-	852,185	-	172,607	679,578	631,619	609,715	589,048	551,052	516,973
31.12.2026	1,062	13.7	1,444,542	281,189	-	140,114	32,585	-	990,654	16,683	176,002	797,969	706,339	665,986	628,788	562,654	505,863
31.12.2027	1,053	13.6	1,463,796	284,937	-	147,601	2,494	-	1,028,765	272,575	115,473	640,717	540,137	497,436	458,978	392,848	338,479
31.12.2028	1,064	13.7	1,550,810	301,874	-	150,888	2,026	-	1,096,021	403,142	101,035	591,845	475,178	427,435	385,426	315,550	260,551
31.12.2029	1,053	13.6	1,557,926	303,260	-	171,813	687	-	1,082,166	484,224	79,402	518,540	396,498	348,366	306,989	240,405	190,233
31.12.2030	1,062	13.7	1,595,563	310,586	-	152,449	-	-	1,132,528	530,023	119,766	482,739	351,546	301,687	259,812	194,615	147,582
31.12.2031	1,053	13.6	1,571,190	305,841	-	130,275	-	-	1,135,073	531,214	123,346	480,513	333,262	279,346	235,104	168,450	122,418
31.12.2032	1,064	13.7	1,621,399	315,615	-	131,463	-	-	1,174,321	549,582	128,414	496,325	327,836	268,407	220,764	151,298	105,372
31.12.2033	1,053	13.6	1,629,214	317,136	-	131,743	-	-	1,180,334	552,396	129,185	498,753	313,752	250,902	201,676	132,207	88,240
31.12.2034	1,043	13.4	1,616,975	314,754	-	152,615	-	-	1,149,606	538,016	128,287	483,303	289,556	226,168	177,663	111,402	71,255
31.12.2035	1,026	13.2	1,533,592	298,523	-	122,298	-	-	1,112,772	520,777	129,883	462,111	263,675	201,163	154,430	92,624	56,776
31.12.2036	1,007	13.0	1,506,927	293,332	-	122,309	-	-	1,091,285	510,722	129,910	450,654	244,893	182,489	136,910	78,545	46,140
31.12.2037	990	12.7	1,482,201	288,519	-	122,135	-	-	1,071,547	501,484	131,057	439,006	227,203	165,370	121,246	66,535	37,456
31.12.2038	972	12.5	1,456,632	283,542	-	122,127	-	-	1,050,963	491,851	128,557	430,556	212,219	150,871	108,102	56,743	30,613
31.12.2039	956	12.3	1,432,975	278,937	-	142,589	-	-	1,011,449	473,358	123,753	414,338	194,500	135,059	94,573	47,483	24,550
31.12.2040	939	12.1	1,408,543	274,181	-	122,003	-	-	1,012,359	473,784	123,872	414,703	185,402	125,747	86,051	41,326	20,476
31.12.2041	922	11.9	1,384,935	269,586	-	121,833	-	-	993,516	464,966	121,567	406,984	173,286	114,797	76,772	35,267	16,746
31.12.2042	906	11.7	1,361,600	265,044	-	121,835	-	-	974,722	456,170	119,267	399,285	161,913	104,767	68,473	30,087	13,691
31.12.2043	890	11.5	1,338,896	260,624	-	121,582	-	-	956,689	447,731	117,060	391,898	151,350	95,655	61,096	25,678	11,198
31.12.2044	875	11.3	1,297,997	252,663	-	133,019	-	-	912,314	426,963	111,631	373,720	137,457	84,854	52,966	21,293	8,899
31.12.2045	859	11.1	1,274,809	248,149	-	111,919	-	-	914,740	428,098	111,928	374,714	131,259	79,144	48,279	18,565	7,435
31.12.2046	845	10.9	1,252,707	243,847	-	111,452	-	-	897,408	419,987	109,807	367,614	122,640	72,227	43,058	15,838	6,079
31.12.2047	830	10.7	1,230,883	239,599	-	110,986	-	-	880,299	411,980	107,713	360,606	114,573	65,907	38,398	13,509	4,969
31.12.2048	815	10.5	1,211,323	235,791	-	110,524	-	-	865,008	404,824	105,842	354,342	107,222	60,244	34,301	11,543	4,069
31.12.2049	801	10.3	1,190,428	231,724	-	130,690	-	-	828,014	387,510	101,316	339,188	97,749	53,644	29,849	9,608	3,246
31.12.2050	786	10.1	1,168,350	227,426	-	109,616	-	-	831,308	389,052	101,719	340,537	93,465	50,100	27,243	8,388	2,716
31.12.2051	773	10.0	1,148,596	223,581	-	109,201	-	-	815,813	381,801	99,823	334,190	87,355	45,736	24,305	7,158	2,221
31.12.2052	759	9.8	1,127,659	219,506	-	108,760	-	-	799,393	374,116	97,814	327,463	81,521	41,689	21,651	6,099	1,813
31.12.2053	746	9.6	1,107,926	215,664	-	108,346	-	-	783,915	366,872	95,920	321,123	76,136	38,030	19,301	5,201	1,482
31.12.2054	733	9.4	1,088,172	211,819	-	128,538	-	-	747,814	349,977	91,503	306,335	69,171	33,747	16,739	4,314	1,178
31.12.2055	720	9.3	1,069,606	208,205	-	107,543	-	-	753,857	352,805	92,242	308,810	66,409	31,646	15,340	3,782	990
31.12.2056	708	9.1	1,051,144	204,612	-	107,156	-	-	739,377	346,029	90,470	302,878	62,032	28,873	13,677	3,225	809
31.12.2057	695	9.0	1,032,683	201,018	-	106,768	-	-	724,897	339,252	88,698	296,947	57,921	26,333	12,191	2,750	661
31.12.2058	683	8.8	1,017,450	198,053	-	106,387	-	-	713,010	333,689	87,244	292,077	54,258	24,094	10,901	2,352	542
31.12.2059	671	8.6	1,000,142	194,684	-	126,633	-	-	678,826	317,690	80,416	280,719	49,665	21,541	9,524	1,966	434

Total Discounted Cash Flow from 3P (Proved + Probable + Possible) Reserves as of 31 December 2023 (in Dollars in thousands in relation to the Partnership's share)																	
Cash Flow components																	
Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Gas sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Develop-ment costs	Abandon-ment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Taxes		Total Discounted Cash Flow after tax					
										Levy	Income Tax	Discounted at 0%	Discounted at 5%	Discounted at 7.5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2060	660	8.5	982,835	191,315	-	105,665	-	-	685,855	320,980	81,276	283,599	47,785	20,244	8,747	1,727	365
31.12.2061	648	8.3	985,959	191,923	-	105,349	-	-	688,687	322,306	81,623	284,759	45,696	18,909	7,985	1,508	306
31.12.2062	636	8.2	968,284	188,482	-	104,987	-	35,689	639,126	299,111	83,767	256,248	39,163	15,828	6,532	1,180	229
31.12.2063	625	8.1	951,787	185,271	-	104,651	-	35,689	626,176	293,050	82,183	250,943	36,526	14,419	5,815	1,005	187
31.12.2064	51	0.7	78,035	15,190	-	17,221	-	35,689	9,935	4,649	6,779	(1,494)	(207)	(80)	(31)	(5)	(1)
Total	**34,883**	**449.0**	**51,686,916**	**9,955,833**	**-**	**4,996,399**	**428,959**	**107,066**	**36,198,658**	**15,489,438**	**4,449,456**	**16,259,765**	**8,172,358**	**6,388,047**	**5,223,541**	**3,831,745**	**3,040,871**

Caution – it is clarified that Discounted Cash Flow figures, whether calculated at a specific cap rate or without a cap rate, represent present value but do not necessarily represent fair value.

Caution regarding forward-looking information – the Discounted Cash Flow figures as aforesaid are forward-looking information, within the meaning thereof in the Securities Law. The above figures are based on various assumptions including in relation to the quantities of gas and condensate that shall be produced, the pace and duration of the natural gas sales from the project, operation costs, capital expenditures, abandonment expenses, royalty rates and the sale prices, in respect of which there is no certainty that they will materialize. It is noted that the quantities of natural gas and/or condensate that shall actually be produced and sold, the said expenses and the said income may be materially different from the above estimates and assumptions, *inter alia* as a result of operating and technical conditions and/or regulatory changes and/or supply and demand conditions in the natural gas and/or condensate market and/or the actual performance of the project and/or as a result of the actual sale prices and/or as a result of geopolitical changes that shall occur.

(4) Set forth below is an analysis of sensitivity to the main parameters comprising the Discounted Cash Flow (the gas price and the gas sales volume) as of 31 December 2023 (Dollars in thousands) which was performed by the Partnership[12]

Sensitivity / Category	Present value discounted at 0%	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%	Sensitivity / Category	Present value discounted at 0%	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%
10% increase in the gas price					**10% decrease in the gas price**				
1P (Proved) Reserves	15,190,202	5,210,045	3,840,182	3,050,538	1P (Proved) Reserves	12,411,440	4,338,719	3,203,056	2,540,702
Probable Reserves	1,890,518	344,395	245,765	198,795	Probable Reserves	1,531,472	281,272	204,203	167,898
Total 2P (Proved+Probable) Reserves	17,080,721	5,554,440	4,085,947	3,249,333	Total 2P (Proved+Probable) Reserves	13,942,912	4,619,991	3,407,259	2,708,600
Possible Reserves	831,039	151,522	93,359	66,527	Possible Reserves	674,479	122,340	75,769	54,502
Total 3P (Proved+Probable+Possible) Reserves	17,911,760	5,705,962	4,179,306	3,315,860	Total 3P (Proved+Probable+Possible) Reserves	14,617,390	4,742,330	3,483,029	2,763,102
15% increase in the gas price					**15% decrease in the gas price**				
1P (Proved) Reserves	15,883,219	5,422,731	3,993,561	3,171,698	1P (Proved) Reserves	11,719,489	4,120,030	3,042,173	2,411,248
Probable Reserves	1,977,400	358,431	254,757	205,384	Probable Reserves	1,445,901	268,321	196,033	161,865
Total 2P (Proved+Probable) Reserves	17,860,619	5,781,163	4,248,318	3,377,082	Total 2P (Proved+Probable) Reserves	13,165,390	4,388,351	3,238,206	2,573,113
Possible Reserves	864,613	154,306	93,640	65,750	Possible Reserves	637,136	116,091	72,157	52,075
Total 3P (Proved+Probable+Possible) Reserves	18,725,232	5,935,469	4,341,959	3,442,833	Total 3P (Proved+Probable+Possible) Reserves	13,802,526	4,504,442	3,310,363	2,625,188

[12] With respect to a sensitivity analysis for the Discounted Cash Flow to the variable of the gas sales volume, it is noted that costs were not included in respect of other wells which may be required in order to make adjustments for growth in the gas sales volume.

Sensitivity / Category	Present value discounted at 0%	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%	Sensitivity / Category	Present value discounted at 0%	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%
20% increase in the gas price					**20% decrease in the gas price**				
1P (Proved) Reserves	16,580,114	5,638,173	4,149,185	3,294,691	1P (Proved) Reserves	11,027,965	3,899,534	2,879,121	2,279,502
Probable Reserves	2,070,138	377,125	268,057	215,970	Probable Reserves	1,355,866	252,718	185,746	154,109
Total 2P (Proved+Probable) Reserves	18,650,252	6,015,299	4,417,241	3,510,662	Total 2P (Proved+Probable) Reserves	12,383,830	4,152,252	3,064,867	2,433,611
Possible Reserves	901,957	160,511	97,166	68,049	Possible Reserves	598,611	109,732	68,502	49,634
Total 3P (Proved+Probable+Possible) Reserves	19,552,209	6,175,810	4,514,407	3,578,710	Total 3P (Proved+Probable+Possible) Reserves	12,982,441	4,261,984	3,133,369	2,483,245

Sensitivity / Category	Present value discounted at 0%	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%	Sensitivity / Category	Present value discounted at 0%	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%
10% increase in the gas sales volume					**10% decrease in the gas sales volume**				
1P (Proved) Reserves	13,989,305	5,180,555	3,839,468	3,054,551	1P (Proved) Reserves	12,384,817	4,333,891	3,200,450	2,539,101
Probable Reserves	1,679,470	342,910	246,199	199,201	Probable Reserves	1,520,015	274,878	198,729	163,127
Total 2P (Proved+Probable) Reserves	15,668,775	5,523,465	4,085,667	3,253,752	Total 2P (Proved+Probable) Reserves	13,904,832	4,608,769	3,399,179	2,702,228
Possible Reserves	725,986	149,128	93,014	66,503	Possible Reserves	681,974	128,970	81,634	59,669
Total 3P (Proved+Probable+Possible) Reserves	16,394,761	5,672,593	4,178,681	3,320,255	Total 3P (Proved+Probable+Possible) Reserves	14,586,806	4,737,739	3,480,813	2,761,898
15% increase in the gas sales volume					**15% decrease in the gas sales volume**				
1P (Proved) Reserves	14,071,781	5,366,186	3,986,411	3,173,802	1P (Proved) Reserves	11,668,146	4,103,924	3,030,448	2,401,945
Probable Reserves	1,645,664	360,141	258,969	209,124	Probable Reserves	1,439,862	267,391	195,441	161,425
Total 2P (Proved+Probable) Reserves	15,717,444	5,726,327	4,245,380	3,382,926	Total 2P (Proved+Probable) Reserves	13,108,008	4,371,314	3,225,889	2,563,370
Possible Reserves	750,240	152,077	93,393	65,762	Possible Reserves	634,772	115,800	72,032	52,017
Total 3P (Proved+Probable+Possible) Reserves	16,467,684	5,878,404	4,338,773	3,448,688	Total 3P (Proved+Probable+Possible) Reserves	13,742,780	4,487,115	3,297,920	2,615,387

Sensitivity / Category	Present value discounted at 0%	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%	Sensitivity / Category	Present value discounted at 0%	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%
20% increase in the gas sales volume[13]					**20% decrease in the gas sales volume**				
1P (Proved) Reserves	14,135,908	5,553,811	4,139,242	3,299,852	1P (Proved) Reserves	10,966,279	3,882,623	2,867,270	2,270,252
Probable Reserves	1,566,630	374,169	269,778	217,263	Probable Reserves	1,340,894	246,711	180,953	150,143
Total 2P (Proved+Probable) Reserves	15,702,538	5,927,980	4,409,020	3,517,115	Total 2P (Proved+Probable) Reserves	12,307,173	4,129,334	3,048,223	2,420,395
Possible Reserves	844,765	161,617	97,790	68,295	Possible Reserves	595,342	109,342	68,335	49,557
Total 3P (Proved+Probable+Possible) Reserves	16,547,303	6,089,598	4,506,810	3,585,410	Total 3P (Proved+Probable+Possible) Reserves	12,902,515	4,238,676	3,116,557	2,469,952

[13] Due to infrastructure restrictions, it is not possible to increase the gas quantities at this rate.

(b) Contingent resources in the Leviathan Reservoir

(1) Quantity Data

According to the report received by the Partnership from NSAI, the project relating to the contingent gas and condensate resources in the Leviathan Reservoir, is classified as a project at a 'development pending' maturity level, and the volume of the resources is as specified below:

Natural Gas[14] BCF						
Category	**Total (100%) in the Petroleum Asset (Gross)**			**The Total Rate Attributed to the Holders of the Equity Interests of the Partnership (Net)[15]**		
	Phase I – First Stage	**Future Development**	**Total**	**Phase I – First Stage**	**Future Development**	**Total**
1C - Low Estimate	2,050.3	0.0	2,050.3	725.1	0.0	725.1
2C - Best Estimate	3,142.3	3,160.5	6,302.8	1,111.3	1,117.7	2,229.0
3C - High Estimate	2,947.0	7,600.0	10,547.0	1,042.2	2,687.8	3,730.0

Condensate[16] Million Barrels						
Category	**Total (100%) in the Petroleum Asset (Gross)**			**The Total Rate Attributed to the Holders of the Equity Interests of the Partnership (Net)[17]**		
	Phase I – First Stage	**Future Development**	**Total**	**Phase I – First Stage**	**Future Development**	**Total**
1C - Low Estimate	4.5	0.0	4.5	1.6	0.0	1.6
2C - Best Estimate	6.9	7.0	13.9	2.4	2.5	4.9
3C - High Estimate	6.5	16.7	23.2	2.3	5.9	8.2

[14] The amounts in the table may not add up due to rounding-off differences.
[15] See Footnote 4 above.
[16] The amounts in the table may not add up due to rounding-off differences.
[17] See Footnote 4 above.

(2) In view of the significant volume of contingent resources attributed to the Leviathan Project, the potential markets for these resources are the domestic market and/or the regional market and/or the international market. For details regarding the potential markets for the said resources and a review of the possibilities for export of the gas, see Section 7.11 of the Periodic Report. In addition, for details regarding gas export engagements and an examination of the possibility for the export of additional gas, see Sections 7.10.3(b), 7.10.3(c) and 7.11.2 of the Periodic Report, Sections 6(b) and 7 of the Q2 Report and Section 9 of the Q3 Report.

(3) The Resources Report states that reclassification of contingent resources in the Leviathan Project in the Phase I – First Stage category as reserves is contingent on approval for the drilling of additional wells, approval for future development, demonstration of the existence of a future market for the sale of natural gas and a commitment to develop the resources. Insofar as the said conditions are fulfilled, the contingent resources, in whole or in part, may be classified as reserves.

Caution – There is no certainty that any part of the contingent resources will be commercially recoverable.

Caution regarding forward-looking information – NSAI's estimates regarding quantities of reserves and contingent resources of natural gas and condensate in the Leviathan Reservoir are forward-looking information, within the meaning thereof in the Securities Law. The above estimates are based, *inter alia*, on geological, geophysical, engineering and other information received from the Operator, from the wells in the Reservoir and from wells in adjacent reservoirs, and constitute professional estimates and assumptions of NSAI only, in respect of which there is no certainty. The natural gas and/or condensate quantities that shall actually be produced and sold may be different to the said estimates and assumptions, *inter alia* as a result of operating and technical conditions and/or regulatory changes and/or supply and demand conditions in the natural gas and/or condensate market and/or commercial conditions and/or geopolitical changes and/or the actual performance of the Reservoir. The said estimates and assumptions may be updated insofar as additional information shall accumulate and/or as a result of a gamut of factors relating to projects for oil and natural gas exploration and production.

(4) Discounted Cash Flow figures

In accordance with the various assumptions, primarily as specified in Section 1(a)(3) above, set forth below is the estimated Discounted Cash Flow as of 31 December 2023, in Dollars in thousands, after levy and income tax, attributed to the Partnership's share, from the contingent resources in the Leviathan Reservoir, for each one of the contingent resource categories specified above[18]:

Total Discounted Cash Flow from the 1C - Low Estimate Contingent Resources as of 31 December 2023 (in Dollars in thousands in relation to the Partnership's share)																	
Cash Flow components																	
										Taxes		Total Discounted Cash Flow after tax					
Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Gas sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Develop-ment costs	Abandon-ment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Levy	Income Tax	Discounted at 0%	Discounted at 5%	Discounted at 7.5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2024	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2025	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2026	37	0.5	40,285	7,545	-	200	-	-	32,540	-	7,484	25,056	22,179	20,912	19,744	17,667	15,884
31.12.2027	55	0.7	59,556	11,593	-	295	-	-	47,668	30,153	4,028	13,486	11,369	10,470	9,661	8,269	7,125
31.12.2028	67	0.9	74,070	14,418	-	363	-	-	59,289	29,971	6,743	22,575	18,125	16,304	14,701	12,036	9,938
31.12.2029	55	0.7	62,772	12,219	-	304	-	-	50,249	33,336	3,890	13,023	9,958	8,749	7,710	6,038	4,778
31.12.2030	64	0.8	74,610	14,523	-	357	110,999	-	(51,270)	(18,560)	16,730	(49,440)	(36,004)	(30,898)	(26,609)	(19,932)	(15,115)
31.12.2031	55	0.7	70,864	13,794	-	324	-	-	56,746	26,557	4,390	25,798	17,893	14,998	12,623	9,044	6,573
31.12.2032	67	0.9	92,801	18,064	-	409	-	-	74,327	34,785	6,542	33,000	21,798	17,846	14,678	10,060	7,006
31.12.2033	55	0.7	79,321	15,440	-	345	-	-	63,536	29,735	5,221	28,580	17,979	14,377	11,557	7,576	5,056
31.12.2034	64	0.8	92,020	17,912	-	402	-	-	73,706	34,494	6,466	32,746	19,619	15,324	12,037	7,548	4,828
31.12.2035	55	0.7	79,731	15,520	-	349	-	-	63,861	29,887	5,261	28,713	16,383	12,499	9,595	5,755	3,528
31.12.2036	67	0.9	96,489	18,782	-	424	-	-	77,282	36,168	6,903	34,211	18,591	13,853	10,393	5,963	3,503
31.12.2037	55	0.7	79,731	15,520	-	352	-	-	63,859	29,886	5,261	28,712	14,860	10,816	7,930	4,352	2,450
31.12.2038	67	0.9	96,079	18,702	-	425	-	-	76,951	36,013	6,863	34,075	16,796	11,940	8,555	4,491	2,423
31.12.2039	85	1.1	122,892	23,922	-	546	-	-	98,424	46,062	9,490	42,871	20,125	13,974	9,785	4,913	2,540
31.12.2040	135	1.7	194,392	37,840	-	867	110,999	-	44,686	20,913	28,445	(4,672)	(2,089)	(1,417)	(969)	(466)	(231)
31.12.2041	159	2.1	229,025	44,581	-	1,026	-	-	183,418	85,840	19,890	77,688	33,078	21,913	14,655	6,732	3,197
31.12.2042	202	2.6	290,471	56,542	-	1,306	-	-	232,623	108,867	25,911	97,845	39,677	25,673	16,779	7,373	3,355
31.12.2043	227	2.9	326,221	63,501	-	1,473	-	-	261,247	122,264	29,413	109,570	42,316	26,744	17,082	7,179	3,131
31.12.2044	270	3.5	388,784	75,679	-	1,763	99,390	-	211,952	99,194	45,098	67,660	24,886	15,362	9,589	3,855	1,611
31.12.2045	290	3.7	416,714	81,116	-	1,897	99,390	-	234,311	109,657	45,548	79,105	27,710	16,708	10,192	3,919	1,570
31.12.2046	327	4.2	470,339	91,554	-	2,150	99,390	-	277,244	129,750	48,515	98,978	33,020	19,447	11,593	4,264	1,637
31.12.2047	347	4.5	499,387	97,209	-	2,293	99,390	-	300,494	140,631	49,074	110,789	35,200	20,249	11,797	4,150	1,527

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

Total Discounted Cash Flow from the 1C - Low Estimate Contingent Resources as of 31 December 2023 (in Dollars in thousands in relation to the Partnership's share)																	
Cash Flow components																	
										Taxes		Total Discounted Cash Flow after tax					
Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Gas sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Develop-ment costs	Abandon-ment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Levy	Income Tax	Discounted at 0%	Discounted at 5%	Discounted at 7.5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2048	339	4.4	487,097	94,816	-	2,246	210,390	-	179,645	84,074	56,255	39,317	11,897	6,684	3,806	1,281	451
31.12.2049	299	3.9	430,132	83,728	-	1,997	99,390	-	245,017	114,668	35,161	95,188	27,432	15,054	8,377	2,696	911
31.12.2050	256	3.3	369,088	71,845	-	2,399	-	-	294,843	137,987	18,532	138,325	37,965	20,351	11,066	3,407	1,103
31.12.2051	218	2.8	316,430	61,595	-	2,813	-	-	252,022	117,946	14,569	119,507	31,238	16,355	8,692	2,560	794
31.12.2052	183	2.4	268,175	52,202	-	3,215	-	-	212,758	99,571	9,764	103,423	25,747	13,167	6,838	1,926	573
31.12.2053	151	1.9	223,136	43,435	-	3,564	-	-	176,137	82,432	5,283	88,422	20,964	10,471	5,315	1,432	408
31.12.2054	121	1.6	182,498	35,524	-	3,911	-	-	143,063	66,953	2,379	73,730	16,648	8,122	4,029	1,038	284
31.12.2055	95	1.2	144,504	28,129	-	3,145	-	-	113,230	52,992	1,015	59,223	12,736	6,069	2,942	725	190
31.12.2056	71	0.9	108,970	21,212	-	2,342	-	-	85,416	39,975	(102)	45,544	9,328	4,342	2,057	485	122
31.12.2057	50	0.6	75,805	14,756	-	1,629	-	-	59,420	27,809	(997)	32,609	6,361	2,892	1,339	302	73
31.12.2058	30	0.4	45,009	8,761	-	967	-	-	35,281	16,511	(389)	19,158	3,559	1,580	715	154	36
31.12.2059	12	0.2	17,767	3,458	-	382	-	-	13,927	6,518	(2,348)	9,757	1,726	749	331	68	15
31.12.2060	(4)	(0.0)	(5,922)	(1,153)	-	(127)	-	-	(4,642)	(2,173)	(3,477)	1,008	170	72	31	6	1
31.12.2061	(19)	(0.2)	(28,427)	(5,533)	-	(611)	-	-	(22,283)	(10,428)	(5,636)	(6,218)	(998)	(413)	(174)	(33)	(7)
31.12.2062	(31)	(0.4)	(47,378)	(9,222)	-	(1,018)	-	25,300	(62,437)	(29,221)	(4,730)	(28,486)	(4,354)	(1,760)	(726)	(131)	(25)
31.12.2063	(47)	(0.6)	(72,252)	(14,064)	-	(1,553)	-	25,300	(81,934)	(38,345)	(7,116)	(36,473)	(5,309)	(2,096)	(845)	(146)	(27)
31.12.2064	(21)	(0.3)	(31,862)	(6,202)	-	(685)	-	25,300	(50,275)	-	(3,817)	(46,458)	(6,440)	(2,483)	(979)	(162)	(29)
Total	**4,511**	**58.1**	**6,419,323**	**1,249,263**	**-**	**42,491**	**929,340**	**75,899**	**4,122,331**	**1,962,873**	**501,512**	**1,657,946**	**612,137**	**395,003**	**265,891**	**136,396**	**81,183**

Total Discounted Cash Flow from the 2C - Best Estimate Contingent Resources as of 31 December 2023 (in Dollars in thousands in relation to the Partnership's share)																	
Cash Flow components																	
										Taxes		Total Discounted Cash Flow after tax					
Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Gas sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Develop-ment costs	Abandon-ment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Levy	Income Tax	Discounted at 0%	Discounted at 5%	Discounted at 7.5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2024	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2025	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2026	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2027	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2030	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2031	-	-	-	-	-	-	110,999	-	(110,999)	(51,948)	10,671	(69,723)	(48,357)	(40,533)	(34,114)	(24,442)	(17,763)
31.12.2032	12	0.1	16,186	3,151	-	71	-	-	12,964	6,067	(967)	7,864	5,194	4,253	3,498	2,397	1,669
31.12.2033	21	0.3	30,164	5,872	-	131	-	-	24,161	11,308	403	12,450	7,832	6,263	5,034	3,300	2,203
31.12.2034	51	0.7	72,618	14,135	-	317	-	-	58,165	27,221	4,564	26,380	15,805	12,345	9,697	6,081	3,889
31.12.2035	61	0.8	88,258	17,180	-	387	-	-	70,692	33,084	6,097	31,511	17,980	13,717	10,530	6,316	3,872
31.12.2036	92	1.2	132,946	25,879	-	584	-	-	106,483	49,834	10,476	46,173	25,091	18,697	14,027	8,048	4,727
31.12.2037	100	1.3	144,118	28,053	-	636	-	-	115,429	54,021	11,571	49,837	25,793	18,773	13,764	7,553	4,252
31.12.2038	128	1.7	184,337	35,882	-	816	-	-	147,639	69,095	15,512	63,032	31,068	22,087	15,826	8,307	4,482
31.12.2039	138	1.8	197,744	38,492	-	879	-	-	158,373	74,118	16,826	67,429	31,653	21,979	15,391	7,727	3,995
31.12.2040	167	2.2	240,197	46,756	-	1,072	-	-	192,370	90,029	20,985	81,355	36,372	24,669	16,881	8,107	4,017
31.12.2041	173	2.2	249,135	48,496	-	1,116	110,999	-	88,524	41,429	33,809	13,286	5,657	3,748	2,506	1,151	547
31.12.2042	200	2.6	287,119	55,889	-	1,291	-	-	229,939	107,611	25,582	96,745	39,231	25,385	16,591	7,290	3,317
31.12.2043	207	2.7	298,291	58,064	-	1,347	-	-	238,880	111,796	26,676	100,408	38,777	24,508	15,653	6,579	2,869
31.12.2044	236	3.0	339,869	66,157	-	1,654	-	-	272,057	127,323	30,736	113,998	41,929	25,884	16,157	6,495	2,714
31.12.2045	241	3.1	347,513	67,645	-	2,139	-	-	277,728	129,977	31,430	116,322	40,747	24,569	14,987	5,763	2,308
31.12.2046	266	3.4	384,159	74,779	-	2,735	99,390	-	207,255	96,995	44,524	65,736	21,930	12,916	7,700	2,832	1,087
31.12.2047	272	3.5	393,993	76,693	-	3,210	-	-	314,090	146,994	33,593	133,503	42,417	24,400	14,216	5,001	1,840
31.12.2048	299	3.9	433,991	84,479	-	3,824	-	-	345,688	161,782	37,459	146,447	44,314	24,898	14,176	4,771	1,682
31.12.2049	303	3.9	440,473	85,741	-	4,285	99,390	-	251,057	117,495	47,597	85,965	24,774	13,596	7,565	2,435	823
31.12.2050	327	4.2	475,957	92,648	-	4,860	99,390	-	279,059	130,600	48,738	99,722	27,370	14,671	7,978	2,456	795
31.12.2051	332	4.3	483,449	94,106	-	5,285	-	-	384,058	179,739	38,859	165,460	43,250	22,644	12,034	3,544	1,100
31.12.2052	358	4.6	522,109	101,632	-	5,878	99,390	-	315,209	147,518	53,428	114,263	28,445	14,547	7,555	2,128	633
31.12.2053	360	4.6	524,987	102,192	-	6,262	210,390	-	206,143	96,475	62,050	47,618	11,290	5,639	2,862	771	220
31.12.2054	347	4.5	504,543	98,212	-	6,565	298,171	-	101,594	47,546	63,599	(9,550)	(2,157)	(1,052)	(522)	(135)	(37)
31.12.2055	325	4.2	472,767	92,027	-	6,785	99,390	-	274,565	128,497	34,345	111,724	24,026	11,449	5,550	1,368	358
31.12.2056	303	3.9	442,088	86,055	-	7,008	-	-	349,025	163,344	20,469	165,212	33,837	15,750	7,461	1,759	441
31.12.2057	283	3.6	393,523	76,602	-	7,196	-	-	309,725	144,951	16,803	147,970	28,862	13,122	6,075	1,370	329
31.12.2058	263	3.4	365,454	71,138	-	7,407	-	-	286,909	134,273	14,011	138,624	25,752	11,435	5,174	1,116	257
31.12.2059	244	3.1	339,619	66,109	-	7,628	-	-	265,882	124,433	8,702	132,747	23,486	10,186	4,504	930	205
31.12.2060	226	2.9	313,099	60,947	-	7,735	-	-	244,418	114,388	8,362	121,668	20,501	8,685	3,753	741	157
31.12.2061	208	2.7	286,731	55,814	-	7,128	-	-	223,789	104,733	6,981	112,075	17,985	7,442	3,143	593	120

Total Discounted Cash Flow from the 2C - Best Estimate Contingent Resources as of 31 December 2023 (in Dollars in thousands in relation to the Partnership's share)																	
Cash Flow components																	
Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Gas sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Develop-ment costs	Abandon-ment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Taxes		Total Discounted Cash Flow after tax					
										Levy	Income Tax	Discounted at 0%	Discounted at 5%	Discounted at 7.5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2062	192	2.5	262,666	51,129	-	6,573	-	33,733	171,230	80,136	9,451	81,643	12,478	5,043	2,081	376	73
31.12.2063	176	2.3	239,763	46,671	-	6,045	-	33,733	153,314	71,751	10,821	70,742	10,297	4,065	1,639	283	53
31.12.2064	2	0.0	1,183	230	-	71	-	33,733	(32,851)	(8,612)	(6,395)	(17,844)	(2,474)	(954)	(376)	(62)	(11)
Total	**6,913**	**89.0**	**9,909,048**	**1,928,856**	**-**	**118,920**	**1,227,511**	**101,199**	**6,532,563**	**3,064,001**	**797,769**	**2,670,792**	**751,155**	**424,825**	**248,994**	**92,952**	**37,223**

Total Discounted Cash Flow from the 3C - High Estimate Contingent Resources as of 31 December 2023 (in Dollars in thousands in relation to the Partnership's share)

Cash Flow components

Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Gas sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Develop-ment costs	Abandon-ment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Taxes		Total Discounted Cash Flow after tax					
										Levy	Income Tax	Discounted at 0%	Discounted at 5%	Discounted at 7.5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2024	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2025	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2026	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2027	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2030	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2031	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2033	-	-	-	-	-	-	110,999	-	(110,999)	(51,948)	10,671	(69,723)	(43,861)	(35,075)	(28,193)	(18,482)	(12,335)
31.12.2034	19	0.2	26,813	5,219	-	117	-	-	21,476	10,051	75	11,351	6,800	5,312	4,172	2,616	1,673
31.12.2035	27	0.4	39,102	7,611	-	171	-	-	31,319	14,657	1,279	15,383	8,777	6,696	5,141	3,083	1,890
31.12.2036	57	0.7	82,672	16,093	-	363	-	-	66,216	30,989	5,549	29,678	16,127	12,018	9,016	5,173	3,039
31.12.2037	63	0.8	90,493	17,615	-	399	-	-	72,479	33,920	6,316	32,243	16,687	12,146	8,905	4,887	2,751
31.12.2038	90	1.2	129,595	25,226	-	574	-	-	103,794	48,576	10,147	45,071	22,215	15,793	11,316	5,940	3,205
31.12.2039	97	1.3	139,649	27,184	-	621	-	-	111,845	52,344	11,132	48,369	22,706	15,767	11,040	5,543	2,866
31.12.2040	126	1.6	180,986	35,230	-	808	-	-	144,948	67,836	15,183	61,930	27,687	18,778	12,850	6,171	3,058
31.12.2041	131	1.7	187,689	36,535	-	841	-	-	150,313	70,347	15,839	64,127	27,304	18,088	12,097	5,557	2,639
31.12.2042	156	2.0	224,556	43,711	-	1,010	110,999	-	68,836	32,215	30,123	6,498	2,635	1,705	1,114	490	223
31.12.2043	162	2.1	233,728	45,497	-	1,166	-	-	187,066	87,547	19,060	80,459	31,073	19,639	12,543	5,272	2,299
31.12.2044	190	2.4	273,726	53,282	-	1,773	-	-	218,670	102,338	24,204	92,129	33,886	20,918	13,057	5,249	2,194
31.12.2045	193	2.5	280,208	54,544	-	2,230	-	-	223,434	104,567	24,786	94,081	32,956	19,871	12,122	4,661	1,867
31.12.2046	218	2.8	315,693	61,451	-	2,799	-	-	251,443	117,675	28,214	105,554	35,214	20,739	12,363	4,548	1,745
31.12.2047	223	2.9	324,364	63,139	-	3,245	-	-	257,980	120,734	29,013	108,232	34,388	19,781	11,525	4,055	1,491
31.12.2048	249	3.2	363,200	70,699	-	3,832	99,390	-	189,279	88,583	42,324	58,372	17,663	9,924	5,651	1,902	670
31.12.2049	252	3.2	367,359	71,509	-	4,238	-	-	291,612	136,474	30,843	124,295	35,820	19,658	10,938	3,521	1,189
31.12.2050	276	3.6	402,843	78,416	-	4,812	99,390	-	220,225	103,065	43,825	73,335	20,128	10,789	5,867	1,806	585
31.12.2051	280	3.6	409,191	79,651	-	5,209	99,390	-	224,940	105,272	42,116	77,553	20,272	10,614	5,640	1,661	515
31.12.2052	305	3.9	446,865	86,985	-	5,774	-	-	354,106	165,721	35,194	153,190	38,136	19,502	10,128	2,853	848
31.12.2053	307	4.0	449,861	87,568	-	6,157	99,390	-	256,745	120,157	46,274	90,314	21,413	10,696	5,428	1,463	417
31.12.2054	329	4.2	483,021	94,023	-	6,683	110,999	-	271,316	126,976	48,308	96,033	21,684	10,579	5,247	1,352	369
31.12.2055	333	4.3	488,181	95,027	-	7,056	298,171	-	87,926	41,149	63,831	(17,054)	(3,668)	(1,748)	(847)	(209)	(55)

Total Discounted Cash Flow from the 3C - High Estimate Contingent Resources as of 31 December 2023 (in Dollars in thousands in relation to the Partnership's share)																	
Cash Flow components																	
										Taxes		Total Discounted Cash Flow after tax					
Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Gas sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Develop-ment costs	Abandon-ment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Levy	Income Tax	Discounted at 0%	Discounted at 5%	Discounted at 7.5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2056	357	4.6	523,379	101,879	-	7,574	198,781	-	215,146	100,688	49,870	64,587	13,228	6,157	2,917	688	172
31.12.2057	343	4.4	503,877	98,083	-	7,830	-	-	397,964	186,247	23,663	188,054	36,681	16,676	7,720	1,741	419
31.12.2058	324	4.2	474,422	92,349	-	8,046	-	-	374,026	175,044	21,877	177,105	32,900	14,610	6,610	1,426	328
31.12.2059	305	3.9	448,159	87,237	-	8,247	-	-	352,675	165,052	16,528	171,095	30,270	13,129	5,805	1,198	264
31.12.2060	287	3.7	422,992	82,338	-	8,452	-	-	332,202	155,470	15,166	161,565	27,223	11,533	4,983	984	208
31.12.2061	271	3.5	379,670	73,905	-	8,622	-	-	297,143	139,063	13,162	144,918	23,255	9,623	4,063	767	156
31.12.2062	255	3.3	356,936	69,480	-	8,747	-	33,733	244,977	114,649	15,681	114,647	17,522	7,082	2,922	528	103
31.12.2063	239	3.1	333,925	65,000	-	8,220	-	33,733	226,971	106,222	14,621	106,128	15,447	6,098	2,459	425	79
31.12.2064	19	0.2	27,086	5,273	-	631	-	33,733	(12,550)	(4,649)	(5,882)	(2,019)	(280)	(108)	(43)	(7)	(1)
Total	**6,483**	**83.5**	**9,410,241**	**1,831,760**	**-**	**126,249**	**1,227,511**	**101,199**	**6,123,523**	**2,867,033**	**748,993**	**2,507,497**	**642,290**	**346,990**	**194,559**	**66,862**	**24,871**

Caution – it is clarified that Discounted Cash Flow figures, whether calculated at a specific cap rate or without a cap rate, represent present value but do not necessarily represent fair value.

Caution regarding forward-looking information – the Discounted Cash Flow figures as aforesaid are forward-looking information, within the meaning thereof in the Securities Law. The above figures are based on various assumptions including in relation to the quantities of gas and condensate that shall be produced and sold, the pace and duration of the natural gas sales from the project, operation costs, capital expenditures, abandonment expenses, royalty rates and the sale prices, in respect of which there is no certainty that they will materialize. It is noted that the quantities of natural gas and/or condensate that shall actually be produced and sold, the said expenses and the said income may be materially different from the above estimates and assumptions, *inter alia* as a result of operating and technical conditions and/or regulatory changes and/or supply and demand conditions in the natural gas and/or condensate market and/or the actual performance of the project and/or as a result of the actual sale prices and/or as a result of geopolitical changes that shall occur.

(c) Summary of the figures on the Discounted Cash Flow from the reserves and from the contingent resources classified at Phase I – First Stage

Set forth below are tables summarizing the figures on the Discounted Cash Flow from the reserves and from the contingent resources which are presented in addition to the figures on the Discounted Cash Flows from the reserves and the contingent resources as stated in Sections 1(a)(3) and 1(b)(4) above[19].

Total Discounted Cash Flow from the 1P + 1C - Proved Reserves and Low Estimate Contingent Resources as of 31 December 2023 (in Dollars in thousands in relation to the Partnership's share)																	
Cash Flow components																	
										Taxes		Total Discounted Cash Flow after tax					
Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Gas sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Develop-ment costs	Abandon-ment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Levy	Income Tax	Discounted at 0%	Discounted at 5%	Discounted at 7.5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2024	825	10.6	1,099,444	165,374	-	150,842	262,580	-	520,648	-	130,883	389,765	380,372	375,923	371,626	363,458	355,805
31.12.2025	888	11.4	1,189,923	178,983	-	144,629	128,588	-	737,723	-	146,281	591,442	549,703	530,639	512,653	479,585	449,925
31.12.2026	1,014	13.0	1,348,592	252,568	-	134,806	32,585	-	928,633	-	165,575	763,058	675,436	636,849	601,279	538,038	483,732
31.12.2027	1,032	13.3	1,369,863	266,652	-	139,578	2,494	-	961,139	195,505	117,645	647,989	546,267	503,081	464,187	397,306	342,321
31.12.2028	1,043	13.4	1,413,739	275,193	-	138,005	2,026	-	998,515	333,507	94,624	570,384	457,947	411,935	371,450	304,107	251,103
31.12.2029	1,032	13.3	1,423,197	277,034	-	158,918	687	-	986,558	408,058	74,931	503,569	385,051	338,308	298,126	233,465	184,741
31.12.2030	1,040	13.4	1,461,361	284,463	-	139,286	110,999	-	926,613	430,525	119,544	376,545	274,212	235,321	202,658	151,803	115,117
31.12.2031	1,032	13.3	1,479,946	288,080	-	119,212	-	-	1,072,653	502,002	113,155	457,496	317,298	265,965	223,842	160,381	116,554
31.12.2032	1,043	13.4	1,549,947	301,706	-	120,127	-	-	1,128,113	527,957	120,207	479,950	317,020	259,552	213,480	146,307	101,895
31.12.2033	1,032	13.3	1,564,756	304,589	-	120,349	-	-	1,139,818	533,435	121,675	484,709	304,917	243,837	195,997	128,485	85,755
31.12.2034	1,040	13.4	1,577,907	307,149	-	141,237	-	-	1,129,521	528,616	123,277	477,629	286,156	223,512	175,577	110,094	70,419
31.12.2035	1,032	13.3	1,534,159	298,633	-	106,512	-	-	1,129,014	528,378	129,318	471,317	268,928	205,171	157,506	94,469	57,907
31.12.2036	1,043	13.4	1,550,890	301,890	-	106,618	-	-	1,142,382	534,635	133,609	474,138	257,655	191,999	144,044	82,638	48,544
31.12.2037	1,032	13.3	1,534,159	298,633	-	106,577	-	-	1,128,949	528,348	135,528	465,073	240,694	175,189	128,446	70,486	39,680
31.12.2038	1,040	13.4	1,546,428	301,021	-	106,664	-	-	1,138,742	532,931	136,744	469,066	231,201	164,366	117,772	61,818	33,351
31.12.2039	1,032	13.3	1,534,089	298,620	-	127,251	-	-	1,108,219	518,646	133,041	456,532	214,307	148,813	104,204	52,318	27,050
31.12.2040	1,043	13.4	1,550,819	301,876	-	106,753	110,999	-	1,031,190	482,597	149,153	399,440	178,578	121,119	82,884	39,805	19,722
31.12.2041	1,032	13.3	1,534,089	298,620	-	106,714	-	-	1,128,755	528,258	135,562	464,936	197,962	131,143	87,704	40,289	19,130
31.12.2042	1,040	13.4	1,546,357	301,008	-	106,806	-	-	1,138,544	532,839	136,759	468,946	190,161	123,046	80,419	35,336	16,079
31.12.2043	1,032	13.3	1,534,089	298,620	-	106,787	-	-	1,128,682	528,223	135,553	464,906	179,545	113,475	72,478	30,462	13,284
31.12.2044	1,043	13.4	1,550,819	301,876	-	127,508	99,390	-	1,022,044	478,317	144,221	399,506	146,941	90,709	56,620	22,762	9,513
31.12.2045	1,032	13.3	1,534,089	298,620	-	106,864	99,390	-	1,029,215	481,673	142,813	404,730	141,774	85,484	52,146	20,052	8,031

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

Total Discounted Cash Flow from the 1P + 1C - Proved Reserves and Low Estimate Contingent Resources as of 31 December 2023 (in Dollars in thousands in relation to the Partnership's share)

Cash Flow components

Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Gas sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Develop-ment costs	Abandon-ment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Taxes		Total Discounted Cash Flow after tax					
										Levy	Income Tax	Discounted at 0%	Discounted at 5%	Discounted at 7.5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2046	1,040	13.4	1,546,357	301,008	-	106,960	99,390	-	1,038,999	486,252	141,724	411,024	137,122	80,756	48,143	17,708	6,797
31.12.2047	1,032	13.3	1,534,297	298,660	-	106,945	99,390	-	1,029,302	481,713	138,251	409,337	130,057	74,814	43,587	15,335	5,641
31.12.2048	996	12.8	1,485,190	289,101	-	106,754	210,390	-	878,946	411,347	141,821	325,778	98,579	55,388	31,536	10,613	3,741
31.12.2049	931	12.0	1,391,346	270,834	-	126,967	99,390	-	894,154	418,464	114,590	361,100	104,064	57,110	31,777	10,229	3,455
31.12.2050	863	11.1	1,294,150	251,914	-	105,948	-	-	936,288	438,183	97,019	401,086	110,083	59,008	32,087	9,880	3,198
31.12.2051	801	10.3	1,204,774	234,517	-	105,569	-	-	864,688	404,674	89,534	370,480	96,841	50,703	26,944	7,935	2,462
31.12.2052	743	9.6	1,120,985	218,206	-	105,214	-	-	797,565	373,260	81,321	342,983	85,384	43,665	22,677	6,388	1,899
31.12.2053	688	8.9	1,042,781	202,984	-	104,881	-	-	734,916	343,941	73,655	317,320	75,234	37,579	19,073	5,139	1,464
31.12.2054	638	8.2	970,163	188,848	-	125,180	-	-	656,136	307,071	65,159	283,905	64,106	31,276	15,513	3,998	1,092
31.12.2055	591	7.6	901,373	175,458	-	103,177	-	-	622,738	291,441	63,358	267,938	57,620	27,458	13,310	3,281	859
31.12.2056	548	7.1	835,043	162,546	-	101,745	-	-	570,752	267,112	59,283	244,357	50,046	23,294	11,035	2,602	653
31.12.2057	507	6.5	773,451	150,557	-	100,455	-	-	522,439	244,502	55,658	222,280	43,357	19,711	9,125	2,058	495
31.12.2058	469	6.0	715,413	139,259	-	99,242	-	-	476,911	223,194	53,649	200,067	37,166	16,504	7,467	1,611	371
31.12.2059	434	5.6	662,112	128,884	-	118,739	-	-	414,489	193,981	44,020	176,488	31,225	13,543	5,988	1,236	273
31.12.2060	402	5.2	612,365	119,201	-	97,099	-	-	396,065	185,359	42,908	167,798	28,273	11,978	5,176	1,022	216
31.12.2061	371	4.8	566,171	110,209	-	96,143	-	-	359,819	168,395	38,473	152,951	24,544	10,156	4,289	810	164
31.12.2062	343	4.4	523,531	101,908	-	95,265	-	60,988	265,369	124,193	40,944	100,233	15,319	6,191	2,555	461	90
31.12.2063	312	4.0	476,152	92,686	-	94,285	-	60,988	228,193	106,794	36,395	85,004	12,373	4,884	1,970	340	63
31.12.2064	16	0.2	23,808	4,634	-	16,053	-	60,988	(57,868)	-	-	(57,868)	(8,022)	(3,093)	(1,219)	(201)	(36)
Total	**34,150**	**439.5**	**50,108,121**	**9,642,621**	**-**	**4,638,664**	**1,358,299**	**182,965**	**34,285,571**	**14,604,325**	**4,217,858**	**15,463,388**	**7,935,496**	**6,196,363**	**5,046,130**	**3,663,909**	**2,882,554**

Total Discounted Cash Flow from the 2P + 2C - Proved + Probable Reserves and Best Estimate Contingent Resources as of 31 December 2023 (in Dollars in thousands in relation to the Partnership's share)

Cash Flow components

Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Gas sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Development costs	Abandonment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Taxes		Total Discounted Cash Flow after tax					
										Levy	Income Tax	Discounted at 0%	Discounted at 5%	Discounted at 7.5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2024	867	11.2	1,154,741	173,691	-	152,961	262,580	-	565,509	-	141,201	424,308	414,082	409,239	404,562	395,669	387,338
31.12.2025	953	12.3	1,276,381	191,988	-	147,574	128,588	-	808,231	-	162,498	645,733	600,163	579,349	559,711	523,608	491,226
31.12.2026	1,062	13.7	1,422,435	276,885	-	137,792	32,585	-	975,172	-	176,279	798,894	707,157	666,757	629,517	563,306	506,449
31.12.2027	1,053	13.6	1,440,076	280,319	-	145,425	2,494	-	1,011,838	260,680	114,315	636,842	536,870	494,427	456,202	390,472	336,432
31.12.2028	1,064	13.7	1,510,121	293,954	-	148,144	2,026	-	1,065,996	383,157	98,725	584,114	468,971	421,851	380,391	311,428	257,147
31.12.2029	1,053	13.6	1,518,003	295,488	-	169,083	687	-	1,052,744	462,741	77,577	512,427	391,824	344,259	303,370	237,571	187,990
31.12.2030	1,062	13.7	1,556,050	302,894	-	149,681	-	-	1,103,475	516,426	116,211	470,837	342,879	294,249	253,407	189,817	143,944
31.12.2031	1,053	13.6	1,554,849	302,661	-	128,596	110,999	-	1,012,593	473,894	132,613	406,087	281,643	236,078	198,689	142,359	103,457
31.12.2032	1,064	13.7	1,610,265	313,448	-	129,746	-	-	1,167,071	546,189	124,974	495,908	327,561	268,182	220,579	151,171	105,284
31.12.2033	1,053	13.6	1,619,990	315,341	-	130,016	-	-	1,174,633	549,728	125,935	498,970	313,889	251,012	201,764	132,265	88,278
31.12.2034	1,062	13.7	1,634,478	318,161	-	150,990	-	-	1,165,327	545,373	127,658	492,296	294,943	230,376	180,969	113,475	72,581
31.12.2035	1,053	13.6	1,568,374	305,293	-	120,334	-	-	1,142,747	534,805	130,998	476,943	272,138	207,620	159,386	95,596	58,598
31.12.2036	1,064	13.7	1,585,272	308,583	-	120,533	-	-	1,156,156	541,081	135,294	479,781	260,721	194,284	145,759	83,622	49,122
31.12.2037	1,053	13.6	1,568,374	305,293	-	120,400	-	-	1,142,681	534,775	137,208	470,698	243,606	177,308	129,999	71,338	40,160
31.12.2038	1,062	13.7	1,581,901	307,926	-	120,563	-	-	1,153,412	539,797	138,539	475,076	234,163	166,472	119,280	62,610	33,778
31.12.2039	1,053	13.6	1,568,304	305,280	-	141,075	-	-	1,121,950	525,072	134,721	462,156	216,948	150,646	105,488	52,963	27,383
31.12.2040	1,064	13.7	1,585,201	308,569	-	120,671	-	-	1,155,961	540,990	138,890	476,081	212,842	144,358	98,787	47,442	23,507
31.12.2041	1,053	13.6	1,568,304	305,280	-	120,539	110,999	-	1,031,486	482,736	149,189	399,561	170,126	112,703	75,372	34,624	16,440
31.12.2042	1,062	13.7	1,581,830	307,913	-	120,706	-	-	1,153,211	539,703	138,554	474,955	192,597	124,622	81,449	35,788	16,285
31.12.2043	1,053	13.6	1,568,304	305,280	-	120,614	-	-	1,142,411	534,648	137,232	470,530	181,717	114,848	73,355	30,830	13,445
31.12.2044	1,064	13.7	1,568,285	305,276	-	133,092	-	-	1,129,917	528,801	135,704	465,412	171,182	105,673	65,961	26,517	11,082
31.12.2045	1,053	13.6	1,551,578	302,024	-	112,448	-	-	1,137,105	532,165	136,583	468,357	164,062	98,922	60,344	23,205	9,294
31.12.2046	1,062	13.7	1,564,962	304,629	-	112,550	99,390	-	1,048,392	490,648	147,445	410,300	136,881	80,614	48,058	17,677	6,785
31.12.2047	1,053	13.6	1,551,797	302,067	-	112,530	-	-	1,137,200	532,210	134,309	470,682	149,547	86,026	50,119	17,633	6,486
31.12.2048	1,064	13.7	1,570,946	305,794	-	112,655	-	-	1,152,497	539,369	136,181	476,948	144,322	81,089	46,169	15,537	5,477
31.12.2049	1,053	13.6	1,554,208	302,536	-	133,227	99,390	-	1,019,055	476,918	141,569	400,568	115,438	63,352	35,250	11,347	3,833
31.12.2050	1,062	13.7	1,567,615	305,146	-	112,727	99,390	-	1,050,352	491,565	143,113	415,674	114,087	61,155	33,254	10,239	3,315
31.12.2051	1,053	13.6	1,554,208	302,536	-	112,709	-	-	1,138,964	533,035	131,229	474,699	124,083	64,966	34,524	10,168	3,155
31.12.2052	1,064	13.7	1,570,946	305,794	-	112,833	99,390	-	1,052,928	492,770	143,695	416,462	103,677	53,019	27,535	7,757	2,306
31.12.2053	1,053	13.6	1,554,208	302,536	-	112,802	210,390	-	928,481	434,529	150,435	343,517	81,445	40,682	20,647	5,564	1,585
31.12.2054	1,026	13.2	1,516,224	295,142	-	133,276	298,171	-	789,634	369,549	147,787	272,298	61,485	29,998	14,879	3,835	1,047

Total Discounted Cash Flow from the 2P + 2C - Proved + Probable Reserves and Best Estimate Contingent Resources as of 31 December 2023 (in Dollars in thousands in relation to the Partnership's share)																	
Cash Flow components																	
										Taxes		Total Discounted Cash Flow after tax					
Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Gas sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Develop-ment costs	Abandon-ment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Levy	Income Tax	Discounted at 0%	Discounted at 5%	Discounted at 7.5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2055	991	12.8	1,464,833	285,138	-	112,472	99,390	-	967,832	452,945	119,173	395,714	85,098	40,552	19,657	4,846	1,268
31.12.2056	956	12.3	1,414,538	275,348	-	112,279	-	-	1,026,911	480,594	103,415	442,901	90,710	42,221	20,001	4,717	1,183
31.12.2057	922	11.9	1,366,520	266,001	-	112,096	-	-	988,423	462,582	99,849	425,992	83,092	37,776	17,488	3,945	948
31.12.2058	890	11.5	1,319,597	256,868	-	111,916	-	-	950,814	444,981	95,247	410,586	76,273	33,870	15,323	3,306	761
31.12.2059	859	11.1	1,274,910	248,169	-	132,353	-	-	894,388	418,574	82,961	392,853	69,504	30,146	13,329	2,751	607
31.12.2060	829	10.7	1,232,239	239,863	-	111,492	-	-	880,884	412,254	83,595	385,035	64,877	27,485	11,876	2,344	496
31.12.2061	799	10.3	1,188,104	231,272	-	110,521	-	-	846,312	396,074	80,508	369,730	59,332	24,551	10,367	1,958	397
31.12.2062	771	9.9	1,146,272	223,129	-	109,602	-	69,422	744,120	348,248	85,114	310,758	47,494	19,195	7,921	1,431	278
31.12.2063	744	9.6	1,105,602	215,212	-	108,708	-	69,422	712,260	333,337	84,778	294,144	42,814	16,902	6,816	1,178	219
31.12.2064	61	0.8	90,018	17,522	-	17,522	-	69,422	(14,449)	-	1,421	(15,869)	(2,200)	(848)	(334)	(55)	(10)
Total	**40,291**	**518.6**	**59,200,861**	**11,416,250**	**-**	**5,035,252**	**1,656,470**	**208,265**	**40,884,624**	**17,682,943**	**5,022,722**	**18,178,960**	**8,648,042**	**6,625,986**	**5,337,221**	**3,841,853**	**3,019,356**

Total Discounted Cash Flow from the 3P + 3C - Proved + Probable + Possible Reserves and High Estimate Contingent Resources as of 31 December 2023 (in Dollars in thousands in relation to the Partnership's share)																	
Cash Flow components																	
Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Gas sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Develop-ment costs	Abandon-ment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Taxes		Total Discounted Cash Flow after tax					
										Levy	Income Tax	Discounted at 0%	Discounted at 5%	Discounted at 7.5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2024	867	11.2	1,155,238	173,766	-	152,963	262,580	-	565,929	-	141,298	424,631	414,397	409,551	404,870	395,970	387,633
31.12.2025	983	12.7	1,337,188	206,064	-	150,351	128,588	-	852,185	-	172,607	679,578	631,619	609,715	589,048	551,052	516,973
31.12.2026	1,062	13.7	1,444,542	281,189	-	140,114	32,585	-	990,654	16,683	176,002	797,969	706,339	665,986	628,788	562,654	505,863
31.12.2027	1,053	13.6	1,463,796	284,937	-	147,601	2,494	-	1,028,765	272,575	115,473	640,717	540,137	497,436	458,978	392,848	338,479
31.12.2028	1,064	13.7	1,550,810	301,874	-	150,888	2,026	-	1,096,021	403,142	101,035	591,845	475,178	427,435	385,426	315,550	260,551
31.12.2029	1,053	13.6	1,557,926	303,260	-	171,813	687	-	1,082,166	484,224	79,402	518,540	396,498	348,366	306,989	240,405	190,233
31.12.2030	1,062	13.7	1,595,563	310,586	-	152,449	-	-	1,132,528	530,023	119,766	482,739	351,546	301,687	259,812	194,615	147,582
31.12.2031	1,053	13.6	1,571,190	305,841	-	130,275	-	-	1,135,073	531,214	123,346	480,513	333,262	279,346	235,104	168,450	122,418
31.12.2032	1,064	13.7	1,621,399	315,615	-	131,463	-	-	1,174,321	549,582	128,414	496,325	327,836	268,407	220,764	151,298	105,372
31.12.2033	1,053	13.6	1,629,214	317,136	-	131,743	110,999	-	1,069,335	500,449	139,857	429,030	269,891	215,828	173,483	113,725	75,904
31.12.2034	1,062	13.7	1,643,788	319,973	-	152,732	-	-	1,171,083	548,067	128,362	494,654	296,356	231,480	181,835	114,018	72,929
31.12.2035	1,053	13.6	1,572,694	306,134	-	122,469	-	-	1,144,091	535,435	131,163	477,494	272,452	207,860	159,570	95,707	58,666
31.12.2036	1,064	13.7	1,589,600	309,425	-	122,673	-	-	1,157,502	541,711	135,459	480,332	261,021	194,507	145,926	83,718	49,179
31.12.2037	1,053	13.6	1,572,694	306,134	-	122,534	-	-	1,144,025	535,404	137,373	471,249	243,891	177,515	130,151	71,422	40,207
31.12.2038	1,062	13.7	1,586,227	308,769	-	122,701	-	-	1,154,757	540,426	138,704	475,627	234,435	166,665	119,419	62,683	33,817
31.12.2039	1,053	13.6	1,572,624	306,121	-	143,209	-	-	1,123,294	525,702	134,885	462,707	217,206	150,826	105,614	53,026	27,416
31.12.2040	1,064	13.7	1,589,529	309,411	-	122,810	-	-	1,157,307	541,620	139,055	476,632	213,089	144,525	98,902	47,497	23,534
31.12.2041	1,053	13.6	1,572,624	306,121	-	122,674	-	-	1,143,830	535,312	137,406	471,111	200,591	132,885	88,869	40,824	19,384
31.12.2042	1,062	13.7	1,586,156	308,755	-	122,844	110,999	-	1,043,558	488,385	149,390	405,783	164,548	106,472	69,587	30,576	13,914
31.12.2043	1,053	13.6	1,572,624	306,121	-	122,748	-	-	1,143,755	535,277	136,120	472,357	182,423	115,294	73,640	30,950	13,497
31.12.2044	1,064	13.7	1,571,723	305,945	-	134,793	-	-	1,130,985	529,301	135,834	465,850	171,342	105,772	66,023	26,542	11,093
31.12.2045	1,053	13.6	1,555,017	302,693	-	114,149	-	-	1,138,174	532,666	136,714	468,795	164,215	99,015	60,400	23,226	9,302
31.12.2046	1,062	13.7	1,568,400	305,298	-	114,251	-	-	1,148,851	537,662	138,020	473,168	157,854	92,966	55,422	20,385	7,824
31.12.2047	1,053	13.6	1,555,248	302,738	-	114,231	-	-	1,138,278	532,714	136,727	468,837	148,961	85,689	49,922	17,564	6,460
31.12.2048	1,064	13.7	1,574,524	306,490	-	114,356	99,390	-	1,054,287	493,406	148,166	412,714	124,885	70,168	39,951	13,445	4,739
31.12.2049	1,053	13.6	1,557,786	303,232	-	134,929	-	-	1,119,625	523,985	132,158	463,482	133,569	73,302	40,787	13,129	4,435
31.12.2050	1,062	13.7	1,571,193	305,842	-	114,428	99,390	-	1,051,533	492,117	145,543	413,872	113,592	60,889	33,110	10,195	3,300
31.12.2051	1,053	13.6	1,557,786	303,232	-	114,410	99,390	-	1,040,753	487,073	141,938	411,742	107,627	56,350	29,945	8,819	2,736
31.12.2052	1,064	13.7	1,574,524	306,490	-	114,535	-	-	1,153,498	539,837	133,008	480,654	119,657	61,191	31,779	8,952	2,662
31.12.2053	1,053	13.6	1,557,786	303,232	-	114,503	99,390	-	1,040,661	487,029	142,194	411,437	97,548	48,725	24,730	6,664	1,899
31.12.2054	1,062	13.7	1,571,193	305,842	-	135,221	110,999	-	1,019,130	476,953	139,810	402,367	90,855	44,327	21,986	5,667	1,547

Total Discounted Cash Flow from the 3P + 3C - Proved + Probable + Possible Reserves and High Estimate Contingent Resources as of 31 December 2023 (in Dollars in thousands in relation to the Partnership's share)																	
Cash Flow components																	
										Taxes		Total Discounted Cash Flow after tax					
Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Gas sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Develop-ment costs	Abandon-ment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Levy	Income Tax	Discounted at 0%	Discounted at 5%	Discounted at 7.5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2055	1,053	13.6	1,557,786	303,232	-	114,599	298,171	-	841,783	393,955	156,073	291,756	62,742	29,899	14,493	3,573	935
31.12.2056	1,064	13.7	1,574,524	306,490	-	114,730	198,781	-	954,523	446,717	140,341	367,465	75,260	35,030	16,594	3,913	981
31.12.2057	1,038	13.4	1,536,560	299,101	-	114,598	-	-	1,122,861	525,499	112,361	485,000	94,602	43,009	19,911	4,491	1,079
31.12.2058	1,007	13.0	1,491,872	290,402	-	114,434	-	-	1,087,036	508,733	109,121	469,182	87,159	38,703	17,510	3,778	870
31.12.2059	977	12.6	1,448,301	281,921	-	134,880	-	-	1,031,500	482,742	96,945	451,814	79,935	34,670	15,329	3,164	698
31.12.2060	947	12.2	1,405,827	273,653	-	114,117	-	-	1,018,057	476,451	96,443	445,164	75,008	31,777	13,731	2,710	573
31.12.2061	919	11.8	1,365,629	265,828	-	113,971	-	-	985,830	461,368	94,785	429,676	68,951	28,531	12,048	2,275	461
31.12.2062	891	11.5	1,325,220	257,962	-	113,734	-	69,422	884,103	413,760	99,448	370,895	56,684	22,910	9,454	1,708	332
31.12.2063	865	11.1	1,285,712	250,272	-	112,872	-	69,422	853,147	399,273	96,803	357,071	51,973	20,517	8,275	1,430	266
31.12.2064	71	0.9	105,121	20,462	-	17,852	-	69,422	(2,615)	-	897	(3,513)	(487)	(188)	(74)	(12)	(2)
Total	**41,367**	**532.4**	**61,097,157**	**11,787,593**	**-**	**5,122,648**	**1,656,470**	**208,265**	**42,322,181**	**18,356,470**	**5,198,448**	**18,767,262**	**8,814,648**	**6,735,038**	**5,418,101**	**3,898,607**	**3,065,742**

(d) Set forth below is an analysis of sensitivity to the main parameters comprising the Discounted Cash Flow of reserves and contingent resources (the gas price and the gas sales volume) as of 31 December 2023 (Dollars in thousands) which was performed by the Partnership[20]

Sensitivity / Category	Present value discounted at 0%	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%
10% increase in the gas price				
Proved reserves and low estimate contingent resources	17,060,936	5,515,249	3,998,668	3,146,016
Proved+probable reserves and best estimate contingent resources	20,071,014	5,834,906	4,191,480	3,292,241
Proved+probable+possible reserves and high estimate contingent resources	20,721,316	5,925,717	4,255,487	3,344,650
15% increase in the gas price				
Proved reserves and low estimate contingent resources	17,855,954	5,744,299	4,160,206	3,271,778
Proved+probable reserves and best estimate contingent resources	21,010,663	6,077,364	4,360,143	3,422,833
Proved+probable+possible reserves and high estimate contingent resources	21,685,346	6,167,812	4,422,798	3,473,581
20% increase in the gas price				
Proved reserves and low estimate contingent resources	18,655,889	5,976,568	4,324,384	3,399,718
Proved+probable reserves and best estimate contingent resources	21,960,047	6,327,235	4,535,357	3,559,255
Proved+probable+possible reserves and high estimate contingent resources	22,662,881	6,420,740	4,599,905	3,611,418

Sensitivity / Category	Present value discounted at 0%	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%
10% decrease in the gas price				
Proved reserves and low estimate contingent resources	13,877,007	4,580,444	3,330,487	2,619,009
Proved+probable reserves and best estimate contingent resources	16,294,006	4,837,510	3,487,629	2,740,137
Proved+probable+possible reserves and high estimate contingent resources	16,819,818	4,911,631	3,540,561	2,784,053
15% decrease in the gas price				
Proved reserves and low estimate contingent resources	13,076,309	4,340,237	3,156,891	2,480,908
Proved+probable reserves and best estimate contingent resources	15,355,954	4,590,132	3,312,292	2,601,815
Proved+probable+possible reserves and high estimate contingent resources	15,851,970	4,661,104	3,363,229	2,644,178
20% decrease in the gas price				
Proved reserves and low estimate contingent resources	12,279,210	4,101,547	2,984,306	2,343,494
Proved+probable reserves and best estimate contingent resources	14,414,568	4,338,640	3,132,916	2,459,656
Proved+probable+possible reserves and high estimate contingent resources	14,879,721	4,406,025	3,181,571	2,500,275

[20] With respect to a sensitivity analysis for the Discounted Cash Flow to the variable of the gas sales volume, it is noted that no changes were made in the drilling forecast for adjustment to the number of required wells, and no costs were included for additional wells which may be required for adjustment to the increase in gas sale quantities.

Sensitivity / Category	Present value discounted at 0%	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%
10% increase in the gas sales volume				
Proved reserves and low estimate contingent resources	15,701,933	5,477,460	3,996,204	3,149,766
Proved+probable reserves and best estimate contingent resources	18,334,050	5,798,354	4,190,738	3,296,758
Proved+probable+possible reserves and high estimate contingent resources	18,935,396	5,889,528	4,254,977	3,349,251
15% increase in the gas sales volume				
Proved reserves and low estimate contingent resources	15,738,980	5,670,765	4,149,118	3,273,080
Proved+probable reserves and best estimate contingent resources	18,387,500	6,013,543	4,356,363	3,428,801
Proved+probable+possible reserves and high estimate contingent resources	18,854,471	6,099,327	4,418,202	3,479,382
20% increase in the gas sales volume [21]				
Proved reserves and low estimate contingent resources	15,803,705	5,867,957	4,308,579	3,403,616
Proved+probable reserves and best estimate contingent resources	18,300,335	6,223,592	4,524,968	3,565,620
Proved+probable+possible reserves and high estimate contingent resources	18,891,048	6,318,969	4,590,452	3,618,092

Sensitivity / Category	Present value discounted at 0%	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%
10% decrease in the gas sales volume				
Proved reserves and low estimate contingent resources	13,837,750	4,568,925	3,322,310	2,612,628
Proved+probable reserves and best estimate contingent resources	16,247,912	4,825,493	3,479,229	2,733,621
Proved+probable+possible reserves and high estimate contingent resources	16,781,588	4,906,404	3,538,110	2,782,749
15% decrease in the gas sales volume				
Proved reserves and low estimate contingent resources	13,017,326	4,322,811	3,144,473	2,471,190
Proved+probable reserves and best estimate contingent resources	15,286,708	4,571,938	3,299,520	2,591,872
Proved+probable+possible reserves and high estimate contingent resources	15,780,813	4,642,824	3,350,433	2,634,228
20% decrease in the gas sales volume				
Proved reserves and low estimate contingent resources	12,211,082	4,085,712	2,974,030	2,335,907
Proved+probable reserves and best estimate contingent resources	14,322,220	4,314,186	3,115,669	2,446,176
Proved+probable+possible reserves and high estimate contingent resources	14,784,805	4,381,453	3,164,290	2,486,784

[21] With respect to a sensitivity analysis for the Discounted Cash Flow to the variable of the gas sales volume, it is noted that no costs were included for additional drillings which may be required in order to accommodate the increase in the gas sales volume.

2. Agreement between the report data and data of previous reports pertaining to the petroleum asset

The main differences between the estimates of the reserves and the contingent resources according to the Resources Report and those included in the Previous Resources Report, derive from an update to the flow model in the Reservoir based, *inter alia*, on production data, due to which approx. 427 BCF of 2C contingent resources (future development) were reclassified as 2C contingent resources (Phase I – First Stage). In addition, production of approx. 392 BCF of natural gas and approx. 874 thousand barrels of condensate performed in 2023 was taken into account.

3. Production data

Below is a table which includes data on natural gas production in 2023 in the Leviathan Project:[22,23,24]

		Q1	Q2	Q3	Q4
Total output (attributed to the holders of the Partnership's equity interests) in the period (in MMCF for natural gas)		45,277.33	40,043.67	46,237.36	44,042.08
Average price per output unit (attributed to the holders of the Partnership's equity interests) (Dollars per MCF)		6.21	6.26	6.18	6.28
Average royalties (any payment derived from the output of the producing asset, including from the gross income from the petroleum asset) paid per output unit (attributed to the holders of the Partnership's equity interests) (Dollars per MCF)	The State	0.67	0.67	0.67	0.68
	Third parties	0.16	0.16	0.16	0.16
	Interested parties	0.08	0.08	0.08	0.08
Average production costs per output unit (attributed to the holders of the Partnership's equity interests) (Dollars per MCF)[25,26]		0.82	0.88	0.80	0.85
Average net revenues per output unit (attributed to the holders of the Partnership's equity interests) (Dollars per MCF)		4.48	4.47	4.47	4.51

[22] The data presented in the table above on the rate attributed to the holders of the Partnership's equity interests on the average price per output unit, royalties paid, production costs and revenues, net, have been rounded off to two digits after the decimal point.

[23] Since the total costs entailed by the production of condensate during 2023 exceeded the total revenues received therefor, and since condensate is a byproduct of natural gas production, the above table does not present separate information on condensate production. All the costs and expenses in connection with the condensate production have been attributed to the natural gas production.

[24] It is clarified that the production data for 2023 are based on unaudited financial data.

[25] The data include current production costs only, and do not include the Reservoir's exploration and development costs, and future tax payments to be made by the Partnership.

[26] The average production costs per output unit include costs for the transmission of natural gas via the INGL transmission system to the EMG terminal in Ashkelon, to the terminal of FAJR on the Jordanian border, and costs of transmission via the Jordanian transmission system (FAJR) to the delivery point in Aqaba in Jordan, for the supply of the gas to Egypt in the sum of approx. $38.1 million in Q1/2023,

	Q1	Q2	Q3	Q4
Depletion rate in the reported period relative to the total quantities of gas in the project (in %)	0.64%	0.57%	0.66%	0.62%

4. Opinion of the Evaluator

Attached hereto as **Annex A** is a report on reserves and contingent resources in the Leviathan Reservoir prepared by NSAI as of 31 December 2023, and NSAI's consent to its inclusion herein is attached to this chapter as **Annex A**.

5. Management declaration

(1) Date of the declaration: 19 March 2024;

(2) Name of the corporation: NewMed Energy - Limited Partnership;

(3) Name and position of the resource evaluation officer at the Partnership: Gabi Last, Chairman of the General Partner's Board;

(4) We confirm that the evaluator was provided with all of the data required for performance of its work;

(5) We confirm that no information has come to our attention which indicates the existence of dependency between the evaluator and the Partnership;

(6) We confirm that, to the best of our knowledge, the resources reported are the best and most current estimates in our possession;

(7) We confirm that the data included in this report were prepared according to the professional terms listed in Chapter G of the Third Schedule to the Securities Regulations (Details of the Prospectus and Draft Prospectus – Structure and Form), 5729-1969, and within the meaning afforded thereto in Petroleum Resources Management System (2018), as published by the SPE, the AAPG, the WPC and the SPEE, as being at the time of release of the Resources Report;

(8) We confirm that no change has been made to the identity of the evaluator who performed the last contingent resource or reserve disclosure released by the Partnership.

Gabi Last, Chairman of the General Partner's Board

The partners in the Leviathan Reservoir and their holding rates are as follows:

The Partnership	45.34%
Chevron	39.66%
Ratio Energies - Limited Partnership	15.00%

approx. $38.8 million in Q2/2023, approx. $40.1 million in Q3/2023 and approx. $37.4 million in Q4/2023 (100%).

Sincerely,

NewMed Energy Management Ltd.

General Partner of NewMed Energy – Limited Partnership

By: Yossi Abu, CEO

and Zvi Karcz, VP Exploration

NETHERLAND, SEWELL
& ASSOCIATES, INC.
WORLDWIDE PETROLEUM CONSULTANTS
ENGINEERING • GEOLOGY • GEOPHYSICS • PETROPHYSICS

March 19, 2024

NewMed Energy Limited Partnership
19 Abba Eban Boulevard
Herzliya 4612001
Israel

Ladies and Gentlemen:

As independent consultants, Netherland, Sewell & Associates, Inc. hereby grant permission to NewMed Energy Limited Partnership (NewMed) to use our report dated March 19, 2024, to be filed with the Israel Securities Authority and the Tel Aviv Stock Exchange. This report sets forth our estimates of the proved, probable, and possible reserves and future revenue, as of December 31, 2023, 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, 2023, to the NewMed interest in these properties.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: Richard B. Talley, Jr.
Richard B. Talley, Jr., P.E.
Chief Executive Officer

JRC:MDK

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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, 2023

BASED ON PRICE AND COST PARAMETERS

specified by

NEWMED ENERGY LIMITED PARTNERSHIP

NETHERLAND, SEWELL & ASSOCIATES, INC.

WORLDWIDE PETROLEUM CONSULTANTS

ENGINEERING • GEOLOGY
GEOPHYSICS • PETROPHYSICS

NETHERLAND, SEWELL
& ASSOCIATES, INC.
WORLDWIDE PETROLEUM CONSULTANTS
ENGINEERING • GEOLOGY • GEOPHYSICS • PETROPHYSICS

March 19, 2024

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, 2023, 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, 2023, 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 18, 2024, exchange rate was 3.65 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, 2023, 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)	13,472.1	6,108.3	29.6	13.4
Probable	1,699.3	770.5	3.7	1.7
Proved + Probable (2P)	15,171.4	6,878.7	33.4	15.1
Possible	684.4	310.3	1.5	0.7
Proved + Probable + Possible (3P)	15,855.8	7,189.0	34.9	15.8

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, 2023, to be:

Category	Future Net Revenue After Levy and Corporate Income Taxes (MM$) Discounted at 0%	Discounted at 5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
Proved (1P)	13,805.4	7,323.4	4,780.2	3,527.5	2,801.4
Probable	1,702.7	573.5	308.0	221.4	180.8
Proved + Probable (2P)	15,508.2	7,896.9	5,088.2	3,748.9	2,982.1
Possible	751.6	275.5	135.3	82.8	58.7
Proved + Probable + Possible (3P)	16,259.8	8,172.4	5,223.5	3,831.7	3,040.9

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, 2023, 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, 2023, 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[1]	2,050.3	3,142.3	2,947.0	4.5	6.9	6.5
Future Development	0.0	3,160.5	7,600.0	0.0	7.0	16.7
Total	2,050.3	6,302.8	10,547.0	4.5	13.9	23.2

[1] The contingent resources shown in this report represent volumes that are incrementally recoverable over volumes classified as reserves. For Phase I – First Stage, the 3C contingent resources are less than the 2C contingent resources because a larger portion of the estimated volumes for the high estimate case has been classified as reserves.

We estimate the NewMed working interest contingent resources by development phase for these properties, as of December 31, 2023, 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[1]	929.6	1,424.7	1,336.2	2.0	3.1	2.9
Future Development	0.0	1,433.0	3,445.8	0.0	3.2	7.6
Total	929.6	2,857.7	4,782.0	2.0	6.3	10.5

[1] The contingent resources shown in this report represent volumes that are incrementally recoverable over volumes classified as reserves. For Phase I – First Stage, the 3C contingent resources are less than the 2C contingent resources because a larger portion of the estimated volumes for the high estimate case has been classified as reserves.

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, 2023, to be:

	Net Contingent Cash Flow After Levy and Corporate Income Taxes (MM$)				
Category	Discounted at 0%	Discounted at 5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
Low Estimate (1C)	1,657.9	612.1	265.9	136.4	81.2
Best Estimate (2C)	2,670.8	751.2	249.0	93.0	37.2
High Estimate (3C)	2,507.5	642.3	194.6	66.9	24.9

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 price parameters specified by NewMed. Gas prices are based on NewMed's estimates of approved and future sales contracts. These contract prices are derived mainly from various formulae that include indexation 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 and are adjusted for quality and market differentials. The forecasted Brent Crude prices are escalated on January 1 of each year through December 31, 2033, and then held constant thereafter; the escalation rates have been specified by NewMed.

Operating costs used in this report are based on operating expense records of NewMed. Operating costs include the overhead expenses allowed under joint operating agreements, direct project-level costs, insurance costs, workover costs, and transportation costs. Since all properties are nonoperated, headquarters general and administrative overhead expenses of NewMed are not included. 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, regional midstream infrastructure, 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, 2023, 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, the operator of the properties; public data sources; and the nonconfidential files of NSAI and were accepted as accurate. Supporting work data are on file in our office. We have not examined the contractual rights to the 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 is a Senior Vice President and Mr. Long is a Vice President in the firm's Houston office at 1301 McKinney Street, Suite 3200, Houston, Texas 77010, USA. Mr. 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: Richard B. Talley, Jr.
Richard B. Talley, Jr., P.E.
Chief Executive Officer

By: John R. Cliver
John R. Cliver P.E. 107216
Senior Vice President

STATE OF TEXAS
J. R. CLIVER
107216
LICENSED
PROFESSIONAL ENGINEER

Date Signed: March 19, 2024

JRC:MDK

By: Zach Long
Zachary R. Long, P.G. 11792
Vice President

STATE OF TEXAS
Z. R. LONG
GEOLOGY
11792
LICENSED
PROFESSIONAL GEOSCIENTIST

Date Signed: March 19, 2024

NETHERLAND, SEWELL & ASSOCIATES, INC.

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.

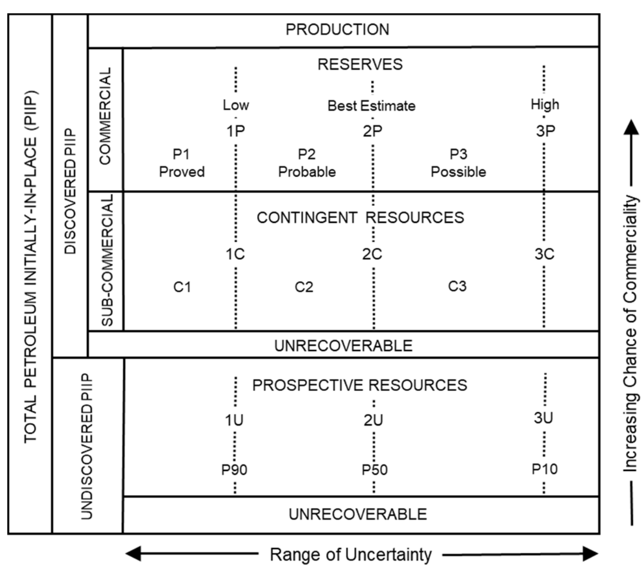

Figure 1.1—Resources classification framework

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.

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

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1.2 Project-Based Resources Evaluations

1.2.0.1 The resources evaluation process consists of identifying a recovery project or projects associated with one or more petroleum accumulations, estimating the quantities of PIIP, estimating that portion of those in-place quantities that can be recovered by each project, and classifying the project(s) based on maturity status or chance of commerciality.

1.2.0.2 The concept of a project-based classification system is further clarified by examining the elements contributing to an evaluation of net recoverable resources (see Figure 1.2).

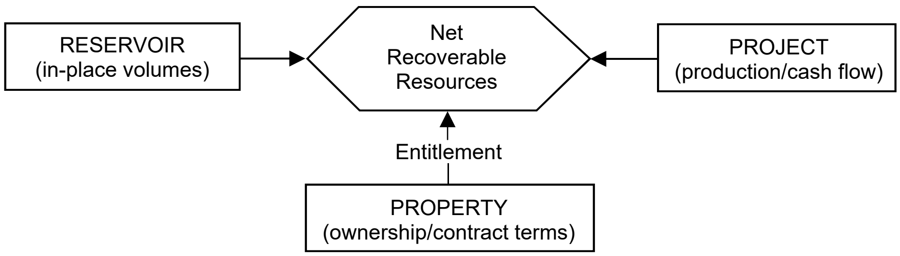

Figure 1.2—Resources evaluation

1.2.0.3 **The reservoir** (contains the petroleum accumulation): Key attributes include the types and quantities of PIIP and the fluid and rock properties that affect petroleum recovery.

1.2.0.4 **The project:** A project may constitute the development of a well, a single reservoir, or a small field; an incremental development in a producing field; or the integrated development of a field or several fields together with the associated processing facilities (e.g., compression). Within a project, a specific reservoir's development generates a unique production and cash-flow schedule at each level of certainty. The integration of these schedules taken to the project's earliest truncation caused by technical, economic, or the contractual limit defines the estimated recoverable resources and associated future net cash flow projections for each project. The ratio of EUR to total PIIP quantities defines the project's recovery efficiency. Each project should have an associated recoverable resources range (low, best, and high estimate).

1.2.0.5 **The property** (lease or license area): Each property may have unique associated contractual rights and obligations, including the fiscal terms. This information allows definition of each participating entity's share of produced quantities (entitlement) and share of investments, expenses, and revenues for each recovery project and the reservoir to which it is applied. One property may encompass many reservoirs, or one reservoir may span several different properties. A property may contain both discovered and undiscovered accumulations that may be spatially unrelated to a potential single field designation.

1.2.0.6 An entity's net recoverable resources are the entitlement share of future production legally accruing under the terms of the development and production contract or license.

1.2.0.7 In the context of this relationship, the project is the primary element considered in the resources classification, and the net recoverable resources are the quantities derived from each project. A project represents a defined activity or set of activities to develop the petroleum accumulation(s) and the decisions taken to mature the resources to reserves. In general, it is recommended that an individual project has assigned to it a specific maturity level sub-class (See Section 2.1.3.5, Project Maturity Sub-Classes) at which a decision is made whether or not to proceed (i.e., spend more money) and there should be an associated range of estimated recoverable quantities for the project (See Section 2.2.1, Range of Uncertainty). For completeness, a developed field is also considered to be a project.

1.2.0.8 An accumulation or potential accumulation of petroleum is often subject to several separate and distinct projects that are at different stages of exploration or development. Thus, an accumulation may have recoverable quantities in several resources classes simultaneously.

1.2.0.10 Not all technically feasible development projects will be commercial. The commercial viability of a development project within a field's development plan is dependent on a forecast of the conditions that will exist during the time period encompassed by the project (see Section 3.1, Assessment of Commerciality). Conditions include technical, economic (e.g., hurdle rates, commodity prices), operating and capital costs, marketing, sales route(s), and legal, environmental, social, and governmental factors forecast to exist and impact the project during the time period being evaluated. While economic factors can be summarized as forecast costs and product prices, the underlying influences include, but are not limited to, market conditions (e.g., inflation, market factors, and contingencies), exchange rates, transportation and processing infrastructure, fiscal terms, and taxes.

1.2.0.11 The resources being estimated are those quantities producible from a project as measured according to delivery specifications at the point of sale or custody transfer (see Section 3.2.1, Reference Point) and may permit forecasts of CiO quantities (see Section 3.2.2., Consumed in Operations). The cumulative production forecast from the effective date forward to cessation of production is the remaining recoverable resources quantity (see Section 3.1.1, Net Cash-Flow Evaluation).

1.2.0.12 The supporting data, analytical processes, and assumptions describing the technical and commercial basis used in an evaluation must be documented in sufficient detail to allow, as needed, a qualified reserves evaluator or qualified reserves auditor to clearly understand each project's basis for the estimation, categorization, and classification of recoverable resources quantities and, if appropriate, associated commercial assessment.

2.0 Classification and Categorization Guidelines

2.1 Resources Classification

2.1.0.1 The PRMS classification establishes criteria for the classification of the total PIIP. A determination of a discovery differentiates between discovered and undiscovered PIIP. The application of a project further differentiates the recoverable from unrecoverable resources. The project is then evaluated to determine its maturity status to allow the classification distinction between commercial and sub-commercial projects. PRMS requires the project's recoverable resources quantities to be classified as either Reserves, Contingent Resources, or Prospective Resources.

2.1.1 Determination of Discovery Status

2.1.1.1 A discovered petroleum accumulation is determined to exist when one or more exploratory wells have established through testing, sampling, and/or logging the existence of a significant quantity of potentially recoverable hydrocarbons and thus have established a known accumulation. In the absence of a flow test or sampling, the discovery determination requires confidence in the presence of hydrocarbons and evidence of producibility, which may be supported by suitable producing analogs (see Section 4.1.1, Analogs). In this context, "significant" implies that there is evidence of a sufficient quantity of petroleum to justify estimating the in-place quantity demonstrated by the well(s) and for evaluating the potential for commercial recovery.

2.1.1.2 Where a discovery has identified potentially recoverable hydrocarbons, but it is not considered viable to apply a project with established technology or with technology under development, such quantities may be classified as Discovered Unrecoverable with no Contingent Resources. In future evaluations, as appropriate for petroleum resources management purposes, a portion of these unrecoverable quantities may become recoverable resources as either commercial circumstances change or technological developments occur.

2.1.2 Determination of Commerciality

2.1.2.1 Discovered recoverable quantities (Contingent Resources) may be considered commercially mature, and thus attain Reserves classification, if the entity claiming commerciality has demonstrated a firm intention to proceed with development. This means the entity has satisfied the internal decision criteria (typically rate of return at or above the weighted average cost-of-capital or the hurdle rate). Commerciality is achieved with the entity's commitment to the project and all of the following criteria:

A. Evidence of a technically mature, feasible development plan.
B. Evidence of financial appropriations either being in place or having a high likelihood of being secured to implement the project.
C. Evidence to support a reasonable time-frame for development.
D. A reasonable assessment that the development projects will have positive economics and meet defined investment and operating criteria. This assessment is performed on the estimated entitlement forecast quantities and associated cash flow on which the investment decision is made (see Section 3.1.1, Net Cash-Flow Evaluation).
E. A reasonable expectation that there will be a market for forecast sales quantities of the production required to justify development. There should also be similar confidence that all produced streams (e.g., oil, gas, water, 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.

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

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Approved by the Society of Petroleum Engineers (SPE) Board of Directors

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.

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

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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

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Class/Sub-Class	Definition	Guidelines
Justified for Development	Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals/contracts will be obtained.	To move to this level of project maturity, and hence have Reserves associated with it, the development project must be commercially viable at the time of reporting (see Section 2.1.2, Determination of Commerciality) and the specific circumstances of the project. All participating entities have agreed and there is evidence of a committed project (firm intention to proceed with development within a reasonable time-frame). There must be no known contingencies that could preclude the development from proceeding (see Reserves class). The project decision gate is the decision by the reporting entity and its partners, if any, that the project has reached a level of technical and commercial maturity sufficient to justify proceeding with development at that point in time.
Contingent Resources	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable owing to one or more contingencies.	Contingent Resources may include, for example, projects for which there are currently no viable markets, where commercial recovery is dependent on technology under development, where evaluation of the accumulation is insufficient to clearly assess commerciality, where the development plan is not yet approved, or where regulatory or social acceptance issues may exist. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by the economic status.
Development Pending	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.	The project is seen to have reasonable potential for eventual commercial development, to the extent that further data acquisition (e.g., drilling, seismic data) and/or evaluations are currently ongoing with a view to confirming that the project is commercially viable and providing the basis for selection of an appropriate development plan. The critical contingencies have been identified and are reasonably expected to be resolved within a reasonable time-frame. Note that disappointing appraisal/evaluation results could lead to a reclassification of the project to On Hold or Not Viable status. The project decision gate is the decision to undertake further data acquisition and/or studies designed to move the project to a level of technical and commercial maturity at which a decision can be made to proceed with development and production.
Development on Hold	A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay.	The project is seen to have potential for commercial development. Development may be subject to a significant time delay. Note that a change in circumstances, such that there is no longer a probable chance that a critical contingency can be removed in the foreseeable future, could lead to a reclassification of the project to Not Viable status. The project decision gate is the decision to either proceed with additional evaluation designed to clarify the potential for eventual commercial development or to temporarily suspend or delay further activities pending resolution of external contingencies.
Development Unclarified	A discovered accumulation where project activities are under evaluation and where justification as a commercial development is unknown based on available information.	The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are ongoing to clarify the potential for eventual commercial development. This sub-class requires active appraisal or evaluation and should not be maintained without a plan for future evaluation. The sub-class should reflect the actions required to move a project toward commercial maturity and economic production.

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, 2023

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$)
12-31-2024	1,099.4	121.6	14.6	29.2	165.4	262.6	0.0	150.8	520.6
12-31-2025	1,189.9	131.6	15.8	31.6	179.0	128.6	0.0	144.6	737.7
12-31-2026	1,308.3	144.7	65.6	34.7	245.0	32.6	0.0	134.6	896.1
12-31-2027	1,310.3	144.9	75.4	34.8	255.1	2.5	0.0	139.3	913.5
12-31-2028	1,339.7	148.2	77.0	35.6	260.8	2.0	0.0	137.6	939.2
12-31-2029	1,360.4	150.5	78.2	36.1	264.8	0.7	0.0	158.6	936.3
12-31-2030	1,386.8	153.4	79.8	36.8	269.9	0.0	0.0	138.9	977.9
12-31-2031	1,409.1	155.8	81.0	37.4	274.3	0.0	0.0	118.9	1,015.9
12-31-2032	1,457.1	161.2	83.8	38.7	283.6	0.0	0.0	119.7	1,053.8
12-31-2033	1,485.4	164.3	85.4	39.4	289.1	0.0	0.0	120.0	1,076.3
12-31-2034	1,485.9	164.3	85.5	39.4	289.2	0.0	0.0	140.8	1,055.8
12-31-2035	1,454.4	160.9	83.6	38.6	283.1	0.0	0.0	106.2	1,065.2
12-31-2036	1,454.4	160.9	83.6	38.6	283.1	0.0	0.0	106.2	1,065.1
12-31-2037	1,454.4	160.9	83.6	38.6	283.1	0.0	0.0	106.2	1,065.1
12-31-2038	1,450.3	160.4	83.4	38.5	282.3	0.0	0.0	106.2	1,061.8
Subtotal	20,646.0	2,283.4	1,076.5	548.0	3,907.9	429.0	0.0	1,928.8	14,380.3
Remaining	23,042.8	2,548.5	1,325.2	611.6	4,485.4	0.0	107.1	2,667.4	15,783.0
Total	43,688.8	4,832.0	2,401.7	1,159.7	8,393.4	429.0	107.1	4,596.2	30,163.2

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$)	Discounted at 20% (MM$)
12-31-2024	0.0	0.0	520.6	23.0	130.9	389.8	380.4	371.6	363.5	355.8
12-31-2025	0.0	0.0	737.7	23.0	146.3	591.4	549.7	512.7	479.6	449.9
12-31-2026	0.0	0.0	896.1	23.0	158.1	738.0	653.3	581.5	520.4	467.8
12-31-2027	18.1	165.4	748.1	23.0	113.6	634.5	534.9	454.5	389.0	335.2
12-31-2028	32.3	303.5	635.7	23.0	87.9	547.8	439.8	356.7	292.1	241.2
12-31-2029	40.0	374.7	561.6	23.0	71.0	490.5	375.1	290.4	227.4	180.0
12-31-2030	45.9	449.1	528.8	23.0	102.8	426.0	310.2	229.3	171.7	130.2
12-31-2031	46.8	475.4	540.5	23.0	108.8	431.7	299.4	211.2	151.3	110.0
12-31-2032	46.8	493.2	560.6	23.0	113.7	446.9	295.2	198.8	136.2	94.9
12-31-2033	46.8	503.7	572.6	23.0	116.5	456.1	286.9	184.4	120.9	80.7
12-31-2034	46.8	494.1	561.7	23.0	116.8	444.9	266.5	163.5	102.5	65.6
12-31-2035	46.8	498.5	566.7	23.0	124.1	442.6	252.5	147.9	88.7	54.4
12-31-2036	46.8	498.5	566.6	23.0	126.7	439.9	239.1	133.7	76.7	45.0
12-31-2037	46.8	498.5	566.6	23.0	130.3	436.4	225.8	120.5	66.1	37.2
12-31-2038	46.8	496.9	564.9	23.0	129.9	435.0	214.4	109.2	57.3	30.9
Subtotal		5,251.5	9,128.8		1,777.2	7,351.6	5,323.3	4,066.1	3,243.6	2,678.9
Remaining		7,390.0	8,393.0		1,939.1	6,453.8	2,000.0	714.2	283.9	122.5
Total		12,641.5	17,521.8		3,716.3	13,805.4	7,323.4	4,780.2	3,527.5	2,801.4

Notes: Remaining represents estimates after December 31, 2038, through the end of the lease term in 2064.
Totals may not add because of rounding.

(1) Operating costs include the overhead expenses allowed under joint operating agreements, direct project-level costs, insurance costs, workover costs, and transportation costs.
(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, 2023

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$)
12-31-2024	55.3	6.1	0.7	1.5	8.3	0.0	0.0	2.1	44.9
12-31-2025	86.5	9.6	1.1	2.3	13.0	0.0	0.0	2.9	70.5
12-31-2026	114.1	12.6	16.2	3.0	31.9	0.0	0.0	3.2	79.1
12-31-2027	129.8	14.4	7.5	3.4	25.3	0.0	0.0	6.1	98.4
12-31-2028	170.5	18.9	9.8	4.5	33.2	0.0	0.0	10.5	126.8
12-31-2029	157.6	17.4	9.1	4.2	30.7	0.0	0.0	10.5	116.4
12-31-2030	169.3	18.7	9.7	4.5	33.0	0.0	0.0	10.8	125.6
12-31-2031	145.8	16.1	8.4	3.9	28.4	0.0	0.0	9.7	107.7
12-31-2032	136.9	15.1	7.9	3.6	26.7	0.0	0.0	10.0	100.3
12-31-2033	104.4	11.5	6.0	2.8	20.3	0.0	0.0	9.9	74.2
12-31-2034	76.0	8.4	4.4	2.0	14.8	0.0	0.0	9.8	51.3
12-31-2035	25.7	2.8	1.5	0.7	5.0	0.0	0.0	13.8	6.9
12-31-2036	-2.1	-0.2	-0.1	-0.1	-0.4	0.0	0.0	13.8	-15.4
12-31-2037	-30.2	-3.3	-1.7	-0.8	-5.9	0.0	0.0	13.5	-37.8
12-31-2038	-52.8	-5.8	-3.0	-1.4	-10.3	0.0	0.0	13.5	-56.0
Subtotal	1,286.7	142.3	77.4	34.2	253.8	0.0	0.0	140.1	892.8
Remaining	4,316.3	477.4	248.2	114.6	840.2	0.0	0.0	180.1	3,296.0
Total	5,603.0	619.7	325.6	148.7	1,094.0	0.0	0.0	320.2	4,188.8

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$)	Discounted at 20% (MM$)
12-31-2024	0.0	0.0	44.9	23.0	10.3	34.5	33.7	32.9	32.2	31.5
12-31-2025	0.0	0.0	70.5	23.0	16.2	54.3	50.5	47.1	44.0	41.3
12-31-2026	0.0	0.0	79.1	23.0	18.2	60.9	53.9	48.0	42.9	38.6
12-31-2027	25.8	95.3	3.0	23.0	0.7	2.3	2.0	1.7	1.4	1.2
12-31-2028	35.9	79.6	47.1	23.0	10.8	36.3	29.1	23.6	19.4	16.0
12-31-2029	44.0	88.0	28.4	23.0	6.5	21.9	16.7	13.0	10.1	8.0
12-31-2030	46.8	67.3	58.2	23.0	13.4	44.9	32.7	24.1	18.1	13.7
12-31-2031	46.8	50.4	57.3	23.0	13.2	44.1	30.6	21.6	15.5	11.2
12-31-2032	46.8	47.0	53.4	23.0	12.3	41.1	27.1	18.3	12.5	8.7
12-31-2033	46.8	34.7	39.5	23.0	9.1	30.4	19.1	12.3	8.1	5.4
12-31-2034	46.8	24.0	27.3	23.0	6.3	21.0	12.6	7.7	4.8	3.1
12-31-2035	46.8	3.2	3.7	23.0	0.8	2.8	1.6	0.9	0.6	0.3
12-31-2036	46.8	-7.2	-8.2	23.0	-1.9	-6.3	-3.4	-1.9	-1.1	-0.6
12-31-2037	46.8	-17.7	-20.1	23.0	-4.6	-15.5	-8.0	-4.3	-2.3	-1.3
12-31-2038	46.8	-26.2	-29.8	23.0	-6.9	-22.9	-11.3	-5.8	-3.0	-1.6
Subtotal		438.5	454.3		104.5	349.8	286.9	239.3	203.2	175.6
Remaining		1,539.0	1,757.1		404.1	1,352.9	286.6	68.7	18.2	5.2
Total		1,977.5	2,211.3		508.6	1,702.7	573.5	308.0	221.4	180.8

Notes: Remaining represents estimates after December 31, 2038, through the end of the lease term in 2064.
Totals may not add because of rounding.

(1) Operating costs include the overhead expenses allowed under joint operating agreements, direct project-level costs, insurance costs, workover costs, and transportation costs.
(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, 2023

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$)
12-31-2024	1,154.7	127.7	15.3	30.7	173.7	262.6	0.0	153.0	565.5
12-31-2025	1,276.4	141.2	16.9	33.9	192.0	128.6	0.0	147.6	808.2
12-31-2026	1,422.4	157.3	81.8	37.8	276.9	32.6	0.0	137.8	975.2
12-31-2027	1,440.1	159.3	82.8	38.2	280.3	2.5	0.0	145.4	1,011.8
12-31-2028	1,510.1	167.0	86.9	40.1	294.0	2.0	0.0	148.1	1,066.0
12-31-2029	1,518.0	167.9	87.3	40.3	295.5	0.7	0.0	169.1	1,052.7
12-31-2030	1,556.0	172.1	89.5	41.3	302.9	0.0	0.0	149.7	1,103.5
12-31-2031	1,554.8	172.0	89.4	41.3	302.7	0.0	0.0	128.6	1,123.6
12-31-2032	1,594.1	176.3	91.7	42.3	310.3	0.0	0.0	129.7	1,154.1
12-31-2033	1,589.8	175.8	91.4	42.2	309.5	0.0	0.0	129.9	1,150.5
12-31-2034	1,561.9	172.7	89.8	41.5	304.0	0.0	0.0	150.7	1,107.2
12-31-2035	1,480.1	163.7	85.1	39.3	288.1	0.0	0.0	119.9	1,072.1
12-31-2036	1,452.3	160.6	83.5	38.6	282.7	0.0	0.0	119.9	1,049.7
12-31-2037	1,424.3	157.5	81.9	37.8	277.2	0.0	0.0	119.8	1,027.3
12-31-2038	1,397.6	154.6	80.4	37.1	272.0	0.0	0.0	119.7	1,005.8
Subtotal	21,932.7	2,425.8	1,153.8	582.2	4,161.8	429.0	0.0	2,068.9	15,273.1
Remaining	27,359.1	3,025.9	1,573.5	726.2	5,325.6	0.0	107.1	2,847.4	19,079.0
Total	49,291.8	5,451.7	2,727.3	1,308.4	9,487.4	429.0	107.1	4,916.3	34,352.1

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$)	Discounted at 20% (MM$)
12-31-2024	0.0	0.0	565.5	23.0	141.2	424.3	414.1	404.6	395.7	387.3
12-31-2025	0.0	0.0	808.2	23.0	162.5	645.7	600.2	559.7	523.6	491.2
12-31-2026	0.0	0.0	975.2	23.0	176.3	798.9	707.2	629.5	563.3	506.4
12-31-2027	25.8	260.7	751.2	23.0	114.3	636.8	536.9	456.2	390.5	336.4
12-31-2028	35.9	383.2	682.8	23.0	98.7	584.1	469.0	380.4	311.4	257.1
12-31-2029	44.0	462.7	590.0	23.0	77.6	512.4	391.8	303.4	237.6	188.0
12-31-2030	46.8	516.4	587.0	23.0	116.2	470.8	342.9	253.4	189.8	143.9
12-31-2031	46.8	525.8	597.8	23.0	121.9	475.8	330.0	232.8	166.8	121.2
12-31-2032	46.8	540.1	614.0	23.0	125.9	488.0	322.4	217.1	148.8	103.6
12-31-2033	46.8	538.4	612.1	23.0	125.5	486.5	306.1	196.7	129.0	86.1
12-31-2034	46.8	518.2	589.0	23.0	123.1	465.9	279.1	171.3	107.4	68.7
12-31-2035	46.8	501.7	570.3	23.0	124.9	445.4	254.2	148.9	89.3	54.7
12-31-2036	46.8	491.2	558.4	23.0	124.8	433.6	235.6	131.7	75.6	44.4
12-31-2037	46.8	480.8	546.5	23.0	125.6	420.9	217.8	116.2	63.8	35.9
12-31-2038	46.8	470.7	535.1	23.0	123.0	412.0	203.1	103.5	54.3	29.3
Subtotal		5,690.0	9,583.1		1,881.7	7,701.4	5,610.2	4,305.3	3,446.7	2,854.5
Remaining		8,929.0	10,150.0		2,343.3	7,806.8	2,286.7	782.9	302.2	127.7
Total		14,618.9	19,733.1		4,225.0	15,508.2	7,896.9	5,088.2	3,748.9	2,982.1

Notes: Remaining represents estimates after December 31, 2038, through the end of the lease term in 2064.
Totals may not add because of rounding.

(1) Operating costs include the overhead expenses allowed under joint operating agreements, direct project-level costs, insurance costs, workover costs, and transportation costs.
(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
POSSIBLE RESERVES
NEWMED ENERGY LIMITED PARTNERSHIP INTEREST
LEVIATHAN FIELD, LEASES I/14 AND I/15, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2023

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$)
12-31-2024	0.5	0.1	0.0	0.0	0.1	0.0	0.0	0.0	0.4
12-31-2025	60.8	6.7	5.7	1.6	14.1	0.0	0.0	2.8	44.0
12-31-2026	22.1	2.4	1.3	0.6	4.3	0.0	0.0	2.3	15.5
12-31-2027	23.7	2.6	1.4	0.6	4.6	0.0	0.0	2.2	16.9
12-31-2028	40.7	4.5	2.3	1.1	7.9	0.0	0.0	2.7	30.0
12-31-2029	39.9	4.4	2.3	1.1	7.8	0.0	0.0	2.7	29.4
12-31-2030	39.5	4.4	2.3	1.0	7.7	0.0	0.0	2.8	29.1
12-31-2031	16.3	1.8	0.9	0.4	3.2	0.0	0.0	1.7	11.5
12-31-2032	27.3	3.0	1.6	0.7	5.3	0.0	0.0	1.8	20.2
12-31-2033	39.4	4.4	2.3	1.0	7.7	0.0	0.0	1.9	29.9
12-31-2034	55.1	6.1	3.2	1.5	10.7	0.0	0.0	1.9	42.4
12-31-2035	53.5	5.9	3.1	1.4	10.4	0.0	0.0	2.4	40.7
12-31-2036	54.6	6.0	3.1	1.4	10.6	0.0	0.0	2.4	41.6
12-31-2037	57.9	6.4	3.3	1.5	11.3	0.0	0.0	2.4	44.3
12-31-2038	59.1	6.5	3.4	1.6	11.5	0.0	0.0	2.4	45.2
Subtotal	590.5	65.3	36.2	15.7	117.2	0.0	0.0	32.2	441.1
Remaining	1,804.6	199.6	103.8	47.9	351.3	0.0	0.0	47.8	1,405.5
Total	2,395.1	264.9	140.0	63.6	468.4	0.0	0.0	80.1	1,846.6

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$)	Discounted at 20% (MM$)
12-31-2024	0.0	0.0	0.4	23.0	0.1	0.3	0.3	0.3	0.3	0.3
12-31-2025	0.0	0.0	44.0	23.0	10.1	33.8	31.5	29.3	27.4	25.7
12-31-2026	1.7	16.7	-1.2	23.0	-0.3	-0.9	-0.8	-0.7	-0.7	-0.6
12-31-2027	26.5	11.9	5.0	23.0	1.2	3.9	3.3	2.8	2.4	2.0
12-31-2028	36.8	20.0	10.0	23.0	2.3	7.7	6.2	5.0	4.1	3.4
12-31-2029	44.7	21.5	7.9	23.0	1.8	6.1	4.7	3.6	2.8	2.2
12-31-2030	46.8	13.6	15.5	23.0	3.6	11.9	8.7	6.4	4.8	3.6
12-31-2031	46.8	5.4	6.1	23.0	1.4	4.7	3.3	2.3	1.6	1.2
12-31-2032	46.8	9.5	10.8	23.0	2.5	8.3	5.5	3.7	2.5	1.8
12-31-2033	46.8	14.0	15.9	23.0	3.7	12.2	7.7	4.9	3.2	2.2
12-31-2034	46.8	19.9	22.6	23.0	5.2	17.4	10.4	6.4	4.0	2.6
12-31-2035	46.8	19.1	21.7	23.0	5.0	16.7	9.5	5.6	3.3	2.0
12-31-2036	46.8	19.5	22.1	23.0	5.1	17.0	9.3	5.2	3.0	1.7
12-31-2037	46.8	20.7	23.6	23.0	5.4	18.1	9.4	5.0	2.7	1.5
12-31-2038	46.8	21.1	24.0	23.0	5.5	18.5	9.1	4.6	2.4	1.3
Subtotal		212.7	228.4		52.5	175.8	117.9	84.5	64.2	51.1
Remaining		657.8	747.7		172.0	575.7	157.6	50.8	18.7	7.6
Total		870.5	976.1		224.5	751.6	275.5	135.3	82.8	58.7

Notes: Remaining represents estimates after December 31, 2038, through the end of the lease term in 2064.
Totals may not add because of rounding.

[1] Operating costs include the overhead expenses allowed under joint operating agreements, direct project-level costs, insurance costs, workover costs, and transportation costs.
[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 IV

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, 2023

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$)
12-31-2024	1,155.2	127.8	15.3	30.7	173.8	262.6	0.0	153.0	565.9
12-31-2025	1,337.2	147.9	22.7	35.5	206.1	128.6	0.0	150.4	852.2
12-31-2026	1,444.5	159.8	83.1	38.3	281.2	32.6	0.0	140.1	990.7
12-31-2027	1,463.8	161.9	84.2	38.9	284.9	2.5	0.0	147.6	1,028.8
12-31-2028	1,550.8	171.5	89.2	41.2	301.9	2.0	0.0	150.9	1,096.0
12-31-2029	1,557.9	172.3	89.6	41.4	303.3	0.7	0.0	171.8	1,082.2
12-31-2030	1,595.6	176.5	91.8	42.4	310.6	0.0	0.0	152.4	1,132.5
12-31-2031	1,571.2	173.8	90.4	41.7	305.8	0.0	0.0	130.3	1,135.1
12-31-2032	1,621.4	179.3	93.2	43.0	315.6	0.0	0.0	131.5	1,174.3
12-31-2033	1,629.2	180.2	93.7	43.2	317.1	0.0	0.0	131.7	1,180.3
12-31-2034	1,617.0	178.8	93.0	42.9	314.8	0.0	0.0	152.6	1,149.6
12-31-2035	1,533.6	169.6	88.2	40.7	298.5	0.0	0.0	122.3	1,112.8
12-31-2036	1,506.9	166.7	86.7	40.0	293.3	0.0	0.0	122.3	1,091.3
12-31-2037	1,482.2	163.9	85.2	39.3	288.5	0.0	0.0	122.1	1,071.5
12-31-2038	1,456.6	161.1	83.8	38.7	283.5	0.0	0.0	122.1	1,051.0
Subtotal	22,523.2	2,491.1	1,190.0	597.9	4,278.9	429.0	0.0	2,101.1	15,714.1
Remaining	29,163.7	3,225.5	1,677.3	774.1	5,676.9	0.0	107.1	2,895.3	20,484.5
Total	51,686.9	5,716.6	2,867.3	1,372.0	9,955.8	429.0	107.1	4,996.4	36,198.7

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$)	Discounted at 20% (MM$)
12-31-2024	0.0	0.0	565.9	23.0	141.3	424.6	414.4	404.9	396.0	387.6
12-31-2025	0.0	0.0	852.2	23.0	172.6	679.6	631.6	589.0	551.1	517.0
12-31-2026	1.7	16.7	974.0	23.0	176.0	798.0	706.3	628.8	562.7	505.9
12-31-2027	26.5	272.6	756.2	23.0	115.5	640.7	540.1	459.0	392.8	338.5
12-31-2028	36.8	403.1	692.9	23.0	101.0	591.8	475.2	385.4	315.5	260.6
12-31-2029	44.7	484.2	597.9	23.0	79.4	518.5	396.5	307.0	240.4	190.2
12-31-2030	46.8	530.0	602.5	23.0	119.8	482.7	351.5	259.8	194.6	147.6
12-31-2031	46.8	531.2	603.9	23.0	123.3	480.5	333.3	235.1	168.5	122.4
12-31-2032	46.8	549.6	624.7	23.0	128.4	496.3	327.8	220.8	151.3	105.4
12-31-2033	46.8	552.4	627.9	23.0	129.2	498.8	313.8	201.7	132.2	88.2
12-31-2034	46.8	538.0	611.6	23.0	128.3	483.3	289.6	177.7	111.4	71.3
12-31-2035	46.8	520.8	592.0	23.0	129.9	462.1	263.7	154.4	92.6	56.8
12-31-2036	46.8	510.7	580.6	23.0	129.9	450.7	244.9	136.9	78.5	46.1
12-31-2037	46.8	501.5	570.1	23.0	131.1	439.0	227.2	121.2	66.5	37.5
12-31-2038	46.8	491.9	559.1	23.0	128.6	430.6	212.2	108.1	56.7	30.6
Subtotal		5,902.7	9,811.5		1,934.2	7,877.2	5,728.1	4,389.8	3,510.9	2,905.6
Remaining		9,586.7	10,897.8		2,515.2	8,382.5	2,444.2	833.7	320.8	135.3
Total		15,489.4	20,709.2		4,449.5	16,259.8	8,172.4	5,223.5	3,831.7	3,040.9

Notes: Remaining represents estimates after December 31, 2038, through the end of the lease term in 2064.
Totals may not add because of rounding.

[1] Operating costs include the overhead expenses allowed under joint operating agreements, direct project-level costs, insurance costs, workover costs, and transportation costs.
[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.

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, 2023

	NewMed Working Interest Production	Average Per Production Unit ($/MCF)				Reserves
Year	(BCF)	Price Received	Royalties Paid	Production Costs	Net Revenue	Depletion Rate[1] (%)
2023[2]	175.6	6.23	0.91	0.84	4.48	2.5
2022	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

Note: Values in this table have been provided by NewMed; these values are based on historical data since January 2021.

[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 2023 data are representative of unaudited financial data.

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, 2023

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$)
12-31-2024	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	40.3	4.5	2.0	1.1	7.5	0.0	0.0	0.2	32.5
12-31-2027	59.6	6.6	3.4	1.6	11.6	0.0	0.0	0.3	47.7
12-31-2028	74.1	8.2	4.3	2.0	14.4	0.0	0.0	0.4	59.3
12-31-2029	62.8	6.9	3.6	1.7	12.2	0.0	0.0	0.3	50.2
12-31-2030	74.6	8.3	4.3	2.0	14.5	111.0	0.0	0.4	-51.3
12-31-2031	70.9	7.8	4.1	1.9	13.8	0.0	0.0	0.3	56.7
12-31-2032	92.8	10.3	5.3	2.5	18.1	0.0	0.0	0.4	74.3
12-31-2033	79.3	8.8	4.6	2.1	15.4	0.0	0.0	0.3	63.5
12-31-2034	92.0	10.2	5.3	2.4	17.9	0.0	0.0	0.4	73.7
12-31-2035	79.7	8.8	4.6	2.1	15.5	0.0	0.0	0.3	63.9
12-31-2036	96.5	10.7	5.5	2.6	18.8	0.0	0.0	0.4	77.3
12-31-2037	79.7	8.8	4.6	2.1	15.5	0.0	0.0	0.4	63.9
12-31-2038	96.1	10.6	5.5	2.6	18.7	0.0	0.0	0.4	77.0
Subtotal	998.3	110.4	57.1	26.5	194.0	111.0	0.0	4.6	688.7
Remaining	5,421.0	599.6	311.8	143.9	1,055.2	818.3	75.9	37.9	3,433.6
Total	6,419.3	710.0	368.9	170.4	1,249.3	929.3	75.9	42.5	4,122.3

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$)	Discounted at 20% (MM$)
12-31-2024	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	0.0	0.0	32.5	23.0	7.5	25.1	22.2	19.7	17.7	15.9
12-31-2027	20.3	30.2	17.5	23.0	4.0	13.5	11.4	9.7	8.3	7.1
12-31-2028	33.4	30.0	29.3	23.0	6.7	22.6	18.1	14.7	12.0	9.9
12-31-2029	41.4	33.3	16.9	23.0	3.9	13.0	10.0	7.7	6.0	4.8
12-31-2030	46.5	-18.6	-32.7	23.0	16.7	-49.4	-36.0	-26.6	-19.9	-15.1
12-31-2031	46.8	26.6	30.2	23.0	4.4	25.8	17.9	12.6	9.0	6.6
12-31-2032	46.8	34.8	39.5	23.0	6.5	33.0	21.8	14.7	10.1	7.0
12-31-2033	46.8	29.7	33.8	23.0	5.2	28.6	18.0	11.6	7.6	5.1
12-31-2034	46.8	34.5	39.2	23.0	6.5	32.7	19.6	12.0	7.5	4.8
12-31-2035	46.8	29.9	34.0	23.0	5.3	28.7	16.4	9.6	5.8	3.5
12-31-2036	46.8	36.2	41.1	23.0	6.9	34.2	18.6	10.4	6.0	3.5
12-31-2037	46.8	29.9	34.0	23.0	5.3	28.7	14.9	7.9	4.4	2.4
12-31-2038	46.8	36.0	40.9	23.0	6.9	34.1	16.8	8.6	4.5	2.4
Subtotal		332.4	356.3		85.8	270.5	169.5	112.6	78.9	58.0
Remaining		1,630.4	1,803.1		415.7	1,387.4	442.6	153.3	57.5	23.2
Total		1,962.9	2,159.5		501.5	1,657.9	612.1	265.9	136.4	81.2

Notes: Remaining represents estimates after December 31, 2038, through the end of the lease term in 2064.
Totals may not add because of rounding.

[1] Operating costs include the overhead expenses allowed under joint operating agreements, direct project-level costs, insurance costs, workover costs, and transportation costs.
[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 BEST ESTIMATE (2C) CONTINGENT RESOURCES
NEWMED ENERGY LIMITED PARTNERSHIP INTEREST
LEVIATHAN FIELD, LEASES I/14 AND I/15, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2023

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$)
12-31-2024	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	0.0	0.0	0.0	0.0	0.0	111.0	0.0	0.0	-111.0
12-31-2032	16.2	1.8	0.9	0.4	3.2	0.0	0.0	0.1	13.0
12-31-2033	30.2	3.3	1.7	0.8	5.9	0.0	0.0	0.1	24.2
12-31-2034	72.6	8.0	4.2	1.9	14.1	0.0	0.0	0.3	58.2
12-31-2035	88.3	9.8	5.1	2.3	17.2	0.0	0.0	0.4	70.7
12-31-2036	132.9	14.7	7.6	3.5	25.9	0.0	0.0	0.6	106.5
12-31-2037	144.1	15.9	8.3	3.8	28.1	0.0	0.0	0.6	115.4
12-31-2038	184.3	20.4	10.6	4.9	35.9	0.0	0.0	0.8	147.6
Subtotal	668.6	74.0	38.5	17.7	130.2	111.0	0.0	2.9	424.5
Remaining	9,240.4	1,022.0	531.4	245.3	1,798.7	1,116.5	101.2	116.0	6,108.0
Total	9,909.0	1,095.9	569.9	263.0	1,928.9	1,227.5	101.2	118.9	6,532.6

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$)	Discounted at 20% (MM$)
12-31-2024	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	0.0	0.0	0.0	23.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2027	25.8	0.0	0.0	23.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2028	35.9	0.0	0.0	23.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2029	44.0	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	-51.9	-59.1	23.0	10.7	-69.7	-48.4	-34.1	-24.4	-17.8
12-31-2032	46.8	6.1	6.9	23.0	-1.0	7.9	5.2	3.5	2.4	1.7
12-31-2033	46.8	11.3	12.9	23.0	0.4	12.5	7.8	5.0	3.3	2.2
12-31-2034	46.8	27.2	30.9	23.0	4.6	26.4	15.8	9.7	6.1	3.9
12-31-2035	46.8	33.1	37.6	23.0	6.1	31.5	18.0	10.5	6.3	3.9
12-31-2036	46.8	49.8	56.6	23.0	10.5	46.2	25.1	14.0	8.0	4.7
12-31-2037	46.8	54.0	61.4	23.0	11.6	49.8	25.8	13.8	7.6	4.3
12-31-2038	46.8	69.1	78.5	23.0	15.5	63.0	31.1	15.8	8.3	4.5
Subtotal		198.7	225.9		58.3	167.5	80.4	38.3	17.6	7.3
Remaining		2,865.3	3,242.7		739.4	2,503.3	670.7	210.7	75.4	29.9
Total		3,064.0	3,468.6		797.8	2,670.8	751.2	249.0	93.0	37.2

Notes: Remaining represents estimates after December 31, 2038, through the end of the lease term in 2064.
Totals may not add because of rounding.

(1) Operating costs include the overhead expenses allowed under joint operating agreements, direct project-level costs, insurance costs, workover costs, and transportation costs.
(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.

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, 2023

		Royalties							
Period Ending	Working Interest Revenue (MM$)	State (MM$)	Interested Party (MM$)	Third Party (MM$)	Total (MM$)	Net Capital Costs (MM$)	Net Abandonment Costs (MM$)	Net Operating Expenses[1] (MM$)	Future Net Cash Flow Before Levy and Corporate Income Taxes Discounted at 0% (MM$)
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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2032	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2033	0.0	0.0	0.0	0.0	0.0	111.0	0.0	0.0	-111.0
12-31-2034	26.8	3.0	1.5	0.7	5.2	0.0	0.0	0.1	21.5
12-31-2035	39.1	4.3	2.2	1.0	7.6	0.0	0.0	0.2	31.3
12-31-2036	82.7	9.1	4.8	2.2	16.1	0.0	0.0	0.4	66.2
12-31-2037	90.5	10.0	5.2	2.4	17.6	0.0	0.0	0.4	72.5
12-31-2038	129.6	14.3	7.5	3.4	25.2	0.0	0.0	0.6	103.8
Subtotal	368.7	40.8	21.2	9.8	71.8	111.0	0.0	1.6	184.3
Remaining	9,041.6	1,000.0	520.0	240.0	1,760.0	1,116.5	101.2	124.6	5,939.2
Total	9,410.2	1,040.8	541.2	249.8	1,831.8	1,227.5	101.2	126.2	6,123.5

						Future Net Cash Flow After Levy and Corporate Income Taxes				
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$)	Discounted at 0% (MM$)	Discounted at 5% (MM$)	Discounted at 10% (MM$)	Discounted at 15% (MM$)	Discounted at 20% (MM$)
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	1.7	0.0	0.0	23.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2027	26.5	0.0	0.0	23.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2028	36.8	0.0	0.0	23.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2029	44.7	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	0.0	0.0	23.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2032	46.8	0.0	0.0	23.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2033	46.8	-51.9	-59.1	23.0	10.7	-69.7	-43.9	-28.2	-18.5	-12.3
12-31-2034	46.8	10.1	11.4	23.0	0.1	11.4	6.8	4.2	2.6	1.7
12-31-2035	46.8	14.7	16.7	23.0	1.3	15.4	8.8	5.1	3.1	1.9
12-31-2036	46.8	31.0	35.2	23.0	5.5	29.7	16.1	9.0	5.2	3.0
12-31-2037	46.8	33.9	38.6	23.0	6.3	32.2	16.7	8.9	4.9	2.8
12-31-2038	46.8	48.6	55.2	23.0	10.1	45.1	22.2	11.3	5.9	3.2
Subtotal		86.2	98.0		34.0	64.0	26.7	10.4	3.2	0.2
Remaining		2,780.8	3,158.5		715.0	2,443.5	615.5	184.2	63.6	24.6
Total		2,867.0	3,256.5		749.0	2,507.5	642.3	194.6	66.9	24.9

Notes: Remaining represents estimates after December 31, 2038, through the end of the lease term in 2064.
Totals may not add because of rounding.

[1] Operating costs include the overhead expenses allowed under joint operating agreements, direct project-level costs, insurance costs, workover costs, and transportation costs.
[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.

VOLUMETRIC INPUT SUMMARY
LEVIATHAN FIELD, LEASES I/14 AND I/15, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2023

	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

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, 2023

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$)
12-31-2024	1,099.4	121.6	14.6	29.2	165.4	262.6	0.0	150.8	520.6
12-31-2025	1,189.9	131.6	15.8	31.6	179.0	128.6	0.0	144.6	737.7
12-31-2026	1,348.6	149.2	67.6	35.8	252.6	32.6	0.0	134.8	928.6
12-31-2027	1,369.9	151.5	78.8	36.4	266.7	2.5	0.0	139.6	961.1
12-31-2028	1,413.7	156.4	81.3	37.5	275.2	2.0	0.0	138.0	998.5
12-31-2029	1,423.2	157.4	81.9	37.8	277.0	0.7	0.0	158.9	986.6
12-31-2030	1,461.4	161.6	84.0	38.8	284.5	111.0	0.0	139.3	926.6
12-31-2031	1,479.9	163.7	85.1	39.3	288.1	0.0	0.0	119.2	1,072.7
12-31-2032	1,549.9	171.4	89.1	41.1	301.7	0.0	0.0	120.1	1,128.1
12-31-2033	1,564.8	173.1	90.0	41.5	304.6	0.0	0.0	120.3	1,139.8
12-31-2034	1,577.9	174.5	90.7	41.9	307.1	0.0	0.0	141.2	1,129.5
12-31-2035	1,534.2	169.7	88.2	40.7	298.6	0.0	0.0	106.5	1,129.0
12-31-2036	1,550.9	171.5	89.2	41.2	301.9	0.0	0.0	106.6	1,142.4
12-31-2037	1,534.2	169.7	88.2	40.7	298.6	0.0	0.0	106.6	1,128.9
12-31-2038	1,546.4	171.0	88.9	41.0	301.0	0.0	0.0	106.7	1,138.7
Subtotal	21,644.3	2,393.9	1,133.6	574.5	4,102.0	540.0	0.0	1,933.4	15,069.0
Remaining	28,463.8	3,148.1	1,637.0	755.5	5,540.7	818.3	183.0	2,705.3	19,216.6
Total	50,108.1	5,542.0	2,770.6	1,330.1	9,642.6	1,358.3	183.0	4,638.7	34,285.6

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$)	Discounted at 20% (MM$)
12-31-2024	0.0	0.0	520.6	23.0	130.9	389.8	380.4	371.6	363.5	355.8
12-31-2025	0.0	0.0	737.7	23.0	146.3	591.4	549.7	512.7	479.6	449.9
12-31-2026	0.0	0.0	928.6	23.0	165.6	763.1	675.4	601.3	538.0	483.7
12-31-2027	20.3	195.5	765.6	23.0	117.6	648.0	546.3	464.2	397.3	342.3
12-31-2028	33.4	333.5	665.0	23.0	94.6	570.4	457.9	371.4	304.1	251.1
12-31-2029	41.4	408.1	578.5	23.0	74.9	503.6	385.1	298.1	233.5	184.7
12-31-2030	46.5	430.5	496.1	23.0	119.5	376.5	274.2	202.7	151.8	115.1
12-31-2031	46.8	502.0	570.7	23.0	113.2	457.5	317.3	223.8	160.4	116.6
12-31-2032	46.8	528.0	600.2	23.0	120.2	479.9	317.0	213.5	146.3	101.9
12-31-2033	46.8	533.4	606.4	23.0	121.7	484.7	304.9	196.0	128.5	85.8
12-31-2034	46.8	528.6	600.9	23.0	123.3	477.6	286.2	175.6	110.1	70.4
12-31-2035	46.8	528.4	600.6	23.0	129.3	471.3	268.9	157.5	94.5	57.9
12-31-2036	46.8	534.6	607.7	23.0	133.6	474.1	257.7	144.0	82.6	48.5
12-31-2037	46.8	528.3	600.6	23.0	135.5	465.1	240.7	128.4	70.5	39.7
12-31-2038	46.8	532.9	605.8	23.0	136.7	469.1	231.2	117.8	61.8	33.4
Subtotal		5,583.9	9,485.1		1,863.0	7,622.1	5,492.9	4,178.6	3,322.4	2,736.8
Remaining		9,020.4	10,196.1		2,354.9	7,841.3	2,442.6	867.5	341.5	145.7
Total		14,604.3	19,681.2		4,217.9	15,463.4	7,935.5	5,046.1	3,663.9	2,882.6

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 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.
Remaining represents estimates after December 31, 2038, through the end of the lease term in 2064.
Totals may not add because of rounding.

(1) Operating costs include the overhead expenses allowed under joint operating agreements, direct project-level costs, insurance costs, workover costs, and transportation costs.
(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 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, 2023

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$)
12-31-2024	1,154.7	127.7	15.3	30.7	173.7	262.6	0.0	153.0	565.5
12-31-2025	1,276.4	141.2	16.9	33.9	192.0	128.6	0.0	147.6	808.2
12-31-2026	1,422.4	157.3	81.8	37.8	276.9	32.6	0.0	137.8	975.2
12-31-2027	1,440.1	159.3	82.8	38.2	280.3	2.5	0.0	145.4	1,011.8
12-31-2028	1,510.1	167.0	86.9	40.1	294.0	2.0	0.0	148.1	1,066.0
12-31-2029	1,518.0	167.9	87.3	40.3	295.5	0.7	0.0	169.1	1,052.7
12-31-2030	1,556.0	172.1	89.5	41.3	302.9	0.0	0.0	149.7	1,103.5
12-31-2031	1,554.8	172.0	89.4	41.3	302.7	111.0	0.0	128.6	1,012.6
12-31-2032	1,610.3	178.1	92.6	42.7	313.4	0.0	0.0	129.7	1,167.1
12-31-2033	1,620.0	179.2	93.2	43.0	315.3	0.0	0.0	130.0	1,174.6
12-31-2034	1,634.5	180.8	94.0	43.4	318.2	0.0	0.0	151.0	1,165.3
12-31-2035	1,568.4	173.5	90.2	41.6	305.3	0.0	0.0	120.3	1,142.7
12-31-2036	1,585.3	175.3	91.2	42.1	308.6	0.0	0.0	120.5	1,156.2
12-31-2037	1,568.4	173.5	90.2	41.6	305.3	0.0	0.0	120.4	1,142.7
12-31-2038	1,581.9	175.0	91.0	42.0	307.9	0.0	0.0	120.6	1,153.4
Subtotal	22,601.3	2,499.7	1,192.3	599.9	4,291.9	540.0	0.0	2,071.8	15,697.6
Remaining	36,599.6	4,047.9	2,104.9	971.5	7,124.3	1,116.5	208.3	2,963.4	25,187.0
Total	59,200.9	6,547.6	3,297.2	1,571.4	11,416.3	1,656.5	208.3	5,035.3	40,884.6

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$)	Discounted at 20% (MM$)
12-31-2024	0.0	0.0	565.5	23.0	141.2	424.3	414.1	404.6	395.7	387.3
12-31-2025	0.0	0.0	808.2	23.0	162.5	645.7	600.2	559.7	523.6	491.2
12-31-2026	0.0	0.0	975.2	23.0	176.3	798.9	707.2	629.5	563.3	506.4
12-31-2027	25.8	260.7	751.2	23.0	114.3	636.8	536.9	456.2	390.5	336.4
12-31-2028	35.9	383.2	682.8	23.0	98.7	584.1	469.0	380.4	311.4	257.1
12-31-2029	44.0	462.7	590.0	23.0	77.6	512.4	391.8	303.4	237.6	188.0
12-31-2030	46.8	516.4	587.0	23.0	116.2	470.8	342.9	253.4	189.8	143.9
12-31-2031	46.8	473.9	538.7	23.0	132.6	406.1	281.6	198.7	142.4	103.5
12-31-2032	46.8	546.2	620.9	23.0	125.0	495.9	327.6	220.6	151.2	105.3
12-31-2033	46.8	549.7	624.9	23.0	125.9	499.0	313.9	201.8	132.3	88.3
12-31-2034	46.8	545.4	620.0	23.0	127.7	492.3	294.9	181.0	113.5	72.6
12-31-2035	46.8	534.8	607.9	23.0	131.0	476.9	272.1	159.4	95.6	58.6
12-31-2036	46.8	541.1	615.1	23.0	135.3	479.8	260.7	145.8	83.6	49.1
12-31-2037	46.8	534.8	607.9	23.0	137.2	470.7	243.6	130.0	71.3	40.2
12-31-2038	46.8	539.8	613.6	23.0	138.5	475.1	234.2	119.3	62.6	33.8
Subtotal		5,888.6	9,808.9		1,940.0	7,868.9	5,690.6	4,343.6	3,464.3	2,861.8
Remaining		11,794.3	13,392.7		3,082.7	10,310.0	2,957.4	993.6	377.5	157.6
Total		17,682.9	23,201.7		5,022.7	18,179.0	8,648.0	5,337.2	3,841.9	3,019.4

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 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.
Remaining represents estimates after December 31, 2038, through the end of the lease term in 2064.
Totals may not add because of rounding.

(1) Operating costs include the overhead expenses allowed under joint operating agreements, direct project-level costs, insurance costs, workover costs, and transportation costs.
(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.

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, 2023

		Royalties							
Period Ending	Working Interest Revenue (MM$)	State (MM$)	Interested Party (MM$)	Third Party (MM$)	Total (MM$)	Net Capital Costs (MM$)	Net Abandonment Costs (MM$)	Net Operating Expenses[1] (MM$)	Future Net Cash Flow Before Levy and Corporate Income Taxes Discounted at 0% (MM$)
12-31-2024	1,155.2	127.8	15.3	30.7	173.8	262.6	0.0	153.0	565.9
12-31-2025	1,337.2	147.9	22.7	35.5	206.1	128.6	0.0	150.4	852.2
12-31-2026	1,444.5	159.8	83.1	38.3	281.2	32.6	0.0	140.1	990.7
12-31-2027	1,463.8	161.9	84.2	38.9	284.9	2.5	0.0	147.6	1,028.8
12-31-2028	1,550.8	171.5	89.2	41.2	301.9	2.0	0.0	150.9	1,096.0
12-31-2029	1,557.9	172.3	89.6	41.4	303.3	0.7	0.0	171.8	1,082.2
12-31-2030	1,595.6	176.5	91.8	42.4	310.6	0.0	0.0	152.4	1,132.5
12-31-2031	1,571.2	173.8	90.4	41.7	305.8	0.0	0.0	130.3	1,135.1
12-31-2032	1,621.4	179.3	93.2	43.0	315.6	0.0	0.0	131.5	1,174.3
12-31-2033	1,629.2	180.2	93.7	43.2	317.1	111.0	0.0	131.7	1,069.3
12-31-2034	1,643.8	181.8	94.5	43.6	320.0	0.0	0.0	152.7	1,171.1
12-31-2035	1,572.7	173.9	90.4	41.7	306.1	0.0	0.0	122.5	1,144.1
12-31-2036	1,589.6	175.8	91.4	42.2	309.4	0.0	0.0	122.7	1,157.5
12-31-2037	1,572.7	173.9	90.4	41.7	306.1	0.0	0.0	122.5	1,144.0
12-31-2038	1,586.2	175.4	91.2	42.1	308.8	0.0	0.0	122.7	1,154.8
Subtotal	22,891.9	2,531.8	1,211.2	607.6	4,350.7	540.0	0.0	2,102.8	15,898.4
Remaining	38,205.3	4,225.5	2,197.3	1,014.1	7,436.9	1,116.5	208.3	3,019.9	26,423.7
Total	61,097.2	6,757.3	3,408.5	1,621.8	11,787.6	1,656.5	208.3	5,122.6	42,322.2

						Future Net Cash Flow After Levy and Corporate Income Taxes				
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$)	Discounted at 0% (MM$)	Discounted at 5% (MM$)	Discounted at 10% (MM$)	Discounted at 15% (MM$)	Discounted at 20% (MM$)
12-31-2024	0.0	0.0	565.9	23.0	141.3	424.6	414.4	404.9	396.0	387.6
12-31-2025	0.0	0.0	852.2	23.0	172.6	679.6	631.6	589.0	551.1	517.0
12-31-2026	1.7	16.7	974.0	23.0	176.0	798.0	706.3	628.8	562.7	505.9
12-31-2027	26.5	272.6	756.2	23.0	115.5	640.7	540.1	459.0	392.8	338.5
12-31-2028	36.8	403.1	692.9	23.0	101.0	591.8	475.2	385.4	315.5	260.6
12-31-2029	44.7	484.2	597.9	23.0	79.4	518.5	396.5	307.0	240.4	190.2
12-31-2030	46.8	530.0	602.5	23.0	119.8	482.7	351.5	259.8	194.6	147.6
12-31-2031	46.8	531.2	603.9	23.0	123.3	480.5	333.3	235.1	168.5	122.4
12-31-2032	46.8	549.6	624.7	23.0	128.4	496.3	327.8	220.8	151.3	105.4
12-31-2033	46.8	500.4	568.9	23.0	139.9	429.0	269.9	173.5	113.7	75.9
12-31-2034	46.8	548.1	623.0	23.0	128.4	494.7	296.4	181.8	114.0	72.9
12-31-2035	46.8	535.4	608.7	23.0	131.2	477.5	272.5	159.6	95.7	58.7
12-31-2036	46.8	541.7	615.8	23.0	135.5	480.3	261.0	145.9	83.7	49.2
12-31-2037	46.8	535.4	608.6	23.0	137.4	471.2	243.9	130.2	71.4	40.2
12-31-2038	46.8	540.4	614.3	23.0	138.7	475.6	234.4	119.4	62.7	33.8
Subtotal		5,988.9	9,909.5		1,968.3	7,941.2	5,754.9	4,400.2	3,514.1	2,905.8
Remaining		12,367.5	14,056.2		3,230.2	10,826.0	3,059.8	1,017.9	384.5	159.9
Total		18,356.5	23,965.7		5,198.4	18,767.3	8,814.6	5,418.1	3,898.6	3,065.7

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 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.
Remaining represents estimates after December 31, 2038, through the end of the lease term in 2064.
Totals may not add because of rounding.

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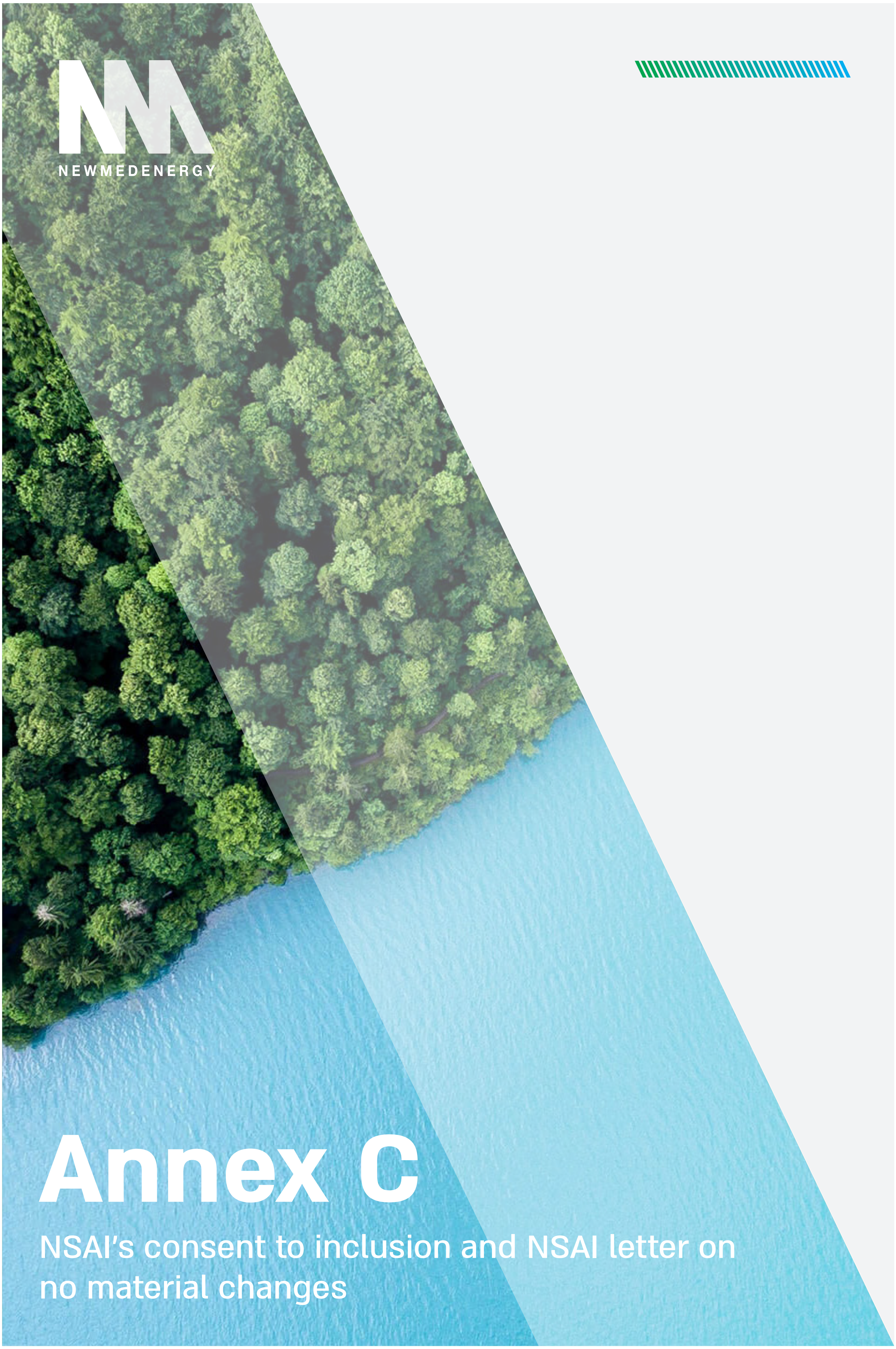
(3) Corporate income tax rates and estimates of corporate income taxes are provided by NewMed and are its expected corporate income taxes per year.



Annex C

NSAI's consent to inclusion and NSAI letter on no material changes

March 19, 2024

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 in the 2023 Annual Report of NewMed to be published in March 2024 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, 2024, which sets forth our estimates of the proved, probable, and possible reserves and future revenue, as of December 31, 2023, 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, 2023, to the NewMed interest in these properties.

- The report dated September 5, 2023, which sets forth our estimates of the unrisked contingent and prospective resources, as of August 31, 2023, to the NewMed 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 NewMed working interest in two Leviathan Deep prospects located in Leases I/14 and I/15, offshore Israel.

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 September 5 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 September 5 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

JRC: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.

18 March 2024

NewMed Energy – Limited Partnership

Report of the Board of Directors of the General Partner for the Year Ended 31 December 2023

The board of directors of NewMed Energy Management Ltd. (the "**General Partner**") hereby respectfully submits the board of directors' report for the year ended 31 December 2023 (the "**Report Year**").

Part One – Explanations of the Board of Directors on the State of the Partnership's Business

1. Main figures from the description of the Partnership's business

For a description of the Partnership's business and the developments that occurred in the Report Year – see Chapter A (Description of the Partnership's Business) of this Report.

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 is examining business opportunities for exploration, development, production, and marketing of natural gas, condensate and oil in other countries[1], and is also considering and promoting possible investments in renewable energy projects, in the context of the collaboration with Enlight Renewable Energy Ltd.[2], and is further examining options for entering the hydrogen sector, including blue hydrogen which is produced from natural gas and may constitute a low-carbon substitute for energy consumers.

Following the barbaric attack perpetrated by the Hamas terrorist organization on 7 October 2023, targeting communities and military bases in the south of

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[1] For details with respect to an exploration license in Morocco, see Section 7.6 of Chapter A (Description of the Partnership's Business) of this Report.

[2] For details regarding the Enlight transaction, see Section 7.9 of Chapter A (Description of the Partnership's Business) of this Report.

Israel, the Israeli government declared the Iron Swords war against this terrorist organization (the "**War**"). As of the report approval date, the War is ongoing and it is impossible to predict how long it will last or its impact on the Partnership, its business and its assets. For further details, see Section G below and Section 6.9 of Chapter A (Description of the Partnership's Business) of this Report.

As of the report approval date, due to the uncertainty formed in the external environment, the discussions in connection with an offer received by the General Partner from Abu Dhabi National Oil Company (ADNOC) P.J.S.C. and BP Exploration Operating Company, as specified in Note 1D to the financial statements (Chapter C of this Report), have been suspended until their renewal or termination of the transaction promotion process.

The Partnership's net profit in 2023 totaled approx. $434 million, compared with approx. $470 million last year. The decrease in profit derived mainly from the decrease in net income from the sale of natural gas from the Leviathan reservoir, from the decrease in financial income and from the increase in income tax expenses. Conversely, there was a decrease in depreciation, depletion and amortization expenses and in financial expenses, as specified below.

The Partnership's net profit in Q4/2023 totaled approx. $102 million compared with approx. $141 million in the same quarter last year. The decrease in profit derived mainly from the decrease in net income from the sale of natural gas from the Leviathan reservoir, from the decrease in financial income and from an increase in income tax expenses. Conversely, there was a decrease in depreciation, depletion and amortization expenses and a decrease in financial expenses, as specified below.

B. Analysis of statements of comprehensive income

Below are main figures with regards to the Partnership's statements of comprehensive income (dollars in millions):

	1-3/23	4-6/23	7-9/23	10-12/23	2023	10-12/22	2022
Revenues							
From natural gas and condensate sales	281.1	250.8	285.8	276.7	1,094.4	288.3	1,143.9
Net of royalties	41.1	36.4	41.9	40.4	159.8	41.2	172.0
Revenues, net	**240.0**	**214.4**	**243.9**	**236.3**	**934.6**	**247.1**	**971.9**
Expenses and costs:							
Cost of natural gas and condensate production	38.2	34.8	37.0	38.6	148.6	34.5	134.1
Depreciation, depletion and amortization expenses	19.9	20.9	19.3	19.1	79.2	26.6	131.0
Other direct expenses	0.8	0.9	1.1	2.5	5.3	2.0	5.2
G&A expenses	5.6	5.8	5.0	4.4	20.8	7.8	19.7
Total expenses and costs	**64.5**	**62.4**	**62.4**	**64.6**	**253.9**	**70.9**	**290.0**
The Partnership's share in the profits (losses) of a company accounted for at equity	(1.3)	(0.1)	(0.7)	0.8	(1.3)	0.3	(3.1)
Operating income	**174.2**	**151.9**	**180.8**	**172.5**	**679.4**	**176.5**	**678.8**
Financial expenses	(37.2)	(31.9)	(30.5)	(34.2)	(133.8)	(42.7)	(155.3)
Financial income	19.9	6.9	7.8	[3](5.9)	28.7	15.8	71.1
Financial expenses, net	(17.3)	(25.0)	(22.7)	(40.1)	(105.1)	(26.9)	(84.2)
Profit before taxes on the income	**156.9**	**126.9**	**158.1**	**132.4**	**574.3**	**149.6**	**594.6**
Taxes on the income	(36.2)	(34.0)	(40.2)	(32.4)	(142.8)	(5.7)	(116.0)
Income from continuing operations	**120.7**	**92.9**	**117.9**	**100.0**	**431.5**	**143.9**	**478.6**
Income (loss) from discontinued operations	-	-	-	2.1	2.1	(2.4)	(13.2)
Income from the sale of natural gas and oil assets	-	-	-	-	-	-	4.3
Total income (loss) from discontinued operations	-	-	-	2.1	**2.1**	**(2.4)**	**(8.9)**
Net profit and comprehensive income	**120.7**	**92.9**	**117.9**	**102.1**	**433.6**	**141.5**	**469.7**

[3] The negative financial income in Q4/2023 derives from a negative revaluation (expense) in the quarter of production-based royalties from the Karish and Tanin leases.

Net revenues totaled approx. $935 million in 2023, compared with approx. $972 million last year, down around 4%. The decrease mainly derived from the decrease in the natural gas quantities sold from the Leviathan reservoir, from approx. 11.4 BCM (100%) last year to approx. 11.0 BCM (100%) in the Report Year, and from a decrease in the average price per thermal unit (MMBTU) from approx. $6.17 last year to approx. $6.11 in the Report Year. The drop in the quantities sold resulted primarily from the decrease in sales in Israel following the commencement of production from the Karish reservoir counterbalanced by a rise in the export of natural gas to Egypt. The drop in the average price of natural gas resulted primarily from a decrease in 2023 compared with 2022 in the Brent barrel price to which some of the natural gas sale agreements are linked.

Net revenues totaled approx. $236 million in Q4/2023 compared with approx. $247 million in the same period last year, down around 4%. The decrease mainly derives from the decrease in the natural gas quantities sold from the Leviathan reservoir, from approx. 2.9 BCM in Q4/2022 to approx. 2.8 BCM in Q4/2023, and from a decrease in the average price per thermal unit (MMBTU) from approx. $6.21 in Q4/2022 to approx. $6.17 in Q4/2023.

The table below specifies the gas quantities (100%) sold from the Leviathan reservoir in the Report Year and in 2022, referring to the customers' geographic location:

2023 - (BCM)*					
	Israel	Jordan	Egypt	Total	Average Price**
Q1	0.6	0.7	1.5	2.8	**$6.09**
Q2	0.3	0.6	1.6	2.5	**$6.14**
Q3	0.4	0.8	1.7	2.9	**$6.06**
Q4	0.7	0.6	1.5	2.8	**$6.17**
Total/Average	**2.0**	**2.7**	**6.3**	**11.0**	**$6.11**

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**

* 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 totaled approx. $149 million in 2023 compared with approx. $134 million last year, demonstrating an increase of approx. 11% and consisting mainly of 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 rise in the Report Year mainly derives from an increase in the expenses of transmission of the gas to Egypt, which derive, *inter alia*, from the rise in the quantity of gas sold to Egypt, which was partially offset mainly by a decrease in maintenance costs during the period.

The cost of gas and condensate production in Q4/2023 totaled approx. $39 million, compared with approx. $35 million in the same quarter last year. The increase in the period derived from the aforesaid reasons.

Depreciation, depletion and amortization expenses totaled approx. $79 million in the Report Year, compared with approx. $131 million last year, demonstrating a decrease of 40%. The decrease mainly derives from depreciation of the "New Ofek" project and an update of the Yam Tethys asset retirement obligation last year, to the Statement of Comprehensive Income.

Depreciation and amortization expenses in Q4/2023 totaled approx. $19 million, compared with approx. $27 million in the same quarter last year. The decrease mainly derives from an update of the Yam Tethys asset retirement obligation in the same quarter last year.

Other direct expenses in 2023 totaled approx. $5 million, similarly to 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 the production stage, including renewable energy projects.

Other direct expenses totaled approx. $2 million in Q4/2023, similarly to the same period last year.

G&A expenses totaled approx. $21 million in the Report Year, compared with approx. $20 million last year, and include, *inter alia,* salary expenses, professional services and D&O insurance. Such rise in expenses mainly derived from a revaluation of the cost of a participation-unit based payment to the Partnership's CEO in 2023 following an increase in the price of the participation units on TASE.

G&A expenses totaled approx. $4 million in Q4/2023, compared with approx. $8 million in the same quarter last year. The decrease in Q4/2023 compared with Q4/2022 mainly results from a decrease in professional services' expenses and in payroll and related expenses.

The Partnership's share in the profits (losses) of a company accounted for at equity totaled a loss of approx. $1 million in the Report Year, compared with a loss of approx. $3 million last year. The loss in the period derived from the losses of 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 decrease in loss results from the increase in profits from the natural gas transmission, which increase was offset by the amortization of the excess cost of the investment.

The Partnership's share in the profits (losses) of a company accounted for at equity totaled a profit of approx. $0.8 million in Q4/2023, compared with a profit of approx. $0.3 million in the same quarter last year.

Financial expenses totaled approx. $134 million in the Report Year, compared with approx. $155 million last year, showing a decrease of approx. 14%. The financial expenses in the Report Year mainly derived from interest on the Leviathan Bond bonds in the sum of approx. $127 million (last year approx. $146 million), an expense in respect of an update of royalty receivables in the sum of approx. $5 million and financial expenses in respect of loans and facilities provided by banking corporations in the sum of approx. $2 million (last year approx. $1 million. The drop in financial expenses in the Report Year compared with last year mainly derived from repayment of the first series (2023) of Leviathan Bond bonds in H1/2023, as specified in Section C.2 below, which led to a decrease in financial expenses in H2/2023.

Financial expenses totaled approx. $34 million in Q4/2023, compared with approx. $43 million in the same quarter last year. The financial expenses in Q4/2023 mainly derived from interest on the Leviathan Bond bonds in the sum of approx. $29 million (last year approx. $36 million). The decrease in financial expenses compared with Q4/2022 mainly derived from the aforesaid reasons.

Financial income totaled approx. $29 million in the Report Year, compared with approx. $71 million last year. The decrease in financial income mainly derives from the revaluation of a receivable of approx. $6 million in respect of the Karish and Tanin leases, compared with the revaluation of royalties and a receivable of approx. $62 million in respect of the Karish and Tanin leases last year, which was mainly offset by an increase in income from deposits from approx. $6 million last year to approx. $15 million in the Report Year. For further details, see Note 8B to the financial statements (Chapter C of this Report).

Financial income amounted to expenses of approx. $6 million in Q4/2023 and mainly derived from a reversal of income due to the update of royalties receivable from the Karish and Tanin leases in the sum of approx. $11 million, offset by income from interest on deposits, compared with income of approx. $16 million last year, which mostly derived from an update of royalties receivable from the Karish and Tanin leases.

Taxes on income totaled approx. $143 million in the Report Year compared with approx. $116 million last year, demonstrating a decrease of approx. 23%. The increase mainly derived from the fact that tax expenses last year included an update of deferred taxes as a result of a change in an estimate in the tax basis for other long-term assets as a result of a change in the forecast for recovery of the value of a financial asset.

Taxes on income totaled an expense of approx. $32 million in Q4/2023 compared with approx. $6 million in the same quarter last year. The increase mostly derived from the aforesaid reason.

Income (loss) from discontinued operations totaled a profit of approx. $2 million in the Report Year, compared with a loss of approx. $9 million last year. The discontinued operations originate from the sale of the Partnership's holdings in the Tamar project in December 2021 (the "**Tamar Transaction**"). The profit this year derived from excess advance payments previously paid by the Tamar partners as implied by the draft royalty audit reports for the years 2013-2018 that were received from the Ministry of Energy. Discussions are being held between the State and the Tamar partners, through the operator, with respect to overpayments made by the Tamar partners in 2013-2018. Based on understandings being finalized vis-à-vis the Ministry of Energy following discussions that were recently held in connection with the draft audit reports. See Note 15B to the financial statements (Chapter C of this Report). The loss last year derived mainly from the write-off of an asset of royalties receivable from the State and the recording of additional overriding royalties due to the dismissal of a claim that had been filed with the District Court by the Partnership and Chevron for a refund of royalties, as stated in Note 12L1 to the financial statements (Chapter C of this Report).

Income (loss) from discontinued operations totaled approx. $2.1 million in Q4 compared with a loss of approx. $2.4 million in the same quarter last year. The profit in the quarter and the loss in the same quarter last year derived from the foregoing.

3. Financial position, liquidity and financing sources

A. Financial position

The main changes in the items of the statement of financial position as of 31 December 2023, compared with the statement of financial position as of 31 December 2022, are specified below:

Total assets as of 31 December 2023 totaled approx. $3,846 million, compared with approx. $3,939 million as of 31 December 2022.

Current assets as of 31 December 2023 totaled approx. $568 million compared with approx. $771 million as of 31 December 2022, as specified below:

(1) **Cash and cash equivalents** as of 31 December 2023 totaled approx. $29 million, compared with approx. $22 million as of 31 December 2022. The cash receipts mainly derive from net receipts from the sale of natural gas in the Leviathan project and from receipts from Energean in respect of royalties and repayment of debt from the Karish and Tanin project which was mainly offset by payments in the Report Year, mainly in respect of a profit distribution to the participation unit holders, investments in the A-3 well in Cyprus, advance tax payments and oil and gas profit levy payments in respect of the Partnership’s holdings in the Tamar project in previous years.

(2) Short-term investments and deposits as of 31 December 2023 totaled approx. $158 million, compared with approx. $396 million as of 31 December 2022, and primarily consist of Leviathan Bond deposits in the sum of approx. $146 million (approx. $384 million last year). The decrease mainly derived from use of the deposits which were used as a safety cushion for repayment of the Leviathan Bond Series 2023 bonds in May and June 2023 and from classification in 2022 of the safety cushion designated for the repayment of Leviathan Bond Series 2023 bonds in the sum of $100 million under this item and from classification of the safety cushion of $100 million after its re-deposit in H2/2023 under long-term deposits.

(3) Trade receivables as of 31 December 2023 totaled approx. $194 million, compared with approx. $199 million as of 31 December 2022. The decrease mainly derived from the drop in revenue in Q4 compared with the same period last year.

(4) Other receivables as of 31 December 2023 totaled approx. $187 million, compared with approx. $134 million as of 31 December 2022. The increase mainly derived from the classification of amounts receivable in respect of a loan to Energean in the context of sale of the Karish and Tanin leases from long-term assets, as specified in Note 8B to the financial statements (Chapter C of this Report), which was partly offset by a decrease in the balance of the operator in the context of the joint ventures.

(5) Current taxes receivable as of 31 December 2022 totaled approx. $20 million received in the Report Year after the filing of the Partnership's tax report for 2021.

Non-current assets as of 31 December 2023 totaled approx. $3,278 million, compared with approx. $3,168 million on 31 December 2022, as specified below:

(1) Investments in oil and gas assets as of 31 December 2023 totaled approx. $2,647 million, compared with approx. $2,547 million as of 31 December 2022. The movement in the Report Year mainly derived from investments of approx. $139 million in the Leviathan project and approx. $29 million in the Block 12 project (the A-3 well) in Cyprus. Conversely, the Partnership recorded depreciation, depletion, and amortization expenses in the Leviathan project in the sum of approx. $68 million. For further details, see Note 7 to the financial statements (Chapter C of this Report).

(2) Investment in a company accounted for at equity as of 31 December 2023 totaled approx. $58 million compared with approx. $60 million as of 31 December 2022, and is due to the investment in shares of EMED. The decrease in investment derived from the recording of in respect of the investment in the Report Year, which was largely due to the amortization of excess purchase cost, which was offset by profits from operations of gas transmission via the EMG pipeline. For details see Note 6 to the financial statements (Chapter C of this Report).

(3) **Long-term bank deposits** as of 31 December 2023 totaled approx. $102 million, compared with approx. $0.5 million as of 31 December 2022. The increase derives from the classification, in 2022, of the safety cushion intended for the repayment of Leviathan Bond Series 2023 bonds in the sum of $100 million under short-term deposits, and from the refilling of the safety cushion in the sum of approx. $100 million, after its redeposit in H2/2023, under long-term deposits.

(4) **Other long-term assets** as of 31 December 2023 totaled approx. $470 million, compared with approx. $560 million as of 31 December 2022. The decrease mainly derived from the classification of royalties and a receivable in respect of the Karish and Tanin leases from this item to the short term and was partly offset by advance payments of oil and gas profit levy for the Partnership's holdings in the Tamar project in previous years and an increase in other long-term assets in the context of joint ventures (mainly the construction and expansion of natural gas transmission systems from Israel to Jordan and Egypt).

Current liabilities as of 31 December 2023 totaled approx. $211 million, compared with approx. $582 million as of 31 December 2022, as specified below:

(1) **Current maturities of bonds** as of 31 December 2022 totaled approx. $425 million and included Series 2023, which was repaid in the Report Year, net of issue expenses, and net of bonds which were purchased in the context of a buyback plan.

(2) **Income taxes payable** as of 31 December 2023 totaled approx. $28 million, which mainly include an estimate of taxes payable in respect of the Partnership's taxable income for the tax year 2023, net of the advances the Partnership paid to the tax authorities in the Report Year. As of the date of approval of the financial statements, this balance has been paid.

(3) **Short-term liability to a banking corporation** as of 31 December 2023 totaled approx. $80 million and derived from a loan taken out of the credit facility provided to the Partnership by a banking corporation. This liability was repaid in January 2024. For details see Section C1 below.

(4) **Trade and other payables** as of 31 December 2023 totaled approx. $101 million, compared with approx. $97 million as of 31 December 2022. The increase mainly derived from an increase in payables in the context of the joint ventures.

(5) **Other short-term liabilities** as of 31 December 2023 totaled approx. $2

million compared with approx. $10 million as of 31 December 2022, 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 in the abandonment actions during 2023.

Non-current liabilities as of 31 December 2023 totaled approx. $2,123 million, compared with approx. $2,070 million as of 31 December 2022, as specified below:

(1) **Bonds** as of 31 December 2023 totaled approx. $1,735 million and include the Leviathan Bond bonds (net of issue expenses) (for details see Part Four below), compared with approx. $1,731 million as of 31 December 2022.

(2) **Deferred taxes** as of 31 December 2023 totaled approx. $314 million, compared with approx. $ 270 million as of 31 December 2022. The increase mainly derived from an increase in the temporary differences between the measurement basis of oil and gas assets, as reported for tax purposes (ILS) and the measurement basis as reported in the financial statements ($).

(3) **Other long-term liabilities** as of 31 December 2023 totaled approx. $74 million, compared with approx. $69 million as of 31 December 2022. The increase mainly derives from an update of obligations to retire Leviathan project's assets.

The capital of the limited partnership as of 31 December 2023 totaled approx. $1,512 million, compared with approx. $1,287 million as of 31 December 2022. The change in capital mainly derived from the comprehensive income recorded in the Report Year in the sum of approx. $434 million, which was offset by profits distributed in the Report Year in the sum of approx. $211 million.

B. <u>Cash flow</u>

(1) Cash flows generated by the Partnership from operating activities in the Report Year totaled approx. $559 million, compared with approx. $505 million last year.

(2) Cash flows generated by the Partnership from investment activities in the Report Year totaled approx. $36 million, compared with cash flows used by the Partnership for investment activities totaling approx. $273 million last year. In the Report Year, the Partnership invested approx. $136 million in oil and gas assets (mainly in the Leviathan project and Block 12 in Cyprus), and approx. $13 million in other long-term assets (mainly in connection with expansion of infrastructures for transmission to Egypt), and it recorded a decrease in the investments and short-term deposits item, primarily in connection with use of the safety cushions for repayment of the 2023 Series of the Leviathan Bond bonds in the sum of approx. $238 million.

(3) Cash flows used for financing activities in the Report Year totaled approx. $589 million, compared with approx. $429 million last year. Cash flows in the Report Year were primarily used for a profit distribution to the participation unit holders and for repayment and repurchase of Leviathan Bond bonds, as stated in Section E below. Conversely, the Partnership drew down $80 million from the credit facility from a banking corporation (see Section C1 below).

C. <u>Financing</u>

(1) On 5 February 2023, the Partnership signed documents for bank credit facilities with an Israeli bank, intended to be used by the Partnership for its operating activities. In the Report Year, the Partnership drew down $80 million out of credit facility A, which was repaid by the Partnership on 11 January 2024. In addition, on 9 January 2023, credit facility B was canceled at the Partnership's request. On 14 March 2024, the Partnership signed, with an Israeli bank, for the provision of a credit facility in the sum of $100 million. Upon the taking effect of this facility, the previous facilities were canceled. For further details, see Note 10D to the financial statements (Chapter C of this Report).

(2) On 30 June 2023, full and final repayment was made of the first series of the Leviathan Bond bonds, following partial prepayment on 1 May 2023 of $280 million plus accrued interest in the sum of approx. $4.5 million, out of a total series in the sum of $500 million. In accordance with the terms and conditions of the bonds, the repayment of the first series during the quarter prior to the original maturity date was not subject to the payment of a prepayment fee to the bondholders. For further details see Part Five below and Note 10B to the financial statements (Chapter C of this Report).

(3) As a result of the War, the Leviathan Bond bonds were placed on negative watch by the rating agencies Moody's and Fitch. In addition, the rating agency S&P downgraded the bonds' rating outlook to negative. In February 2024, following the downgrade of the credit rating of the State of Israel and Israeli banks by the Moody's rating agency, Moody's announced that following consideration of a downgrade, it had decided to affirm, rather than downgrade, the rating of the Leviathan Bond bonds. However, under the shadow of the Iron Swords War, Moody's changed the rating outlook of the Leviathan Bond bonds to negative. In March 2024, the rating agency S&P released a rating affirmation report in which it left the rating of the Leviathan Bond bonds unchanged as well as the negative rating outlook, due to the risk of escalation of the War.

In addition, although, as a consequence of the War, there has been an increase in the returns on the Leviathan Bond bonds, such increase does not affect the nominal interest of the bonds, the Partnership's cash flow and the ability to repay the bonds, although it may have an adverse effect on the Partnership's ability to raise additional debt, and increase the financing costs of raising additional debt as aforesaid.

D. Profit distributions:

(1) On 1 March 2023, the General Partner's board of directors approved a minimal distribution to the limited partner in the sum of ILS 1 million (approx. $0.3 million) 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.

(2) On 27 March 2023, after receiving the recommendation of the General Partner's financial statements review committee, the General Partner's board of directors approved a profit distribution in the sum total of $60 million ($0.05112 per participation unit), with the record date for the distribution being 9 April 2023, and such profit distribution was carried out on 20 April 2023.

(3) On 10 May 2023, after receiving the recommendation of the General Partner's financial statements review committee, the General Partner's board of directors approved a profit distribution in the sum total of $50 million ($0.04260 per participation unit), with the record date for the distribution being 22 May 2023, and such profit distribution was carried out on 15 June 2023.

(4) On 20 August 2023, after receiving the recommendation of the General Partner's financial statements review committee, the General Partner's board of directors approved a profit distribution in the sum total of $50 million ($0.04260 per participation unit), with the record date for the distribution being 30 August 2023, and such profit distribution was carried out on 14 September 2023.

(5) On 20 August 2023, the General Partner's board of directors approved a minimal distribution to the limited partner in the sum of ILS 0.5 million (approx. $0.1 million), 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.

(6) On 15 November 2023, after receiving the recommendation of the General Partner's financial statements review committee, the General Partner's board of directors approved a profit distribution in the sum total of $50 million ($0.04260 per participation unit), with the record date for the distribution being 27 November 2023, and such profit distribution was carried out on 21 December 2023.

(7) On 15 November 2023, the General Partner's board of directors approved a minimal distribution to the limited partner in the sum of ILS 0.5 million (approx. $0.1 million), 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.

(8) On 18 March 2024, after receiving the recommendation of the General Partner's financial statements review committee, the General Partner's board of directors approved a profit distribution in the sum total of $60 million ($0.05112 per participation unit), with the record date for the distribution being 28 March 2024, and such profit distribution will be carried out on 11 April 2024.

E. <u>Plan for buyback of Leviathan Bond bonds</u>:

On 22 May 2022, the General Partner's board of directors approved a plan for the buyback of the Leviathan Bond bonds, in an aggregate amount of up to $100 million for a period of two years. The Partnership performed buybacks under the said buyback plan in the sum of approx. $100 million. Further thereto, on 22 January 2023, the General Partner's board of directors authorized the Partnership to adopt another plan for the buyback of the Leviathan Bond bonds in an aggregate amount of up to $100 million, by way of an OTC purchase, a purchase on the TACT-Institutional system on TASE or by other methods (the "**Additional Buyback Plan**"). The Additional Buyback Plan took effect on 23 January 2023, and will expire at the lapse of two years, i.e. on 23 January 2025. It is noted that all of the aforesaid buybacks were repaid in the framework of repayment of the bonds as stated in Section C.2 above. On 15 November 2023, the General Partner's board of directors approved the continued performance of buybacks in accordance with the buyback plan, out of the bond series maturing on 30 June 2025 and/or our of the bond series maturing on 30 June 2027. By the date of approval of the financial statements, the Partnership has performed buybacks in accordance with the Additional Buyback Plan in the aggregate amount of approx. $7.7 million. It is clarified that the said decision does not obligate the Partnership and/or Leviathan Bond to perform bond buybacks, and that the Partnership's management may decide not to buy back any bonds whatsoever.

For further details regarding the bonds, see Part Five below and Note 10B to the financial statements (Chapter C of this Report).

F. On 30 April 2023, the Partnership released a temporary tax certificate for an entitled holder and a seller of the participation units due to the holding of participation units of the Partnership for 2021.

G. <u>The Iron Swords War and its possible impact on the Partnership's business</u>:

Since the outbreak of the War on 7 October 2023, thousands of rockets have been fired from the Gaza Strip mainly into the south and center of the State of Israel. At the same time, as the fighting has progressed, the terrorist organization Hezbollah has escalated the tension on the Israel-Lebanon border and initiated combat operations against Israel. Consequently, and in view of the possibility of expansion of the War on the northern border and other fronts, the IDF mobilized hundreds of thousands of reservists, communities located close to the frontlines on the southern and northern borders were evacuated, and the Home Front Command periodically limited the activity of workplaces and educational institutions. As of the report approval date, the Israeli economy has resumed normal operations under the shadow of war, most of the restrictions imposed by the Homefront Command upon the outbreak of the War have been lifted, and most of the people called for reserve duty by emergency decrees have been discharged and returned to their homes.

Shortly after the War broke out, the Houthi rebel movement, which controls parts of Yemen and is supported by Iran, began attacking and launching missiles and UAVs at Israel and at vessels and tankers sailing near the shores of Yemen in the Red Sea. Such hostilities by the Houthi rebels' are causing disruptions in the maritime trade routes to Israel and other countries and affecting maritime shipping prices and may also affect the prices of energy products.

As a result of the War, in October 2023, the credit rating agencies Moody's and Fitch announced that the credit rating of the State of Israel was under review for a downgrade, and credit rating agency S&P Global Ratings announced a downgrade of the credit rating outlook of the State of Israel from stable to negative, while leaving the current credit rating unchanged. Further thereto, on 10 February 2024, the Moody's credit rating agency announced a downgrade of the State of Israel's credit rating by one notch to A2 and stated that Israel's credit rating had been placed on negative rating watch, explaining that the downgrade was primarily motivated by Moody's assessments that the continued war, its effects and its extensive implications materially raised the political risk in Israel and weakened the executive and legislative branches and financial strength in the foreseeable future, and adding that the negative outlook resulted from the existing additional risks, particularly the risk of escalation vis-à-vis the Hezbollah terrorist organization in the North, which has the potential for a much more significant adverse effect on the economy than at present. In addition, the credit rating agency S&P Global Ratings announced a downgrade of the State of Israel's credit rating outlook from stable to negative, leaving the existing credit rating unchanged. Further thereto, it is possible that other rating agencies may also announce negative rating actions with respect to the Israeli economy in the near future.

Upon the outbreak of the War on 7 October 2023 as aforesaid, the Tamar partners halted gas production from the Tamar reservoir following an order received by the operator from the Ministry of Energy. Gas production from the Tamar reservoir was resumed on 13 November 2023. Production from the Leviathan and Karish reservoirs continued as usual, without interruption. However, as a result of the halting of production from the Tamar reservoir as aforesaid, the Leviathan partners supplied natural gas also to a number of customers of the Tamar reservoir in the domestic market, and mainly to the IEC, and as a result, the quantity of natural gas allocated for export to Egypt was reduced. At the same time, due to the War, gas piping through the EMG pipeline had been halted and resumed on 14 November 2023. During this period, the entire gas supply to Egypt was piped via the Jordan-north export pipeline and the Jordanian transmission system. Transmission of the gas to Egypt in this manner entails additional transmission costs. As a consequence of the aforesaid, the total gas quantity supplied to Egypt in October and November 2023 was around 84% of the contract quantity of gas that the Leviathan partners were obligated to supply according to the export agreement.

Since the outbreak of the War and until the report approval date, production from the Leviathan reservoir has continued as usual, and so the Partnership's revenues and profitability have suffered no material adverse effect. However, as a result of the War, operating expenses entailed by the production of the gas have increased by an immaterial rate, chiefly due to the difficulty of foreign companies in sending crews to the region, which led to an increase in the paid rates and the need for further logistic activities to transport manpower and equipment. Furthermore, planned maintenance activities were postponed, changed and modified.

Moreover, following the War, a delay has occurred in several projects that are promoted by the Leviathan Partners, as follows:

The laying of the Ashdod-Ashkelon offshore pipeline as part of the Combined Section project. For further details, see Section 7.12.2 of Chapter A (Description of the Partnership's Business) of this Report;

Commencement of condensate piping to Ashdod Refinery Ltd. via the pipeline of Energy Infrastructures Ltd. For further details, see Section 7.11.4 of Chapter A (Description of the Partnership's Business) of this Report.

As of the report approval date, significant uncertainty exists, making it impossible to estimate how the War will develop and whether it will expand to additional fronts, how long it will be, and what results and repercussions it will have. Under these circumstances, it is impossible to estimate the chances of materialization of the risk factors arising from the War and their possible effect, whose materialization could have a material adverse effect on the Partnership, its assets and its business.

H. <u>War between Russia and Ukraine and its possible impact on the Partnership's business</u>:

Following the Russian army's invasion of Ukraine in early 2022, the U.S. and the member states of the European Union imposed a series of economic punitive measures against Russia, which included, *inter alia*, 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, concurrently with the existing Nord Stream 1 pipeline, discontinuation of some collaborations with Russian entities by international companies, including significant companies in the fields of natural gas and oil production, and more. In September 2022, a series of explosions and leaks occurred in the Nord Steam 1 and Nord Stream 2 pipelines which were caused, in the estimation of the countries in whose territory the explosions occurred, as a result of sabotage. Further thereto, the sale of natural gas from Russia to the European market was significantly reduced, and a shortage of natural gas occurred in countries that had consumed significant quantities of natural gas from Russia. In addition, a sharp drop was recorded in the volume of oil sales from Russia to western countries. The war in Ukraine led in 2022 to a steep and unusual rise in the global prices of oil and natural gas, with the Brent oil price peaking in June 2022 at over around $120 per barrel, a price significantly higher than the price environment to which the world had grown accustomed in the preceding years.

From mid-2022, a decline was recorded in the energy prices in the global markets, which 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 the effect of the weather, which was relatively mild in the winter months in Europe.

In 2023, a relative stabilization was recorded in the fluctuations in the Brent price, and it is traded at between $70 and $95 per barrel.

Against this backdrop, many European countries have recently sought to diversify their natural gas sources, with the aim of reducing the dependency on natural gas from Russia, which has led to a significant increase in the demand for natural gas, particularly in areas where pipelines may be connected for the transmission of natural gas to Europe, as well as an increase in the 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.

I. <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 Covid and the war between Russia and Ukraine, 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.

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 will be a partner.

In the H2/2023 Financial Stability Report released by the Bank of Israel on 31 January 2024, which report focuses on an analysis of the implications and risks arising from the War for the economy of Israel, the authors noted, *inter alia*, that the scenario of the central risk for global financial stability is a renewed inflationary upsurge in the world, which would lead to additional monetary contraction by the central banks, perhaps even to stagflation. In the said scenario, banks, including banks that are defined as systemically important in many key countries, might encounter difficulties, which may also affect the domestic banking system.

Energy product prices and the inflation rate also have an effect on the operating costs of gas production, as well as on the development costs in the Partnership's projects, including the drilling of development, appraisal and exploration wells. The Partnership, together with its partners in the Leviathan and Aphrodite projects, is examining the impact of the said factors on the additional development options and/or expansion of its assets.

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 the Iron Swords war, 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.

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. **<u>The interest rate risk</u>**

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 20 November 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 1 July 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 31 December 2023
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 21F2 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 21F3 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 21F2 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%
	4.189	3.808	3.627	3.446	3.264
Cash and cash equivalents	(0.1)	-	0.6	-	0.1
Bank deposits	-	-	0.2	-	-
Trade and other payables	-	-	(0.4)	-	-
Total	**(0.1)**	**-**	**0.4**	**-**	**0.1**

7. Report on linkage bases in Dollars in thousands, as of 31 December 2023:

	Financial Balances			
	In dollars or dollar-linked	In non-linked ILS	Non-financial balances	Total
Assets				
Cash and cash equivalents	28.5	0.6	-	29.1
Short-term deposits	157.4	0.2	-	157.6
Trade receivables	194.5	-	-	194.5
Other receivables	155.6	-	31.5	187.1
Investments in oil and gas assets	-	-	2,647.3	2,647.3
Investment in company accounted for at equity	-	-	58.4	58.4
Long-term deposits	101.9	-	-	101.9
Other long-term assets	229.2	-	241.1	470.3
Total assets	**867.1**	**0.8**	**2,978.3**	**3,846.2**
Liabilities				
Other short-term liabilities	-	-	2.2	2.2
Trade and other payables	75.9	0.4	24.8	101.1
Income tax payable	-	-	27.7	27.7
Short-term loan from banking corporation	80.0	-	-	80.0
Bonds	1,735.1	-	-	1,735.1
Deferred taxes	-	-	313.9	313.9
Other long-term liabilities	-	-	73.7	73.7
Total liabilities	**1,891.0**	**0.4**	**442.3**	**2,333.7**
Total net balance	**(1,023.9)**	**0.4**	**2,536.0**	**1,512.5**

8. Report on linkage bases in Dollars in thousands, as of 31 December 2022:

	Financial Balances			
	In dollars or dollar-linked	In non-linked ILS	Non-financial balances	Total
Assets				
Cash and cash equivalents	19.8	2.6	-	22.4
Short-term deposits	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	**(1,201.7)**	**1.7**	**2,487.4**	**1,287.4**

Part Three – Corporate Governance Aspects

1. The Partnership's donation policy

In November 2023, the General Partner's board of directors resolved to adopt a detailed donation policy, under which, *inter alia*, the total annual donations shall not exceed 0.25% of the Partnership's annual pre-tax profit. The General Partner's board of directors intends to allocate a significant portion of the donation budget to support the many communities who have been negatively affected by the Iron Swords War as described above. In 2023, the Partnership donated approx. ILS 820 thousand.

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: 1 February 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. **Appointment procedure**

The appointment of Mr. Gana as the internal auditor was approved by the board of directors of the General Partner on 27 January 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. **Identity of the organizational supervisor of the internal auditor**

The chairman of the board of directors of the General Partner.

d. **The work plan**

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 multi-year work plan.

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 VP Budget and Control 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.

e. **Scope of engagement**

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 totaled 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. **Conduct of the audit**

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, the members of the audit committee and the members of the General Partner's board of directors and discussed at length by the audit committee. Below are dates on which the audit committee discussed the internal auditor's reports: 15 March 2023, 18

July 2023, 25 December 2023, 31 January 2024 and 14 March 2024.

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 2023, the Partnership recorded a total annual expense of ILS 136 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:

	Y2023		Y2022	
	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	1,093	542	1,805	1,271

*** 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 11 March 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 14 March 2019 and 17 March 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. <u>Corporate Social Responsibility at the Partnership ("ESG")</u>

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 the years 2022-2023 in Q2/2024.

Part Four – Disclosure in connection with the Partnership's Financial Reporting

<u>Subsequent events</u>

See Note 22 to the financial statements (Chapter C of this Report).

Part Five – Details of bonds issued by Leviathan Bond Ltd.

Leviathan Bond bond series	2025	2027	2030
Par value on the issue date	600	600	550
Issue date	18 August 2020	18 August 2020	18 August 2020
Par value as of 31 December 2023	600	600	550
Linked par value as of 31 December 2023	600	600	550
Value on the Partnership's books as of 31 December 2023	597.7	595.0	542.3
TASE value as of 31 December 2023[4]	582.3	567.0	502.7
Fixed annual interest rate	6.125%	6.500%	6.750%
Principal payment date	30 June 2025	30 June 2027	30 June 2030
Interest payment dates	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		
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		

[4] The bonds are traded in Israel on the "TACT-institutional" system on TASE.

[5] The bonds' principal and interest are stated in dollars.

[6] The financing documents prescribe provisions regarding early redemption of the bonds, including (1) early redemption initiated by the issuer, subject to payment of a prepayment fee (make whole premium); and (2) mandatory early redemption in certain cases that were defined, including by way of a buyback of bonds and/or the issue of a tender offer to all of the bondholders, including upon a sale of all or some of the interests in the Leviathan project.

[7] See the Partnership's immediate reports of 19 August 2020 (Ref. No. 2020-01-090852 and 2020-01-091134) and 23 August 2020 (Ref. No. 2020-01-092247), the information in which is incorporated herein by reference.

Leviathan Bond bond series	2025	2027	2030
Rating as of the report approval date[8]	Fitch Rating: BB Rating Watch Negative Moody's: Ba3 Negative S&P: BB- Negative Standard & Poor's Maalot: ilA+ Negative		
Has the Partnership fulfilled, by 31 December 2023 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 of this Report)		

[8] In view of the aforesaid regarding the events of the Iron Swords War, the rating agencies have updated the bonds' rating outlook and forecast - see immediate reports of 26 October 2023, 1 November 2023, 6 November 2023, 6 November 2023, 4 March 2024, 18 March 2024 and 18 March 2024 (Ref.: 2023-01-098338, 2023-01-100228, 2023-01-122076, 2023-01-122103, 2024-01-022044, 2024-01-027651 and 2024-01-027663, respectively), the information in which is incorporated herein by reference.

[9] A series of bond certificates will be deemed material if the total liabilities of the corporation thereunder as of 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 General Partner’s board of directors, the Partnership’s management and its employees are committed to the war effort, express their deepest condolences to the families of those who have fallen and were murdered, hope for the safe return of the hostages and missing persons, and wish all the injured a swift recovery.

May He who blessed our fathers Abraham, Isaac and Jacob, bless the soldiers of the Israel Defense Forces and members of the Security Agencies who keep guard over our country and cities of our Lord from the border with Lebanon to the Egyptian desert and from the Mediterranean Sea to the approach to the Arava, be they on land, air or sea. Amen.

The General Partner’s board of directors also expresses its appreciation for the General Partner’s management, 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
CEO

Gabi Last
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)

	31.12.2023 Audited	31.12.2022 Audited
Assets:		
Current Assets:		
Short term Bank deposits	33	253,279
Loans to shareholders	-	499,603
Related parties	**	**
	33	752,882
Noncurrent Assets:		
Loans to shareholders	1,749,034	1,749,625
Long term bank deposits	101,411	-
	1,850,445	1,749,625
	1,850,478	2,502,507
Liabilities and Equity:		
Current Liabilities:		
Bonds	-	500,000
Related parties	1,444	153,279
	1,444	653,279
Noncurrent Liabilities:		
Bonds	1,750,000	1,750,000
Loans from shareholders	100,000	100,000
	1,850,000	1,850,000
Equity (Deficit)	(966)	(772)
	1,850,478	2,502,507

**** Less than $1,000**

Statements of Comprehensive Income (Expressed in US$ Thousands)

	For the year Ended 31.12.2023 Audited	For the year Ended 31.12.2022 Audited
Financial expenses	134,437	146,252
Financial income	(134,243)	(147,398)
Total comprehensive expenses (income)	194	(1,146)

SPONSOR FINANCIAL DATA REPORT[10]

	ITEM	YEAR ENDED 31.12.2023 QUANTITY/ACTUAL AMOUNT (IN USD$,000)
A.	Total Offtake (BCM)	11.0[11]
B.	Leviathan Revenues (100%)	2,414,063[12]
C.	Loss Proceeds, if any, paid to Revenue Account	-
D.	Sponsor Deposits, if any, into Revenue Account	110,300
E.	Gross Revenues (before Royalties)	1,106,583
F.	Overriding Royalties	
	(a) Statutory Royalties	122,291
	(b) Third Party Royalties	48,504
G.	Net Revenues	935,788
H.	Costs and Expenses:	
	(a) Interest Income (Fees Under the Financing Documents)	11,494
	(b) Taxes	(40,779)
	(c) Operation and Maintenance Expenses	(139,132)
	(d) Capital Expenditures	(107,069)
	(e) Insurance (income)	(22,178)
I.	Total Costs and Expenses (sum of Items H(a), (b), (c), (d) and (e))	(297,664)
J.	Total Cash Flows Available for Debt Service (Item G *minus* Item H)	638,124
K.	Total Cash Flow from operation (Item G minus Items H(c) and H(e)	774,478
L.	Total Debt Service	(624,581)
M.	Total Distribution to the Sponsor	(225,000)

[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 1 January 2023 until 31 December 2023 for 100% of the Leviathan partners on an accrual basis.
[12] Gas sales from 1 January 2023 until 31 December 2023 for 100% of the Leviathan partners on an accrual basis.

Annex B to the Board of Directors' Report

Summary of Data of a Valuation of Royalties from the Karish and Tanin Leases

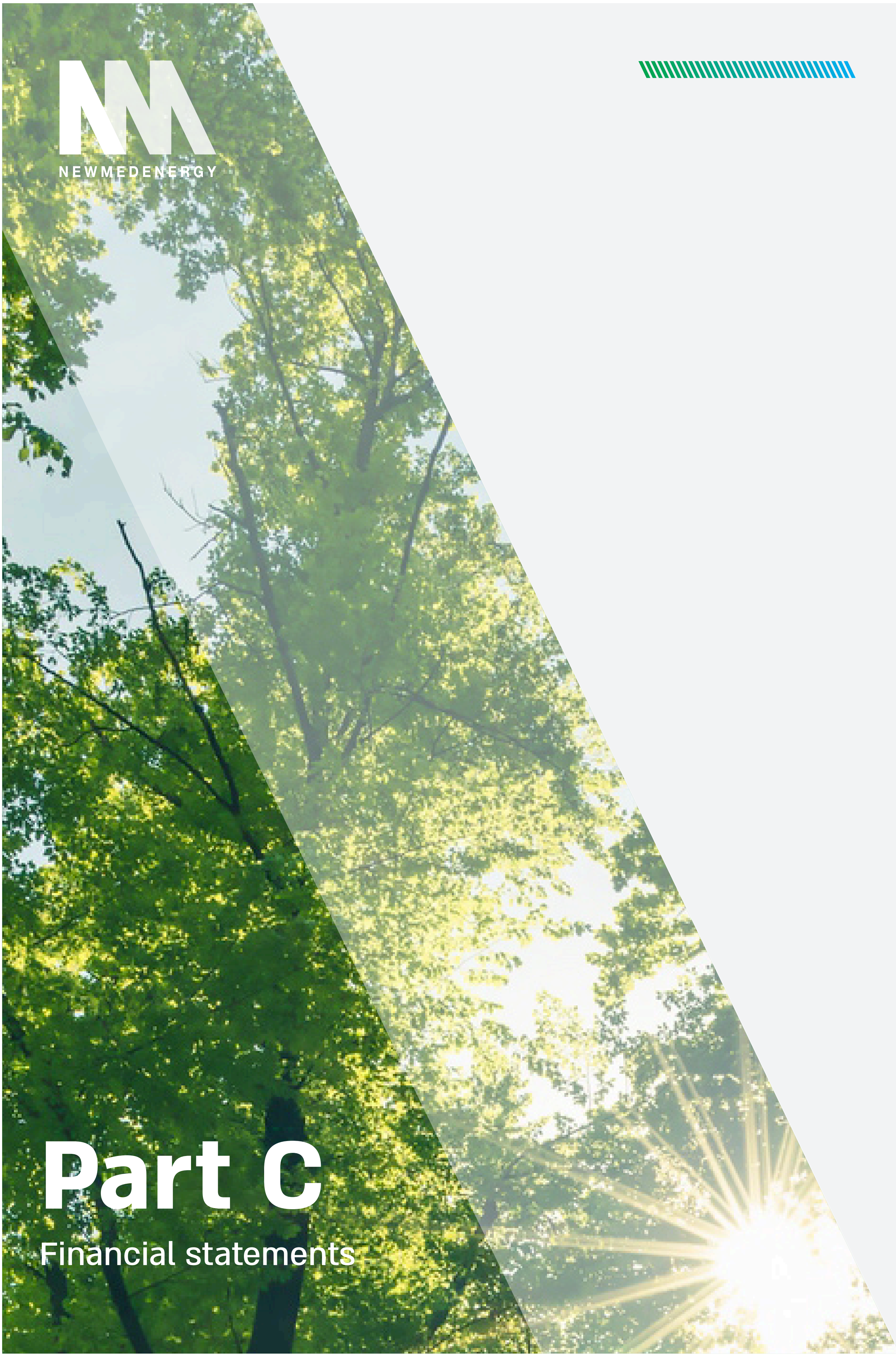
Following are details of a highly material valuation with respect to the profit from the revaluation of royalties from the sale of the Partnership's interests in the Karish and Tanin leases (for further details, see Note 8B to the financial statements (Chapter C of this Report) and the valuation attached 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:	31 December 2023
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. $273.2 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 and/or NewMed Energy Management Ltd., the general partner of the Partnership (the

Identification of the object of the valuation:	Royalties in respect of the sale of all of the interests in the Karish and Tanin leases.
	"**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: 1 October 2022 to 31 December 2042; 2. Average annual rate of natural gas production from the Karish lease: approx. 3.64 BCM; average annual rate of condensate production from the Karish lease: approx. 4.59 million barrels; 3. Period of production of gas from the Tanin reservoir: 1 January 2030 to 31 December 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; 5. Royalty component cap rate: 10.88%; 6. Effective royalty rate to be paid to the State for the gas and the condensate: 11.06%; 7. Gas price formula: The basic price in

Identification of the object of the valuation:	Royalties in respect of the sale of all of the interests in the Karish and Tanin leases.
	the contracts according to which the valuation was prepared was estimated based on the formula specified in the price mechanism between Energean and ICL and ORL and between Energean and OPC and weighting the price of the gas in the Ramat Hovav contract; 8. Condensate price: The condensate price forecast was estimated based on a long-term oil price forecast average of the World Bank[13] and the EIA[14] and the forward prices of Brent according to Bloomberg data and based on the assumption that the condensate price will be derived from the Brent price with adjustments to oil quality differences; 9. On 23 March 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. 39.4 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%.

[13] A World Bank quarterly report: Commodity Markets Outlook, October 2023.
[14] U.S Energy Information Administration: Analysis & Projections, December 2023.



Part C

Financial statements

18 March 2024

To

The Board of Directors of the General Partner of NewMed Energy – Limited Partnership (the "Partnership")

<u>19 Abba Eban, Herzliya</u>

Dear Sir/Madam,

Re: <u>Consent given simultaneously with the release of a periodic report in connection with the shelf prospectus of the Partnership (the "Offering Document")</u>

We hereby notify you that we agree to the inclusion (including by way of reference) in the above referenced Offering Document of our reports as specified below:

1. Auditors' report of 18 March 2024 on the Partnership's financial statements as of 31 December 2023 and 2022 and for each of the three years in the period ended 31 December 2023.

2. The Auditors' report of 18 March 2024 on the audit of components of internal control over financial reporting of the Partnership as of 31 December 2023.

Kost Forer Gabbay & Kasierer
Certified Public Accountants

Ziv Haft
Certified Public Accountants

<u>NewMed Energy – Limited Partnership</u>

<u>Financial Statements as of 31 December 2023</u>

<u>in U.S. Dollars in Millions</u>

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 31 December 2023

in U.S. Dollars in Millions

Contents

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 31 December 2023. 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 31 December 2023.

We have also audited, based on Generally Accepted Auditing Standards in Israel, the financial statements of the Partnership as of 31 December 2023 and 2022, and for each of the three years in the period ended 31 December 2023, and our report of 18 March 2024 included an unqualified opinion on the aforesaid financial statements.

Tel Aviv, 18 March 2024

Kost Forer Gabbay & Kasierer	**Ziv Haft**
Certified Public Accountants	**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 31 December 2023 and 2022 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 31 December 2023. 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 31 December 2023 and 2022 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 31 December 2023 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 31 December 2023 is $2,647.3 million and the depletion costs for the investments in oil and gas assets for the year ended 31 December 2023 amounts to a total of $67.7 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 and 2H 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 2023 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 31 December 2023 and our report as of 18 March 2024 included an unqualified opinion on the effective maintenance of such components.

Tel Aviv, 18 March 2024

Kost Forer Gabbay & Kasierer **Certified Public Accountants**	**Ziv Haft** **Certified Public Accountants**

NewMed Energy – Limited Partnership

Statements of Financial Position (Dollars in millions)

	Note	31.12.2023	31.12.2022
Assets:			
Current assets:			
Cash and cash equivalents	3	29.1	22.4
Short-term deposits	4	157.6	395.9
Trade receivables	21G	194.5	199.0
Trade and other receivables	5	187.1	134.1
Current taxes receivable	19	-	19.9
		568.3	771.3
Non-current assets:			
Investments in oil and gas assets	7	2,647.3	2,547.2
Investments in a company accounted for at equity	6	58.4	59.7
Long-term deposits	4	101.9	0.5
Other long-term assets	8	470.3	560.3
		3,277.9	3,167.7
		3,846.2	3,939.0
Liabilities and equity:			
Current liabilities:			
Current maturities for bonds	10A	-	424.8
Short-term liability to a banking corporation	10D	80.0	-
Declared profits for distribution	13C	-	50.0
Income taxes payable	19	27.7	-
Trade and other payables	9	101.1	96.9
Other short-term liabilities	11	2.2	9.9
		211.0	581.6
Non-current liabilities:			
Bonds	10A	1,735.1	1,731.0
Deferred taxes	19	313.9	269.8
Other long-term liabilities	11	73.7	69.2
		2,122.7	2,070.0
Equity:	13		
Partners' equity		154.8	154.8
Capital reserves		(28.6)	(29.9)
Retained earnings		1,386.3	1,162.5
		1,512.5	1,287.4
		3,846.2	3,939.0

The attached notes constitute an integral part of the financial statements.

18 March 2024			
Date of approval of the Financial Statements	Gabi Last Chairman of the Board	Yossi Abu CEO	Tzachi Habusha VP Finance

NEWMEDENERGY

NewMed Energy – Limited Partnership

Statements of Comprehensive Income (Dollars in millions)

	Note	For the year ended on 31.12.2023	31.12.2022	31.12.2021
Revenues:				
From natural gas and condensate sales	14	1,094.4	1,143.9	882.5
Net of royalties	15	159.8	172.0	128.7
Revenues, net		**934.6**	**971.9**	**753.8**
Expenses and costs:				
Cost of production of natural gas and condensate	16	148.6	134.1	118.4
Depreciation, depletion and amortization expenses	7	79.2	131.0	113.1
Other direct expenses		5.3	5.2	4.2
G&A	17	20.8	19.7	17.3
Total expenses and costs		**253.9**	**290.0**	**253.0**
The Partnership's share in the losses of a company accounted for at equity	6	(1.3)	(3.1)	(4.5)
Operating profit		**679.4**	**678.8**	**496.3**
Financial expenses	18	(133.8)	(155.3)	(211.3)
Financial income	18	28.7	71.1	31.4
Financial expenses, net		(105.1)	(84.2)	(179.9)
Profit before income taxes		**574.3**	**594.6**	**316.4**
Taxes on income	19	(142.8)	(116.0)	(207.8)
Profit from continuing operations		**431.5**	**478.6**	**108.6**
Profit (loss) from discontinued operations		2.1	(13.2)	151.7
Profit from the sale of natural gas and oil assets		-	4.3	144.6
Total profit (loss) from discontinued operations	7C9	**2.1**	**(8.9)**	**296.3**
Net income		**433.6**	**469.7**	**404.9**
Other comprehensive income from discontinued operations:				
Amounts which shall not subsequently be reclassified to profit or loss:				
Profit from investment in equity instruments designated for measurement at fair value through other comprehensive income		-	-	13.6
Comprehensive income (loss) from discontinued operations		**2.1**	**(8.9)**	**309.9**
Total comprehensive income		**433.6**	**469.7**	**418.5**
Basic and diluted profit (loss) per participation unit (in Dollars):				
from continuing operations		0.368	0.408	0.093
from discontinued operations		0.001	(0.008)	0.252
Profit per participation unit		0.369	0.400	0.345
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 Partner-ship's equity	Capital reserve for equity-based financial instruments at fair value against other comprehensive income	Capital reserve for cash flow hedging transa-ctions	Other capital reserves	Retained earnings
Balance as of 31 December 2020	**154.8**	**(70.6)**	**22.0**	**891.5**	**997.7**
Changes in the year ended 31 Dec. 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 31 December 2021	**154.8**	**(57.0)**	**26.3**	**814.4**	**938.5**
Changes in the year ended 31 Dec. 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 19A5)	-	-	-	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 31 December 2022	**154.8**	**(57.0)**	**27.1**	**1,162.5**	**1,287.4**
Changes in the year ended 31 Dec. 2023:					
Comprehensive income	-	-	-	433.6	433.6
Profits distributed (Note 13C)	-	-	-	(210.6)	(210.6)
Tax advances receivable for previous years (Note 13D)	-	-	-	0.8	0.8
Participation unit-based payment (Note 13H)	-	-	1.3	-	1.3
Balance as of 31 December 2023	**154.8**	**(57.0)**	**28.4**	**1,386.3**	**1,512.5**

The attached notes constitute an integral part of the financial statements.

NewMed Energy – Limited Partnership

Statements of Cash Flows (Dollars in millions)

	31.12.2023	31.12.2022	31.12.2021
Cash Flows - Current Operations:			
Net profit	**433.6**	**469.7**	**404.9**
Adjustments for:			
Depreciation, depletion and amortization	84.3	137.6	133.1
Taxes on income	75.4	59.5	207.8
Update of asset retirement obligation	(1.3)	(34.3)	(46.4)
Revaluation of short-term and long-term investments and deposits	(0.1)	(0.2)	-
Participation unit-based payment (Note 13H)	1.0	1.0	-
Benefit from a control holder included in expenses against a capital reserve (Note 13G)	-	-	4.3
Revaluation of other long-term assets	(8.1)	(66.4)	(43.0)
The Partnership's share in the losses of a company accounted for at equity, net	1.3	3.1	4.5
Income from the sale of oil and gas assets (Annex C)	-	(4.3)	(144.6)
Changes in assets and liabilities items:			
Decrease (increase) in trade receivables	4.5	(46.5)	(8.0)
Increase in trade and other receivables (including operator of joint ventures)	(3.1)	(4.6)	(15.3)
Decrease (increase) in other long-term assets	19.0	1.1	(6.8)
Decrease in trade and other payables (including operator of joint ventures)	(29.7)	(5.2)	(44.6)
Increase (decrease) in assets and liability for oil and gas profit levy	(17.3)	(5.8)	8.5
Decrease in another long-term liability	-	-	(0.7)
	125.9	**35.0**	**48.8**
Net cash deriving from current operations	**559.5**	**504.7**	**453.7**
Cash Flows - Investment Activity:			
Investment in oil and gas assets	(136.4)	(98.5)	(30.4)
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	(13.2)	(28.4)	(34.4)
Proceeds from the disposition of financial assets (Note 7C9(b))	-	-	30.6
Royalties based on future production from the Karish and Tanin leases (Note 8B)	36.7	-	-
Repayment of a loan to Energean in the context of the sale of the Karish and Tanin leases (Note 8B)	13.3	12.5	14.3
Short-term deposit withdrawal (deposit), net	238.4	(194.1)	68.6
Decrease (increase) of short-term investments, net	-	19.2	(20.0)
Long-term deposit in bank deposits	(101.4)	-	-
Decrease (increase) in other receivables – due to operator of the joint ventures	(1.3)	1.4	(1.6)
Net cash deriving from (used for) investment activity	**36.1**	**(273.4)**	**982.0**
Cash Flows - Financing Activity:			
Receipt of a short-term loan from a banking corporation	80.0	-	-
Distributed profits	(260.6)	(100.3)	-
Distributed profits, balancing payments and tax for the period up to and including 2021	-	(99.1)	(236.6)
Payments on account of the tax liable by participation unit holders for the period up to and including 2021	-	(170.2)	(16.8)
Reimbursement received from income tax for previous years	17.1	15.1	3.2
Early redemption of issued bonds	-	(74.6)	(19.9)
Repayment of bonds	(425.4)	-	(1,015.4)
Net cash used in financing activity	**(588.9)**	**(429.1)**	**(1,285.5)**
Increase (decrease) in cash and cash equivalents	6.7	(197.8)	150.2
Cash and cash equivalents balance at the beginning of the year	22.4	220.2	70.0
Cash and cash equivalents balance at the end of the year	29.1	22.4	220.2
Annex A - Finance and investment activity not involving cash flows:			
Investments in oil and gas assets against liabilities, net	63.0	3.6	37.5
Investments in other long-term assets against liabilities, net	5.1	5.3	-
Declared distributable profits, balancing payments and tax	-	50.0	86.2

The attached notes constitute an integral part of the financial statements.

NewMed Energy – Limited Partnership

Statements of Cash Flows (Dollars in millions)

	For the year ended on		
	31.12.2023	31.12.2022	31.12.2021
Annex B - Additional information on cash flows:			
Interest paid (including capitalized interest)	124.9	143.3	193.5
Interest received	17.6	7.3	4.2
Proceeds not yet received from the sale (see Annex C and Note 7C9)	-	-	10.5
Taxes and levy paid	53.1	81.6	-
Annex C – sale of rights in the Tamar and Dalit Leases (see also Note 7C9)			
Includes the following assets and liabilities as of the selling date:			
Working capital, net	-	-	10.6
Oil and gas assets	-	-	829.8
Other long-term assets	-	-	21.3
Oil and gas asset retirement obligations	-	-	(40.9)
Total assets net of liabilities	-	**-**	**820.8**
Proceeds received from the sale	-	14.8	954.9
Proceeds not yet received from the sale	-	(10.5)	10.5
Profit from sale of oil and gas assets	-	**4.3**	**144.6**

The attached notes constitute an integral part of the financial statements.

Note 1 – General:

A. NewMed Energy – Limited Partnership (the "**Partnership**") was founded according to a partnership agreement signed on 1 July 1993 between NewMed Energy Management Ltd. as general partner of the first part (the "**General Partner**"), and NewMed Energy Trusts Ltd. 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 1 July 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 7C4 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 12N 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 partners in which, as of the date of approval of the financial statements, are the Partnership, Chevron Mediterranean Ltd and Ratio Energies – Limited Partnership ("**Chevron**" or the "**Operator**" and "**Ratio Energies**", respectively, and jointly: the "**Leviathan Partners**"), the piping of gas from which commenced in December 2019. The Leviathan reservoir currently supplies natural gas to several customers in the Israeli and regional market, and among its prominent customers are, *inter alia*, Blue Ocean Energy in Egypt ("**Blue Ocean**") and the Jordanian national electricity company ("**NEPCO**"). In addition to the rights in the Leviathan reservoir, 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.

Note 1 - General (Cont.):

D. On 27 March 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 26 March 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 27 March 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.

During 2023, the Committee held regular meetings for the purpose of promoting the transaction, and used legal and economic advisors who it appointed for such purpose, and concurrently the Consortium performed a due diligence with respect to the Partnership, its assets and its business. On 13 March 2024, the Partnership and the Committee updated by an immediate report that the Committee and the Consortium have agreed, due to the uncertainty created by the external environment, to suspend discussions in relation to the transaction. They also updated that, the Consortium reiterated its interest in the transaction, and that the process will remain suspended until such time as discussions resume or the process is terminated.

Note 1 - General (Cont.):

D. (Cont.)

There can be no certainty that discussions will resume or that an agreement will be reached in the future, nor as to the terms of an agreement should one be reached.

E. The Iron Swords war and its impact on the Partnership's business:

Following the deadly attack perpetrated by the terrorist organization "Hamas" on 7 October 2023, targeting communities and military bases in the South of Israel, the Israeli Government declared the "Iron Swords" war against this terrorist organization (the "**Iron Swords War**" or the "**War**"). As of the date of approval of the financial statements, the War is ongoing and it is impossible to predict how long it will last or its impact on the Partnership, its business and its assets.

1. Since the outbreak of the War on 7 October 2023, thousands of rockets have been fired from the Gaza Strip mainly into the south and center of the State of Israel. At the same time, as the fighting has progressed, the terrorist organization 'Hezbollah' has escalated the tension on the Israel-Lebanon border and initiated combat operations against Israel. Consequently, and in view of the possibility of expansion of the War on the northern border and other fronts, the IDF mobilized hundreds of thousands of reservists, communities located close to the frontlines on the southern and northern borders were evacuated, and the Home Front Command has been periodically issuing current instructions limiting the activity of workplaces and educational institutions. As of the date of approval of the financial statements, the Israeli economy has resumed normal operations under the shadow of war, most of the restrictions imposed by the Homefront Command upon the breakout of war have been lifted, and most of the people called for reserve duty by emergency decrees have been discharged and gone back to their homes.
2. Shortly after the War broke out, the Houthi rebel movement, which controls parts of Yemen and is supported by Iran, began attacking and launching missiles and UAVs at Israel and at vessels and tankers sailing near the shores of Yemen in the Red Sea. The Houthi rebels' said hostile activity is causing disruptions to the maritime trade routes to Israel and other countries, and is impacting maritime shipping prices and may also impact energy product prices.
3. As a result of the War, in October 2023, the credit rating agencies Moody's and Fitch announced that they were considering a possible downgrade of the credit rating of the State of Israel. S&P Global Ratings also announced the downgrade of the credit rating of the State of Israel from stable to negative, while keeping the existing credit rating unchanged. Further thereto, on 10 February 2024, the credit rating agency Moody's announced a downgrade of the State of Israel's credit rating by one notch to A2, stating that Israel's credit rating had been placed on an additional Negative Rating Watch, and that the main motive for the downgrade is Moody's estimations that the continued war, its extensive effects and ramifications, materially increase the political risk in Israel and weaken the executive branch and the legislature, and the financial robustness in the foreseeable future, adding that the negative forecast derives from the additional existing risks, particularly the risk of escalation vis-à-vis the Hezbollah terrorist organization in the north which could potentially harm the economy much more significantly than now. Further thereto, other rating agencies may also make negative rating announcements about the Israeli economy in the near future.

Note 1 – General (Cont.):

E. The Iron Swords war and its impact on the Partnership's business (Cont.):

4. With the outbreak of the War on 7 October 2023, as aforesaid, the Tamar partners halted gas production from the Tamar reservoir following an order received by Chevron from the Ministry of Energy. Gas production from the Tamar reservoir was resumed on 13 November 2023. Production from the Leviathan and Karish reservoirs continued as usual, without interruption. However, as a result of the halting of production from the Tamar reservoir as aforesaid, the Leviathan Partners supplied natural gas also to a number of customers of the Tamar reservoir in the domestic market, and mainly to the Israel Electric Corp. Ltd. ("**IEC**"), and as a result, the quantity of natural gas allocated for export to Egypt was reduced. At the same time, due to the War, the flow of gas through the EMG pipeline was halted, and was resumed on 14 November 2023. During this period, the entire gas supply to Egypt was piped via the Jordan-North Export Pipeline and the Jordanian transmission system. Transmission of the gas to Egypt in this manner entails additional transmission costs. As a consequence of the aforesaid, the total gas quantity supplied to Egypt in October and November 2023 was around 84% of the contract quantity of gas that the Leviathan Partners were obligated to supply according to the export agreement.
5. Since the outbreak of the War, and until the date of approval of the financial statements, production from the Leviathan reservoir has continued as usual, such that the Partnership's revenues and profitability have not been materially impacted. However, as a result of the War, the operating expenses entailed by gas production have increased by an immaterial rate, mainly due to the difficulty experienced by foreign companies in sending work teams to the region, which has led to a rise in the rates paid and to a need for additional logistics to transport manpower and equipment. In addition, scheduled maintenance actions have been delayed, changed and adapted.
6. In addition, as a result of the War, there has been a delay in several projects being promoted by the Leviathan Partners, as follows:
   (a) Work on the laying of the Ashdod-Ashkelon offshore pipeline, part of the Combined Section project. For further details, see Section 12M1 below.
   (b) Commencement of the piping of the condensate to Ashdod Refinery Ltd. ("**ARF**") via the pipeline of Energy Infrastructures Ltd. (PEI). For further details, see Note 12E below.
7. Natural gas platforms, the offshore and onshore production and transmission facilities, and other essential infrastructure systems in Israel and in the export countries may constitute targets for missile firing and acts of sabotage, and impact they suffer, if any, may cause extremely significant damage and disrupt or shut down the production and/or transmission activities for such amount of time and to such extent that may prove to be considerable. In such cases, the insurance policies that Chevron and the Partnership have acquired may possibly prove insufficient to cover the damage and loss suffered by the Partnership. In this context, it is noted that there is risk that at the renewal date of the insurance policies, chiefly in connection with war and terrorism, it will be impossible to acquire appropriate policies on reasonable commercial terms or at all. Another risk that arises from the War is for impact on the facilities for intake of condensate, a byproduct of the natural gas production from the Leviathan project. The risk of events of this type may increase significantly in the event of escalation on the northern front of the State of Israel or in case of expansion of the War to additional fronts.

Note 1 – General (Cont.):

E. The Iron Swords war and its impact on the Partnership's business (Cont.):

(7) (Cont.)

In such case of escalation of the War, the risk of imposition by the Government of restrictions on the regular production operations of the Leviathan reservoir and/or the Tamar or Karish reservoirs may increase as well. Restriction or discontinuation of the production from the Tamar and/or Karish reservoirs is expected to compel the Leviathan Partners to increase the quantities of supply to the domestic market at the expense of the export to Egypt. Moreover, against the backdrop of the ongoing War, there is an increase in the geopolitical risk related to the export of natural gas from the Leviathan reservoir pursuant to the export agreements, which accounted for most of the Partnership's revenues in 2023. In addition to the foregoing, in the event of significant escalation of the security situation, which leads to the early termination of the export agreements or which results in physical damage to the Leviathan project which is not remedied or in other events that are reasonably expected to cause a material adverse effect, and subject to remedying periods, qualifications and conditions, there is a risk of breach of the terms and conditions of the bonds of Leviathan Bond, which are secured by the Partnership's interests in the Leviathan project and are traded on the TACT-Institutional system of Tel Aviv Stock Exchange Ltd. (in this section: the "**Bonds**"), which may provide the holders of the Bonds with a cause for acceleration and enforcement of the collateral. For further details with respect to the Bonds, see Note 10B below. It is further noted that an increase in the returns on the Bonds due to the development of the War may adversely affect the Partnership's ability to raise additional debt and increase the finance costs in respect of such additional debt raising.

8. As of the date of approval of the financial statements, significant uncertainty exists, making it impossible to estimate how the War will develop and whether it will expand to additional fronts, how long the War will last, its results and its repercussions. Under these circumstances, it is impossible to estimate the chances of materialization of the risk factors arising from the War and their possible effect, whose materialization could have a material adverse effect on the Partnership, its assets and its business.

F. 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 2 September 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[1] (in this section: the "**Buyers**" and the "**Agreement**", as applicable). On 9 December 2021, the transaction was closed (see Note 7C9 for further details).

G. 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 and S.O.A. Energy Israel Ltd. ("**SAO**") and the operator of the joint venture in Cyprus, Chevron Cyprus Ltd. ("**Chevron Cyprus**").

[1] 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.

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. The description of the accounting policy in these financial statements has been reduced and adjusted for the first time in accordance with the requirements of the amendment to IAS 1 "Presentation of Financial Statements". See Section R1 below regarding the initial application of this amendment and other amendments to new IFRS standards.

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, with the exception of financial assets and liabilities which are measured at fair value and an investment in a company accounted for at equity.

The Partnership has elected to present the profit or loss items using the function of expense method.

C. 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.

D. The operating cycle period:

The Partnership's operating cycle period is one year.

Note 2 - Significant Accounting Policies (Cont.):

E. 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 (Leviathan Bond Ltd.).

Note 2 - Significant Accounting Policies (Cont.):

F. Financial instruments:

1) Financial assets:

Financial assets were recognized when the Partnership became a party to the contractual provisions of the instrument using transaction settlement date accounting.

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 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.

2) 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.

G. 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 IFRIC 21, according to which the levy payment liability is only recognized upon the occurrence of the event that creates the payment liability (see Section P below).

Asset retirement obligation:

An asset retirement obligation was recorded on the Partnership's books. See Section I below regarding costs in respect of asset retirement obligations.

Note 2 - Significant Accounting Policies (Cont.):

G. Provisions: (Cont.)

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.

H. Expenses of oil and gas exploration, development of proved reservoirs and investment in oil and gas assets:

The Partnership's accounting policy in respect of the treatment of investments in oil and gas exploration is the "successful efforts" method, whereby:

1) 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.

2) Investments in reservoirs before they are proven uncommercial, were classified as "exploration and appraisal assets", and are presented at cost (see Note 7 below).

3) 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.

4) 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 Section I below), are amortized to the statement of comprehensive income as specified in Paragraph 5 below.

5) 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 accordance with the depreciation based on 2P, 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.

6) 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 Section J below).

Note 2 - Significant Accounting Policies (Cont.):

I. 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 H5 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.

J. Impairment of non-financial assets:

For the purpose of examination of impairment, a cash-producing unit is comprised of all of the Partnership's investments in the single reservoir.

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.

K. Recognition of revenues:

The Partnership recognizes revenues from the sale of natural gas and condensate when the customer obtains control of the promised goods. The income is measured according to the amount of consideration to which the Partnership expects to be entitled in exchange for the transfer of the goods transferred to the customer, other than amounts collected for the benefit of third parties, such as the entitlement of the state, interested parties and third parties to receive royalties as a certain percentage of that income. A contract for the sale of natural gas and/or condensate includes a series of distinct goods that are in fact identical and have the same pattern of transfer to the customer. Therefore, they are identified as a single performance obligation. Income from the sale of natural gas and/or condensate is recognized throughout the term of the contract since the end customer receives and consumes the supplied goods at the same time.

Note 2 - Significant Accounting Policies (Cont.):

L. 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 its 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 H1(e) above. The estimated gas quantity in the proven and probable reservoirs in the reported period is determined on an annual basis, according to the opinions of independent external experts on the evaluation of reserves in oil and gas reservoirs. Evaluation of the proved 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.

Note 2 – Significant Accounting Policies (Cont.):

L. Critical accounting estimates and judgements (Cont.):

Oil 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 oil 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 19C below). In accordance with the estimates made by the Partnership, as of 31 December 2023, 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 the 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.

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 assets, management judgment is required to determine the amount of deferred tax 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.

M. 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;

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.

Note 2 – Significant Accounting Policies (Cont.):

M. Fair value (Cont.):

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.

N. 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.

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**").

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.

O. Taxes on income:

In 2021 an amendment to the Income Tax Regulations was published, changing the tax regime that applies to the Partnership from the tax year 2022, such that it is taxed as a company (see Note 19A below). In view thereof, the Partnership recognized, for the first time as of 30 September 2021, a deferred tax liability for temporary differences that were reversed after 1 January 2022. In addition, 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.

Note 2 – Significant Accounting Policies (Cont.):

O. Taxes on income (Cont.):

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.

P. Oil and gas profit levy:

The Partnership includes, in its financial statements, expenses in respect of its levy payment liability under the Taxation of Profits and Natural Resources Law. The Levy is calculated for each project separately. The Partnership recognized as an asset the payment of a levy due to the Tamar Project that exceeds the amount of the expected provision for the levy.

Q. Leases:

The Partnership reached the conclusion with respect to the contracts in which the Operator engages in the context of the joint ventures, 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 (head lease or sub-lease) vis-à-vis the Operator or the lessors according to the provisions of IFRS 16.

R. Initial implementation of new financial reporting standards and amendments to existing accounting standards

1. Amendment to IAS 1 regarding disclosure on accounting policy

   In these financial statements, the Partnership is applying for the first time the amendment to IAS 1: "Presentation of Financial Statements". According to the amendment, the Partnership includes a disclosure on material accounting policies in lieu of the previously-required disclosure on significant accounting policies.

   The amendment defines an accounting policy as material when it can reasonably be expected that a disclosure on this policy, combined with the additional information contained in the financial statements, would influence the decisions made by the principal users of the financial statements based thereon. The amendment also clarifies that information about the accounting policy is expected to be material if without it, the users of the financial statements would be denied the possibility of understanding other material information in the financial statements. The amendment further clarifies that there is no need to disclose information about non-material accounting policies. This amendment was implemented in these financial statements.

2. Amendment to IAS 12 on Deferred Taxes related to Assets and Liabilities arising from a Single Transaction

   This amendment clarifies that the exemption from the recording of deferred taxes resulting from the initial recognition of an asset or a liability in certain transactions does not apply to transactions, the initial recognition of which creates the same amounts of taxable temporary differences and deductible temporary differences, such as lease transactions in which the lessee recognizes a right-of-use asset in an amount equal to the liability for the lease. The effect of implementing the amendment is not material to the Partnership.

Note 2 – Significant Accounting Policies (Cont.):

R. Initial implementation of new financial reporting standards and amendments to existing accounting standards (Cont.)

3. Amendment to IAS 8 on Definition of Accounting Estimates
   This amendment clarifies how entities should distinguish between changes in accounting policies and changes in accounting estimates and is applied prospectively as of 1 January 2023. This change did not have a material effect on the Partnership's financial statements.

4. Amendment to IAS 12 on the OECD-BEPS Pillar Two international tax reform
   In May 2023, the IASB published an amendment to IAS 12, Income Taxes (in this section: the "**Amendment**"), following the OECD-BEPS - Pillar Two international tax reform ("**Pillar 2**" or the "**International Tax Reform**").
   The Amendment introduces:
   (a) A mandatory temporary exception from the application of the requirements in IAS 12 to recognize and disclose deferred tax assets and liabilities arising from the adoption of the Pillar 2 rules ("**Temporary Exception**"); and
   (b) Targeted disclosure requirements for multinational entities affected by the international tax reform.
   The Temporary Exception stated in section (a) above applies immediately, and it is required to give a disclosure about the application thereof. The other targeted disclosure requirements, mentioned in section (b) above, apply to annual reporting periods beginning on or after 1 January 2023, but do not apply to periods ending on or before 31 December 2023.
   The Partnership implements the Temporary Exception, and therefore, no disclosure has been made and no deferred tax assets and liabilities resulting from the adoption of the Pillar 2 rules have been recognized. Also, the aforementioned Amendment is not expected to have a material effect on the Partnership's financial statements.

S. Disclosure on new regulations in the period preceding their application:

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:

- 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.

Notes to the Financial Statements as of 31 December 2023 (Dollars in millions)

Note 2 – Significant Accounting Policies (Cont.):

S. Disclosure on new regulations in the period preceding their application: (Cont.)

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 1 January 2024. Earlier application is permitted. The amendments will be retroactively implemented.

The aforementioned Amendment is not expected to have a material effect on the Partnership's financial statements.

Note 3 – Cash and Cash Equivalents:

Composition:

	Interest rate as of 31.12.2023	31.12.2023	31.12.2022
In Dollars:	%		
Cash in banks		0.9	19.8
Deposits in banks	4.85-5.78	27.6	-
		28.5	**19.8**
In ILS:			
Cash in banks		0.3	0.2
Deposits in banks	1.8	0.3	2.4
		0.6	2.6
Total		**29.1**	**22.4**

Note 4 – Short-Term and Long-Term Deposits[2]:

Composition:

	Interest rate as of 31.12.2023	31.12.2023	31.12.2022
	%		
Under current assets:			
in dollars	4.85-6.00	157.4	395.7
in ILS		0.2	0.2
		157.6	**395.9**
Under non-current assets:			
in dollars	4.81	**101.9**	**0.5**

[2] With respect to pledges and guarantees, see Note 12J.

Notes to the Financial Statements as of 31 December 2023 (Dollars in millions)

Note 5 – Trade and Other Receivables:

Composition:

	31.12.2023	31.12.2022
Trade and other receivables in the context of joint ventures	27.1	46.5
Receivables from a company accounted for at equity (see Note 21G3 below)	10.6	1.3
Loan to Energean in the context of the sale of the Karish and Tanin leases (see Note 8B below)	46.2	12.9
Royalties based on future production from the Karish and Tanin leases (see Note 8B below)	71.7	66.4
The Ministry of Energy due to royalties (see Notes 12B and 15)	18.5	-
Interested parties due to overriding royalties (see Notes 12B and 15)	2.6	-
Third party due to overriding royalties (see Notes 12B and 15)	5.7	-
Prepaid expenses and other receivables	4.7	7.0
Total	**187.1**	**134.1**

Note 6 – Investment in a Company Accounted for at Equity:

A. EMED Pipeline B.V. ("**EMED**" or the "**Company Accounted for at Equity**") was established in July 2018, and its operations began in September 2019. As of 31 December 2023, the Partnership holds 25% (31 December 2022: identical) of the issued and paid-up capital of EMED.

B. Following is condensed financial information regarding the investment of the Partnership in the Company Accounted for at Equity:

	31.12.2023	31.12.2022
Cost of investment	75.0	75.0
Accrued losses	(16.6)	(15.3)
Total	**58.4**	**59.7**

C. 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:

	31.12.2023	31.12.2022
Assets	521.0	555.4
Liabilities	(287.6)	(316.7)

	For the year ended		
	31.12.2023	31.12.2022	31.12.2021
Loss before tax	(5.5)	(12.3)	(17.9)
Comprehensive Loss	(5.3)	(12.4)	(18.0)

Notes to the Financial Statements as of 31 December 2023 (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[3]	Total
Cost			
Balance as of 31 December 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 31 December 2022	**127.6**	**2,927.6**	**3,055.2**
Changes during 2023:			
Investments	29.5	139.4	168.9
Write-offs	-	(1.2)	(1.2)
Balance as of 31 December 2023	**157.1**	**3,065.8**	**3,222.9**
Accumulated amortization[4]			
Balance as of 31 December 2021	**-**	**432.4**	**432.4**
Changes during 2022:			
Depreciation and amortizations[5]	-	75.6	75.6
Balance as of 31 December 2022	**-**	**508.0**	**508.0**
Changes during 2023:			
Depreciation and amortizations[5]	-	67.7	67.7
Write-offs	-	(0.1)	(0.1)
Balance as of 31 December 2023	**-**	**575.6**	**575.6**
Amortized cost as of 31 December 2022	**127.6**	**2,419.6**	**2,547.2**
Amortized cost as of 31 December 2023	**157.1**	**2,490.2**	**2,647.3**

[3] Including the balance of asset retirement amortized cost as of the date of the statement of financial position in the sum of approx. $32.2 million (31 December 2022: approx. $29.7 million).
[4] In 2023, the depreciation rate in the Leviathan project was ~2,5% (2022: 3%).
[5] In 2023, the amount excludes an update in connection with an oil and gas asset retirement obligation in the Yam Tethys project in the amount of approx. $(3.3) million (2022: in the amount of approx. $30.1 million) recorded directly in the statement of comprehensive income.

Notes to the Financial Statements as of 31 December 2023 (Dollars in millions)

Note 7 – Investments in Oil and Gas Assets (Cont.):

A. Composition (Cont.):

2. Composition by joint ventures:

	31.12.2023	31.12.2022
Oil and gas assets:		
Ratio-Yam joint venture (Section C1)	2,490.2	2,419.6
Exploration and appraisal assets:		
Block 12 Cyprus (Section C2)	157.1	127.6
Total	**2,647.3**	**2,547.2**

B. Details on the Partnership's rights in oil and gas assets and in exploration and appraisal assets (as of 31 December 2023):

	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%

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 C11 below and as to pledges registered on part of the oil and gas assets see Note 10B.

Note 7 – Investments in Oil and Gas Assets (Cont.):

C. The Partnership's oil and gas exploration business:

1. Joint Venture "Ratio Yam":

a) Joint Venture "Ratio Yam" is a venture for the 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 the "**Leviathan Leases**").

b) Plan for development of the Leviathan reservoir:

On 2 June 2016, the development plan was approved by the Petroleum Commissioner at the Ministry of Energy (the "**Commissioner**"). This plan, which is divided into two phases (Phase 1 – First Stage and Phase 1 – Second Stage), includes the supply of natural gas to the domestic market and for export of a total volume of up to ~21 BCM per year, and the supply of condensate to the domestic market (in this section: the "**Development Plan**" or the "**Plan**"). According to the Plan, a production system will be built that includes up to 8 first wells that will be connected by a subsea pipeline to a permanent platform, which is located in the territorial waters of Israel in accordance with the provisions of NOP 37/H and on which the gas and condensate processing systems will be installed. Gas will be piped from the Platform to the shore to the northern 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 will be connected to an existing fuel pipeline of Europe Asia Pipeline Co. ("**EAPC**"), which leads to the container site of PEI and from there to 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 the piping of condensate to ORL is not possible.

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

1. **Phase 1 - First Stage** – the current stage, in which 4 first subsea production wells were drilled, a subsea production system was built, which connects the production wells with the platform, and a transmission system to the shore and related onshore facilities were built. At this point, the gas production capacity is ~12 BCM per year.

   On 23 February 2017, the Leviathan Partners adopted the final investment decision (FID) for the development of Phase 1 – First Stage, with a budget of approx. $3.75 billion (100%). The total cost invested in the development of Phase 1 - First Stage, as of 31 December 2023, is approx. $4.1 billion (100%). After a preliminary running-in period, on 31 December 2019, the piping of natural gas from the Leviathan reservoir commenced. On 1 January 2020, the sale of natural gas from the Leviathan reservoir to Jordan began, under the agreement with NEPCO (as specified in Note 12C2 below) and on 15 January 2020, the piping of natural gas from the Leviathan reservoir to Egypt began under the agreement with Blue Ocean (as specified in Note 12C3 below).

   In June 2023, an additional fifth production well, Leviathan-8, was connected to the existing subsea production system of the Leviathan project and production began therefrom, on schedule and on budget.

Note 7 – Investments in Oil and Gas Assets (Cont.):

C. The Partnership's oil and gas exploration business (Cont.):

1. The Ratio-Yam joint venture (Cont.):

c) (Cont.)

1. (Cont.)

In addition, to increase the gas production capacity to ~14 BCM per year from mid-2025, the Leviathan Partners adopted a final investment decision (FID) on 29 June 2023 to carry out a project in which a third subsea transmission pipeline will be laid from the field to the platform, and improvements on the platform will be upgraded (the "**Third Pipeline**") with a total budget of approx. $568 million (100%, the Partnership's share – approx. $258 million).

Phase 1 - Second Stage – expected to include, *inter alia*, 3 additional production wells, insofar as required, related subsea systems and expansion of the platform's processing facilities to increase the system's total gas production capacity to a total of up to ~21 BCM per year.

As of the date of approval of the financial statements, the Leviathan Partners are promoting the development of Phase 1 – Second Stage as aforesaid, with the aim of adopting a final investment decision (FID). This plan includes modular expansion of infrastructures for the piping of natural gas from the Leviathan reservoir, as aforesaid, and may also include the laying of a fourth subsea transmission pipeline from the field to the platform (the "**Fourth Pipeline**"), to allow a maximum daily production capacity of ~2,350 MMCF (~21 BCM per year) and supply to consumers in the domestic market and in the regional market, and primarily the Egyptian and LNG markets.

2. On 21 June 2023 and 21 December 2023, the partners in the Leviathan project submitted an in-principle application to the Commissioner to approve an increase in the natural gas export volume produced from the Leviathan project, according to the Government resolution applicable to the export of gas from the Leviathan reservoir, via an existing and future regional pipeline or via an FLNG facility, in addition to an increase in the volumes of natural gas which will be piped from the Leviathan project to the domestic market. As of the date of approval of the financial statements, a formal response to the Partnership's application has yet to be received from the Ministry of Energy, and there is no certainty that it will be granted, and if so – on what terms.

3. In the context of promotion of Phase 1 – Second Stage, the Leviathan Partners approved, in 2023 and 2024, in accordance with the joint operating agreement, budgets in the sum total of approx. $44.9 million and approx. $19.9 million (100%, the Partnership's share – approx. $20.4 and approx. $9 million), respectively, for performance and completion of pre-FEED of the alternatives for expansion of the Leviathan reservoir's production system, including the construction of subsea infrastructures, connection of additional production wells, and performance of the required changes on the platform. As of the date of approval of the financial statements, the pre-FEED phase has completed, and in the estimation of the Operator, commencement of the FEED stage is expected mid-2024.

Note 7 – Investments in Oil and Gas Assets (Cont.):

C. The Partnership's oil and gas exploration business (Cont.):

1. The Ratio-Yam joint venture (Cont.):

c) (Cont.)

3. (Cont.)

In addition, in the said years, the Leviathan Partners approved budgets in the sum total of approx. $51.5 million and approx. $11.4 million (100%, the Partnership's share – approx. $23.4 and $5.2 million), respectively, for the performance of pre-FEED to examine the various alternatives for the export of natural gas, *inter alia*, through the construction of an FLNG facility. In this regard it is noted that in the context of exploring the option of constructing an FLNG facility, indications have been received that point to a substantial change in the estimated costs of constructing an FLNG facility, and therefore, in 2024, the Leviathan Partners intend to review additional options of constructing an FLNG facility, *inter alia*, in view of the option for the modular development of the Leviathan project.

4. In the estimation of the Operator in the Leviathan project, before performance of the FEED, the estimated cost of Phase 1 – Second Stage (excluding the costs of the Fourth Pipeline and an FLNG facility, insofar as it is decided to approve them) is approx. $2.4 billion (100%, the Partnership's share – approx. $1.09 billion), insofar as a FID is adopted for the development of Phase 1 - Second Stage during H1/2025, the estimated timeframe for first gas production is expected between mid-2028 and mid-2029.

5. Additional production wells will be required during the years of operation 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.

d) Evaluation of reserves and contingent resources in the Leviathan Leases:

In March 2024, 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 31 December 2023. According to the report, the overall quantity of natural gas and condensate resources in the best estimate is assessed at ~608.1 BCM and ~47.3 million barrels, respectively, and is divided into categories of resources classified as reserves or contingent resources.

The quantity of the proved reserves is ~381.5 BCM and the quantity of the proved + probable reserves is ~429.6 BCM.

Additionally, the proved condensate reserves are ~29.6 million barrels, and the quantity of proved + probable reserves is ~33.4 million barrels.

Note 7 – Investments in Oil and Gas Assets (Cont.):

C. The Partnership's oil and gas exploration business (Cont.):

1. The Ratio-Yam joint venture (Cont.):

d) 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 were 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 ~298.7 BCM (high estimate) and ~58.1 BCM (low estimate). The quantity of contingent condensate resources ranges between ~23.2 million barrels (high estimate) and ~4.5 million barrels (low estimate). See Section 10 below on uncertainty in the evaluation of reserves.

e) Deep Targets:

In 2019, an analysis was performed of reprocessing of seismic surveys, *inter alia* in connection with exploration drilling to the deep targets in the Leviathan Leases (the "**Data Reprocessing**"), as a result of which a new 'isolated carbonate buildup' deep target was defined in the area of the Leviathan Leases. In addition, the analysis of the Data Reprocessing revealed that it is necessary to reclassify and redefine the two deep targets which were previously defined in the area of the lease as a single 'submarine clastic channel' target.

In January 2020, a report on evaluation of prospective resources in the Leases was received from NSAI, updated as of 31 December 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 31 December 2023, the details presented in the aforesaid report remain unchanged. See Section 10 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.

2. Block 12 in Cyprus:

The Partnership has a production sharing contract (PSC) (the "**PSC**"), whereby the Partnership holds 30% of the rights in the Aphrodite reservoir in Block 12, which is in the area of the EEZ of Cyprus.

Note 7 – Investments in Oil and Gas Assets (Cont.):

C. The Partnership's oil and gas exploration business (Cont.):

2. Block 12 in Cyprus (Cont.):

a) On 7 November 2019, the right holders in the PSC (in this section: the "**Partners**") and the Government of Cyprus signed an amendment to the PSC (the "**First Amendment to the PSC**"), in the framework of which, other changes and updates were made, *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.
Concurrently the Partners were granted an exploitation license (the "**Exploitation License**"), and a development and production plan was approved for the reservoir (the "**Development Plan**").
Further to the aforesaid, on 9 November 2022, an additional amendment to the PSC was signed extending the Partner's commitment to drill another A-3 appraisal/development well (Aphrodite 3) (the "**A-3 Well**") and terminate the same until August 2023 (the PSC and the amendments thereto as aforesaid will be jointly referred to as the "**Additional Amendment to the PSC**").

b) 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 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).
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 an FID being 6 years after the date of receipt of the Exploitation License, namely until November 2025.

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).

c) 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 20D.

d) The Aphrodite reservoir development plan, as approved by the Cypriot government on 7 November 2019, 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 (the "**Floating Production Facility**"), through 5 first production wells, and a subsea system for transmission to the Egyptian market (the "**Approved Plan**").

Note 7 – Investments in Oil and Gas Assets (Cont.):

C. The Partnership's oil and gas exploration business (Cont.):

2. Block 12 in Cyprus (Cont.):

d) (Cont.)

Further to the Partners in the Aphrodite reservoir exploring additional development alternatives, with the aim of reducing the development costs and shortening the timeframe to commencement of production of gas from the reservoir, *inter alia* by integration with existing facilities and/or development plans of nearby assets in Egypt, on 31 May 2023 the Partners submitted, for the Cypriot government's approval, an updated plan for the development of the reservoir, which includes a change to the outline of the Approved Plan, according to which the production and processing of natural gas from the Aphrodite reservoir will be performed through the construction of a subsea pipeline and connection thereof to existing offshore and onshore infrastructure in Egypt, in lieu of the construction of a floating production facility above the reservoir, which was included in the Approved Plan (the "**Changes Plan**"). However, the Cypriot government decided not to approve the Changes Plan, *inter alia* because it is expected, according to the Cypriot government, to increase the technical and commercial complexity of development of the reservoir and is not expected to reap the advantages claimed in the Changes Plan. Therefore, the Partners were required to meet the FEED Execution Milestone which was determined in the PSC for 7 November 2023, in accordance with the Approved Plan, including the construction of the Floating Production Facility in the area of the reservoir. By the date of approval of the financial statements, the binding work plan for Block 12 was fulfilled in full, except in connection with the FEED Execution Milestone.

In the context of meetings and letters exchanged with the Cypriot government, the Minister of Energy at the Cypriot government authorized the Partners to submit a proposal for an optimal development plan, for his approval, by 31 March 2024, such that if and insofar as the minister approves the same, the date for meeting the milestone will be postponed, in the minister's discretion. The minister also clarified to the Partners that the Republic of Cyprus reserves all of its rights under the PSC in relation to missing the Feed Execution Milestone. As specified in Section 2B2 above, Failure to reach a milestone set in the conditions of the PSC may, subject to specific terms and conditions, confer on the Cypriot government a cause for termination of the PSC and the license.

As of the date of approval of the financial statements, Chevron Cyprus is continuing to hold discussions with the Cypriot government regarding an optimal development plan for the reservoir, including in connection with re-examination of the Cypriot government's demand to build the Floating Production Facility and in connection with the timetable for meeting the Feed Execution Milestone. However, there is no guarantee that the Cypriot government will approve any changes to the details of the Approved Plan and in such a case, the government may impose sanctions against the Partners in accordance with the provisions of the PSC.

Note 7 – Investments in Oil and Gas Assets (Cont.):

C. The Partnership's oil and gas exploration business (Cont.):

2. Block 12 in Cyprus (Cont.):

d) (Cont.)

In accordance with Chevron Cyprus' estimation, which was provided to the Partnership and the Cypriot government, and before completion of technical-financial feasibility studies, including the FEED, the estimated cost of the approved development plan, which includes the construction of a floating production facility above the reservoir, including the cost of installing the pipelines to the target markets, was estimated in 2022 at approx. $3.6 billion (100%, the Partnership's share – approx. $1.1 billion). It is emphasized that formulating the development plan and adopting a final investment decision for development of the Aphrodite reservoir are subject, *inter alia*, to the update of the approved development plan, execution 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 precedent are fulfilled, the supply of natural gas from the Aphrodite reservoir may begin in 2028 at the earliest.

e) In accordance with the terms and conditions of the PSC, on 15 September 2022, the Partners approved a budget for the drilling of the A-3 Well in the sum of $130 million (100%, the Partnership's share – approx. $39 million). The A-3 Well is an appraisal well whose purpose is to corroborate the estimates of the Operator and the Partnership regarding the nature and scope of the reservoir, and which is designed to be used in the future as a production well. The drilling of the A-3 Well began in May 2023 and was completed in July 2023, on schedule and on budget.

f) On 21 September 2022, the general meeting of the unit holders approved a decision not to distribute profits, for purposes of investment in Block 12.

g) Following completion of the drilling of the A-3 appraisal well in September 2023 a report was prepared 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 31 August 2023, ranges between ~126 BCM (the high estimate) and ~74 BCM (the low estimate). According to the aforesaid report, the amount of the contingent condensate resources in the Aphrodite reservoir, classified under the "Development Pending" stage as of 31 December 2023, range between ~10.6 million barrels (the high estimate) and ~5.1 million barrels (the low estimate). As of 31 December 2023, the details specified in the aforesaid report were not changed. See Section 10 below with respect to uncertainty in the evaluation of reserves.

h) As of the date of approval of the financial statements, a temporary budget has been approved by the Partners in Block 12 for 2024 in the sum of approx. $29 million (100%, the Partnership's share – approx. $8.7 million), which will later be updated according to agreements that shall be reached by the partners in the Aphrodite reservoir with the Cypriot government.

Note 7 – Investments in Oil and Gas Assets (Cont.):

C. The Partnership's oil and gas exploration business (Cont.):

2. Block 12 in Cyprus (Cont.):

i) 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 Ishai/370 license (the "**Iishai 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 Iishai 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 9 March 2021, such governments signed an MOU which instructs the partners in the Aphrodite reservoir and the holders of the rights in the Iishai 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 Ministry of Energy 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. On 11 April 2022, the Israeli Ministry of Energy announced that the Israeli and Cypriot ministers of energy had agreed on the appointment of an external expert to examine the quantity of natural gas in the reservoir and determine the division between the EEZs of Israel and Cyprus. On 29 January 2024, talks were held between the Israeli and Cypriot ministers of energy, in which it was agreed to intensify the inter-government efforts to resolve the issue as soon as possible.

3. The Yam Tethys joint venture:

The Yam Tethys joint venture is located in the areas of the Ashkelon and Noa leases. Production of the natural gas from the Yam Tethys project 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 23 July 2012 between the Partnership together with the other Yam Tethys partners and the Tamar partners (see Section (a) below). On 3 May 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 reservoir, 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).

Note 7 – Investments in Oil and Gas Assets (Cont.):

C. The Partnership's oil and gas exploration business (Cont.):

3. The Yam Tethys joint venture (Cont.):

The consideration determined in the Agreement is the average monthly price of the Leviathan project from sales of natural gas. 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 Leviathan customers 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. On 30 June 2023 the last agreement for the sale of gas in the Yam Tethys project was terminated and accordingly the aforementioned Agreement was also terminated.

a) Agreement for the grant of usage rights in the facilities of the Yam Tethys Project:

On 23 July 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 Project the Partnership assigned the buyers its interests in the Usage Agreement as partners in the Tamar Project (see Section 9B below).

The 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:

As of the date of approval of the financial statements, all of the project's wells are plugged and abandoned according to the directions of the Commissioner.

Upon receipt of all the required approvals, in 2021, the Operator began the decommissioning of all of the project facilities, other than the platform.

At the same time, a discussion is being held with respect to possible future uses and/or decommissioning 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.

Note 7 – Investments in Oil and Gas Assets (Cont.):

C. The Partnership's oil and gas exploration business (Cont.):

3. The Yam Tethys joint venture (Cont.):

b) (Cont.):

The budget for the decommissioning of the Yam Tethys facilities other than the platform and the onshore terminal, as 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. $277 million (100%, the Partnership's share - approx. $134 million).

As of the date of the financial statements, the Yam Tethys partners incurred approx. $273 million with respect to such abandonment (100%, the Partnership's share - approx. $132 million).

4. The Boujdour License in Morocco:

On 6 December 2022, the Partnership, jointly with Adarco Energy Limited[6] ("**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**")[7], 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 grant each of the Partnership and Adarco 37.5% of the interests[8] in the License, with the remaining interests in the License, the rate of which is 25%, granted to ONHYM, in accordance with existing regulation in Morocco. On 1 June 2023, NewMed Energy UK Limited (formerly 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 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 also bear, in addition to their relative share of the costs, the costs in respect of ONHYM's share, in accordance with the existing regulation in Morocco.

[6] Adarco has informed the Partnership that Adarco is a company controlled by Mr. Yariv Elbaz (a Moroccan investor) and members of his family.

[7] The License includes *de facto* 17 areas of different licenses.

[8] 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 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).

Note 7 – Investments in Oil and Gas Assets (Cont.):

C. The Partnership's oil and gas exploration business (Cont.):

4. The Boujdour License in Morocco (Cont.):

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.

On 2 January 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, and to approve refrainment from distribution of profits 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.

In December 2022, the Partnership provided a bank guarantee in the sum of approx. \$1.75 million (100%) in favor of ONHYM.

Furthermore, 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.

5. Exploration licenses in zone "I" in the area of blocks 4, 5, 6, 7, 8 and 11 in the EEZ of the State of Israel.

On 29 October 2023, the Commissioner gave the Partnership, the State Oil Company of Azerbaijan Republic ("**SOCAR**"), and BP (in this section, collectively, the "**Partners**"), a notice of winning of the bid they submitted in connection with the licenses in zone "I", as part of the fourth competitive process for natural gas exploration in the northwest area of Israel's EEZ, entitling them to receive 6 exploration licenses in blocks 4, 5, 6, 7, 8, and 11, located in the Mediterranean Sea, in the area of Israel's EEZ (in this section: the "**Licenses**"). The holding rate in the joint venture of the Partnership's and BP's is 33.33% each, and Socar's is 33.34%.

The Partners are continuing to comply with the terms and conditions of an agreement which regulated, *inter alia*, the terms of the said bid and also determined principles for the joint operating agreement which is expected to be signed after the Licenses are granted.

Completion of the process of issuance of the Licenses to the Partners, in accordance with the provisions of the Petroleum Law, the regulations and the terms and conditions of the competitive process, is subject, *inter alia*, to the provision of a guarantee in the sum of \$5 million (100%, the Partnership's share – approx. \$1.7 million) and payment of a signature bonus to the Ministry of Energy in the sum of approx. \$5 million (100%, the Partnership's share – approx. \$1.7 million), by 28 December 2023.

Note 7 – Investments in Oil and Gas Assets (Cont.):

C. The Partnership's oil and gas exploration business (Cont.):

5. Exploration licenses in zone "I" in the area of blocks 4, 5, 6, 7, 8 and 11 in the EEZ of the State of Israel (Cont.):

On 18 December 2023, the general meeting of the unit holders approved the Partnership's participation in oil and/or natural gas exploration and production in the area of the License and to approve refrainment from the distribution of profits for the purpose of investment in actions in the area of the Licenses, in accordance with the work plans as shall be approved by the Partners in the Licenses from time to time. In December 2023, the Partners provided the guarantee and paid the signature bonus, as aforesaid.
In the Partnership's estimation, the process of issuance of the Licenses to the Partners is expected to be completed during Q2/2024.

6. Alon-D License (in this section: the "License"):

On 21 June 2020, the License expired after requests to extend it were denied by the Commissioner. On 26 November 2023, the Supreme Court, sitting as the High Court of Justice, dismissed a petition filed by the partners in the License against the Minister of Energy and others in connection with their interests in the Alon D license, ruling that the petitioners were not entitled to extension or renewal of the License.
Due to the expiration of the License, the Partnership and Chevron (the "**Bidders**"), which were the partners in the License, submitted a bid in the competitive process announced by the Ministry of Energy on 23 June 2020 for the granting of a license for natural gas and oil exploration in Block 72, the area of which shares a significant overlap with the area where the License extended ("**Block 72**"), which scored the highest. On 10 January 2021, the Concentration Committee announced its recommendation not to allow the Bidders to win the competitive process in view of competition in the natural gas sector and economy-wide concentration considerations. Consequently, the Bidders approached the Commissioner requesting that the recommendation of the Concentration Committee not be taken into account as it is deficient, inaccurate and disregards material facts. As of the date of approval of the financial statements, the Commissioner's decision on the competitive process with respect to Block 72 has not yet been received. Part of Block 72 is located in an area in which the exploration rights have been transferred to Lebanon in the context of the Maritime Agreement with Lebanon, as specified below.
On 27 October 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 thereto, the State of Israel and the consortium of international companies that hold the exploration license in block 9 in Lebanon, which borders Block 72 in Israel, signed an MOU relating to Israel's economic interests in the event of a discovery in block 9. To the best of the Partnership's knowledge, in October 2023, the Consortium reported that in the first well that was drilled in the area of block 9, no commercial discovery was made.

Note 7 – Investments in Oil and Gas Assets (Cont.):
C. The Partnership's oil and gas exploration business (Cont.):

7. **New Ofek/405 ("Ofek") and New Yahel/406 ("Yahel") Licenses:**

   On 19 March 2019, the Partnership entered into an agreement with S.O.A. Energy Israel Ltd (in this section: 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.
   On 22 May 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 plugging and abandonment of the well, and that it does not intend to support any proposal to extend the term of the license, towards the expiration date of the license. On 20 June 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.
   On 12 March 2024, the partners in the Ofek license received a letter from the Commissioner, according to which the Operator is required to complete abandonment of the well and the site by the earlier of: (a) three months after expiration of the declaration on special home front conditions; and (b) 31 August 2024.

8. **Eran license:**

   The Eran license expired on 14 June 2013. Following the decision of the Commissioner not to extend the Eran license, on 3 October 2013, the holders of the interests in the Eran license (including the Partnership that held approx. 45.34% of the interests in the license) submitted an appeal to the Minister of Energy from the decision of the Petroleum Commissioner as aforesaid. On 10 August 2014, the Minister of Energy denied such appeal.
   On 17 November 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 2 June 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 20 March 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 11 April 2019, a judgment was entered on the mediation arrangement agreed to by the parties, as aforesaid.
   Negotiations are 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.

Note 7 – Investments in Oil and Gas Assets (Cont.):

C. The Partnership's oil and gas exploration business (Cont.):

9. 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**" and/or "**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, on 2 September 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[9] (in this section: the "**Buyers**" and the "**Agreement**", as applicable). On 9 December 2021, the transaction was closed and the Partnership received the sale proceeds in the sum of approx. $955[10] 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 export agreements and export permits from Jordan 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 1 August 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.

[9] 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.

[10] See footnote 5 above.

Note 7 – Investments in Oil and Gas Assets (Cont.):

C. The Partnership's oil and gas exploration business (Cont.):

9. 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 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). 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).

Note 7 – Investments in Oil and Gas Assets (Cont.):

C. The Partnership's oil and gas exploration business (Cont.):

9. The Michal-Matan joint venture (discontinued operations) (Cont.):

b. (Cont.)

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 27 April 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 5 May 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 31 December 2023 (Dollars in millions)

Note 7 – Investments in Oil and Gas Assets (Cont.):

C. The Partnership's oil and gas exploration business (Cont.):

9. 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		
	31.12.2023	**31.12.2022**	**31.12.2021**
Revenues:			
From natural gas and condensate sales	-	-	289.8
Net of royalties	2.6[11]	(15.3)[12]	(57.1)
Revenues (expenses), net	**2.6**	**(15.3)**	**232.7**
Costs and expenses:			
Cost of natural gas and condensate production	-	0.4	(29.7)
Depreciation, depletion and amortization expenses	-	-	(7.2)
Other direct expenses	-	-	(0.2)
Total costs and expenses	**-**	**0.4**	**(37.1)**
Operating income (loss) before oil and gas profit levy	2.6	(14.9)	195.6
Oil and gas profit levy	-	(2.1)	(43.9)
Operating income (loss)	**2.6**	**(17.0)**	**151.7**
Financial expenses	-	-	(0.4)
Financial income	-	-	0.4
Financial expenses, net	-	-	-
Income (loss) before income tax	**2.6**	**(17.0)**	**151.7**
Income tax	(0.5)	3.8	-
Profit (loss) from discontinued operations	2.1	(13.2)	151.7
Income from sale of oil and gas assets	-	4.3	144.6
Total profit (loss) from discontinued operations	**2.1**	**(8.9)**	**296.3**
Other comprehensive income from discontinued operations			
Amounts that will not be reclassified in the future 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 (loss) from discontinued operations	**2.1**	**(8.9)**	**309.9**

[11] The amount includes an update of royalties due to the adjustment of the investment return date in accordance with the provisions of Note 12L6 below, an update of royalties to the State and overriding royalties in accordance with the provisions of Note 15b4 below and an update of royalties to the State and overriding royalties in connection with the provisions of Footnote 12.

[12] 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 31 December 2023 (Dollars in millions)

Note 7 – Investments in Oil and Gas Assets (Cont.):

C. The Partnership's oil and gas exploration business (Cont.):

9. 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		
	31.12.2023	**31.12.2022**	**31.12.2021**
Current	(17.3)	4.0	175.2
Investment	-	15.8	841.9
Financing	-	-	-

10. 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.

11. 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 31 December 2023 (Dollars in millions)

Note 8 – Other Long-Term Assets:

A. Composition:

	31.12.2023	31.12.2022
Future production-based royalties from the Karish and Tanin leases (see Paragraph B below)	209.7	256.7
Loan to Energean in the context of the sale of the Karish and Tanin leases (See Paragraph B below)	-	40.7
Ministry of Energy for royalties (see Notes 12B & 15)	15.7	30.5
Interested parties for overriding royalties (see Notes 12B & 15)	1.9	4.1
Third party for overriding royalties (see Notes 12B and 15)	4.3	7.7
Access fees for the Blue Ocean agreement (see Note 12C3)[13]	92.6	100.9
Receivables from a company accounted for at equity (see Note 21G3)	19.5	23.6
Fixed Assets	0.3	0.3
Right-of-use asset for lease	2.5	2.8
Oil and gas profit levy (see Note 19C)	12.6	-
Other long-term assets in the context of joint ventures[14]	111.2	93.0
Total	**470.3**	**560.3**

B. Agreement for the sale of rights in the Karish I/17 and Tanin I/16 leases (in this section: "Leases"):

On 16 August 2016[15], 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[16] 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, which 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 (below 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;

[13] The access fees are amortized in accordance with the length of the period of the Blue Ocean agreement.

[14] 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. $105.9 million (2022: approx. $93.0 million). With respect to the construction of a transmission system from the Leviathan project to Jordan, see Note 12C2 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.

[15] According to the Gas Framework, the Partnership and Chevron were required to sell their entire interests in the Leases.

[16] 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 oil 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 15 April 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 14 January 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). On 29 February 2024 Energean reported that the production from Karish North has begun on 22 February 2024.

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 23 March 2023. According to this report, as of 31 December 2022, the Reservoirs contain natural gas reserves (2P) of ~99.6 BCM and hydrocarbon liquids of ~95.6 million barrels.

Based on Energean's reports of January 2024, the sales forecast for 2024 is expected to be ~5.7 BCM to ~6.4 BCM.

The Partnership engaged with an external independent appraiser in order to assess the fair value of the remaining royalties and Annual Installments as of 31 December 2023. Below are main parameters out of the valuations that were used to measure the royalties and the Annual Installments: cap rate for the Annual Installments is estimated at 7.81% (2022: 6.95%); the cap rate before tax estimated for the royalties component is estimated at 10.88% (2022: 10.5%); the rate of the value of the royalty to the State at the wellhead is 11.06%[17]; gas production from the Karish lease: from 2024 until 2042; forecast average annual production rate from the Karish lease: ~3.64 BCM natural gas; average annual production rate from the Karish lease of ~4.59 million barrels of condensate; dates of gas production from the Tanin lease: starting from 2030 until 2041; forecast average annual production rate from the Tanin lease: ~2.17 BCM natural gas; average annual production rate from the Tanin lease of ~0.37 million barrels of condensate;

[17] The royalty rate at the wellhead is based on the rate of advance payments required by the Ministry of Energy. This rate may change in the future in view of the royalty audit by the Ministry of Energy.

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 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 ~99.6 BCM and ~95.6 MMBBL, respectively.

The update to the valuation derives mainly from the cap rates, a change in the estimations published by Energean regarding the production rate forecast, the price of sale and the lapse of time (see also Note 21F 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 24 March 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 as a result thereof, the periodic payment for 2022 on account of the Loan, scheduled for March 2022, shall be deferred. On 22 September 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 31 May 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% as of the date of the claim. The Partnership's position is that Energean's announcement of 30 April 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. On 10 May 2023, the parties filed a joint motion with the court regarding their consent to defer to a mediation proceeding, without this delaying the litigation of the claim. On 13 August 2023, the court approved an agreed procedural arrangement between the parties, whereby, *inter alia*, a pretrial hearing was scheduled for 7 December 2023. On 5 November 2023, mutual agreements at which the parties had arrived were entered as a judgment, whereby Energean will pay the Partnership, in two installments during 2024, a total amount of approx. $47.4 million, which constitutes the entire balance of the consideration plus agreed annual interest. This constitutes the full and final discharge of the parties' claims in relation to the disputes to which the legal proceeding pertained. Between the date of the claim and the date of the aforesaid arrangement Energean paid the Annual Instalments in September 2022 and in April 2023 a sum of approx. $12.4 million and approx. $13.3 million, respectively.

Notes to the Financial Statements as of 31 December 2023 (Dollars in millions)

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.):

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 Partnership's 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 sale agreement which is subject to the duty to pay royalties. It is the Partnership's position, based on its legal counsel, 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 which is subject to royalties. 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. Until the date of approval of the financial statements, Energean is paying the Partnership royalties due to the condensate which is produced from the Karish lease under protest. Energean reported that production of first gas from the Karish North reservoir started at the end of February 2024.

Note 9 – Trade and Other Payables:

Composition:

	31.12.2023	31.12.2022
Related parties (see Note 20)	0.3	0.5
Related parties for overriding royalties (see Notes 12B and 15)	4.9	6.3
Third parties for overriding royalties (see Notes 12B and 15)	8.7	8.8
Liability for participation unit-based payment (See Note 13H)	-	0.3
Oil and gas profit levy (see Note 19C)	-	4.7
Ministry of Energy in respect of royalties (see Notes 12B and 15)	10.1	11.3
Payables in the context of joint ventures[18]	75.2	58.7
Current maturities for a lease liability (see Note 20E2)	0.3	0.3
Expenses due	0.3	2.9
Trade and other payables	1.3	3.1
Total	**101.1**	**96.9**

[18] Include mainly expenses incurred by the Operator of the joint ventures and not yet paid.

Notes to the Financial Statements as of 31 December 2023 (Dollars in millions)

Note 10 – Bonds, loans 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:

	31.12.2023	31.12.2022
Leviathan Bond (see Section B below)	1,735.1	2,155.8
Net of current maturities	-	(424.8)[19]
Total (net of current maturities)	**1,735.1**	**1,731.0**

2) Maturities by years after the date of statement of financial position:

	Amount	Amortized Cost	Interest	Stated Maturity
Leviathan Bond-2025	600.0	597.7	6.125%	June 2025
Leviathan Bond-2027	600.0	595.0	6.500%	June 2027
Leviathan Bond-2030	550.0	542.4	6.750%	June 2030
Total	**1,750.0**	**1,735.1**		

B. Bonds of Leviathan Bond:

On 18 August 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 30 June and on 30 December.

On 3 August 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**").

[19] Net of buybacks in the sum of approx. $74.6 million as specified in Section C below.

Note 10 – Bonds, loans and credit facilities from banking corporations (Cont.):
B. Bonds of Leviathan Bond (Cont.):

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.

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.

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;

Note 10 – Bonds, loans and credit facilities from banking corporations (Cont.):

B. Bonds of Leviathan Bond (Cont.):

to refrain from modifying or amending the Leviathan Agreements or material Gas Agreements, as defined in the Financing Documents ("**Material Gas Agreements**"), or the royalty agreements or engage in a new royalty agreement; to refrain from approval of certain acts in the context of the JOA; etc.

The Issuer undertook not to take additional financial debt, with the exception of the issue of additional bonds or other secured debt *pari passu*, subject to conditions that were specified, including (i) the sum of the secured debt of the Issuer (including the bonds) does not exceed, at any time, $2.5 billion; (ii) certain financial ratios that were specified in the Financing Documents in relation to the issuance of additional debt as aforesaid are maintained.

In addition, the Partnership undertook not to take any additional financial debt which is secured by the Pledged Assets, with the exception of an additional loan that it shall receive from the Issuer on terms and conditions back-to-back to additional debt that the Issuer shall raise subject to the restrictions set forth therefor in the Financing Documents.

The Partnership undertook not to make any merger transaction or change its business in a manner which would likely cause an material adverse effect ("**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, other than a certain period before the specified repayment date, during which prepayment will not be charged with 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 27 July 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.

Note 10 – Bonds, loans and credit facilities from banking corporations (Cont.):

B. Bonds of Leviathan Bond (Cont.):

The Financing Documents include a payment waterfall mechanism, whereby the Partnership's entire revenues from the Leviathan project is transferred to an account that is pledged in favor of the Trustee (the "**Revenues Account**"), which is used to make various payments in connection with the project and the bonds, including payment of royalties to the State and to the royalty interests owners; payments to the Trustee; taxes and the levy under the Taxation of Profits from Natural Resources Law, 5771-2011 (in this section: the "**Law**"); capital expenses and operating expenses in connection with the Leviathan project; principal and interest payments; deposits into safety cushions; and balancing payments in connection with tax payments under Section 19 of the Law. The transfer of the amounts remaining in the Revenues Account after the making of the said payments to a non-pledged account of the Partnership is subject to conditions determined, including fulfillment of an NPV Coverage Ratio of at least 1.5[20].

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;

[20] The NPV Coverage Ratio was defined as the ratio between the current value of the available cash flow to the debt service (as defined in the Financing Documents) which is 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 of the issuer which is secured by the Pledged Assets net of cash accrued in certain 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, loans and credit facilities from banking corporations (Cont.):

B. Bonds of Leviathan Bond (Cont.):

(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.

On 3 August 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 approval of the financial statements, the Partnership fulfills its undertakings as aforesaid.

On 1 May 2023 a partial prepayment of the first series of the bonds, as described above, whose original maturity date was 30 June 2023, was made according to the terms and conditions of the bonds, for a total of $280 million (out of a total series of $500 million). The outstanding balance of the first series of the bonds was repaid in full and on schedule on 30 June 2023, according to the terms and conditions of the bonds.

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 22 January 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 23 January 2023 and shall end after two years, i.e., on 23 January 2025.

On 15 November 2023, the General Partner's board authorized the continued performance of buybacks in accordance with the buyback plan, from the bond series maturing on 30 June 2025 and/or from the bond series maturing on 30 June 2027. Up to the date of approval of the financial statements, the Partnership made buybacks according to the buyback plan in the sum total of approx. $7.7 million. It is clarified that the said decision does not obligate the Partnership and/or Leviathan Bond to perform a buyback of the bonds, and that the Partnership's management will be entitled to decide not to buy back bonds at all.

D. Credit facilities from banking corporations:

On 5 February 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 6 February 2023 and ending on 6 March 2024.

Note 10 – Bonds and credit facilities from banking corporations (Cont.):

D. Credit facilities from banking corporations (Cont.):

For the non-utilized part of each one of the Credit Facilities, the Partnership paid 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. Each loan utilized from Credit Facility A is bearing 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 30 May 2025.

Each loan utilized from Credit Facility B is bearing SOFR interest plus a margin of 3% per annum, with the principal of the loan, which will be 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 15 February 2023, a one-time commitment fee at a rate of 0.75% of Credit Facility B.

It was further determined that as a perquisite 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 the unpaid balance of all of the loans drawn down from Credit Facilities A and B including the drawdown application, shall not be lower than 200%, and 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 30 June 2025 as defined in the agreement, 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, without the bank’s written and advance consent, 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%. Further grounds for acceleration shall be established upon a cross default with loans of material creditors, in an amount exceeding $15 million. This will not apply to other loans that are limited recourse loans (other than in the event of an acceleration of the Leviathan Bond bonds).

Note 10 – Bonds and credit facilities from banking corporations (Cont.):

D. Credit facilities from banks (Cont.):

In addition, a restriction is in place in connection with a change in the Partnership's business segment (which was broadly defined to include any energy-related business), without the bank's approval. The other covenants are standards and the additional default 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 drawn down funds from the said Credit Facility.

On 9 January 2023, at the Partnership's request, Credit Facility B was terminated. The Partnership had neither used nor drawn a loan from Facility B during the availability period. Furthermore, letters were signed for amendment of the facility agreement whereby the availability period of Credit Facility A would be extended until 31 March 2024. As of the date of signing of the financial statements, the Partnership had drawn down a sum of $80 million from Credit Facility A, which sum was fully repaid in January 2024.

On 14 March 2024, the Partnership signed an agreement with an Israeli bank for the provision of a bank credit facility, which agreement cancels all aforesaid previous facilities, for use by the Partnership in its current activities. According to the terms and conditions of the credit facility, the Partnership may draw down, from time to time, loans in U.S. dollars up to an aggregate amount of $100 million during the availability period commencing on 14 March 2024 and ending on 7 March 2025. As of the date of approval of the financial statements, the Partnership has not yet used the said facility. According to the agreement, the Partnership will pay a quarterly no-use fee at the rate of 0.65% per annum for the unused portion of the credit facility, until its drawdown by the Partnership or the expiration of the availability period, whichever is earlier. Every loan taken out of the credit facility bears SOFR interest plus a margin of 2.5% per annum, with the principal of the loan so drawn due and payable by 15 April 2026.

The provision of the credit facility entails 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 be no less than 1.5 on 2 consecutive testing dates, and that the ratio between surplus sources accumulated until 30 June 2026, and the amount of the credit facility shall be no less than 1, with an amount equal to the balance of the then-undrawn credit facility added to the sources for the purpose of this calculation and being deemed part of such "surplus sources".

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 7C9, 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.

Notes to the Financial Statements as of 31 December 2023 (Dollars in millions)

Note 10 – Bonds and credit facilities from banking corporations (Cont.):

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 31 December 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 12 August 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 31 December 2021 in the sum of approx. $375.4 million.

Note 11 - Other Short-Term and Long-Term Liabilities:

A. Other Long-Term Liabilities:

	31.12.2023	**31.12.2022**
Oil and gas asset retirement obligation (see Note 2I and Section B)	71.3	66.5
Liability due to lease	2.3	2.6
Other	0.1	0.1
Total	**73.7**	**69.2**

B. Transactions in oil and gas asset retirement obligation:

	2023	**2022**
Balance as of 1 January	76.4	122.0
Additions	3.7	24.4
Effect of the passing of time	3.2	1.5
Effect of update of the cap rate and indexation	(2.1)	(19.8)
Amounts incurred for decommissioning of oil and gas assets (see Note 7C3(b) above)	(7.7)	(51.7)
Balance as of 31 December	**73.5**	**76.4**
Net of short-term gas asset retirement obligation (See Note 7C3(b) above)	(2.2)	(9.9)
Total	**71.3**	**66.5**

The cap rate for the measurement of the oil and gas asset retirement obligation as of 31 December 2023 is 6.9% (31 December 2022: 6.7%).

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 1 January 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 21 September 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. 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).

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.)

B. Engagements for the payment of royalties (Cont.):

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 that ended regarding the investment recovery date in the Tamar Project between the Partnership and the Royalty Interest Owners, see Note 12L6 below.
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.
   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 (see also Notes 12P4 and 15 below).

Notes to the Financial Statements as of 31 December 2023 (Dollars in millions)

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.)

C. Engagements for the supply of natural gas:

1. 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[21]:

Customer	Supply commencement date	Agreement period[22]	Total maximum contract quantity for supply (100%) (BCM)	Total quantity supplied until 31 December 2023 (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.	~19.1	~2.3	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. In most of the agreements the parties are not granted an option to extend the agreement period.	~4.2	~0.9	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 Paragraph 2 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.	~45	~10	The linkage formula is based on linkage to the Brent prices and includes a "floor price".
Blue Ocean export agreement (described in Paragraph 3 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.	~60	~16.4	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			**~128**	**~30[23]**	

[21] The figures in the table do not include SPOT agreements for the supply of natural gas from the Leviathan project.
[22] 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.
[23] The total quantity supplied from the Leviathan project by 31 December 2023 (100%) (both under the agreements appearing in the table and both under SPOT agreements and agreements that ended) is ~40 BCM.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.)

C. Engagements for the supply of natural gas (Cont.):

1. 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:

a) In 2023 and until the date of approval of the financial statements, the Partnership signed several SPOT agreements for the sale of natural gas from the Leviathan project with various customers in the Israeli market. During Q4/2023, with the temporary halting of production from the Tamar reservoir following the outbreak of the Iron Swords War, the Leviathan Partners took action to sign such SPOT agreements with all of the relevant customers in the Israeli market to ensure the possibility to supply natural gas to such customers, as required.

b) 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.

c) 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.

d) In accordance with the Gas Framework, each of the buyers, in agreements executed by 13 June 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.):

2. **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 1 January 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.
   On 3 July 2023, the parties agreed to increase the natural gas quantities that would be supplied to NEPCO on a firm basis, temporarily and in relation to a number of months in 2023-2024, and that the minimum annual quantity that NEPCO had undertaken to take or pay for during 2023-2024 would increase accordingly. The aforesaid does not change the total supply volume under the Export to Jordan Agreement (~45 BCM), as specified above.

3. **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**") for the export of natural gas from the Leviathan project to Egypt and on 26 September 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 15 January 2020, the flow of natural gas began in accordance with the Leviathan Agreement.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.)

C. Engagements for the supply of natural gas (Cont.):

3. Agreement for the Export of Natural Gas from the Leviathan Project to Blue Ocean in Egypt (Cont.):

Below is a summary of the details and terms and conditions of the Leviathan export agreement:

a) 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**").

b) The supply of gas began on January 15, 2020, and will be until 31 December 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.

c) The Leviathan Partners undertook to supply the Buyer with annual gas quantities as follows: (i) in the period that commenced on 15 January 2020 and ended on 30 June 2020, ~2.1 BCM per year; (ii) in the period that commenced on 1 July 2020 and ended 30 June 2022, ~3.6 BCM per year; and (iii) in the period commencing 1 July 2022 and ending on the end of the Term of the Leviathan Agreement, ~4.7 BCM per year. Furthermore, the Levithan Agreement includes provisions with respect to the possibility of piping additional gas quantities, over and above the aforesaid daily quantities, on a spot basis. 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 12M below.

d) 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 E below, Blue Ocean's right to reduce the take-or-pay quantity as aforesaid will be revoked (see Note 12L7 below regarding a claim and a motion for class certification thereof which was filed against the Partnership in connection with such clause). Also, in connection with the Buyer's undertaking to take or pay, the agreement stipulates, among other things, instructions and a mechanism that allow the Buyer, after having consumed the minimum billable quantity for a certain year, to receive gas supply in that year without additional payment up to the balance of the amount of gas that was not consumed in previous years and for which it paid the sellers as part of the take-or-pay obligation (make up mechanism), as well as instructions and a mechanism that allow the Buyer to accumulate quantities purchased in any year above the minimum quantity, and use them to reduce the Buyer's obligation (carry forward mechanism).

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.)

C. Engagements for the supply of natural gas (Cont.):

3. Agreement for the Export of Natural Gas from the Leviathan Project to Blue Ocean in Egypt (Cont.):

e) 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.

f) 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.

g) To facilitate an increase in the export quantities to Egypt, and in view of the delay in completion of the Ashdod-Ashkelon combined section project, as specified in Note 12N1 below, the Leviathan Partners and Blue Ocean signed an amendment to the Export to Egypt Agreement, in which it was agreed, *inter alia*, to define an additional gas delivery point in Aqaba, Jordan, under the Export to Egypt Agreement, in which a certain price discount was determined as compensation to Blue Ocean for the additional transmission expenses entailed by transmission of the gas from the additional delivery point, which are borne thereby. The piping of gas to Egypt to the delivery point in Aqaba began in March 2022, and is performed through the Jordan-North Export Pipeline, as specified in Note 12N2 below.

Concurrently with the signing of the Leviathan Agreement, on 26 September 2019 (as amended on 21 August 2023) 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 MMCF per day will be allocated to the Leviathan Partners.
2. Second layer – the capacity above the first layer, up to 150 MMCF per day until 30 June 2022 (the "**Capacity Increase Date**"), and 200 MMCF 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.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.)

C. Engagements for the supply of natural gas (Cont.):

3. Agreement for the Export of Natural Gas from the Leviathan Project to Blue Ocean in Egypt (Cont.):

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. 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 a SPOT agreement, 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.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.)

D. Agreement for the supply of condensate to ORL (Cont.):

The piping of condensate to ORL shall be made on an interruptible basis, up to a maximum quantity that was agreed between the parties (the "**Maximum Quantity**"). The parties may update the Maximum Quantity from time to time, subject to compliance with the conditions that were determined by the authorities in this respect, including the Ministry of Energy and the Ministry of Environmental Protection (“**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.

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. Following the signing of the agreement with **ARF** (as set forth in Paragraph E below), ORL sent a letter to the Leviathan Partners whereby the engagement with ARF is a breach of the ORL Agreement, an anticipatory breach of the agreement and bad faith conduct. Later, on 4 February 2024, the Leviathan Partners notified ORL that the piping of the condensate to ARF was expected to commence in March 2024, and that from that date the quantities delivered to ORL would be significantly reduced. In response to this notice, ORL sent a letter to the Leviathan Partners, according to which the Leviathan Partners’ said notice constitutes a breach of the agreement with ORL. In its said letter, ORL also demanded that the Leviathan Partners provide clarification on the condensate quantities they intend to pipe to ORL. It is the Partnership’s position that ORL’s said claims and demands are groundless.

E. Agreement for the transport of condensate from the Leviathan reservoir

On 1 September 2022, Chevron (on behalf of the Leviathan Partners) and Energy Infrastructures Ltd. (“**PEI**”) signed an agreement intended to regulate an alternative mechanism 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 be in effect for 20 years from the date of commencement of the piping, subject to provisions that confer on the parties the possibility of terminating it before the end of the term.
2. According to the Agreement, 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**") and for receiving all approvals for the transport of condensate through the Pipe and for the ongoing operation and maintenance of the Pipe.
3. Chevron (through the Leviathan Partners, per their share in the Leviathan Leases) undertook to 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.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.)

E. Agreement for the transport of condensate from the Leviathan reservoir (Cont.):

4. 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.
5. 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.

In November 2022, the Leviathan Partners approved a budget of approx. $27 million (100%, the Partnership's share is approx. $12.2 million) for the purpose of implementation of such Agreement.

On 1 February 2024, the Partnership was informed that all of the Agreement's closing conditions have been fulfilled. On 7 March 2024, the piping of condensate to ARF has commenced.

F. Agreement with Ashdod Oil Refinery Ltd. for the sale of condensate from the Leviathan reservoir

On 18 January 2023, the Leviathan Partners, including the Partnership (the "**Sellers**") engaged with ARF in an agreement for the sale of condensate to ARF (the "**Agreement**"). Following is a concise description of the main terms of the Agreement:

1. According to the Agreement, the Sellers undertook to supply to ARF, 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 supplied to ARF, 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 ARF 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. On 7 March 2024, the piping of condensate to ARF has commenced.
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 natural gas and condensate quantities, prices 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, and the Partnership's operation in the joint venture Block 12 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 and 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 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.

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 31 December 2023, 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 21G 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 (see Note 7C3a for details on an agreement for the provision of usage rights in the Yam Tethys project facilities).
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 as provided in Note 12K below.
   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.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.)

K. Pledges and guarantees:

1. Short-term bank deposits as of 31 December 2023 in the sum of approx. $145.8 million that are used for debt service and current payments in the context of the issue of the Leviathan Bond bonds (see Note 10 above).
2. Long-term bank deposits as of 31 December 2023 include an amount of approx. $101.4 million used as a safety cushion for repayment of the principal of the bonds in the context of the issue of Leviathan Bond bonds (see Note 10B above) and a deposit in the sum of $0.5 million used to secure a guarantee in the sum of $1 million, provided by the Partnership and 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 10B 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 7C2 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 M]) 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 152 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, in December 2022 the Partnership provided a bank guarantee in the sum of approx. $1.75 million to ONHYM (see Note 7C4 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 12 March 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 paid by the Plaintiffs, in excess and under protest, to the Defendant, for revenues generated 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 31 December 2023, 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 31 December 2023 is $19.4 million, with the Partnership's share being approx. $9 million. On 14 November 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. On 13 August 2023, the Defendant submitted its answer to the appeal, and a hearing on the appeal was scheduled for 15 July 2024. 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 no hearing has yet been held in the appeal.
   According to the aforesaid, in 2022, 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 14 November 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 $6.2 million (including approx. $1.8 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 7C9 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 18 June 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 6 August 2021, a judgment of the District Court was issued, denying the Certification Motion. On 30 September 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 9 January 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 25 December 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.
   On 7 May 2023, a judgment of the court was issued, denying the Certification Motion. On 6 July 2023, the Petitioners filed an appeal from the judgment with the Supreme Court, requesting the Supreme Court to accept the appeal and order the grant of the Certification Motion.
   On 27 December 2023, PWC filed a counter-appeal on the judgment, which is being heard within the framework of the said appeal, in which it claimed that the District Court erred in not awarding costs in its favor (in this section: the "**Counter-appeal**"). In accordance with the court's decisions, the parties must submit the answers to the appeal and the Counter-appeal by 15 April 2024. A hearing on the appeal and the Counter-appeal has been scheduled for 2 January 2025.
   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 4 February 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**").

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.)

L. Legal proceedings (Cont.):

4. (Cont.)

According to the Petitioners, in essence, the Respondents misled the investing public at the time of the IPO with respect to the ability of Tamar Petroleum to distribute a dividend to its shareholders, for the period commencing on the IPO date and ending at the end of 2021 (in this section: the "**Period**"), and breached duties under various laws, 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.

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 13 August 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 6 April 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 23 January 2022, an amended certification motion was filed. On 23 April 2023, the Petitioners filed a motion for a discovery order, and on 17 July 2023, the court denied the motion for discovery in relation to all the Respondents, except Leader, with respect to which the motion was partly granted. Furthermore, on 16 August 2023, the court approved an agreed procedural arrangement between the parties, whereby the cross-examination of witnesses in the context of the Certification Motion would be conducted in February-April 2024. As of the date of approval of the financial statements, the case is in the trial stage, which is expected to be completed in 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%.

5. On 27 February 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**").

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.)

L. Legal proceedings (Cont.):

5. (Cont.)

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. 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 6 February 2024, the court granted the Petitioner's motion, with the consent of respondents, to cancel the trial hearings scheduled for March-April 2024 and no new dates have been scheduled therefor. 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 6 January 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 4 April 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".

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.)

L. Legal proceedings (Cont.):

6. (Cont.)

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 5 April 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. On 21 December 2023, at the parties' request, the court ordered the dismissal of the Supervisors' Claim and the Counterclaim, with no order for costs, in view of mutual agreements at which the parties had arrived, in the context of which, *inter alia*, the parties confirmed the original calculation that had been made by the Partnership (subject to the correction of an error with respect to retirement costs attributed to the Partnership for which a provision of approx. $1.6 million was made on the Partnership's books as early as 2018). Furthermore, the Royalty Interest Owners and the Partnership confirmed that the principles by which the investment recovery date had been calculated for the Tamar Project would apply (after certain adjustments that are specified under the mutual agreements) also in relation to the calculation of the investment recovery date for the Leviathan project.

7. On 23 April 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 (in this section: the "**Sale Agreements**" and the "**Buyer**", respectively), according to which in a year in which the average daily price of a Brent barrel (as defined in the Sale Agreements) is lower than $50 per barrel, the Buyer is entitled to reduce the minimum annual quantity purchased under the Sale Agreements, to 50% of the annual contract quantity. According to the Petitioner, the alleged non-disclosure in the Partnership's reports establishes causes of action by virtue of various sections of the Securities Law, by virtue of the tort of breach of statutory duty, and by virtue of the tort of negligence.

   The main remedy sought in the Certification Motion is compensation of the class which the Petitioner intends to represent, for the alleged damage incurred thereby, which is estimated, according to the opinion attached to the Certification Motion, at approx. ILS 55.5 million. The Petitioner also moved to issue any and all other remedies in favor of the class, as the court will deem fit under the circumstances.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.)

L. Legal proceedings (Cont.):

7. (Cont.)

   According to the court's decision, the Respondents and the Petitioner must file summations and responding summations in 2024, all by 7 June 2024.
   In the Partnership's estimation, based on the opinion of its legal counsel, the chances of the motion being granted are lower than 50%.

8. On 3 May 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 31 August 2021, and Haifa Port filed a replication on 1 December 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. On 11 September 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.
   On 8 July 2023 and 18 July 2023, the court denied the motions the parties had filed with respect to the preliminary proceedings and scheduled a last pretrial hearing for 4 June 2024.
   On 3 April 2023, Haifa Port filed a motion for summary dismissal of the counterclaim, arguing lack of controversy between itself and Chevron, because the invoices and mooring fees had been paid by an agent. Such motion was denied on 21 June 2023 and the court issued an order for costs against Haifa Port.
   In the Partnership's estimation, based on the opinion of its legal counsel, the Main Case is more likely to be denied than granted.

9. On 3 December 2023, a participation unit holder of the Partnership (in this section: the "**Petitioner**") filed a motion against the Partnership, in accordance with Section 65OO of the Partnerships Ordinance and Section 198A of the Companies Law, for the issuance of a discovery and inspection order before filing a derivative claim against the General Partner; Mr. Yossi Abu, CEO of the General Partner; and the members of the General Partner's board of directors (including members of the compensation committee) in the relevant period (in this section: the "**Discovery Motion**").

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.)

L. Legal proceedings (Cont.):

9. (Cont.)

   In summary, the Discovery Motion is based on the claim that the approval of Mr. Abu's current terms of office and employment by the compensation committee and the board of directors, in the "overruling", against the position of the general meeting of the participation unit holders, was done in violation of the law, while breaching the duties of care and fiduciary duty applicable to the members of the board of directors and in violation of Mr. Abu's duty, as CEO of the General Partner, to act in the best interests of the Partnership. As part of the Discovery Motion, it was claimed that the approval of Mr. Abu's terms of office and employment in the overruling was done without the conditions required therefor being met pursuant to the Partnerships Ordinance; that there was no sufficient re-discussion of the terms of office and employment of Mr. Abu and that no reference was made therein to the general meeting's objection; and that the reasons detailed by the board of directors did not refer to the mere rejection by the general meeting of the approval of Mr. Abu's terms of office and employment.

   In proximity to the filing of the Discovery Motion, the Petitioner filed with the court, a notice regarding additional motions for discovery and inspection before the filing of the derivative action, which were filed by him or by his counsel, based, as he alleges, on a "similar factual matrix"; against other respondents: Delek Group Ltd. (D.A. 58205-11-23); Electra Ltd. (D.A. 50050-11-23), Matrix I.T. Ltd. (D.A. 60805-11-23); and Scope Metals Ltd. (D.A. 47021-11-23) (the "**Additional Proceedings**").

   On 6 December 2023, the court ordered that the parties to the Additional Proceedings consider consolidating their hearings by choosing a lead case ("**Locomotive Case**") which shall govern the decisions in all of the Additional Proceedings; or in any other way (the "**Consolidation of the Hearing**"). On 8 January 2024, the Petitioner informed the court of his consent to the Consolidation of the Hearing, and on that date the Partnership filed its objection with the court to the Consolidation of the Hearing, since, *inter alia*, these are different and distinct proceedings, which concern other decisions, made by other entities, in relation to the terms of office of other officers and in other corporations; and that under these circumstances the consolidation of the proceedings is not expected to simplify and streamline the hearing thereof, and there is no concern of conflicting decisions between them, as required by law in order to consolidate the hearing in parallel proceedings. To the best of the Partnership's knowledge, the respondents in the Additional Proceedings also opposed the proposal for Consolidation of the Hearing. In accordance with the court's decision, the Partnership must file its answer to the Discovery Motion by 2 April 2024.

   In the Partnership’s estimation, based on the opinion of its legal counsel, the chances of the motion being granted are lower than 50%.

10. On 15 December 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**”).

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.)

L. Legal proceedings (Cont.):

10. (Cont.)

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. On 7 February 2024, a judgment was granted, denying the Certification Motion and charging the Petitioner with expenses.

M. Engagement in a transmission agreement for the export of gas:

As of the date of approval of the financial statements, the pipeline infrastructure for export to the Partnership's customers in Egypt and Jordan includes the main systems specified below-

1. On 28 May 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 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 (~5 BCM per year). According to the Export to Egypt Agreement, as described in Note 12C3 above, the additional compressor was installed in Ashkelon, that allows the increase of the piping capacity in the EMG system to ~600 MMCF per day (~6 BCM per annum). Upon completion of the Ashdod-Ashkelon combined section, the transmission capacity in the EMG system could be increased to ~800 MMCF per day (~8 BCM per annum), and even more, given certain conditions in the Israeli and Egyptian transmission systems.

On 18 January 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 14 February 2021 (above and below: the "**Transmission Agreement**" or, in this section: the "**Agreement**"). Below is a concise description of the principals of the Agreement, as amended from time to time:

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 ~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.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.)

M. Engagement in a transmission agreement for the export of gas to Egypt (Cont.):

1. (Cont.)

a. (Cont.)

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.

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, then the minimum quantity for piping as aforesaid will be increased accordingly.

c. Under the Transmission Agreement, INGL has undertaken to construct the Combined Section in accordance with the provisions of the decision of the Natural Gas Commission 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 (the "**Combined Section**") (see Paragraph f) (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.

d. Piping gas under the Transmission Agreement will commence on a date to be coordinated and agreed between the parties, but no earlier than 1 July 2022 and no later than 1 April 2023 (the "**Piping Commencement Date**"), and subject to INGL's right to defer the Piping Commencement Date in the event of delay in the approval of the NOP under which the Combined Section is being constructed. In February 2023, Chevron received a letter from INGL whereby, due to a malfunction in the vessel performing the infrastructure work for laying of the Combined Section (in this section: the "**Work**"), and further to a preliminary assessment received by INGL from the contractor performing the Work, a delay of at least 6 months was expected in completion thereof, such that the possible time frame for the Date of Commencement of Transmission had been postponed to the period from 1 October 2023 to 1 April 2024. This notice by INGL was given as a notice of *force majeure* under the Transmission Agreement, stating that its full implications were not yet known thereto at that time. In a letter of 9 March 2023 Chevron rejected INGL's claim of *force majeure*, until such time as information was provided about the malfunction and its effect on INGL's ability to fulfill its undertakings under the Transmission Agreement. In October 2023, Chevron informed the Partnership that it had received notice from INGL whereby following the outbreak of the Swords of Iron war, the Work on the project had been suspended, and the forecast for the Piping Commencement Date was about four months from the date of resumption of the Work. In February 2024, Chevron informed the Partnership that it had received notice from INGL whereby the foreign contractor performing the Work for construction of the Combined Section did not intend to continue maintaining its availability for resumption of the Work, and intended to return in August-September 2024 to complete its undertakings in the project .

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.)

M. Engagement in a transmission agreement for the export of gas to Egypt (Cont.):

1. (Cont.)

   d. (Cont.)

   In view of the aforesaid, the Leviathan Partners are considering the implications resulting therefrom and the possibilities available to them. In February 2024, Chevron sent INGL a letter stating that, according to Chevron's position, the Piping Commencement Date occurred on 30 April 2023 at the latest, and therefore, *inter alia* INGL is required to provide transmission services according to the Transmission Agreement starting from such date, and to reimburse Chevron for the excess transmission fees it collected from such date forth. On 26 February 2024, Chevron received a letter of reply from INGL, in which INGL rejected all of Chevron's claims and whereby the Piping Commencement Date will only be possible after completion of the Combined Section. According to the position of Chevron and the Leviathan Partners, this position of INGL's is contrary to the provisions of the Transmission Agreement. As of the date of approval of the financial statements, the parties are holding discussions in an attempt to resolve the said dispute.

   e. 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.

   f. 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 both Leviathan and Tamar 56.5% out of the total cost of construction of the Combined Section, which is estimated at ILS 738 million. On 2 May 2022, INGL updated the budget of the Combined Section to a total of approx. ILS 796 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 as aforesaid (56.5%), see Note 12P5 above.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.)

M. Engagement in a transmission agreement for the export of gas to Egypt (Cont.):

1. (Cont.)

g. 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. ILS 152 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).

h. The Leviathan Partners and the Tamar partners will bear the costs stated in Paragraph f at the rates of 69% and 31%, respectively.

i. 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 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.

j. It was further determined that the transmission period under the 2019 Agreement will be extended until the date of expiration of the 2019 Agreement according to the terms and conditions thereof or by 1 January 2025 or until the Piping Commencement Date pursuant to the Transmission Agreement, whichever is earlier.

k. 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 h 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.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.)

M. Engagement in a transmission agreement for the export of gas to Egypt (Cont.):

1. (Cont.)

    l. The expected completion date of the project for construction of the Combined Section has been postponed several times. In October 2023, Chevron updated the Partnership that it had received notice from INGL whereby as a result of the outbreak of the Iron Swords War, work on the said project had been suspended, and piping is expected to commence around four months after the date of resumption of the work. In February 2024, Chevron updated the Partnership that it had received notice from INGL whereby the foreign contractor performing the work on construction of the Combined Section has no intention of continuing to remain on standby to continue the work, and that it intends to return in August-September 2024 to complete its undertakings in the project. In view of the foregoing, the Leviathan Partners are examining the implications arising therefrom and the options available to them.

2. The Jordan-North Export Pipeline, which connects between the Israeli transmission system and the Jordanian transmission system near the Sheikh Hussein Bridge. The construction of this export pipeline was completed in December 2019, *inter alia* through the construction of a natural gas pipeline by INGL from the Tel Kashish station to the border with Jordan, including the construction of a station near the border whose purpose is to measure the gas exported to Jordan. The follow-on pipeline on the Jordanian side was built by FAJR, the Jordanian transmission company (which is Egyptian-owned), which connects the Israeli transmission system to the existing transmission pipeline in Jordan and the Arab Gas Pipeline, and connects to the Egyptian transmission system in the area of Aqaba (above and below: the "**Jordan-North Export Pipeline**"). As of the date of approval of the financial statements, the total maximum gas supply capacity in the Jordan-North Export Pipeline is approx. 7 BCM per annum, of which around 3.5 BCM is allocated for the NEPCO Agreement. In view of the delay in completion of the project for construction of the Ashdod-Ashkelon Combined Section (as aforesaid in Section M1D), the Leviathan Partners have signed a set of agreements intended to allow the piping of quantities of natural gas to Egypt under the Export to Egypt Agreement, through Jordan, using the Jordan-North Export Pipeline. In accordance with the said set of agreements, in March 2022, natural gas piping to Egypt through Jordan began, 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 ~350 MMCF (~3.5 BCM per year). It is noted in this context that the Ministry of Energy authorized the Leviathan Partners to add a point of delivery of natural gas to Egypt in Aqaba, Jordan. It is further noted that transmission of the gas to Egypt via the Jordan-North Export Pipeline entails additional transmission costs compared with transmission of the gas via the EMG pipeline.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.)

M. Engagement in a transmission agreement for the export of gas to Egypt (Cont.):

2. (Cont.)

The aforesaid set of agreements includes the agreements specified below:

a) 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.

b) 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.

c) Agreement between Chevron and INGL for supply of interruptible transmission services in relation to the piping of natural gas from the Leviathan reservoir via the Jordan-North Export Pipeline to the point of connection to the FAJR transmission system at the border between Israel and Jordan (the "**Jordan-North INGL Agreement**"). The payment pursuant to the Jordan-North 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 agreement. The term of the Jordan-North INGL Agreement was extended until 1 January 2025, unless the parties consensually extend it, subject to the decisions of the Natural Gas Authority at such time. Concurrently with the signing of the Jordan-North INGL Agreement, Chevron and the other Leviathan partners engaged in a back-to-back services agreement in connection with the Jordan-North INGL Agreement.

d) The Leviathan Partners and Blue Ocean signed an amendment to the Export to Egypt Agreement as specified in Section C3 above.

According to the Export to Egypt Agreement, the Leviathan Partners have been obligated, since July 2022, to supply Blue Ocean with 450 MMCF of natural gas per day. The piping of this full quantity via the EMG pipeline will only be possible after completion of the Combined Section, whose construction, as aforesaid, is delayed. Despite the fact that until the date of approval of the financial statements the piping of gas through Jordan has been conducted as planned, as the transmission agreements with INGL effective on the date of approval of the financial statements are for the provision of interruptible transmission services, it is not certain on the date of approval of the financial statements it will be possible at all times to pipe via Jordan the full quantities that the Leviathan Partners are obligated as aforesaid to supply to Blue Ocean.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.)

M. Engagement in a transmission agreement for the export of gas to Egypt (Cont.):

2. (Cont.)

To increase the transmission capacity to Egypt via the Jordan-North Export Pipeline, the Leviathan Partners approved, by the date of approval of the financial statements, preliminary budgets prior to the adoption of a final investment decision (insofar as shall be adopted) in the sum total of approx. $37.5 million (100%, the Partnership's share – approx. $17 million), for the construction of a compressor station and additional related work in the Jordanian transmission system (the "**FAJR+ Project**").

In the Operator's estimation, the FAJR+ Project's budget is estimated at approx. $335 million (in equal shares between the Leviathan Partners and the Tamar partners, the Partnership's share is approx. $76 million). The FAJR+ Project is expected to increase the total transmission capacity in the Jordan-North Export Pipeline to ~10.5 BCM per annum during H1/2026. As of the date of approval of the financial statements, the Leviathan Partners are acting for adoption of a final investment decision for the FAJR+ Project, which is expected to be adopted by the end of H1/2024.

3. The Jordan-south export pipeline, which connects the Israeli transmission system in the southern area of the Dead Sea to Jordanian industrial plants.

4. As of the date of approval of the financial statements, the Operator, on behalf of the Leviathan Partners and the Tamar partners, is examining the possibility to participate in the construction of a project for a new onshore connection between the Israeli transmission system and the Egyptian transmission system in the area of Nitzana (the "**Nitzana Pipeline**"), which includes a pipeline and the construction of a compressor station in the area of Ramat Hovav. The Nitzana Pipeline (if built) will constitute part of INGL's transmission system and is expected to increase the capacity of transmission to Egypt by ~6 BCM per year. 1. [sic] For promotion of the construction of the Nitzana Pipeline, the Leviathan Partners approved, by the date of approval of the financial statements, preliminary budgets prior to an undertaking to participate in the financing of the Nitzana Pipeline, according to the INGL's decision in respect thereof, and prior to the adoption of a final investment decision (insofar as shall be adopted) in the sum total of approx. $14.5 million (100%, the Partnership's share – approx. $6.6 million). In the Operator's estimation, the Nitzana Pipeline project's budget is estimated at approx. $360 million (in equal shares between the gas exporters participating in the funding thereof; the Partnership's share is approx. $82 million). As of the date of approval of the financial statements, the Partnership, together with the other Leviathan partners, is examining all of the commercial conditions in this project in comparison with the alternatives of other projects to increase the capacity for export to Egypt, and accordingly, will make a decision on whether and how to participate in the Nitzana project.

N. Engagement for collaboration in renewable energies:

On 21 September 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.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.)

N. Engagement for collaboration in renewable energies (Cont.):

Accordingly, on 13 March 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 13 March 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:

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.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.)

N. Engagement for collaboration in renewable energies (Cont.):

5) (Cont.)

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.

7) 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.

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 29 September 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 15 February 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.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.)

P. Regulation:

1. **The Gas Framework:**

   On 16 August 2015, Government Resolution No. 476 (readopted by the Government Resolution of 22 May 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 17 December 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 1 January 2030.
      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 1 January 2025.
      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 aforesaid restrictive arrangements had been contingent upon the satisfaction of certain conditions, including the transfer of all the interests of the Partnership and Chevron in the Tanin and Karish leases (see Note 8B above), the transfer of all the interests of the Partnership in the Tamar Project (see Note 7C9 above) and the transfer of some of the interests of Chevron (interests in excess of 25%) in the Tamar Project, all of which were completed in accordance with the framework by December 2021.

P. Regulation (Cont.):

1. The Gas Framework (Cont.):

c) Satisfying 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:

1. The consumer shall be subject to no restriction with respect to the purchase of natural gas from any other natural gas supplier.
2. The consumer will have the possibility of selling natural gas that it purchased in a resale, in accordance with the conditions and provisions set forth in the Exemption.
3. The parties shall not apply any restriction to the sale price at which the consumer shall sell the natural gas in a resale.
4. 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.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.)

P. Regulation (Cont.):

2. Environmental Regulation:

The Partnership acts to prevent and/or minimize the environmental hazards that may occur in the course of its operations, has prepared for the financial, legal and operating implications deriving from such laws, regulations and directives and allocates budgets for compliance therewith in the framework of its annual work plans for its various assets.

a) On 20 May 2020, Chevron received a notice from the MoEP of the intention to impose an administrative monetary 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 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 regards to said administrative monetary penalty and to schedule it 30 days after receipt of the information. As of the date of approval of the financial statements, the requested information has not yet been received and therefore the count of days for responding to the aforesaid notice has not yet begun. Due the long time that passed since the process began and the response of the MoEP to the freedom of information request not yet being received, there is no certainty of the completion of the process.

b) On 2 August 2023, Chevron received notice from the MoEP regarding its intention to impose thereon an administrative monetary penalty of approx. ILS 2.9 million (100%, approx. $0.8 million) for alleged violation of the marine discharge permit of the Leviathan project. Chevron has submitted its arguments with respect to such notice, and on 7 December 2023, the decision of the MoEP on the matter has been issued whereby it was decided to reject the claims of Chevron and that such administrative monetary penalty amount shall remain unchanged. Payment for such administrative monetary penalty was transferred on 26 December 2023.

c) On 6 August 2023, Chevron received a letter of notice and summons to a hearing before the MoEP for alleged non-compliance of the marine discharge permit and the toxins permit of the Leviathan project, and violation of the Prevention of Sea Pollution and the Hazardous Substances Law. The hearing took place on 7 January 2024, and on 21 January 2024, the hearing summary was received, whereby Chevron is required to take all actions to prevent deviations from the marine discharge permit, and that the MoEP is considering exercising its powers according to law.

It is not possible at this stage to estimate whether an administrative monetary penalty will be imposed for the violations and the amount of the administrative monetary penalty that will be imposed, if any.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.)

P. Regulation (Cont.):

3. **Directives on the provision of collateral in connection with the petroleum rights:**
In September 2014, pursuant to Section 57 of the Petroleum Law, the Commissioner published directives for the provision of collateral in connection with petroleum rights.
As of the date of 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 Paragraph 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 July 2022, specific directives were released 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 specified in the contract 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.

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) On 1 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:

On 23 June 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 (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.

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:**
   From time to time, the Natural Gas Commission adopts resolutions that update the rates of the various transmission services.
   According to the Natural Gas Commission's resolution of 3 January 2021 on criteria and rates for the purpose of operation of the transmission system in a flow control regime, the Commission determined that the costs in respect of unaccounted for gas (UFG) in the transmission system that derives from reasons that cannot be attributed to deficient operation of the transmission system, but rather to factors that can be neither prevented nor controlled, such as measurement timing, pressure differences and temperature differences, will be borne by the gas suppliers. The resolution further stipulates that UFG within the range of 0% and 0.5% (either positive or negative) is deemed to be within the reasonable range. The costs in respect of a reasonable UFG-T will be allocated equally between the gas suppliers and the gas consumers.

7. **Draft policy document with respect to the decommissioning of offshore exploration and production infrastructures**
   On 2 May 2023, the Ministry of Energy published for public comment a draft policy document that specifies general principles with respect to the decommissioning of offshore oil and natural gas exploration and production infrastructures, without derogating from the provisions of law applicable to this issue and from the provisions of the lease deeds and operation authorizations. The draft policy document specifies, *inter alia*, rules, criteria and timeframes for the decommissioning of wells and production facilities as well as the abandonment of no-longer used subsea infrastructures and pipelines, *inter alia*, according to the location of such installations in the deep sea, on the seabed or under the seabed. According to the Partnership's preliminary assessment, insofar as the stringent requirements of the draft policy document are approved, costs of decommissioning of the Partnership's assets are expected to increase.

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 31 December 2023: 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 20C4.

C. Distributions 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.

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
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
10.5.2023	15.6.2023	50	0.04260
20.8.2023	14.9.2023	50	0.04260
15.11.2023	21.12.2023	50	0.04260
18.3.2024	11.4.2024	60	0.05112

Notes to the Financial Statements as of 31 December 2023 (Dollars in millions)

Note 13 – Equity (Cont.):
C. Distributions of Profits (Cont.):

3. **Distributions to the Limited Partner:**
   a) On 27 May 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).
   b) On 23 March 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).
   c) On 1 March 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).
   d) On 20 August 2023, the board of directors of the General Partner approved a distribution to the Limited Partner in the sum of approx. ILS 0.5 million (approx. $0.1 million).
   e) On 15 November 2023, the board of directors of the General Partner approved a distribution to the Limited Partner in the sum of approx. ILS 0.5 million (approx. $0.1 million).

   Such distributions are used for payment of the Supervisor' fees and the Trustee's fees and expenses, 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 2021 tax year (for further details see Notes 19A and 19B), as specified below:

Tax Year	Type of Income	Tax Advances in ILS millions	ILS per Participation Unit
2021	Current	Approx. 217.3	0.1851
2021	Capital gain	Approx. 527.9[24]	0.4497

   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 19A1.
2. On 27 December 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 20 January 2021.
3. On 26 December 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 20 January 2022.

[24] 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 31 December 2023 (Dollars in millions)

Note 13 – Equity (Cont.):

E. The composition of equity as of 31 December 2023 is as follows:

	The Limited Partner	The General Partner	Total
The Partnership's equity	154.8	–[25]	154.8
Capital reserves	(28.6)	–[27]	(28.6)
Retained earnings	1,386.2	0.1	1,386.3
Balance as of 31 December 2023	**1,512.4**	**0.1**	**1,512.5**

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 31 May 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 1 January 2022, the Partnership does not record expenses against a capital reserve since the payments are made by the Partnership.

H. With respect to the participation unit-based payment granted to the CEO of the General Partner in the Partnership, see Note 20C4.

[25] Less than $0.1 million.

Notes to the Financial Statements as of 31 December 2023 (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 12C 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		
	31.12.2023	**31.12.2022**	**31.12.2021**
Revenues:			
Domestic market	168.6	284.7	319.5
Regional market	925.8	859.2	563.0
	1,094.4	**1,143.9**	**882.5**
Quantities (BCM)			
Domestic market	0.93	1.71	2.06
Regional market	4.05	3.45	2.80
	4.98	**5.16**	**4.86**

Note 15 – Royalties:

A. Composition:

	For the year ended		
	31.12.2023	**31.12.2022**	**31.12.2021**
Royalties to the State	117.5	126.4	94.7
Royalties to interested parties	14.1	15.2	11.4
Royalties to third parties	28.2	30.4	22.7
Total	**159.8**	**172.0**	**128.8**

(see Note 12B above and Paragraph B below)

Effective rate of the royalties in Leviathan project:

	For the year ended		
	31.12.2023	**31.12.2022**	**31.12.2021**
Effective rate of the royalties in Leviathan project:			
To the State	10.73%	10.93%	10.73%
To interested parties	1.29%	1.31%	1.29%
To a third party	2.57%	2.62%	2.57%

Note 15 – Royalties (Cont.):

B. Royalties to the State and overriding royalties (to interested and third parties) as included on the Partnership's books:

1. According to a demand letter received from the Ministry of Energy in October 2023, the Leviathan Partners should pay the State advances on account of the state royalties in respect of the revenues from the Leviathan project in 2023 at the rate of 11.06%, in lieu of 11.26% as paid by the Leviathan Partners since the date of commencement of the gas supply from the Leviathan reservoir in accordance with a demand letter received from the Ministry of Energy in January 2020. According to a letter from the Ministry of Energy, in January 2024 the rate of 11.06% will continue also in 2024. The rate of the advances paid to the State is higher than the calculation of the rate of the value of the royalty at the wellhead in the royalty reports submitted by Chevron to the Ministry of Energy for the years 2020 and 2021, whereby the rate of the royalties at the wellhead in the Leviathan project is approx. 9.58% and 10.17%, respectively. The royalties rate on which the Partnership relied in its financial statements for 2023, is approx. 10.7% (2022: 10.9%, 2021: 10.7%).
   It is the position of the Partnership that the calculation of the actual rate of the state 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 Leviathan project, and the amounts recorded in the statement of comprehensive income 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. \$34.2 million (2022: approx. \$30.5 million), and was included in the other short-term and long-term assets items.
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 7C9 above) and of the Leviathan project, amounts to approx. \$14.5 million (2022: approx. \$11.8 million, 2021: approx. \$8.8 million), is included in the other short-term and long-term assets item.
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 for offshore petroleum interests, and in September 2020 he released specific directives on the method of calculation of the value of the royalty at the wellhead for 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. In 2022, the Ministry of Energy delivered to Operator draft royalty audit reports for 2013-2018 in accordance with the Specific Directives. The Operator delivered to the Ministry of Energy its response to the said draft reports.

Notes to the Financial Statements as of 31 December 2023 (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.)

The State and the Tamar partners – through the Operator – are holding discussions regarding the excess payments made by the Tamar partners in the years 2013-2018. Based on understandings taking shape with the Ministry of Energy following discussions held recently on the draft audit reports, the Partnership updated non-material differences in the cumulative amounts recorded in the statement of comprehensive income, under the item of expenses for royalties to the State. According to the Partnership's estimation, and based on the understandings taking shape as aforesaid, the Partnership will be entitled to receive from the State (by way of setoff against future royalty payments in 2024) an amount of about $17.2 million, for the years 2013-2018. The Partnership will also be entitled to receive from the royalty interest owners a total amount of approx. $8.3 million for such years. Accordingly, the said refund amounts are presented under the trade and other receivables item.

Note 16 – Cost of Natural Gas and Condensate Production[26]:

Composition:	For the year ended		
	31.12.2023	31.12.2022	31.12.2021
Salaries and social benefits	19.6	19.5	22.2
Guarding and security	0.9	2.0	2.8
Insurance	17.5	17.4	16.1
Delivery, transmission and transportation costs	69.3	49.9	25.7
Operation management and operator fee	17.6	19.5	18.0
Maintenance	18.1	15.8	16.4
Others	5.6	10.0	17.2
Total	**148.6**	**134.1**	**118.4**

[26] Mostly through the joint ventures.

Notes to the Financial Statements as of 31 December 2023 (Dollars in millions)

Note 17 – G&A Expenses:

Composition:	For the year ended		
	31.12.2023	31.12.2022	31.12.2021
Salaries and social benefits	6.5	6.3	4.1
General Partner management fee expenses (Note 12A above)	-	-	1.0
Cost of participation unit-based payment to the CEO (see Note 20C4 below)	2.7	1.0	-
Professional services, net[27]	7.2	8.7	8.6
Other	4.4	3.7	3.6
Total	**20.8**	**19.7**	**17.3**

[27] Including expenses in the sum of approx. $4.3 million in 2021 carried against a capital reserve (see Note 13G above) and starting from 2022 are paid by the Partnership.

Notes to the Financial Statements as of 31 December 2023 (Dollars in millions)

Note 18 – Financial Expenses and Income:

Composition:

	For the year ended		
	31.12.2023	31.12.2022	31.12.2021
Expenses:			
Due to bonds (Notes 10B, 10E and 10F above)	126.9	145.9	207.0
Due to liability to banking corporations (Note 10D)	2.4	0.7	0.7
Revaluation of future production-based royalties from the Karish and Tanin leases (see Note 8B above)	5.0	-	-
Due to a guarantee fee to Delek Group (Notes 12K4 and 20D)	0.4	0.4	0.4
Due to changes in oil and gas asset retirement obligation due to lapse of time	3.2	1.5	1.8
Other[28]	1.1	13.5	1.4
Net of financing costs capitalized to gas and oil assets[29]	(5.2)	(6.7)	-
Total expenses	**133.8**	**155.3**	**211.3**
Income:			
Due to deposits in banks and short-term investments	13.1	5.4	0.6
Revaluation of future production-based royalties from the Karish and Tanin leases (see Note 8B above)	-	60.9	20.0
Revaluation of loan to Energean in the context of the sale of the Karish and Tanin leases (Note 8B above)	5.9	1.6	6.4
Revaluation of amounts receivable from a company accounted for at equity (see Note 21G3 below)	7.1	3.1	1.9
Other	2.6	0.1	2.5
Total income	**28.7**	**71.1**	**31.4**
Total financial expenses, net	**(105.1)**	**(84.2)**	**(179.9)**

[28] See footnote 3 above.
[29] The cap rate used for determining the borrowing costs capitalized in 2023 is approx. 6.7% (2022: 6.5%).

Note 19 – 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).

   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 31 December 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 (in this section: 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 1 January 2022 the Partnership presents current tax expenses in the statement of comprehensive income, in addition to deferred tax expenses as aforesaid.

Note 19 – 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, 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 submitted (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 (according to the corporate tax rate) and the share in the Partnership of the Entitled Holders who are individuals (according to a maximum marginal tax rate). 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 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 28 June 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 1 July 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 9 August 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 21 July 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. The distribution was made by the trustee in September 2023. However, due to difficulties experienced by the trustee in locating some of the entitled holders, the court authorized the trustee to postpone the deadline for filing the summary report on performance of the distribution until 17 March 2024, and left to the trustee's discretion whether another extension was required until 1 May 2024.

Note 19 – 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 ("**TALE**") 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 2017 Tax 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 20 October 2021 the Partnership published final tax certificates for an entitled holder due to 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 19 – Oil and Gas Profit Levy and Taxes (Cont.):
B. Income tax assessments and tax certificates (Cont.):

2. On 13 December 2017, the Partnership published temporary tax certificates for an entitled holder due to the holding of a participation unit of the Partnerships for the tax year 2016. In the context of the disputes which erupted between the Partnership and the Tax Authority and disagreements regarding the amount of the taxable income of the Partnerships for 2016, on 22 November 2018, assessments to the best of judgment were received from the Tax Authority, pursuant to Section 145(a)(2)(b) of the Income Tax Ordinance (in this section: the "**Tax Assessments**"), and on 14 March 2019 the Partnership filed a reasoned administrative objection to the Tax Assessments. Further to the administrative objection to the Tax Assessments filed by the Partnership, on 29 July 2020 the Partnerships received assessments in an order under Section 152(b) of the Income Tax Ordinance (the "**Orders**") by the Tax Authority. The disputes, the subject matter of the Orders, primarily pertain 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 such Orders, the taxable income from a business of the Partnership and the Avner Partnership for 2016 is approx. $125.8 million and approx. $114 million, respectively (in lieu of approx. $107.2 million and approx. $95.4 million, respectively, as stated in the Partnerships' tax reports filed with the Tax Authority). The Partnerships' capital gain for 2016 is approx. $49.3 million and approx. $67.1 million, respectively (in lieu of approx. $7.6 million and approx. $18.1 million, respectively, as stated in the Partnerships' tax reports filed with the Tax Authority). The said amounts were translated from ILS to $ according to the dollar exchange rate known as of 31 December 2023. Insofar as all of the Tax Authority's claims are accepted, the Partnership will be required to make a supplementary tax payment (including interest and linkage differentials) on account of the tax owed by holders of participation units in the Partnerships in the sum total of approx. $43.7 million. On 15 September 2020, the Partnership filed an appeal from the Orders with the Tel Aviv District Court. The assessment reasoning in this appeal was filed by the assessing officer on 9 December 2020 and in accordance with the decision of the court, the notice stating the grounds for the appeal was filed by the Partnership on 3 May 2021. A pretrial hearing on the appeal was held on 25 November 2021 and a date for an additional pretrial hearing was not yet scheduled.
3. On 8 November 2018, the Partnership published a temporary tax certificate for an entitled holder due to holding a participation unit for the tax year 2017. In the context 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 2017, the Partnership received a tax assessment to the best of judgment pursuant to Section 145(a)(2)(b) of the Ordinance, 5721-1961 (in this section: the "**Tax Assessment**"), and on 10 December 2020, the Partnership filed a reasoned administrative objection to the Tax Assessment. On 21 December 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**"). According to such Order, the Partnership's taxable business income in 2017 is approx. $344.2 million (in lieu of approx. $205.4 million, as included in the Partnership's tax report submitted to the Tax Authority) and the Partnership's capital gain including deferred capital gain in 2017 is approx. $654.0 million (in lieu of approx. $593.5 million as stated in the Partnership's tax report submitted to the Tax Authority).

Note 19 – Oil and Gas Profit Levy and Taxes (Cont.):

B. Income tax assessments and tax certificates (Cont.):

3. (Cont.):

The said amounts were translated from ILS to $ according to the dollar exchange rate known as of 31 December 2023. On 22 January 2023, the Partnership filed an appeal from the Order with the Tel Aviv District Court. The grounds for the tax assessment in this appeal were filed by the assessing officer on 30 May 2023 and according to the court's decision, a notice of the grounds for the appeal was filed on 30 January 2024.

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. $105.0 million.

4. On 19 February 2020, the Partnership published a temporary tax certificate for an entitled holder due to the holding of a participation unit of the Partnership for the tax year 2018. In the context 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 24 March 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. $179.5 million (in lieu of approx. $137.8 million, as stated in the Partnership's tax report filed with the Tax Authority) and the Partnership's capital gain for 2018 is approx. $15.9 million, as declared in the report filed thereby as aforesaid. The said amounts were translated from ILS to $ according to the dollar exchange rate known as of 31 December 2023. The main disputes pertain to the interpretation of the manner of recognition of financial expenses and additional expenses borne by the Partnership in practice, similarly 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 of the Tax Authority's claims are accepted, the Partnership will be required to make a supplementary tax payment (including interest and linkage differentials), at the expense of holders of Participation Units in the Partnership, in the amount of approx. $14.2 million. On 10 June 2021 the Partnership filed a reasoned administrative objection to 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 the 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%.

Note 19 – Oil and Gas Profit Levy and Taxes (Cont.):
B. Income tax assessments and tax certificates (Cont.):

7. On 14 July 2021, the Partnership published a temporary tax certificate for an entitled holder due to 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 audit by the Tax Authority, the taxable income is approx. ILS 573.6 million.
8. On 12 April 2022, the Partnership published a temporary tax certificate for 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 audit by the Tax Authority, the taxable income is approx. ILS 277.6 million.
9. On 30 April 2023, the Partnership published a temporary tax certificate for an entitled holder due to the holding of participation units of the Partnership for 2021. According to the tax report filed by the Partnership for 2021, which is subject to audit by the Tax Authority, the Partnership's taxable income from a business for tax purposes is approx. ILS 919 million, the net capital gain mainly due to the sale of the Partnership's holdings in the Tamar and Dalit Leases (see Note 7C9B above) is approx. ILS 1,868 million, and the deferred capital gain for the sale of the Partnership's holdings in Tamar Petroleum (see Note 7C9C 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 tax rate calculated pursuant to Section 19.

    It is clarified that in accordance with the provisions of the aforementioned judgment of 28 June 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 according to the Tax Authority directives, participation unit holders will include in their tax reports, for each one of the years 2016 through 2021, their share in the Partnership's taxable income 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.

Note 19 – Oil and Gas Profit Levy and Taxes (Cont.):

B. Income tax assessments and tax certificates (Cont.):

12. (Cont.):

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 (subject to the relevant tax arrangement, as specified in Paragraph A5 above).

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

"**Net Accrued Revenues**" shall mean, the partners' share in revenues actually received from the gas output (including the Expenditure Coverage Output), net of the operating expenses borne by the partners in the area of the PSC, from the date of signing of the PSC (28 October 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.

Note 19 – Oil and Gas Profit Levy and Taxes (Cont.):

B. Income tax assessments and tax certificates (Cont.):

14. Taxation in Cyprus (Cont.):

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; 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.

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 (in this section: 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 2023, the maximum rate is 46.8%.

Note 19 – Oil and Gas Profit Levy and Taxes (Cont.):

C. Taxation of Profits and Natural Resources Law, 5771-2011 (Cont.):

1) (Cont.)

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**") 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.

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 10 April 2011 and include transition provisions with respect to ventures that began commercial production by 1 January 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 1 January 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.

Note 19 – Oil and Gas Profit Levy and Taxes (Cont.):

C. Taxation of Profits and Natural Resources Law, 5771-2011 (Cont.):

4) On 10 November 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.
5) Disputes have erupted between the TALE 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 TALE 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 with regards to the implementation of the provisions of the Law in the levy reports of the Leviathan Leases, 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 TALE in March 2022. On 23 October 2022, an appeal was filed with the Tel Aviv District Court in respect of a levy assessment order for 2019, which was served to the Leviathan partners in September 2022, and on 15 March 2022, the assessment reasoning of the TALE for the said appeal were received. According to the court's decision, the notice stating the grounds for the appeal will be filed by 21 March 2024. On 6 January 2022, a Leviathan lease levy report for 2020 was submitted to the Tax Authority and on 31 December 2023 an assessment to the best of judgment was received from the Tax Authority pursuant to Section 14(B)(2) of the Law.

   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 19 – Oil and Gas Profit Levy and Taxes (Cont.):

C. Taxation of Profits and Natural Resources Law, 5771-2011 (Cont.):

6) Disputes have erupted between the TALE 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. On 15 March 2022, the assessment reasoning of the TALE were received for the appeal for 2019. According to the court's decision, the notice stating the grounds for appeal will be filed by 30 April 2024.

   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 recording of an expense for the period until the sale of its rights in the Tamar Project (see Note 7C9 above) in an estimated amount, as of 31 December 2023, of approx. \$37.5 million (which includes an amount of approx. \$24.5 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 erupted in respect of 2013-2019. In July 2022, the holders of the rights in the Tamar venture filed an administrative objection with the TALE regarding the said assessment.

   On 25 January 2023, a levy assessment order for 2020 was received. On 8 February 2023, an appeal was filed with the Tel Aviv District Court regarding the order issued to the Tamar venture for 2020, and on 30 April 2023, the TALE assessment reasoning for the appeal regarding 2020 was received. In accordance with the court's decision, the notice stating the grounds for the appeal will be filed by 30 April 2024.

   In this context, it is noted that 14 November 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 8 February 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. Such sum was included in the other long-term assets item.

   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 31 December 2023 (Dollars in millions)

Note 19 – Oil and Gas Profit Levy and Taxes (Cont.):

C. Taxation of Profits and Natural Resources Law, 5771-2011 (Cont.):

7) Disputes have arisen between the TALE 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. $1.8 million.
8) **Taxation of Profits from Natural Resources Regulations:**
   On 2 December 2020, the Taxation of Profits from Natural Resources Regulations (Advances due to the Oil 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 million, due to its rights in the Tamar Project (including the advance for 2020 in the sum of approx. $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 7C9 above.

D. Income taxes included in the statement of comprehensive income

	31.12.2023	31.12.2022	31.12.2021
Current taxes	(97.4)	(50.2)	-
Current taxes due to previous years	(1.8)	-	-
Deferred taxes	(44.1)	(62.0)	(207.8)
Total income taxes	**(143.3)**	**(112.2)**	**(207.8)**
Net of taxes attributed to discontinued operations	0.5	(3.8)	-
Total taxes attributed to continuing operations	**(142.8)**	**(116.0)**	**(207.8)**

Notes to the Financial Statements as of 31 December 2023 (Dollars in millions)

Note 19 – Oil and Gas Profit Levy and Taxes (Cont.):

E. Deferred taxes

1. **Composition:**

	31.12.2023	31.12.2022
Deferred tax liabilities		
Trade and other receivables	4.3	-
Costs of bond issue	0.2	-
Oil and gas assets	296.1	265.7
Other long-term assets	14.6	8.3
Total	**315.2**	**274.0**
Deferred tax assets		
Share-based payment and social benefits	(0.8)	(1.9)
Short-term retirement obligation	(0.5)	(2.3)
Total	**(1.3)**	**(4.2)**
Deferred tax liabilities, net	**313.9**	**269.8**

2. Deferred tax is calculated according to a tax rate of 23% (2022 – identical) based on the tax rate which is expected to apply on the reversal date.
3. No deferred tax liabilities were recorded in respect of temporary differences in the total sum of approx. $1.3 million (2022: approx. $0.1 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 31 December 2023 (Dollars in millions)

Note 19 – 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		
	31.12.2023	**31.12.2022**	**31.12.2021**
Profit before income taxes from continuing operations	**574.3**	**594.6**	**316.4**
Statutory tax rate	23%	23.0%	-[30]
Tax calculated according to the statutory tax rate	**(132.1)**	**(136.8)**	**-**
Decrease (increase) in income taxes due to the following factors:			
Change of estimate of the tax basis for other long-term assets [31]	-	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 ($)	(7.3)	(3.9)	-
Taxes due to previous years	(1.8)	-	-
Others	(1.6)	(0.3)	-
Income taxes	**(142.8)**	**(116.0)**	**-**

[30] For details on the tax regime that applied to the Partnership until 31 December 2021, see Note 19A2 above.

[31] 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 31 December 2023 (Dollars in millions)

Note 20 – Transactions and Balances vis-à-vis Interested Parties, Related Parties and Control Holders:

A. Balances:

	31 December 2023		31 December 2022	
	Parent companies	Related parties and other interested parties	Parent companies	Related parties and other interested parties
Trade and other receivables	2.6	10.6	-	1.3
Other long-term assets	0.3	21.1	2.6	25.2
Trade and other payables	3.6	1.6	5.0	1.8
The highest current debt balance this year	0.1	-	-	-

Note 20 – 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 31 December 2023:

	Note	Parent companies	Related parties and other interested parties
Revenues from gas sale	14, 7C3	(*	-
Expenses due to overriding royalties (continuing operations)	15	-	14.1
Revenues due to overriding royalties (discontinued operations)	7C9	1.1	-
Directors' remuneration	20D	-	0.5
Guarantee fee to Delek Group	12K4	0.4	-
Rent	20E2	0.4	-

*) Less than $0.1 million

Notes to the Financial Statements as of 31 December 2023 (Dollars in millions)

Note 20 – 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 31 December 2022:

	Note	Parent companies	Related parties and other interested parties
Revenues from gas sale	14, 7C3	0.2	-
Expenses due to overriding royalties (continuing operations)	15	0.1	15.1
Expenses due to overriding royalties (discontinued operations)	7C9	2.6	-
Directors' remuneration		-	0.3
	20D		
Guarantee fee to Delek Group	12K4	0.4	-
Rent	20E2	0.4	-

	Note	Parent companies	Related parties and other interested parties
Revenues from gas sale (continuing operations)	14, 7C3	0.2	-
Revenues from gas sale (discontinued operations)	7C9	(*	5.2
Expenses due to overriding royalties (continuing operations)	15	-	11.4
Expenses of General Partner management fees	12A	1.0	-
Directors' remuneration		-	0.3
	20D		
Guarantee fee to Delek Group	12K4	0.4	-
Expenses for control holder bonus against a capital reserve	13G	4.3	-

For the year ended 31 December 2021:

*) Less than $0.1 million

Note 20 – Transactions and Balances vis-à-vis Interested Parties, Related Parties and Control Holders (Cont.):

C. Terms of Employment of the CEO of the General Partner, Mr. Yossi Abu ("Mr. Abu" 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 1 January 2022, the Partnership bears the full cost of his employment (100%), in lieu of the General Partner.

On 28 September 2022, the compensation committee and the board of directors decided, after reopening the discussion thereon, by way of "overruling", 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 21 September 2022. In the matter of the issuance of a motion for discovery and inspection order before filing a derivative claim in connection with approval of Mr. Abu's updated terms of office and employment by the compensation committee and the board of directors by way of "overruling", see Note 12L9 above.

Below is a brief description of the main updated terms of office and employment:

1. The CEO's monthly salary as of 31 December 2023 is ILS 208 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. 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 30 April 2027.

Note 20 – 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.:)

4. The CEO was granted on 27 July 2022 (the date of grant), for no consideration, 3,295,599 non-marketable options exercisable for 3,295,599 participation units. The allocation was made in accordance with the compensation policy and the option plan which was submitted to the Income Tax on 4 August 2022 pursuant to Section 102 of the Income Tax Ordinance [New Version], 5721-1961, and which was adopted by the board of directors on 27 July 2022. The options will vest in 3 equal annual installments, commencing from 1 August 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: 26 July 2027.
   In accordance with the previous compensation policy for officers in the Partnership and the General Partner, which was approved by the meeting of the holders of the participation units on 10 July 2019, as amended from time to time (the "**Previous Compensation Policy**"), and Mr. Abu's previous employment agreement, Mr. Abu was granted with 2,742,231 phantom units, whose base asset is a participation unit that confers the right to participate in the rights of NewMed Energy Trusts Ltd. (the "**Limited Partner**" or the "**Trustee**", and the "**Phantom Options**", respectively), which were exercisable in 3 installments until 1 June 2023. Accordingly, on 21 May 2023, Mr. Abu exercised all of the Phantom Options, at an exercise price (adjusted for profit distribution and tax advances up to and including 2021) of ILS 7.82 for the first installment, ILS 8.36 for the second installment, and ILS 8.92 for the third installment. The total consideration paid by the Partnership to Mr. Abu for the exercise of the Phantom Options amounted to a total of approx. ILS 7,345.5 thousand (approx. $2,019 thousand). A total of approx. ILS 1,179 thousand (approx. $325 thousand) was paid by the General Partner and a total of approx. ILS 6,166.5 thousand (approx. $1,694 thousand) was paid by the Partnership, in accordance with the commitment of the General Partner to bear a proportional part of the proceeds for the exercise of the Phantom Options due to the entry into force of the New Management Arrangement, as detailed in Note 12A above
5. In 2023, Mr. Abu received an annual bonus for 2022 in the sum of approx. ILS 2,932 thousand (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, and in 2021, the CEO received bonuses for 2020 in the sum of approx. ILS 3,977 thousand).

Note 20 – Transactions and Balances vis-à-vis Interested Parties, Related Parties and Control Holders (Cont.):

D. Further to Note 7C2 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 PSC, 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 PSC (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);
   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 PSC 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 PSC 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 PSC, 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. On 21 September 2022, the general meeting of the participation unit holders in the Partnership approved an amendment to the Partnership Agreement, whereby commencing from 1 January 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 such expenses (see Note 12A above). 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 20 – 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.):

2. (Cont.)

   In 2023, the Partnership recorded expenses in the statement of comprehensive income for its share in the aforesaid expense in the sum of approx. $0.4 million.
3. On 28 June 2023, 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 its subsidiaries, including the Partnership's CEO, for a period of one year commencing on 1 July 2023, with a total limit of liability of $270 million per claim and in the aggregate for the insurance period, all under terms and conditions which comply with the compensation policy.
4. In the matter of the commercial arrangement for the supply of natural gas between the Yam Tethys partners and the Leviathan Partners, see Note 7C3 above.
5. On 26 July 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 6 February 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. In May 2023 the additional pledge of approx. 1.1% of the participation units was removed, and they were returned to the General Partner.
6. 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.
7. On 23 December 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 1 January 2021 until 31 December 2023.
8. 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 12L7) 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 21 – 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 receivables, trade and other receivables and trade and other 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.

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.

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:

	31.12.2023			
	Level 1	**Level 2**	**Level 3**	**Total**
Financial assets at fair value through profit or loss:				
Future production-based royalties from the Karish and Tanin leases (see Note 8B above)	-	-	273.2	**273.2**
Loan to Energean in the context of the sale of the Karish and Tanin leases (see Note 8B above)	-	46.2	-	**46.2**
Total financial assets at fair value through profit or loss:	**-**	**46.2**	**273.2**	**319.4**

Notes to the Financial Statements as of 31 December 2023 (Dollars in millions)

Note 21 – Financial Instruments (Cont.):

B. Fair value hierarchy (Cont.):

	31.12.2022			
	Level 1	Level 2	Level 3	Total
Financial assets at fair value through profit or loss:				
Future production-based royalties from the Karish and Tanin leases (see Note 8B above)	-	-	320.8	**320.8**
Loan to Energean in the context of 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**

Adjustment due to fair value measurements classified as level 3 in the financial instruments fair value hierarchy:

	For the year ended 31 December	
	2023	2022
Balance as of January 1	**320.8**	**262.2**
Revenues	(42.6)	(2.3)
Remeasurement recognized in profit or loss	(5.0)	60.9
Balance as of December 31	**273.2**	**320.8**

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 Leviathan Bond bonds which were issued as stated in Note 10B:

	Fair value	Book value
Bonds:		
as of 31 December 2023	1,652.1	1,735.1
as of 31 December 2022	2,115.7	2,155.8

Notes to the Financial Statements as of 31 December 2023 (Dollars in millions)

Note 21 – Financial Instruments (Cont.):

D. Groups of financial instruments:

	As of 31 December	
	2023	**2022**
Financial assets:		
Cash and cash equivalents	29.1	22.4
Deposits	259.5	396.4
Trade receivables	194.5	199.0
Trade and other receivables	155.7	130.0
Other long-term assets	229.2	321.0
Total financial assets	**868.0**	**1,068.8**
Financial liabilities:		
Trade and other payables	1.5	3.5
Short-term liability to a banking corporation	80.0	-
Declared profits for distribution	-	50.0
Bonds (see Note 10B above)	1,735.1	2,155.8
Total financial liabilities	**1,816.6**	**2,209.3**

E. Risk management policy:

The Partnership's transactions expose the Partnership to various financial risks, such as: market risk (including foreign currency risk, fair value risk due to interest rate, linkage to the U.S. CPI, 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, price risk and fair value risk due to interest rate as follows:

1. **Currency risk**:
   Exchange rate risk mainly stems from assets, liabilities and expenses denominated in ILS. The risk mainly stems from the tax advances which the Partnership pays based on the taxable income for tax purposes in ILS, as well as the liability for deferred taxes, and expenses in ILS which expose the Partnership to cash flow risk and profit or loss risk.
2. **Interest risk**:
   Interest risk stems 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.

Notes to the Financial Statements as of 31 December 2023 (Dollars in millions)

Note 21 – Financial Instruments (Cont.):

F. Market risks (Cont.):

2. Interest risk (Cont.):

Following are the balances of financial instruments that bear variable interest according to their book value:

	As of 31 December	
	2023	2022
Financial instruments at variable interest:		
Assets:		
Deposits in banks (including cash and cash equivalents)	287.0	398.3
Trade and other receivables in the context of joint ventures	27.1	46.5
Total	**314.1**	**444.8**
Liabilities:		
Short-term liability to a banking corporation	80.0	-
Total	**80.0**	**-**

Following is the effect of the change in the event of a 0.5% change in the base interest rate, and with respect to a full year, with the other variables remaining constant:

	Effect on Profit or Loss	
	Increase in interest rate	Decrease in interest rate
	0.5%	**0.5%**
2023	1.2	(1.2)
2022	2.2	(2.2)

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. $273.2 million (as of 31 December 2022 in the sum of approx. $320.8 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. $46.2 million (as of 31 December 2022: in the sum of approx. $53.6 million).

Notes to the Financial Statements as of 31 December 2023 (Dollars in millions)

Note 21 – Financial Instruments (Cont.):

F. Market risks (Cont.):

2. Interest risk (Cont.):

Following are tests of sensitivity to a change in the capitalization interest, with the other variables remaining constant:

	As of 31 December 2023				
	Profit (loss) from the change in the capitalization interest				
	2%	1%	**Fair value**	-1%	-2%
Future production-based royalties from the Karish and Tanin leases (see Note 8B above)	(20.7)	(10.8)	**273.2**	11.8	24.6
Loan to Energean in the context of the sale of the Karish and Tanin leases (see Note 8B above)	(0.3)	(0.1)	**46.2**	0.2	0.3
Total	**(21.0)**	**(10.9)**	**319.4**	**12.0**	**24.9**

	As of 31 December 2022				
	Profit (loss) from the change in the capitalization interest				
	2%	1%	**Fair value**	-1%	-2%
Future production-based royalties from the Karish and Tanin leases (see Note 8B above)	(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

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. 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.

Note 21 – Financial Instruments (Cont.):

F. Market risks (Cont.):

3. **Price risk (Cont.):**

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.

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.

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.

Notes to the Financial Statements as of 31 December 2023 (Dollars in millions)

Note 21 – Financial Instruments (Cont.):

F. Market risks (Cont.):

3. Price risk (Cont.):

Below are extended sensitivity tests of future production-based royalties from the Karish and Tanin leases (see Note 8B above) relative to a change in the prices of natural gas and condensate, while the other variables are constant:

As of 31 December 2023								
Profit (loss) from the change in the price of natural gas								
30%	20%	10%	5%	**Fair Value**	-5%	-10%	-20%	-30%
39.5	25.3	14.3	7.1	**273.2**	(10.9)	(14.5)	(30.4)	(15.8)

As of 31 December 2023								
Profit (loss) from the change in the price of condensate								
30%	20%	10%	5%	**Fair Value**	-5%	-10%	-20%	-30%
20.4	13.6	6.7	3.4	**273.2**	(3.6)	(10.7)	(17.7)	(24.7)

As of 31 December 2022								
Profit (loss) from the change in the price of natural gas								
30%	20%	10%	5%	**Fair Value**	-5%	-10%	-20%	-30%
43.0	26.8	14.6	6.6	**320.8**	14.8	8.7	(7.1)	(25.2)

As of 31 December 2022								
Profit (loss) from the change in the price of condensate								
30%	20%	10%	5%	**Fair Value**	-5%	-10%	-20%	-30%
26.2	20.4	10.0	5.0	**320.8**	19.1	13.2	4.5	(7.1)

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 trade receivables balance as of 31 December 2023 is a current balance. The Partnership's principal customers in the report period are Blue Ocean which accounted for approx. 58% of the sales in the report period, and NEPCO which accounted for approx. 27% of the sales in the report period (48% and 27% of the sales in 2022, respectively). In light of past experience and since their current balances are partially backed up by collateral that was provided thereby, the Partnership estimates that the credit risk deriving from the sales of natural gas supplied to Blue Ocean and NEPCO is low.

Notes to the Financial Statements as of 31 December 2023 (Dollars in millions)

Note 21 – Financial Instruments (Cont.):

G. Credit risks (Cont.):

However, in view of the security and economic situation in the region's countries this risk has been increased. Moreover, 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.

Below are turnover and trade receivables, the value of which was not affected:

	Revenues for the year ended 31 December 2023	Trade receivables balance as of 31 December 2023		
		Total	Current balance	Disputed balance
NEPCO	296.3	45.8	45.8	-
Blue Ocean	629.5	128.6	128.6	-
Other customers	168.6	20.1	20.1	-
Total	**1,094.4**	**194.5**	**194.5**	**-**

	Revenues for the year ended 31 December 2022	Trade receivables balance as of 31 December 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**	**-**

1) 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.
2) 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.

Notes to the Financial Statements as of 31 December 2023 (Dollars in millions)

Note 21 – Financial Instruments (Cont.):

G. Credit risks (Cont.):

3) The Partnership has amounts receivable from a company accounted for at equity in the sum of approx. $30.1 million (2022: approx. $24.9 million), which were included under trade and other receivables and other long-term assets items. Amounts receivable are measured at fair value and discounted at an interest[32] 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.

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 and the deposits, 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:

2023	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	1.5	-	-	-	-	**1.5**
Short-term liability to a banking corporation	80.0	-	-	-	-	**80.0**
Bonds	-	112.9	770.6	693.8	605.7	**2,182.9**
Total	**81.5**	**112.9**	**770.6**	**693.8**	**605.7**	**2,264.4**

[32] The cap rate used in determining the fair value of the receivables was estimated at 22.8% as of 31 December 2023 (31 December 2022: 20.55%).

Notes to the Financial Statements as of 31 December 2023 (Dollars in millions)

Note 21 – Financial Instruments (Cont.):

H. Liquidity risk (Cont.):

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 profits for distribution	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**

Changes in liabilities deriving from financing activity:

	Balance as of 31 December 2022	Cash Flow	Effect of changes in amortized cost	Other changes	Balance as of Dec. 31, 2023
Bonds	**2,155.8**	(425.4)	4.5	-	**1,735.1**
Short-term liability to a banking corporation	**-**	80.0	-	-	**80.0**
Declared profits for distribution	**50.0**	(260.0)	-	210.0	**-**
Total liabilities deriving from financing activity	**2,205.8**	**(605.5)**	**4.5**	**210.0**	**1,815.1**

	Balance as of 31 December 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**
Declared profits for distribution and provision for balancing and tax payments	**86.2**	(186.7)	-	150.5	**50.0**
Total liabilities deriving from financing activity	**2,311.0**	**(261.2)**	**5.4**	**150.5**	**2,205.8**

Note 22 – Material Subsequent Events:

A. See Note 1D for details regarding an update in connection with the offer to purchase the Partnership's participation units.

B. See Note 7C1D for details regarding a reserves and contingent resources report in the Leviathan Leases.

C. See Note 12E for details regarding the commencement of the piping of the condensate from the Leviathan reservoir to ARF.

D. See Note 13C2 for details regarding the approval of the board of directors of the General Partner in the Partnership of a profit distribution in the sum of $60 million.

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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:	31 December 2023	**Report Date**:	18 March 2024

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 receipt of royalties 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 2023 and for 2023 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 30 May 2022, the Partnership released a shelf prospectus. For further details, see the Partnership's immediate report of 30 May 2022 (Ref.: 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 21 February 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 31 December 2023	Price of the shares listed on TASE as of 31 December 2023 (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 31 December 2023 (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. ("**NewMed England**"), a wholly (indirectly) owned subsidiary of the Partnership, the sum of £50 thousand, which was transferred thereto for the purpose of its establishment by NewMed Energy UK Limited (formerly Delek Energy Limited), a wholly-owned subsidiary of the Partnership which was incorporated in England and is NewMed England's parent company, and which shall be paid to NewMed England 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 7.20.2 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). The loan principal does not include accrued interest in the sum of approx. $1.4 million.

[7] An SPC which was established for the purpose of obtaining a license for the 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 7.11.3(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 31 December 2023	Price of the shares listed on TASE as of 31 December 2023 (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 31 December 2023 (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	37,347	_[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 7.25.5(a) 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 7 September 2022.

[11] An SPC wholly owned by the Partnership which was incorporated in Cyprus in connection with the EMG transaction (as defined in Section 7.25.5(a) 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 7.25.5 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 31 December 2023	Dividends received (or receivable by the Partnership) after 31 December 2023	Dividend payment dates after 31 December 2023	Management fees received as of 31 December 2023	Management fees received (or receivable by the Partnership) after 31 December 2023	Management fee payment dates after 31 December 2023	Interest	Interest payment dates
Leviathan Bond	194	-	194	-	-	-	-	-	-	-	-
EMED Pipeline	(50)	-	(39)	-	-	-	-	-	-	-	-
EMED B.V.	(5,546)	-	(5,300)	-	-	-	-	-	-	-	-
EMG	44,022	-	34,589	-	-	-	-	-	-	-	-

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 2023 (Dollars in thousands), as recognized in the financial statements as of 31 December 2023[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 an arrangement in connection with the Partnership's management expenses, according to which from 1 January 2022, the Partnership bears all of its management expenses, which until such date 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(a) 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	
Senior officers of the Partnership														
Yossi Abu	CEO	100%	0.05%	861,893	801,072	2,740,276[15][16]	-	-	-	-	-	-	212,152	**4,615,393**
Gabi Last	Active Chairman of the Board	100%	0.00%[17]	525,151	100,260								58,023	**683,434**
Sari Singer Kaufman	General Counsel, EVP	100%	-	397,174	109,287	-	-	-	-	-	-	-	81,122	**587,582**
Tzachi Habusha	VP Finance	100%	-	411,367	109,287	-	-	-	-	-	-	-	50,016	**570,670**
Zvi Karcz	VP Exploration	100%	-	376,561	92,894	-	-	-	-	-	-	-	68,319	**537,774**
Interested parties of the Partnership and/or the General Partner														
External directors	-	-	-	475.0	-	-	-	-	-	-	-	-	-	**475.0**

[15] The total consideration received by Mr. Abu for exercise of the phantom options totaled approx. $2,019 thousand. For further details, see Regulation 21(b)(2) below.

[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.

(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) Compensation policy

On 21 September 2022, the meeting of the Participation Unit holders decided not to approve an updated compensation policy for officers of the Partnership and NewMed Energy Management Ltd., the Partnership's general partner (the "**General Partner**"). For further details, see the Partnership's immediate reports of 6 September 2022 and 21 September 2022 (Ref.: 2022-01-092520 and 2022-01-120358, respectively), the information appearing in which is incorporated herein by reference.

Consequently, on 28 September 2022, the compensation committee and the board of directors of the General Partner (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 29 September 2022 (Ref.: 2022-01-121942), the information appearing in which is incorporated herein by reference.

(2) Yossi Abu

Mr. Yossi Abu ("**Mr. Abu**" or the "**CEO**") has served as CEO of the Partnership since 1 April 2011.

As specified in Regulation 22(a) below, since 1 January 2022, the Partnership has borne the full cost of Mr. Abu's employment (100%), in lieu of the General Partner.

On 21 September 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 6 September 2022 and 21 September 2022 (Ref.: 2022-01-092520 and 2022-01-120358, respectively), the information appearing in which is incorporated herein by reference.

Consequently, on 28 September 2022, the compensation committee and the Board decided, after reopening the discussion thereon, to approve the updated terms of office and employment for Mr. Abu, despite the objection of the meeting of the Participation Unit holders. For further details, see the Partnership's immediate report of 29 September 2022 (Ref.: 2022-01-121942), the information appearing in which is incorporated herein by reference.

For details regarding a motion filed according to Section 65OO of the Partnerships Ordinance [New Version], 5735-1975 (the "**Partnerships Ordinance**") and Section 198A of the Companies Law, 5759-1999 (the "**Companies Law**") for an order for the discovery and inspection of documents prior to the filing of a derivative suit in connection with approval of the updated terms of office and employment for Mr. Abu by the compensation committee and the Board by way of an "overruling", see Section 7.26.9 of Chapter A of this Report.

Accordingly, Mr. Abu's terms of office and employment are as follows (the "**Terms of Office and Employment**"):

Mr. Abu's monthly salary is approx. ILS 208.4 thousand gross (100%)[18] (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 indemnity, 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 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

[18] As of 31 December 2023.

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.

In addition, on 3 October 2022, Mr. Abu was allotted, 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)[19]. The allotment was performed in accordance with the Compensation Policy and the option plan which was submitted to Income Tax on 4 August 2022 pursuant to Section 102 of the Income Tax Ordinance [New Version], and was adopted by the Board on 27 July 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 value of the benefit deriving 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.

For further details, see the Partnership's immediate reports of 3 October 2022 and 12 October 2022 (Ref.: 2022-01-100665, 2022-01-100692 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

[19] 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.

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 – 26 July 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 Terms of Office and Employment, see the Partnership's immediate report of 6 September 2022 (Ref.: 2022-01-092520), the information appearing in which is incorporated herein by reference.

According to the previous compensation policy for officers of the Partnership and the General Partner, which was approved by the meeting of the Participation Unit holders on 10 July 2019, as amended from time to time (the "**Previous Compensation Policy**"), and Mr. Abu's previous employment agreement, Mr. Abu was granted 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**" and the "**Phantom Options**", respectively), and which were exercisable in 3 installments until 1 June 2023. For details regarding the terms and conditions of the Phantom Options, see Regulation 21(b)(2) of Chapter D of the 2021 periodic report, as released on 24 March 2022 (Ref.: 2022-01-033988). Accordingly, on 21 May 2023, Mr. Abu exercised all of the Phantom Options at an exercise price (adjusted to a profit distribution and tax advances up to and including 2021) of ILS 7.82 for the first installment, ILS 8.36 for the second installment, and ILS 8.92 for the third installment. The consideration received by Mr. Abu for exercise of the Phantom Options totaled approx. ILS 7,345.5 thousand, of which approx. ILS 1,179 thousand was paid by the General Partner for the share of the exercise proceeds attributed to the period preceding 1 January 2022, and approx. ILS 6,166.5 thousand was paid by the Partnership for the period after 1 January 2022, according to the date on which the Management Arrangement took effect, as specified in Regulation 22(a) below.

According to the Terms of Office and Employment, in 2023, Mr. Abu received an annual bonus for 2022 in the sum of approx. ILS 2,932 thousand, in accordance with the Previous Compensation Policy and 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 approx. ILS

1,268 thousand: entry into petroleum assets in Morocco; entry into the field of renewable energies; contribution to the promotion of ESG and gender equality at the Partnership; the ability to perform a profit distribution of no less than $100 million; natural gas nominations from the Leviathan project by Dolphinus in an annual amount of no less than 90% of the annual quantity in accordance with the export to Egypt agreement; (b) A component dependent on the quantitative tests specified below (35%): (1) change in adjusted net profit[20] (0%); (2) the making of investments or adoption of an investment decision (27.5%): the actual making of investments by the Partnership in a petroleum asset in an amount of no less than $50 million or the 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 due to the actual making of investments by the Partnership in a petroleum asset in an amount of no less than $50 million, and therefore he was entitled, in respect of this criterion, to an annual bonus of approx. ILS 872 thousand; (3) the raising of money or signing of natural gas sale agreements or signing of export agreements (7.5%): raising of money with the Partnership's share not falling below $200 million, or the signing of binding agreements for the sale of gas in a volume exceeding 25 BCM, or the signing of export agreements. Mr. Abu did not meet this criterion, and therefore was not entitled to an annual bonus therefor; and (c) The Board's discretionary component (25%): approx. ILS 792 thousand.

(3) 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, he held office as Chairman of the Board at the General Partner).

Since 1 November 2022, the Partnership has borne the full cost of Mr. Last's employment (100%).

Mr. Last's gross monthly salary is approx. ILS 125 thousand[21] (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

[20] 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**").
[21] As of 31 December 2023.

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 indemnity, 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, in the sum of up to 3 gross monthly salaries, 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 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.

In 2023, Mr. Last received from the Partnership an annual bonus for 2022 equal to 3 gross monthly salaries, in the sum total of ILS 367 thousand.

(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 gross monthly salary is approx. ILS 91.7 thousand[22] (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

[22] As of 31 December 2023.

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 further entitled to additional related benefits, such as her inclusion in officer indemnity, 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 continuing education, 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 2023, Ms. Singer received from the Partnership an annual bonus for 2022 in the sum of ILS 400 thousand, as a derivative of the components of the CEO's annual bonus.

(5) 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 91.7 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. Habusha is entitled to standard social benefits, a study fund, a pension plan, annual leave days (including entitlement to leave encashment), 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 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 indemnity, exemption and insurance arrangements, communication expenses (mobile

[23] As of 31 December 2023.

phone, internet, newspapers and payment of expenses in respect of reasonable use of his home phone), executive physicals, 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. 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.

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 2023, Mr. Habusha received from the Partnership an annual bonus for 2022 in the sum of ILS 400 thousand as a derivative of the components of the CEO’s annual bonus.

(6) 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 86.6 thousand[24] (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 indemnity, 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, participation in

[24] As of 31 December 2023. In February 2024, the compensation committee and the Board approved an update to Mr. Karcz’s monthly salary commencing from the salary for February 2024. Accordingly, as of the report approval date, Mr. Karcz’s gross monthly salary is approx. ILS 93 thousand (the salary is updated every 3 months according to the CPI).

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 February 2024, the compensation committee and the Board approved the granting to Mr. Karcz of a one-time retention bonus in the sum total of ILS 270 thousand. The retention bonus will be paid in 3 equal installments, as follows: one monthly salary was paid together with the February 2024 salary; one monthly salary will be paid together with the February 2025 salary, provided that he is employed by the Partnership on 28 February 2025; and one monthly salary will be paid together with the February 2026 salary, provided that he is employed by the Partnership on 28 February 2026.

In 2023, Mr. Karcz received from the Partnership an annual bonus for 2022 equal to 4 gross monthly salaries, in the sum total of ILS 340 thousand, as a derivative of the components of the CEO's annual bonus.

(7) External directors

On 22 October 2015, the meeting of the Participation Unit holders decided that Mr. Amos Yaron and Mr. Jacob Zack ("**Mr. Yaron**" and "**Mr. Zack**", respectively), 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 22 October 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 third and final term of office, see the Partnership's immediate reports of 3 October 2021, 14 October 2021 and 24 October 2021 (Ref.: 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 28 January 2019 to approve the appointment of Mr. Efraim Sadka as an external director commencing from 1 April 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 second term of office, see the Partnership's immediate reports of 17 February 2022 and 24 March 2022 (Ref.: 2022-01-019783 and 2022-01-034714, respectively), the information appearing in which is incorporated herein by reference.

(8) The Supervisors

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 65 thousand per month[25] (plus VAT). The monthly fee is updated every 3 months in accordance with changes in the CPI relative to

[25] As of 31 December 2023.

the April 2020 CPI rate. For details regarding the decision of the meeting of the Participation Unit holders of 29 May 2023 to approve the appointment of the Supervisors, from the date of the said meeting's approval and for a period of 18 months or until the date of the closing of the transaction for the purchase of all of the Participation Units held by the public and some of the Participation Units held by Delek Group, if closed, as specified in Section 1.8 of Chapter A of this Report (the "**BP-ADNOC Transaction**"), whichever is earlier, and to approve their terms of office and employment, see the Partnership's immediate reports of 24 April 2023 and 29 May 2023 (Ref.: 2023-01-044772 and 2023-01-057420, respectively).

In addition, 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 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 22 December 2016, the meeting of the participation unit holders confirmed, without derogating from the provisions of the Partnership Agreement signed on 1 July 1993, as amended from time to time, between the General Partner and the Limited Partner (the "**Partnership Agreement**"), and the trust agreement of 1 July 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 18 August 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 10 August 2020 and 18 August 2020 (Ref.: 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 the Participation Unit holders to approve a budget for the Supervisor for overseeing various outlines for the listing of the Partnership's assets on the London Stock Exchange (the "**Restructuring Process**") of 17 July 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 3 March 2021, on 2 January 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 2 July 2019, 17 July 2019, 8 February 2021, 3 March 2021, 12 December 2022 and 3 January 2023 (Ref.: 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 6 September 2018, on 1 June 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 and Infrastructures. For further details regarding the said meetings, see the Partnership's immediate reports of 2 September 2018, 12 September 2018, 25 May 2020 and 1 June 2020 (Ref.: 2018-01-081628, 2018-01-083794, 2020-01-052383 and 2020-01-056283, respectively), the information appearing in which is incorporated herein by reference.

   In addition, on 3 March 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 (the "**Counterclaim**"). For further details regarding the said meeting, see the Partnership's immediate reports of 8 February 2021 and 3 March 2021 (Ref.: 2021-01-015963 and 2021-01-025905, respectively), the information appearing in which is incorporated herein by reference, and for further details regarding the Supervisor's Claim and the Counterclaim, see Section 7.26.5 of Chapter A of this Report.

5. On 24 July 2023, the meeting of the Participation Unit holders decided to approve for the Supervisor a fee in addition to its monthly fee in connection with supervising the BP-ADNOC Transaction and overseeing the independent committee that was appointed by the Board in connection with this transaction, as specified in Section 1.8 of Chapter A of this Report. For further details, see the Partnership's immediate reports of 15 June 2023 and 24 July 2023 (Ref.: 2023-01-066222 and 2023-01-084408, respectively), the information in which is incorporated herein by reference.

(9) <u>The Trustee</u>

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 2 January 2023, the meeting of the Participation Unit holders approved for the Trustee a fee in addition to its annual fee in connection with the Restructuring Process. For further details, see the Partnership's immediate reports of 12 December 2022 and 3 January 2023 (Ref.: 2022-01-150004 and 2023-01-002016, respectively), the information appearing in which is incorporated herein by reference.

3. On 24 July 2023, the meeting of the Participation Unit holders decided to approve for the Trustee a fee in addition to its annual fee for the performance of actions in connection with the BP-ADNOC Transaction. For further details, see the Partnership's immediate reports of 15 June 2023 and 24 July 2023 (Ref.: 2023-01-066222 and 2023-01-084408, respectively), the information in which is incorporated herein by reference.

<u>Regulation 21A</u>: **<u>The Partnership's controlling interest holder</u>**

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. approx. 54.66% of the issued unit capital of the Partnership[26].

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 23 April 2021, the General Partner was entitled to the payment of management fees and to reimbursement of any and all direct expenses entailed by management of the Partnership and incurred thereby.

For further details, see Regulation 22(a) of the 2022 periodic report, as released on 28 March 2023 (Ref.: 2023-01-033096) (the "**2022 Periodic Report**").

According to the decision of the meeting of the Participation Unit holders of 21 September 2022 in

[26] To the best of the Partnership's knowledge, and according to Delek Group's reports, as of the report approval date, a majority of the Participation Units held by Delek Group is pledged in favor of the holders of the bonds issued by Delek Group, and in this context approx. 4.5% of the Participation Unit capital held by the General Partner is pledged.

connection with the costs of management of the Partnership and the General Partner (the "**Management Arrangement**"), from 1 January 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.

According to the 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 for the Partnership's offices which, as of the report approval date, are leased by the Partnership from Delek Group, as specified in Regulation 22(h) below.

Since, according to the Management Arrangement, the General Partner does not bear the Partnership's management expenses, insofar as the General Partner shall pay, out of pocket, any part of the Partnership's management expenses, it will reimbursed 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 regarding the Management Arrangement and its approval, see the Partnership's immediate reports of 6 September 2022 and 21 September 2022 (Ref.: 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 7.25.8(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[27].

In 2023, the Partnership recorded expenses in respect of royalties to Delek Overriding Royalty for the Leviathan project in the sum total of approx. $14.1 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 18 April 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**"), 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. 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

[27] 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 oil and/or gas and/or other valuable substances that shall be produced and exploited from the Leviathan leases to Delek Overriding Royalty.

of the Guarantee fee that the Partnership paid Delek Group in 2023 totaled approx. $368 thousand.[28]

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 ("**Block 12 Work Plan**"[29]), 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)[30]; 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

[28] The engagement was approved on 14 April 2013 by the Board and on 18 April 2013 by the meeting of the Participation Unit holders. For further details, see the Partnership's immediate reports of 14 April 2013 and 18 April 2013 (Ref.: 2013-01-036844 and 2013-01-039418, respectively). Furthermore, on 8 July 2018, the audit committee confirmed that fixing the payment in respect of the Guarantee for a guarantee period of 25 years, as determined on the date of approval of the Guarantee transaction for the first time, is a reasonable period.

[29] The Partnership will deliver to Delek Group prior notice of any intention to approve a Block 12 Work Plan.

[30] The Partnership has entered into 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.

possible only subject to reaching arrangements on division of liability and mutual indemnity 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 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 Limited ("**Chevron Cyprus**"[31]) 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 indemnity 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

[31] To the best of the Partnership's knowledge, Chevron Cyprus is a wholly owned subsidiary of Chevron Corporation ("**Chevron Corp.**").

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 3 May 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. The agreement expired on 30 June 2023. In 2023, the Partnership's share in the revenues from the sale of gas for Delek Group's share in the Yam Tethys project totaled approx. $21 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 17 March 2021 (Ref.: 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) For details regarding the BP-ADNOC Transaction and regarding the activity of the committee that was set up in the context thereof, during the report year, see Section 1.8 of Chapter A of this Report.

(h) Following approval of the Management Arrangement, since 1 January 2022, the Partnership has borne payment of the rent to Delek Group for the Partnership's offices in Herzliya. The audit committee and the Board approved the said engagement at arm's length, in accordance with an opinion of an independent appraiser. The term of the lease, which includes an option period, is expected to end on 14 October 2026, with an option to extend it until 14 October 2031, and the monthly rent is ILS 80 per sqm for the office space and the public spaces, linked to the CPI. In addition, the Partnership pays monthly management fees and a payment for the lease of parking spaces. In 2023, the Partnership paid Delek Group, in respect of the said engagement, the sum of approx. $422 thousand.

<u>Negligible transactions</u> – 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 an accounting with Delek Group in relation to expenses for IT and cybersecurity preparedness services.

<u>Regulation 24</u>: **<u>Holdings of interested parties and senior officers</u>**

For details regarding holdings of interested parties and senior officers of the Partnership and/or the General Partner as of 30 June 2023, see the Partnership's immediate report of 6 July 2023 (Ref.: 2023-01-076488), the information appearing in which is incorporated herein by reference[32].

[32] To the best of the Partnership's knowledge, no change has occurred in the said holdings as of 31 December 2023.

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

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	Daniel 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[33]

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:	9 September 1946	12 October 1962	8 January 1977	14 August 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?[34]	-	-	-	-
Employee of the General Partner, a subsidiary, an affiliate or of an interested party?	Active Chairman of the Board, member of the Partnership's donations committee (the "**Donations Committee**"), a director of a private subsidiary (SPC) of the Partnership and a director of Med-Enlight General Partner (2023) Ltd. (which was established as part of the Partnership's collaboration with Enlight Renewable Energy Ltd. ("**Enlight**"), as specified in Section 7.9 of Chapter A of this Report) ("**Med-Enlight**")	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:	17 May 2001, from 8 January 2020 as Board Chairman, and from 1 April 2022 as Active Chairman of the Board	26 August 2015	7 January 2020	10 September 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

33 The specification of this regulation presents the directors who serve on the Board as of the report approval date.

34 Within the meaning of the term in Section 1 of the Compensation Regulations.

Details	Gabi Last	Leora Pratt Levin	Idan Wells	Tamir Polikar
Occupation in the last five years:	Active Chairman of the Board of the General Partner, member of the Donations Committee, a director of Med-Enlight, Chairman of the Board of Delek Group and the Delek Foundation for Education, Culture and Science (CIC), 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 of the Tshuva Group private companies (at Delek Group's controlling shareholder) and a director of News Co. Ltd. and Keshet Broadcasting Ltd.	A director of the General Partner, deputy CEO and CFO at Delek Group, a director of subsidiaries of Delek Group, real estate developer in Israel and overseas, business consultant and a director of Polikar Holdings Ltd.
Other directorships:	A private subsidiary (SPC) of the Partnership and Med-Enlight	Delek Energy, Delek Sea Maagan (2011) Ltd., Delek Israel Holdings Group Ltd., Delek Infrastructures Ltd., Delek Power Plant Management Ltd., Delek Petroleum Ltd., Delek Property Development Ltd., Delek Overriding Royalty, Mehadrin Ltd., DKL Investments Limited, DKL Energy Limited and an observer on the board of Ithaca Energy Plc	Delek Energy, Ithaca Energy Plc, Mehadrin Ltd., 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 Property Development Ltd., Delek Overriding Royalty, Delek Israel Properties (D.P.) Ltd., Delek, Delek Hungary Limited, Mehadrin Ltd., Polikar Holdings Ltd., Gallipoli Real Estate Investments Ltd., Briza Lgyrp Ltd., and subsidiaries thereof, Elysee Downtown Ltd. and an observer on 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:	5 February 1940	11 April 1946	10 July 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?[35]	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:	22 October 2015	22 October 2015	1 April 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	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) and Atidim High Tech Industries Co. Ltd.
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	No	Yes	Yes

[35] Within the meaning of the term in Section 1 of the Compensation Regulations.

Details	Amos Yaron	Jacob Zack	Efraim Sadka
determined by the board of directors pursuant to Section 92(a)(12) of the Companies Law?			

Regulation 26A: Senior officers of the Partnership and/or the General Partner[36]

Officer	I.D. number	Date of 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	7 December 1977	1 April 2011	CEO of the Partnership, member of the Donations Committee, a director of private subsidiaries (SPCs) of the Partnership, a director of Med-Enlight and of Yes-Enlight General Partner Ltd. and the limited partner of Yes-Enlight Holdings, Limited Partnership (which were established as part of the Partnership's collaboration with Enlight, as specified in Section 7.9 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, member of the Donations Committee, a director of Med-Enlight and of Yes-Enlight General Partner Ltd. and the limited partner of Yes-Enlight Holdings, Limited Partnership, CEO of Delek Energy, and a director of private subsidiaries (SPCs) of the Partnership and private companies owned by him.
Sari Singer Kaufman	037485174	22 February 1980	14 May 2018 – EVP, 1 August 2017 – General Counsel 10 March 2012 – attorney	EVP and General Counsel of the Partnership, member of the Donations Committee and a director of a private subsidiary (SPC) of the Partnership	No	No	LL.B from Tel Aviv University, attorney, member of the Israel Bar Association	EVP and General Counsel of the Partnership, member of the Donations Committee, a director of a private subsidiary (SPC) of the Partnership, and an external director of Steakholder Foods Ltd.
Zvi Karcz	059784355	24 February 1967	12 August 2014 - VP Exploration,	VP Exploration of the Partnership	No	No	B.Sc. in Geology from the Hebrew University of Jerusalem, M.Sc. in Geology from the Hebrew University of	VP Exploration of the Partnership and Chief Geologist of the Partnership

[36] 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 of 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
			7 September 2011 - Chief Geologist				Jerusalem, Ph.D. in Geology and Geophysics from Columbia University, New York, U.S.	
Tzachi Habusha	027268317	23 March 1974	1 January 2022	CFO of the Partnership, member of the Donations Committee, a director of a private subsidiary (SPC) of the Partnership and a director of Med-Enlight	No	No	B.A. in Economics from Bar-Ilan University, LL.M from Bar-Ilan University, MBA from the College of Management, CPA	CFO of the Partnership, member of the Donations Committee, a director of a private subsidiary (SPC) of the Partnership, a director of Med-Enlight and CFO of Israel Airports Authority.
Ronen Edward	024652745	13 October 1969	1 January 2022 - VP Leviathan Project 1 August 2017 – CFO 17 May 2017 – CFO of Avner Oil & Gas Exploration - Limited Partnership	VP Leviathan Project at the Partnership	No	No	B.A. in Accounting and Business Administration from the College of Management, CPA	VP Leviathan Project at the Partnership and CFO of the Partnership and the General Partner
Tal Levi	034837245	19 April 1979	23 May 2022 – VP Budget & Control 1 June 2018 – Head of Control & Investments 10 February 2013 – Controller	VP Budget & Control at the Partnership	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	24 April 1980	14 May 2018 - VP Regulatory & Public Affairs 14 June 2015 - Head of Media & Public Affairs	VP Regulatory & Public Affairs at the Partnership and Chairman of the Donations Committee	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, Chairman of the Donations Committee and Head of Media & Public Affairs at the Partnership
Saar Prag	037693942	17 October 1975	3 June 2021 – VP Natural Gas Trade 1 August 2017 – Head of Natural Gas Trade	VP Natural Gas Trade at the Partnership and a director of private subsidiaries (SPCs) of the Partnership	No	No	LL.B from the Hebrew University of Jerusalem, attorney, member of the Israel Bar Association	VP Natural Gas Trade at the Partnership, a director of private subsidiaries (SPCs) of the Partnership and Head of Natural Gas Trade at the Partnership

Officer	I.D. number	Date of 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
Lior Cohen	303014237	3 April 1989	25 July 2021	Financial Controller at the Partnership	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	2 June 1965	1 February 2016	Internal auditor of the Partnership and the General Partner, and 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 Information Systems Control (CRISC), CPA	Internal auditor of the Partnership and the General Partner, internal auditor of Delek Group, and partner at Rosenblum-Holtzman, CPAs. Mr. Gana has information security and/or cyber expertise.

Regulation 26B: Independent authorized signatories

As of 31 December 2023, 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

(a) On 2 January 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)(b) below and the Partnership's immediate report of 2 January 2023 (Ref.: 2023-01-001458), the information appearing in which is incorporated herein by reference.

(b) On 18 December 2023, the meeting of the Participation Unit holders decided to approve an amendment to Section 5.1 of the Partnership Agreement, such that the licenses in Zone I in the area of blocks 4, 5, 6, 7, 8 and 11 (the "**Zone I Licenses**") shall be added to the list of petroleum assets mentioned in that section. For further details, see Regulation 29(c)(e) below and the Partnership's immediate report of 18 December 2023 (Ref.: 2023-01-137343), 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 a plan to purchase the bonds that were issued by Leviathan Bond (the "**Leviathan Bond Bonds**"), see the Partnership's immediate report of 23 January 2023 (Ref.: 2023-01-010464), the information appearing in which is incorporated herein by reference. On 15 November 2023, the Board authorized the continued performance of buybacks in accordance with a plan for the buyback of the Leviathan Bond Bonds as aforesaid, from the Leviathan Bond bond series maturing on 30 June 2025 and/or from the bond series maturing on 30 June 2027. For further details, see Section

E of Part 1 of the Board of Directors' Report (Chapter B of this Report). It is further noted that on 1 May 2023, Leviathan Bond partially prepaid the first series of the Leviathan Bond Bonds. For further details, see the Partnership's immediate report of 13 April 2023 (Ref.: 2023-01-040410), the information appearing in which is incorporated herein by reference, and Section c.2 of Part 1 of the Board of Directors' Report (Chapter B of this Report).

(b) On 27 March 2023, 10 May 2023, 20 August 2023 and 15 November 2023, 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 9 April 2023, 22 May 2023, 30 August 2023 and 27 November 2023, respectively, and the dates of the said distributions being 20 April 2023, 15 June 2023, 14 September 2023 and 21 December 2023, respectively. For further details, see the Partnership's immediate reports of 28 March 2023, 11 May 2023, 21 August 2023 and 16 November 2023 (Ref.: 2023-01-033114, 2023-01-050355, 2023-01-095958 and 2023-01-104098, respectively), the information appearing in which is incorporated herein by reference. In addition, on 18 March 2024, 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 28 March 2024, and the date of the said distribution being 11 April 2024.

(c) For details on amendments to the Partnership Agreement, see Regulation 28 above.

<u>Regulation 29(c)</u>:

(a) For details on the decision of the meeting of the Participation Unit holders of 2 January 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 Regulations 21(b)(8) and 21(b)(9) above.

(b) For details on the decision of the meeting of the Participation Unit holders of 2 January 2023 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 12 December 2022 and 3 January 2023 (Ref.: 2022-01-150004 and 2023-01-002016, 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 29 May 2023 to approve the appointment of Fahn Kanne & Co., CPAs, together with Keidar Supervision and Management, to serve together as supervisor at the Partnership, and to approve the terms of office and employment of the Supervisor, see Regulation 21(b)(8) above.

(d) For details on the decision of the meeting of the Participation Unit holders of 24 July 2023 to approve for the Supervisor a fee in addition to the monthly fee in connection with supervision of the BP-ADNOC Transaction and overseeing the committee that was set up in the context thereof, and to approve for the Trustee a fee in addition to the annual fee for the performance of actions in the context of the closing of the transaction, see Regulations 21(b)(8) and 21(b)(9) above.

(e) For details on the decision of the meeting of the Participation Unit holders of 18 December 2023 to approve the Partnership's participation in oil and/or natural gas exploration and production activities in the area of the Zone I Licenses, and to this end to amend Section 5.1 of the Partnership Agreement, such that the Zone I Licenses shall be added to the list of petroleum assets specified in that section, and to authorize the General Partner, in accordance with the provisions of Section 9.4 of the Partnership Agreement, to refrain from the distribution of profits for purposes of investment in actions in the area of the Zone I Licenses, in accordance with the work plans as shall be approved by the partners in the Zone I Licenses from time to time, see the Partnership's immediate reports of 22 November 2023 and 18 December 2023 (Ref.: 2023-01-105883 and 2023-01-137334, respectively), the information 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 indemnity undertakings and exemptions from liability that were granted to directors and officers of the Partnership, the General Partner and Leviathan Bond, 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) For details regarding an engagement in a D&O insurance policy for a period of one year from 1 July 2022, see Regulation 29A(4)(c) of Chapter D of the 2022 Periodic Report.

(d) On 28 June 2023, the compensation committee and the Board, in accordance with the 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 the Partnership's CEO, for a period of one year from 1 July 2023, with a total limit of liability of $270 million per claim and in the aggregate, all under terms and conditions which comply with the Compensation Policy, as specified in Regulation 21(b)(1) above. For further details, see the Partnership's immediate report of 28 June 2023 (Ref.: 2023-01-071952), the information in which is incorporated herein by reference.

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: 18 March 2024

NEWMEDENERGY

Part E

Report on the effectiveness of internal control over financial reporting and disclosure

This report is a convenience translation of NewMed Energy – Limited Partnership's Hebrew-language Annual Report on the Effectiveness of Internal Control over Financial Reporting and Disclosure pursuant to Section 38C(a) of the Securities Regulations (Immediate and Periodic Reports), 5730-1970. The original Hebrew-language version is the only binding version and shall prevail in any event of discrepancy.

NewMed Energy – Limited Partnership

2023 Annual Report on the Effectiveness of Internal Control over Financial Reporting and Disclosure pursuant to Regulation 9B(a) of the Securities Regulations (Immediate and Periodic Reports), 5730-1970:

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 "**GP**"), 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 GP;
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 GP, which are designed to provide a reasonable level of 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 GP, has reviewed and evaluated internal control over financial reporting and disclosure at the Partnership and the effectiveness thereof.

The evaluation of the effectiveness of internal control over financial reporting and disclosure performed by the management of the Partnership under the supervision of the board of directors of the GP, included: entity-level controls, including controls over the process of preparation and closing of a financial report and general controls over information systems, controls over the process of the accounting vis-à-vis the operators of the joint ventures, and controls over the cash management process, including investments, and the process of raising and managing 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 GP, as specified above, the board of directors of the GP and the management of the Partnership have reached the conclusion that internal control over financial reporting and disclosure in the Partnership as of December 31, 2023, is effective.

Statement of CEO pursuant to Section 9B(d)(1) of the Regulations:

Statement of Managers

Statement of CEO

I, Yossi Abu, state that:

(1) I have reviewed the periodic report of NewMed Energy - Limited Partnership (the "**Partnership**") for 2023 (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 GP in the Partnership, based on my most current evaluation of internal control over financial reporting and disclosure:

a. Any and all significant flaws and material weaknesses in the setting or maintaining internal control over financial reporting and disclosure which may reasonably adversely affect the Partnership's ability to gather, process, summarize or report financial information in a manner which casts a doubt on the reliability of the financial reporting and preparation of the financial statements in conformity with the provisions of the law; and -

b. Any fraud, either material or immaterial, which involves the CEO or anyone reporting to him directly or which involves other employees who play a significant role in internal control over financial reporting and disclosure;

(5) I, myself or jointly with others in the Partnership:

a. Have set controls and procedures, or confirmed the setting and maintaining of controls and procedures under my supervision, which are designed to ensure that material information in reference to the Partnership, is brought to my knowledge by others in the Partnership, particularly during the preparation of the Reports; and -

b. Have set controls and procedures, or confirmed the setting and maintaining of controls and procedures 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. I 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 GP in the Partnership and the management of the Partnership with regard to the effectiveness of 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 18, 2024	Yossi Abu	CEO	
Date	Full name	Title	Signature

Statement of the most senior financial officer pursuant to Section 9B(d)(2) of the Regulations:

Statement of Managers

Statement of the most senior financial officer

I, Tzachi Habusha, state that:

(1) I have reviewed the financial statements and other financial information included in the reports of NewMed Energy - Limited Partnership (the "**Partnership**") for 2023 (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 GP 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 doubt on the reliability of the financial reporting and preparation of the financial statements in conformity with the provisions of the law; and -

b. Any fraud, either material or immaterial, which involves the CEO or anyone reporting to him directly or which involves other employees who play a significant role in internal control over financial reporting and disclosure;

(5) I, myself or jointly with others in the Partnership:

a. Have set controls and procedures, or confirmed the setting and maintaining of controls and procedures 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 to 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 the setting and maintaining of controls and procedures 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. I have evaluated the effectiveness of internal control over financial reporting and disclosure, insofar as it pertains to the financial statements and to the other financial information included in the Reports as of the date of the Reports; my conclusions regarding my evaluation as aforesaid were presented to the board of directors of the GP in the Partnership and management of the Partnership and are incorporated herein.

The aforesaid does not derogate from my responsibility or from the responsibility of any other person, pursuant to any law.

March 18, 2024	Tzachi Habusha, CPA	VP Finance	
Date	Full name	Title	Signature

Valuation

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 2024

This document is a translation of the original Hebrew-language document by Giza Singer Even Ltd. 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

Table of Contents

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 leases I/16 "Tanin" (the "**Tanin Royalties**") and I/17 "Karish" (the "**Karish Royalties**", and collectively: the "**Royalties**") as of 31 December 2023 (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.

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[1] On 17 May 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 22 February 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 plc[3] (the parent company of Energean Israel Limited[4]), including a resources and reserves report as of 31 December 31 2022 prepared by DeGolyer and MacNaughton and released on 23 March 2023 ("**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,
[signature]

Giza Singer Even Financial Advisory Ltd.
18 March 2024

[3] Formerly, Energean Oil & Gas plc.
[4] Formerly, Ocean Energean Oil and Gas Ltd.

2. Executive Summary

2.1 Background

NewMed Energy – 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 mainly in exploration, development, production and marketing of natural gas, condensate and petroleum in Israel and Cyprus.

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**") and Chevron Energy Mediterranean[5] ("**Chevron**") 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 (17 December 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 16 August 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 divided into 10 annual equal installments plus interest according to the mechanism set in the agreement, 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,[6] by which the Partnerships are charged regarding the original share of NewMed Energy and Avner in the leases (the "**Royalties**").

[5] As of the decision date, NewMed Energy and Avner jointly held 52.941% of the reservoirs (in equal shares) and Chevron Energy Mediterranean held 47.059% of the reservoirs.

[6] As defined in the reports of NewMed Energy and Avner to the TASE on 25 December 2016.

GIZA SINGER EVEN

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 the D&M CPR[7]:

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**

Based on Energean's financial statements as of 30 September 2023, Energean's report to TASE dated 18 January 2023 regarding operating and financial updates as of 31 December 2023 and the conversion rate derived from the above table between the quantity of natural gas and the quantity of the hydrocarbon liquids in the Karish reservoir, during 2023 Energean produced ~4.4 BCM of natural gas and ~3.8 million barrels of hydrocarbon liquids. In the context of the royalties paid by Energean to the Partnership, it does not provide the Partnership with details regarding the production quantities and therefore it is difficult to estimate these quantities. In addition, it transpires from Energean's financial statements that the rate of gas production (in annual terms) is ~6 BCM. According to these reports, and based on the value of the royalties transferred to the company, we reduced the remaining reserves and resources in the Karish reservoir, as specified in the D&M CPR.

On 7 October 2023, the terrorist organization "Hamas" launched a murderous attack on Israel, targeting in particular communities and military bases in the south of the State of Israel. Further to the attack, the Israeli government declared the Iron Swords war against the terrorist organization as aforesaid (the "**War**"). As of the date of approval of the financial statements, the War is in full swing, and it is not possible to foresee how long it will last and what its implications will be on the Partnership, its business and its assets.

[7] https://www.energean.com/media/5400/dm-final-report-energean-israel-2022ye.pdf.

Shortly after the outbreak of the War, gas production from the Tamar reservoir was discontinued according to the government's order. No such order was given for the Leviathan and Karish reservoirs, and as of the writing of this report, production from the Leviathan reservoir continues as usual. At the same time and pursuant to the government's order, the activity of the EMG pipeline, which constitutes a primary transmission infrastructure for piping of gas from Israel to Egypt, was discontinued. Note that on 9 November 2023, the Ministry of Energy notified the operator of the Tamar reservoir that the Tamar reservoir may be reactivated and shortly thereafter the regular activity of the EMG pipeline resumed. As of the Valuation Date, production from the Leviathan, Tamar and Karish reservoirs continues as usual.

Due to the War, in October 2023, the credit rating agencies, Moody's and Fitch, announced that the credit rating of the State of Israel is being considered for possible downgrade. Furthermore, the rating agency, S&P Global, announced the downgrading of the credit rating outlook of the State of Israel from stable to negative, while leaving the existing credit rating unchanged.

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. According to the assumptions specified in the Paper itself, the total value of the Royalties as of 31 December 2023 is estimated at approx. $273.2 million (the value of the Karish Royalties (including Karish North) and the Tanin Royalties are estimated at approx. $232.5 million and approx. $40.7 million, respectively).

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 the Cap Rate (in Base Points)	**+250 bp**	232.6	250.5	234.2	247.9	264.0	275.5	290.6
	+150 bp	241.1	259.5	243.3	257.4	274.2	285.9	301.6
	+50 bp	250.3	269.3	253.2	267.7	285.3	297.2	313.7
	-	255.3	274.5	258.5	**273.2**	291.2	303.3	320.1
	-50 bp	260.4	280.0	264.1	279.0	297.4	309.6	326.8
	-150 bp	271.3	291.5	275.9	291.2	310.7	323.1	341.1
	-250 bp	283.3	304.2	288.9	304.7	325.2	337.9	356.8

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%):

<table>
<tr><th>For 50% of the Revenues from the Karish and Tanin Leases</th><th>For 50% of the Revenues from the Karish and Tanin Leases</th></tr>
<tr><td>3% before the Investment Recovery Date
(0.794% of the total revenues of the reservoir)</td><td rowspan="2">6%
(1.588% of the total revenues of the reservoir)</td></tr>
<tr><td>13% after the Investment Recovery Date
(3.441% of the total revenues of the reservoir)</td></tr>
</table>

3.2 The sold interests

On 7 February 2012, and on 22 May 2013, the Partnerships reported to TASE that significant quantities of natural gas were discovered in the Tanin-1 and Karish-1 wells in the area of the exploration licenses Alon A and Alon C, respectively. In December 2015, the Petroleum Commissioner at the Ministry of Energy award the holders of rights in the exploration licenses, NewMed Energy (26.4705%), Avner (26.4705%) and Chevron (47.059%), the lease deeds of "Tanin" and "Karish", respectively. Note that in May 2017, Avner merged with and into NewMed Energy and consequently Avner was stricken off without dissolution.

On 16 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 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 14 November 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 17 December 2015, the then Prime Minister (in his capacity as Minister of Economic Affairs) signed several exemptions from the Antitrust Law which were adopted in the context of the government resolution on the Gas Framework.

On 16 August 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 Plc. 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 27 December 2016, the Partnerships announced that the closing conditions for the transaction were fulfilled. On 27 March 2018, Energean notified the Partnerships of the adoption of an investment decision for the development of the Karish reservoir. In addition, on 14 January 2021, Energean reported the adoption of a Final Investment Decision (FID) in the "Karish North" reservoir.

On 25 October 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 $40 million which was paid to the Sellers on the transaction closing date;

   ii. The consideration balance, in an amount of $108.5 million, will be paid to the Sellers divided into ten equal annual 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];

   iii. 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.

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[8] On 27 March 2018, Energean notified the Partnerships of the adoption of an investment decision for the development of the Karish reservoir, and from March 2018, Energean began to make the annual payments as aforesaid. For more information, see Section 4.6.2.

[9] As defined in the reports of NewMed Energy and Avner to TASE on 25 December 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, 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 for 2022[13], most of the domestic demand for natural gas derived from the electricity sector, total consumption by which in 2022 amounted to approx. 10.1 BCM, which represents ~80% of the demand for natural gas. The rest of demand for natural gas is attributed to the industrial sector, total consumption by which in 2022 amounted to approx. 2.56 BCM.

- **Clean energy** – The main substances emitted from the burning of natural gas are carbon dioxide and water vapor. Coal and petroleum are more complex fuels, *inter alia*, because they have higher carbon ratios, and nitrogen and sulphur components. Therefore, when they burn, more contaminants are released, including ash particles of substances which are not burned and are consequently emitted into the atmosphere and add to the air pollution. Natural gas combustion on the other hand, releases a relatively small quantity of contaminants, and therefore the use thereof reduces the air pollution. In such context it is noted that thanks to the conversion of most of the electricity production in Israel from coal, fuel oil and diesel oil to use of natural gas, air pollution levels caused by electricity production in Israel have been reduced by tens of percentage points.

- **Energy independence** – The geopolitical characteristics of Israel make it an energetic island with limited ability to import fuels from neighboring countries, which forced it to rely for many years on costly fuels import from Europe. Israel's energetic isolation was somewhat reduced between the years 2008 and 2012 upon the commencement of supply of natural gas from Egypt, however, the sudden cut of supply illustrated the importance of the development of local energy sources. The development of the natural gas market in Israel provides the Israeli industry with energetic security in the long term and will reduce its dependence on international energy prices.

[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 2022 – Natural Gas Authority

- **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 the sales to the ultimate consumer. Moreover, the Israeli market has a few unique taxation systems which apply to the natural gas sector, in addition to excise tax, which apply to natural gas, similarly to all of the other fuel products[14]. Furthermore, according to the Petroleum Law, the State charges royalties at a rate of up to. 12.5% of the total sales of natural gas at the wellhead. Moreover, following the conclusions of the Sheshinski Committee, the State is entitled to proceeds of petroleum and gas profits levy at a rate of up to approx. 50% (deriving, *inter alia*, from 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 13 June 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.[15]

4.1.1 Iron Swords War

On 7 October 2023, the terrorist organization "Hamas" launched a murderous attack on Israel, targeting in particular communities and military bases in the south of the State of Israel. Further to the attack, the Israeli government declared the Iron Swords war against the terrorist organization as aforesaid (the "**War**"). As of the date of approval of the financial statements, the War is in full swing, and it is not possible to foresee how long it will last and what its implications will be on the Partnership, its business and its assets.

[14] Other than the electricity and industrial sectors in which consumers do not pay excise tax for the gas.
[15] For more information on the export of gas from Israel, see Section 4.5.3.

Shortly after the outbreak of the War, gas production from the Tamar reservoir was discontinued according to the government's order. No such order was given for the Leviathan and Karish reservoirs, and as of the writing of this report, production from the Leviathan reservoir continues as usual. As a result of the discontinuation of production from the Tamar reservoir as aforesaid, the Leviathan partners supplied natural gas also to several customers of Tamar reservoir in the domestic market, primarily the IEC Ltd. and consequently, the quantity of natural gas directed for export to Egypt was reduced. At the same time, due to the War and pursuant to the government's order, the activity of the EMG pipeline, which constitutes a primary transmission infrastructure for piping of gas from Israel to Egypt, was discontinued. Further thereto, Eastern Mediterranean Gas Company S.A.E. ("**EMG**") notified Blue Ocean Energy (the gas consumer in Egypt) of the existence of *force majeure* circumstances preventing the piping of gas to Egypt through the EMG pipeline. In view of the aforesaid, in the period between the shutting down of the activity of the EMG pipeline and it resuming activity as described above, the entire gas supply to Egypt was piped through the regional transmission system, which entails additional transmission costs. Note that on 9 November 2023, the Ministry of Energy notified the Tamar reservoir operator that the Tamar reservoir may be reactivated and shortly thereafter the regular activity of the EMG pipeline resumed. As of the Valuation Date, the production activity from the Leviathan, Tamar and Karish reservoirs continues as usual.

Due to the War, in October 2023, the credit rating agencies, Moody's and Fitch, announced that the credit rating of the State of Israel is being considered for possible downgrade. Furthermore, the rating agency, S&P Global, announced the downgrading of the credit rating outlook of the State of Israel from stable to negative, while leaving the existing credit rating unchanged.

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**") – The IEC is a governmental company supervised by the Electricity Authority (the "**PUA-E**"), *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 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. 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 8 December

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]. The IEC is currently working on the construction of two more natural gas-fired power plants, which will replace units 1 and 4 of the Orot Rabin Power Plant, with a total capacity of approx. 1,200 MW/h. These plants are expected to increase the demand for gas in the Israeli market, in parallel with the discontinuation of coal use scheduled for 2025. As part of the IEC's preparations for the discontinuation of coal usage, the IEC is working on the conversion to gas of the 4 production units at the Rutenberg Station in Ashkelon. However, the conversion of the first of such four units has been completed and that unit has been gas-fired (for running-in purposes prior to commercial operation) since July 2023.
On 9 August 2023, fire was ignited using gas for the first time in the first unit on the Rutenberg site as part of the quality assurance of the systems, in preparation for completing its conversion to gas. However, the IEC estimates that this phase is expected to take longer in view of the Iron Swords war.
In 2022, the IEC's natural gas-fired production amounted to ~4.9 GW, which constitute ~43% of the total power produced using natural gas.

- **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[17], 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 2022, the natural gas consumption of the IPPs and cogeneration facilities amounted to approx. 5.3 BCM, which represents approx. 42% of the overall consumption of natural gas in that year in the entire market. The IPPs' natural gas-fired production in 2022 amounted to ~6.4 GW, which constitute ~59% of the total power produced using natural gas.

- **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

[16] Source: IEC's financial statement for 2022.
[17] In this technology, power is not produced but the energy is stored for use during peak hours or hours where it is not possible to produce power from renewable energies.

the power plants or through gas-heated boilers for the production of steam), 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 2022, natural gas consumption by the industrial sector amounted to approx. 2.61 BCM, which figure is identical to the gas consumption in 2021.

- **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. 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[18]. The Tamar partners paid and pay advances on account of royalties to the State at the rate of 11.65% in the years 2017-2018, 11.3% in the years 2019-2022 and 11.06% in the years 2023-2024. In the Leviathan reservoir, the partners paid advances on account of royalties to the State of Israel at the rate of approx. 11.26% in the years 2020-2022, and approx. 11.06% in the years 2023-2024.

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. Further to the aforesaid, on 6 September 2020, the Ministry of Energy published specific instructions for the Tamar reservoir[19] and on 24 July 2022, the Ministry of Energy published specific instructions for the Leviathan reservoir.

According to the H1/2023 Revenues Report of the Natural Resources Administration at the Ministry of Energy[20], revenues of about ILS 1 billion from the natural gas royalties were recorded, reflecting an increase of ~22.8% year-over-year. The increase in revenues from royalties derived from an increase in the quantities of production of natural gas for export, an increase in the quantities of production of hydrocarbon liquids, and from an increase in the dollar exchange rate. The total revenues originating from export amounted to approx. ILS 590 million. The total royalties collected from the Leviathan reservoir amounted to approx. ILS 482 million from the production of ~5.44 BCM, an increase of ~6.4% compared to the revenues from the Leviathan royalties year-over-year. Most of the revenues from royalties from the Leviathan reservoir originated from export sales (~86.12%), and the balance of ~13.88% from domestic sales. The total royalties collected from the Tamar reservoir amounted to approx. ILS 379 million from the production of ~4.91 BCM, an increase of ~3.4% compared to the revenues from the Tamar royalties year-over-year. The increase in revenues from the Tamar and Leviathan royalties was mainly due to an increase in the quantities of export to Egypt year-over-year, as well as an increase in the dollar exchange rate. The total royalties collected from the Karish reservoir (which began producing natural gas in October 2022) amounted to approx. ILS

[18] 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.

[19] https://www.gov.il/BlobFolder/policy/oil_search_publications/he/tamar_royalty.pdf

[20] Revenues Report of the Natural Resources Administration– Royalties, Accounting and Economics Division, the Ministry of Energy and Infrastructure.

145 million from the production of ~1.97 BCM of natural gas and ~947 thousand barrels of hydrocarbon liquids.

- **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 and the total accrued investments, net, as the same are defined in the law (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 will increase gradually to a rate of approx. 47% (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 10 November 2021, the Knesset approved in the second and third reading a bill which prescribes, *inter alia*, rules on payment of disputed assessments.[21]

- **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 17 December 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 thereon by the Commissioner in 2012 (the "**Exemption**")[22]. 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

[21] 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

[22] 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 (13 November 2012) Restrictive Trade Practices 500249.

Petroleum Commissioner pertaining to the qualifying conditions for an operator, whichever is later. On 16 August 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 5 May 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 9 December 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 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 16 August 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. However, starting from Q1/2023, the Gas Authority resumed publication of the weighted price of natural gas in the Israeli market, without thereby imposing a duty on the partners in the gas reservoirs to offer such price to their customers.

On 1 June 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 PUA-E 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. 10.1% and approx. 12.5% of actual power production in the State of Israel in 2022 and 2023, 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[23]. 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 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

[23] "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)

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 25 October 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 6 January 2019, the Government approved the recommendations of the Adiri Committee in Government Resolution 4442[24]. On 13 October 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.[25]

- **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 Valuation Date**,** 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.

- **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

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[24] Website of the Ministry of Energy, Spokesman's Notice of 10 January 2019: https://www.gov.il/he/departments/news/ng_060119

[25] For more information about the existing demand and regulation on the export side, see Section 4.5.3.

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.

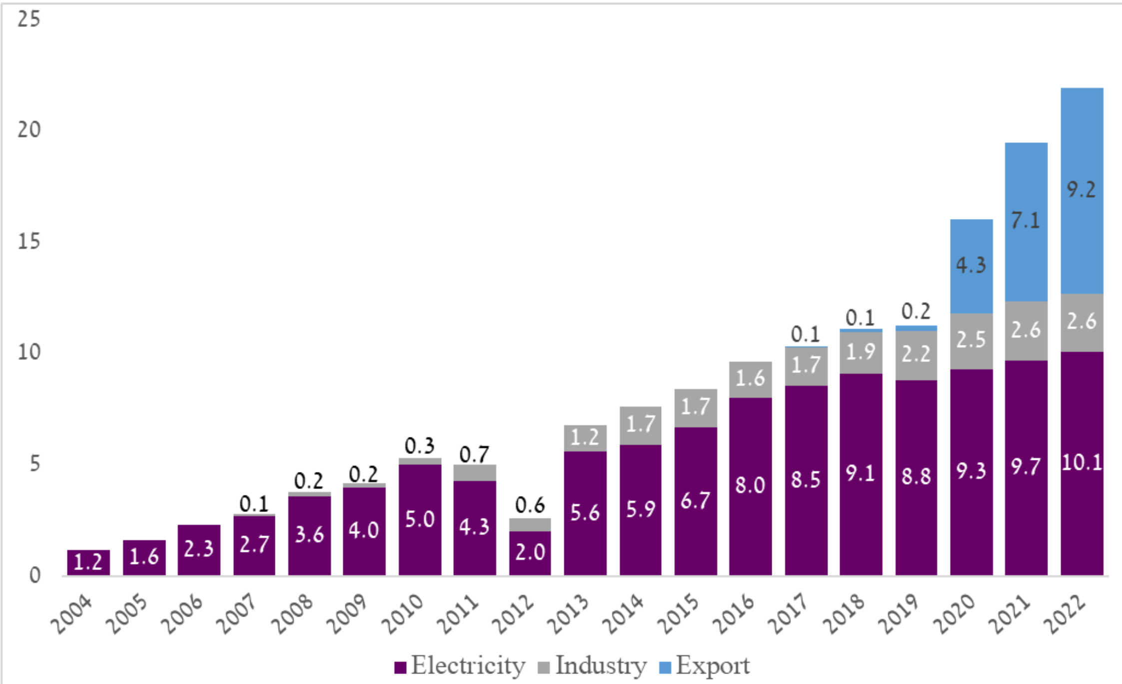
- **Regulatory changes** – The operating segment requires many regulatory approvals, mainly by the entities authorized under the Petroleum Law and the Natural Gas Sector Law, as well as related approvals of the State's authorities (including the Ministry of Energy, the Ministry of Defense, the Ministry 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

Chart 1 – Natural gas consumption in the domestic market in 2004-2022 in BCM per year[26]



The consumption of natural gas in the Israeli market in 2022 (including export of Israeli gas to neighboring countries) amounted to approx. 21.9 BCM, an increase of approx. 12.6% compared with the consumption in 2021. Approx. 52% of the amount was supplied from the Leviathan reservoir, approx. 46.5% of the amount was supplied from the Tamar reservoir, approx. 1.4% of the amount was supplied from the Karish-Tanin reservoir, and the balance (less than 1%) from the import of LNG via the offshore LNG buoy. The consumption in the domestic market (which consumption is comprised of industry and electricity) increased to 12.71 BCM, reflecting an annual increase of 3%, and the export increased to 9.21 BCM, reflecting an annual increase of 26% compared with 2021. From 2004 until the end of 2021, a total quantity of approx. 151 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.

[26] Source: Review of the developments in the natural gas sector, 2022 summary, Natural Gas Authority https://www.gov.il/BlobFolder/news/news-140523/he/ng-2022.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[27], 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, in parallel with the privatization of some of the IEC production plants, the construction of two gas plants and granting licenses for the construction of new plants by private producers. 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 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 1 June 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

[27] 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

production shall be granted preference at any time to electricity production with coal, while operating the coal units at a minimal load which allows flexibility and reliability of the supply to the market.

- In March 2018, the Finance Committee of the Knesset, 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 15 March 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 20 February 2019, the Minister of Finance signed an order postponing the expected rise in excise on coal, and it took effect on 1 January 2021. On 10 January 2023, the Minister of Finance issued an order postponing the increase of excise tax on coal until the end of 2023. On 28 December 2023, the Tax Authority announced that effective from 1 January 2024, excise tax will be ILS 114.67 per ton of coal.[28]

- 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 8 June 2020, a joint notice was released by the Ministry of Energy and the Ministry of Environmental Protection[29] on the Ministers' decision to instruct the IEC to expand the

[28] Source: Website of the Tax Authority – https://www.gov.il/he/departments/general/heshavon31819
[29] Website of the Ministry of Energy, Spokesman's Notice of 8 June 2020: https://www.gov.il/he/departments/news/press_080620

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 24 June 2020, the Minister of Energy[30] 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 25 October 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 8 February 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.[31]

- On 18 April 2021, the Ministry of Energy released a Road Map[32] 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 beginning in 2030 it will impose a total prohibition on the import of cars which run on polluting fuels.

[30] Website of the Ministry of Energy, Spokesman's Notice of 24 June 2020: https://www.gov.il/he/departments/news/press_240620
[31] https://www.calcalist.co.il/local/articles/0,7340,L-3892470,00.html
[32] https://www.gov.il/he/departments/publications/reports/energy_180421

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 13 August 2023, following the policy to discontinue the use of coal, the Ministry of Energy and Infrastructure announced that the Natural Gas Authority at the Ministry of Energy and Infrastructure approved the conversion to gas of the two new electricity production units at the Orot Rabin Power Plant (CCGT 70 and CCGT 80) which are expected to be the first two units to be powered by gas at the Plant.[33]

- According to the IEC's quarterly report for the period ended 30 September 2023, in June 2023, CCGT 70 was activated for purposes of operation tests and running-in (before commercial operation) and in August 2023, the CCGT's fire was ignited for the first time and it was synchronized with the grid. However, due to the eruption of the Iron Swords war and the security situation, GE gave notice of evacuation of some of its employees and subcontractors from Israel and also, approval from the system manager – Noga Ltd. – to reach a stated load that is necessary for continuing to perform the acceptance tests in CCGT 70 was not received. In view of the aforesaid, the IEC estimates that the current forecast for commercial operation of CCGT 70 is at least 4 months after the required foreign experts return to Israel, but not before May 2024. In addition, against the backdrop of the above-described circumstances, at this stage it is not possible to provide a projection for stable operation and commercial operation of CCGT 80. The introduction of the new production units will enable the shutdown of the four coal-fired production units in the Orot Rabin Power Plant and their inclusion in a conservation plan.[34]

- According to the PUA-E's Electricity Sector Status Report for 2022, the total Installed capacity of the IEC's natural gas-fired production facilities in 2022 was ~47%. This figure is expected to increase significantly to approx. ~84% of the IEC's total capacity in 2025.[35]

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)[36]. The enterprises are connected to natural gas through transmission and distribution networks, with the transmission and distribution fees supervised by the Natural Gas Authority.

[33] Source: https://www.gov.il/he/departments/news/news-130823
[34] Source: https://ieccontent.iec.co.il/media/hinjaffd/meshulav0623_isa.pdf
[35] Source: Electricity Sector Status Report, September 2023 – Electricity Authority: https://www.gov.il/BlobFolder/generalpage/dochmeshek/he/Files_Netunei_hashmal_doch_s_2022_nnn.pdf
[36] Source: 2020 Israeli Energy Sector Review – the Ministry of Energy: energy_sector_review_2020.pdf (www.gov.il)

- According to a summary review of the developments in the natural gas market by the Natural Gas Authority at the Ministry of Energy for 2022, approx. 628 km of distribution pipelines have been laid out to date throughout Israel (approx. 53 km of which in 2022) and approx. 900 km of transmission pipelines (approx. 70 km of which in 2022). 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 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 10 July 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

The business relations between the countries in the region have 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 26 September 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 31 December 2019, flow of natural gas has begun from the Leviathan reservoir to the customers with which gas agreements were signed, and from 1 January 2020 also to NEPCO.

- On 19 February 2018, agreements were signed between NewMed Energy and Chevron, and Dolphinus, an Egyptian company, which were assigned on 26 September 2018 to the Tamar partners and the Leviathan partners. On 26 September 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 15 January 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 6 November 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[37]. 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 26 March 2020, the Natural Gas Commission released an addendum to the decision of 7 September 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.

[37] EMED is a company held by NewMed Energy (25%), Chevron (25%) and the East Gas Company (50%).

- On 15 February 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 16 February 2022, the Ministry of Energy approved[38], in view of the increasing demand for natural gas in Egypt, piping of natural gas through the Kingdom of Jordan. Actual piping of the natural gas began on 1 March 2022[39] and increased the volume of natural gas exported to neighboring countries in a manner that secured supply of the annual contract quantity required under the export agreements and beyond in 2022-2023.

- Natural gas export in 2022 amounted to approx. 9.21 BCM (an increase of about 29% from 2021) which constitute ~42% of the total natural gas supply. Approx. 83% of the exported gas was produced from the Leviathan reservoir, and the rest from the Tamar reservoir.

- On 8 May 2023, the Government of Israel, led by the Ministry of Energy and Infrastructure and INGL, approved a plan to increase the infrastructure for the export of natural gas to Egypt. The approved plan includes the establishment of an integrated infrastructure strip and infrastructure facilities in the route between Ramat Hovav and the border with Egypt in the Nitzana area, in addition to the existing maritime pipeline (EMG), and it is expected to increase the potential quantities of natural gas export to Egypt. The length of the segment (Ramat Hovav-Ashalim-Nitzana) is ~65 km, and it will allow the piping of another 6 BCM per annum to Egypt. The value of the State revenues from exports on this scale is estimated at hundreds of millions of shekels per year from taxes and royalties. Further to the aforesaid, the Ministry of Energy published designated regulation for the allocation of the capacity and the costs associated with the construction of this pipeline among the various gas exporters.

[38] "New route for the export of natural gas to Egypt – North Jordan!" – Ministry of Energy, 16 February 2022 https://www.gov.il/he/departments/news/ng_160222

[39] https://mayafiles.tase.co.il/rpdf/1433001-1434000/P1433795-00.pdf

- On 23 August 2023, the Minister of Energy and Infrastructure announced the approval of the increase of the gas export quota from the Tamar reservoir to Egypt. According to the approval outline, the volume of the gas production will increase by 6 BCM per year (an increase of ~60% compared to the current production volume) starting in 2026, 3.5 BCM of which will be earmarked for Egypt. Further to the aforesaid report, on 14 December 2023, the Tamar reservoir partners announced that the Ministry of Energy authorized them to increase the export permit of the reservoir, from 38.7 BCM (approved in August) to 43 BCM. This quantity will enable to increase the additional maximum gas quantity permitted to be exported to Egypt from 3.5 BCM per year to 4 BCM per year. As of the Valuation Date, the export agreement which is the subject-matter of the aforesaid export approval is yet to be signed.

- On 27 December 2023, the Minister of Energy and Infrastructure announced the formation of an inter-ministerial committee for the periodic examination of the policy of the natural gas sector. They chairperson of the committee will be the director general of the Ministry of Energy and its members will be representatives on behalf of the PUA-E, the Ministry of Environmental Protection, the National Economic Council, the Ministry of Finance, the Competition Authority, the Ministry of Justice, The Ministry of Foreign Affairs, and the National Security Council. One of the duties of the committee, which convenes once every 5 years, will be to examine the policy on gas export in new gas reservoirs. The committee is expected to complete its work within several months, and to submit its conclusions to the government in 2024.

4.5.4 Energy prices globally and in Israel

- As a result of the global decrease in coal prices in the first few months of 2023 (as of 31 March 2023, a ton of coal is traded for approx. $137.8 compared with approx. $190.5 on 31 December 2022[40]), the Electricity Authority decreased the electricity tariff for the domestic consumer for 2023 in February and March by approx. 1.5% and 2.4%, respectively, after it increased it by approx. 8.2% in January of that year (these decreases include the weighting of the payment for the energy consumed from the grid (kWh), the payment for capacity according to the size of the consumer's connection to the grid, and the cost of the consumerism services (fixed payment)).[41] Following the outbreak of the war between Russia and Ukraine at the beginning of 2022, global energy prices skyrocketed, further to the increases in energy prices in 2021 (compared with the Covid period). Despite the slight downward trend in energy prices in H2/2022, the current global oil prices also continue to be higher than on the eve of the war's outbreak. So, for

[40] https://markets.businessinsider.com/commodities/coal-price

[41] Decision No. 65203 – Update of the Electricity Tariff for IEC Consumers

example, the average price of a Brent barrel in December 2023 was approx. $77.86, compared with an average price of approx. $70.44 per Brent barrel in 2021.

- 2022 saw a drastic increase in gas prices, created because of a combination of several unique factors, and causing great difficulty throughout the world in the allocation of the limited gas supply. This increase occurred against the backdrop of the vast volatility in the global gas market at the end of 2021 and the resulting reduction in trade volumes. In addition, the eruption of the war between Russia and Ukraine in 2022 and the explosion of the Nord Stream pipeline in September 2022, caused gas prices to increase several more times, and to break new records each time. A record gas price was reached at the end of August 2022, when the natural gas price index reached the level of approx. 454 points (100 = 2010 average), compared with an average level of approx. 130.67 points in 2021.

- As of the Valuation Date, the gas price index is approx. 93.93 points[42]. The decrease in gas prices was caused mainly due to adjustments on the part of the demand in Europe and Asia, growth of the global gas supply and elimination of infrastructural bottlenecks. However, the shortage in the global supply, which was among the causes for the increase in prices still exists, and the market is still in a state of a fragile and unstable equilibrium.

- On 21 September 2023, the global gas association released the 2022 annual price report.[43] According to the report, in 2022 the gas price in Israel was the lowest in the world out of the countries that do not subsidize the natural gas price, except Canada. In 2022 the gas prices in Israel were $4.65 on average – prices that are significantly lower than in countries where there are gas markets based on domestic production, such as the United States (the largest producer of natural gas in the world), Australia, Argentina, etc. The State of Israel does not depend on the import of natural gas, and it supplies the principal part of the demand itself. Furthermore, the gas prices in Israel are fixed in long-term agreements and are therefore not directly impacted by changes in global energy prices. Nevertheless, natural gas prices in Israel are 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.

- According to a forecast prepared for the Partnership by an outside consultant, the domestic demand for natural gas in 2023 is expected to total approx. 13 BCM and gradually increase to approx. 15 and approx. 20 BCM in 2025 and 2030, respectively. The increase in domestic demand between 2023-2030 is expected to derive mainly from an

[42] A World Bank Monthly Commodity Price Data (The Pink Sheet): https://thedocs.worldbank.org/en/doc/5d903e848db1d1b83e0ec8f744e55570-0350012021/related/CMO-Pink-Sheet-October-2023.pdf
[43] https://www.igu.org/resources/global-gas-report-2023-edition/

addition of approx. 3.1 BCM as a result of discontinuance of the use of coal for electricity production, and of an addition of approx. 5.1 BCM as a result of natural growth in the demand for electricity (population growth, improvement in the standard of living and in disposable income). 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.

4.6 Market developments

4.6.1 The "Tamar" and "Leviathan" leases

- On 31 December 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 1 January 2020 and on 15 January 2020, the gas flow from the Leviathan reservoir began to Jordan and to Egypt, respectively.

- On 2 October 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 13 September 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 23 September 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 28 October 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 19 January 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 15 February 2021, INGL reported the fulfillment of the closing conditions determined in the agreement. However, due to the fact that INGL has not yet completed the pipeline section between Ashdod and Ashkelon, the agreement has not yet taken effect. In addition to the aforesaid, on 27 February 2023, INGL informed Chevron that due to a malfunction in a ship carrying out infrastructure work for the laying of a subsea pipeline for INGL in the Ashdod-Ashkelon subsea transmission system segment, a delay of at least 6 months in the completion of the project is expected, such that the window of time during which commencement of the gas flow is possible has been postponed to the period from 1 October 2023 to 1 April 2024. According to the said INGL notice, the said event constitutes *force majeure* as defined in the transmission agreement between the parties. In response to the notice, Chevron approached INGL with a request for additional details and stated that according to the details held thereby, the said event should not be deemed as *force majeure*.

- On 23 February 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 26 May 2021, the Partnership reported that on 11 May 2021, the Separate Marketing Agreement took effect. To the best of the Partnership's knowledge, up to this date no sale was made separately by the Tamar partners.

- On 9 December 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 17 December 2015.

- On 4 July 2021, The IEC entered into a SPOT agreement with the Leviathan partners for the purchase of natural gas from the Leviathan reservoir, which is valid for one year, in which framework it was agreed that the gas price will be determined every month and the parties have no commitment regarding the quantities purchased. On 28 June 2023, the SPOT agreement for the purchase of natural gas from the Leviathan reservoir was extended by another year until 4 July 2024.

- On 20 December 2021, the Tamar partners reported the signing of an amendment to the gas supply agreement between Dalia Energy Companies Ltd. ("**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 8 July 2035 (rather than 8 July 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[44]. On 28 February 2022, the partners reported the satisfaction of the condition precedent of the Remaining Tamar Partners joining the amendment to the agreement[45]. On 24 July 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 24 January 2022, the partners in the Tamar reservoir reported the signing of an amendment to the 2012 IEC-Tamar Agreement[46], whereby the gas price by which the IEC

[44] https://maya.tase.co.il/reports/details/1419083/2/0.
[45] https://maya.tase.co.il/reports/details/1433483/2/0.
[46] https://maya.tase.co.il/reports/details/1427402/2/0.

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 1 January 2025 (instead of 1 July 2024 in the 2012 IEC-Tamar Agreement)[47]. In addition, the term of the 2012 IEC-Tamar Agreement was extended by another 2.5 years, such that this agreement will end on 31 December 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 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 24 July 2022, the agreement took effect after the satisfaction of all conditions precedent.

▪ On 1 May 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.

[47] In the IEC-Tamar agreement of 2012, the Parties determined two dates on which each party may request adjustment of the purchase price, 1 July 2021 and 31 December 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.

- On 19 January 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 9 February 2023, Alon Gas became a private company and was delisted from the trade on TASE. On 8 March 2023, Tomer Energy reported that the transaction received the approval of the Competition Commissioner. As of the Valuation Date, 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 27 March 2018, Energean notified the Partnership of the adoption of an investment decision for the development of the Karish reservoir. Further thereto, starting from March 2018 and until 31 December 2023, Energean paid the Partnership approx. $81.35 million (6 of 10 installments, including interest) and the Partnership is expected to receive the balance of the debt component in 2024.

- **Listing of Energean on the Israeli stock exchange** – On 29 October 2018, trading of Energean Israel’s parent company, Energean 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 27 November 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 25 June 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 21 November 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 17 December 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 2 January 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 right to receive royalties from the reservoirs** – Further to Energean's report of 9 April 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 25 May 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 16 September 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 30 December 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 25 February 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 14 January 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 14 January 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 24 March 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.[48]

- On 28 June 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 11 November 2021, Energean announced its intention to issue, on 18 November 2021, several series of secured senior bonds in a total sum of $450 million, due to mature on 30 April 2027. The annual interest rate of these series is 6.50%, to be paid in semi-annual installments on 30 April and 30 October of each year. Starting from 7 January 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 13 December 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 an increase of the hydrocarbon liquid output of the floating platform (FPSO) 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 14 March 2022, Energean reported that it had entered into a SPOT agreement with IEC for supply of natural gas from the Karish reservoir (in this section below, the "**SPOT Agreement**"). Under the SPOT

[48] TASE UP is a platform for raising of capital or debt for private entities from institutional investors and/or other qualified clients (including private clients) from Israel and overseas. In addition, the private entities can use the platform for trade, without being obligated to release a prospectus, and without being subject to disclosure requirements or current reporting obligations.

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 the first gas from the Karish reservoir, with extension options subject to both parties' consent. Further to the aforesaid, IEC reported in the context of its quarterly report for the period ended 30 September 2023, that on 15 October 2023, the SPOT Agreement was extended for one more year, until 17 October 2024.

- **Signing of an agreement for the sale of natural gas with Hagit East Power Plant partnership** – On 3 May 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 1 June 2022, IEC reported that the process for sale of the plant to Edeltech and Shikun & Binui Energy had been closed.

- **The disagreement between Energean and NewMed Energy in connection with the right to receive the balance of the debt component** - on 31 May 2022, the Partnership filed a financial claim against Energean, in the total amount of $65.1 million, plus linkage differences and interest. As part of the claim, the Partnership claims that according to the provisions of the agreement for the sale of the interests in Tanin and Karish leases to Energean, in the event that Energean obtains the financial financing for the costs of the first phase of the approved development plan in the Tanin and Karish leases, plus the full financial consideration for the debt component, Energean would be obliged to immediately pay the balance of the debt component. Therefore, according to the Partnership's position, Energean's announcement of 30 April 2020 regarding the issuance of bonds in the total amount of $2.5 billion and the release of the proceeds of the issuance to its accounts, constitute grounds for immediate payment of the remaining proceeds.

  Further to the above, on 19 April 2023, a pretrial hearing was held in the claim, and according to the decision issued in the context thereof, on 10 May 2023, the parties filed a joint notice with the court regarding their consent to refer to mediation, without thereby delaying the hearing of the claim.

On 5 November 2023, the Partnership reported a mediation agreement signed between it and Energean which was sanctioned as a judgment. According to the agreement, Energean will pay the Partnership in two installments in 2024, the total amount of approx. $47.4 million, constituting the entire balance of the consideration plus agreed annual interest. A first installment in the amount of $30 million to be paid by 30 March 2024, and a second installment in the amount of approx. $17.4 million to be paid by 15 May 2024. Upon full payment as aforesaid, the parties' arguments in relation to the legal proceeding in this matter will be dismissed.

- On 9 October 2022, Energean reported the piping of natural gas from the shore to the floating platform (FPSO) 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 26 October 2022, Energean reported initial natural gas production from the Karish reservoir and on 28 October 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 17 November 2022, Energean reported that it had signed a sale agreement with Vitol SA for initial marketing of deliveries of hydrocarbon liquids. On 14 February 2023, the company supplied the 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).

- **Update of the volume of resources attributable to the Karish, Karish North and Tanin reservoirs** – On 23 March 2023, Energean released a resource and reserve report as of 31 December 2022, 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[49]. 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

[49] https://www.energean.com/media/5400/dm-final-report-energean-israel-2022ye.pdf

pertaining to the amounts of the capital investments, royalties, taxes and operating costs of the Reservoirs.

- On 18 June 2023, Energean announced that Energean Israel Finance Ltd.[50] intends to issue a secured senior bond series in the total amount of $750 million which is due to mature on 30 September 2033. The annual interest rate of this series is 8.50% and it will be paid in semi-annual installments on 30 March and 30 September of each year. According to the report, the bond is expected to be issued in July 2023 and traded on TASE-UP[51]. Energean intends to use the aforesaid amount, to: (1) pay the company's bonds that are due to mature in 2024; (2) pay the final deferred consideration to Kerogen Fund for the acquisition of Energean Israel; (3) finance interest expenses; and (4) pay fees, accrued interest and other expenses due to the payment of the bonds mentioned in Section 1 above and the issuance of the bond. On 11 July 2023 such bond was issued on TACT-Institutional and on 26 July 2023 the S&P Maalot rating agency gave an il.A rating for the issuance of the secured senior bond with stable outlook.[52]

4.6.3 Additional leases

- On 13 December 2022, the Ministry of Energy published the fourth competitive process for receipt of licenses for natural gas explorations in Israeli waters (in this section below, the "**Process**")[53]. In the context of the Process, 4 zones of exploration licenses were offered, designed to enable a more accurate match between the exploration areas and the geological structures in the sea that may contain natural resources and which will enable a more professional and efficient performance of geological and geophysical surveys. In some of the zones, exploration licenses have already been given in the past, and seismic surveys and other exploration activities have already been performed in them, attesting to a possible potential for discovery of hydrocarbon reservoirs. According to the Process principles, the exploration license will be given for a 3-year period, after which the license holder may request an extension of two additional years and thereafter, of two more years (7 years in total), when specific conditions are met. In addition, in the context of the Process, exploration licenses will only be given in areas that are far from the coast, at a distance greater than at least 40 km.

[50] An Israel-based SPV. The SPV is held by Energean Israel.
[51] TASE-UP is a platform for raising of capital or debt for private entities from institutional investors and/or other (including private) qualified clients from Israel and overseas. In addition, the private entities may use the platform for trade without being obligated to release a prospectus and without being subject to current reporting obligations or disclosure requirements.
[52] Source: https://mayafiles.tase.co.il/rpdf/1537001-1538000/P1537511-00.pdf
[53] https://www.gov.il/he/departments/news/press_131222

- On 16 July 2023, the bidding phase of the Process ended, during which 6 gas exploration bids were received. The bids were submitted by 4 different groups comprised of 9 companies in total, 5 of which are new companies operating in Israel. According to the terms and conditions of the Process, the new companies will be given priority over the existing companies in receiving the exploration licenses.

- On 29 October 2023, the Ministry of Energy and Infrastructure announced the winners in two of the four zones that were offered. According to the announcement, 12 exploration licenses were given to 6 companies, of which 4 are new companies in the Israeli energy sector. In the first zone, licenses were given to the partnership NewMed Energy, to the British energy company BP, and to Azerbaijan's national petroleum company SOCAR (as an operator). In the second zone, licenses were given to the Italian energy company ENI (as an operator), to Dana Petroleum (a Korean-owned Scottish company) and to Ratio.

4.6.4 Subsequent Events

- On 18 January 2024, Energean updated its production forecasts stating that the production rate in 2024 will range between 5.7-6.4 BCM. The company stated that this range derives primarily from Energean's forecast for the demand for gas in 2024 in Israel, which was affected by delays in coal supply and a warmer-than-average winter.

- On 29 February 2024, Energean reported that it had started to produce gas from the Karish North reservoir on 22 February 2024. The production of gas is carried out by means of the second gas export pipeline, installation of which was completed in December 2023. As of the date of the report, the floating platform (FPSO) produces from 4 operating wells, which increase inventory redundancy and allow for flexibility to meet the gas demand requirements of Energean's customers.

- Further to the previous section, Energean further informed in the said report that it had entered into a natural gas supply agreement with Eshkol Energies Generation Ltd. ("**Eshkol**"), a company controlled by Dalia. According to the agreement, starting in June 2024, Energean will sell Eshkol an annual amount of approx. 0.6 BCM of natural gas until 2031 and subsequently an annual amount of 1 BCM until expiration of the term of the contract. The agreement includes clauses that address minimum and maximum prices, a 'take or pay' mechanism and a linkage mechanism. According to the report, the aggregate amount of the contract will be approx. 12 BCM for a 15-year term, and it is expected to generate Energean revenues of approx. $2 billion.

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 divided into 10 equal annual installments, plus interest, according to the mechanism set in the agreement immediately after the date on which the Buyer will adopt a final investment decision (FID) regarding the development of the leases, or on the date on which the total Buyer's expenses in relation to the development of the leases will exceed $150 million (the "**Investment Decision**"), whichever of the two 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 27 March 2018, as aforesaid, Energean notified the Partnership of the adoption of an Investment Decision for the development of the Karish reservoir, and therefore the Debt Component is defined as deferred consideration.

ii. Royalties from revenues (net of existing royalties[54]) 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.

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.

[54] 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%).

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 31 December 2022, prepared by the consulting firm DeGolyer and MacNaughton, a competent resource appraiser ("**D&M CPR**"), released by Energean on 23 March 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 from Karish reservoir 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 in Q1/2024. According to these reports, production from the Tanin lease is expected to begin in 2030. Note that as of the Valuation Date, Energean has not released a notice whether production of the gas from the Karish north reservoir has begun[55].

In the context of the valuation, it was assumed that the production of gas from the Karish North and Tanin reservoirs will be at the end of Q1/2024 and in the beginning of Q1/2030, respectively. It was further assumed that the production of the natural gas reserves in the Karish, Karish North and Tanin reservoirs will end in 2042, 2042 and 2041, respectively, based on assumptions presented in the D&M CPR.

[55] For further information about the commencement of production from the Karish-North reservoir after the report period, see Section 4.6.4.

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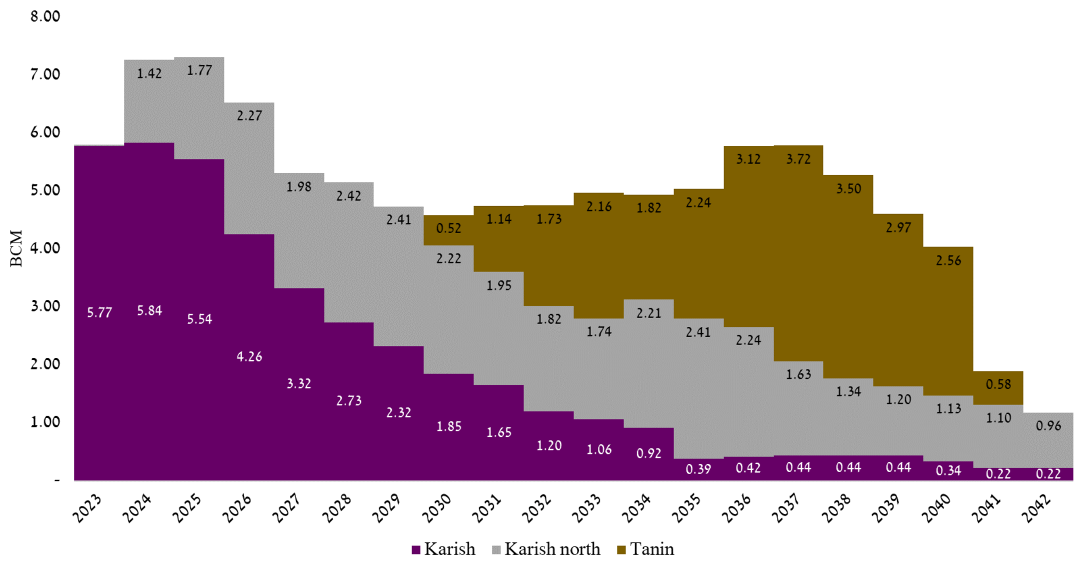
5.2.3 Quantity forecast and annual production rate

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:

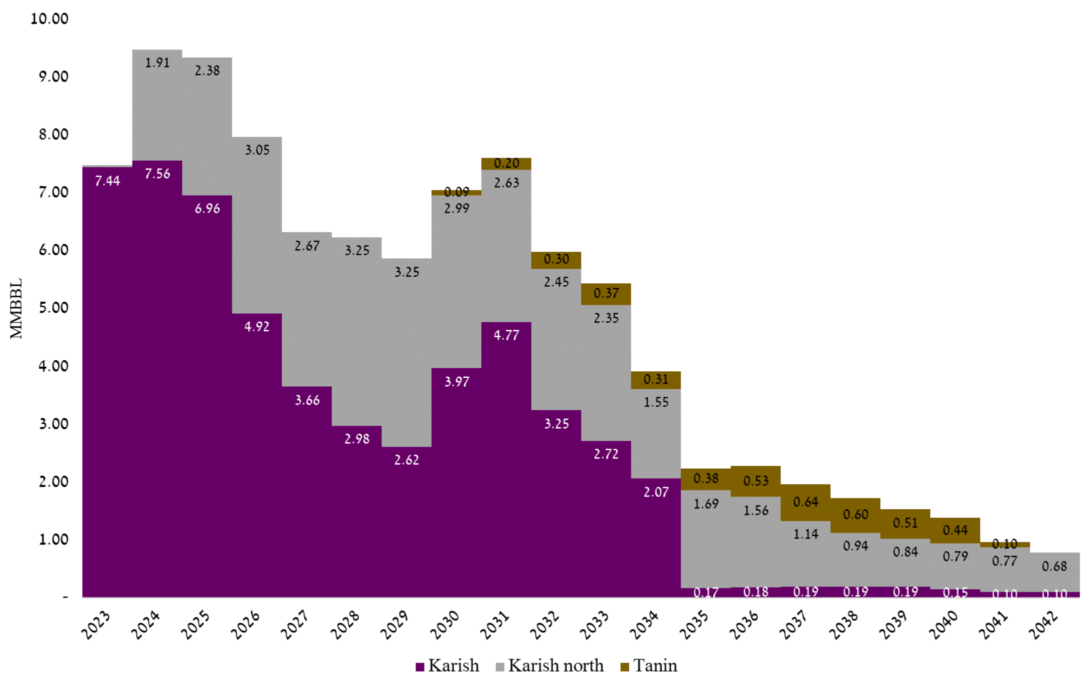
Reservoir	Reserves and Resources	
	Natural Gas (BCM)	Hydrocarbon Liquids (MMBBL)
	2P	2P
Karish	39.4	54.2
Karish North	34.2	36.9
Tanin	26.1	4.5
Total	**99.6**	**95.6**

Based on Energean's financial statements as of 30 September 2023, Energean's report to TASE dated 18 January 2023 on operating and financial updates as of 31 December 2023, and the conversion rate derived from the above table between the quantity of natural gas and the quantity of the hydrocarbon liquids in the Karish reservoir, in 2023 Energean produced ~4.4 BCM of natural gas and ~3.8 million barrels of hydrocarbon liquids. In the context of the royalties Energean pays to the Partnership, it does not provide the Partnership with details regarding the production quantities and therefore it is difficult to estimate these quantities. In addition, it transpires from Energean's financial statements that the gas production rate (in annual terms) is ~6 BCM. According to these reports, and based on the value of the royalties transferred to the company, we reduced the remaining reserves and resources in the Karish reservoir, as specified in the D&M CPR.

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 rate of production of natural gas and condensate used in the valuation was based on the rate 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, in accordance with the various reports of Energean that pertain to the actual rate of production and the forecasted rate of production from the reservoirs, which were released after the publication of the D&M CPR, adjustments were made to the rate of production of the natural gas and condensate in 2024. These reports include, *inter alia*, an actual production rate that is lower than the forecasted rate of production in the D&M CPR and forecasts based on a ramp-up in the rate of production, the feasibility and likelihood of occurrence of which we cannot assess in the absence of further publicly-available information. As of the Valuation Date, such reports are the only source for Energean's forecasts of the rate of production from the reservoirs. Due to these adjustments to the production rate, the balance of the quantity deducted in the 2024 production rate has been postponed to the last years in the production profile.
In addition, according to the D&M CPR, a factor of approx. 37.2 million was taken into account for the conversion from an MMBTU unit to a BCM unit.

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 29.97 Agorot (December 2023). 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, construction of additional natural gas-fired power plants by the IEC, 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. 28.91-32.45 Agorot throughout 2024-2037.
  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).

The base scenario and the low scenario in the D&M CPR assumed a fixed natural gas price of approx. U.S. $4.04 per MMBTU from 2024 and throughout all the years of the forecast.

5.2.5 Condensate price forecast

The condensate price forecast was estimated based on the average long-term petroleum prices forecast by the World Bank[56], the EAI[57], and the forward Brent prices according to Bloomberg.

5.2.6 Royalty rate

The effective royalty rate paid to the Partnership is derived from the effective royalty rate paid to the State. The royalty rate paid to the State is determined according to the Petroleum Law and stands at 12.5% of the value of the gas at the wellhead[58]. However, the royalty rate paid in practice 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. As determined by the Ministry of Energy, the rate of advances paid to the State in 2024 for sales of natural gas and condensate from the Karish lease is 11.06%. This rate constitutes an advance payment only, and the market value of the royalties at the wellhead will be calculated in the future according to the expense deduction rate and method to be agreed with the Ministry of Energy.

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

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[56] A World Bank Semi-Annual Report: Commodity Markets Outlook, October 2023.
[57] U.S Energy Information Administration: Analysis & Projections, December 2023.
[58] On 9 February 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

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 approx. 47% (according to the corporate tax rate[59]) 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. 10.88% 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 operational risk, as specified in the table below:

Parameter	Value	Note
Risk-free interest	3.89%	A
Beta	1.64	B
Market premium	6.07%	C
Specific risk premium	4.1%	D
The company's equity price	**17.9%**	
The debt price	9.0%	E
Tax rate	0.0%	F
Leverage ratio	60%	G
Weighted equity price	**12.6%**	
Net of operational risk	-1.70%	H
Weighted equity price net of operational risk	**10.88%**	

<u>Below are the working assumptions that were used in the calculation of the cap rate:</u>

a. U.S. government bond yield for the average duration of the cash flow (4.49 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	0.81
Ratio Energies Limited Partnership	0.99
Tamar Petroleum Ltd.	0.18
Tomer Energy Royalties (2012) Ltd.	0.32
NewMed Energy Limited Partnership	0.97

[59] Corporate tax of 23% was assumed according to the statutory tax rate known as of the Valuation Date.

Company	Unleveraged Beta
Benchmark company average	**0.66**

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 June 2023).

d. Size risk premium according to Duff & Phelps International Valuation Handbook 2022 in addition to a specific risk premium due to the volatility in the oil prices and the competition in the domestic market.

e. The debt price was estimated based on the yield rate derived from the bond issuance carried out by Energean in July 2023[60].

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 (b) above), as of 10 December 2023, was estimated at approx. 37.0%. In our estimation, the normative leverage ratio for the long-term is 60.0%

h. The cap rate of 12.6%, 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, a reduction was made at the rate of ~1.7% from the risk rate produced by the model.

5.3 Results of the valuation

According to the assumptions specified in the Paper itself, the value of the Royalties as of 31 December 2023 is estimated at approx. $273.2 million (the value of the Karish Royalties (including Karish North) and the Tanin Royalties are estimated at approx. $232.5 million and approx. $40.7 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).

[60] For more information, see Section 4.6.2.

GIZA SINGER EVEN

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	232.6	250.5	234.2	247.9	264.0	275.5	290.6
	+150 bp	241.1	259.5	243.3	257.4	274.2	285.9	301.6
	+50 bp	250.3	269.3	253.2	267.7	285.3	297.2	313.7
	-	255.3	274.5	258.5	**273.2**	291.2	303.3	320.1
	-50 bp	260.4	280.0	264.1	279.0	297.4	309.6	326.8
	-150 bp	271.3	291.5	275.9	291.2	310.7	323.1	341.1
	-250 bp	283.3	304.2	288.9	304.7	325.2	337.9	356.8

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	226.4	239.1	242.0	247.9	253.4	258.8	266.5
	+150 bp	235.9	248.8	251.4	257.4	262.9	268.3	275.9
	+50 bp	246.3	259.5	261.7	267.7	273.3	278.7	286.0
	-	251.9	265.2	267.2	**273.2**	278.8	284.2	291.3
	-50 bp	257.7	271.1	272.9	279.0	284.5	290.0	296.9
	-150 bp	270.4	283.9	285.2	291.2	296.8	302.3	308.8
	-250 bp	284.3	298.0	298.7	304.7	310.2	315.7	321.8

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	252.9	229.6	238.7	247.9	256.6	265.3	274.0
	+150 bp	262.2	238.6	247.9	257.4	266.4	275.3	284.2
	+50 bp	272.3	248.4	258.0	267.7	276.9	286.2	295.4
	-	277.7	253.6	263.3	**273.2**	282.6	292.0	301.3
	-50 bp	283.3	259.0	268.9	279.0	288.5	298.0	307.5
	-150 bp	295.2	270.7	280.9	291.2	301.1	311.0	320.8
	-250 bp	308.3	283.5	294.0	304.7	314.9	325.1	335.3

GIZA SINGER EVEN

Annex A – Cash Flow Forecast

Year	Unit	2024	2025	2026	2027	2028	2029	2030	2031	2032
Production										
Gas production - Karish*	bcm/y	5.70	7.31	6.52	5.30	5.15	4.74	4.07	3.61	3.14
Gas production - Tanin	bcm/y	-	-	-	-	-	-	0.52	1.14	1.73
Condensate production - Karish*	bbl/y m	7.44	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$	4.16	4.46	4.30	4.31	4.37	4.35	4.31	4.32	4.30
Condensate Price	US$	79.91	76.65	70.78	69.05	67.97	67.44	67.19	66.93	66.67
Revenues										
Karish - Revenues*										
Natural Gas Revenues	US$ MM	881.9	1,212.9	1,042.3	849.4	836.2	766.8	652.0	578.6	501.8
Condensate Revenues	US$ MM	594.6	716.3	564.1	436.5	423.8	395.6	467.6	495.5	379.6
Total Gross Revenues	US$ MM	1,476.6	1,929.2	1,606.5	1,285.9	1,260.0	1,162.4	1,119.6	1,074.2	881.3
Tanin - Revenues										
Natural Gas Revenues	US$ MM	-	-	-	-	-	-	83.7	183.3	276.7
Condensate Revenues	US$ MM	-	-	-	-	-	-	6.0	13.3	19.7
Total Gross Revenues	US$ MM	-	-	-	-	-	-	89.7	196.6	296.4
K&T - Total Gross Revenues	US$ MM	1,476.6	1,929.2	1,606.5	1,285.9	1,260.0	1,162.4	1,209.3	1,270.7	1,177.7
New-Med Energy - Transaction Revenues										
Karish ORRI, Net*	US$ MM	66.9	53.5	41.2	27.9	24.6	20.8	18.5	16.6	13.4
Tanin ORRI Net	US$ MM	-	-	-	-	-	-	4.1	8.9	13.4

GIZA SINGER EVEN

Year	Unit	2024	2025	2026	2027	2028	2029	2030	2031	2032
Transaction ORRI, Net*	*US$ MM*	***66.9***	***53.5***	***41.2***	***27.9***	***24.6***	***20.8***	***22.6***	***25.5***	***26.8***
*Karish Discounted Transaction Revenues**	*US$ MM*	*63.4*	*46.2*	*31.9*	*19.5*	*15.5*	*11.8*	*9.5*	*7.7*	*5.6*
Tanin Discounted Transaction Revenues	*US$ MM*	-	-	-	-	-	-	*2.1*	*4.1*	*5.6*
Total Discounted Transaction Revenues	*US$ MM*	***63.4***	***46.2***	***31.9***	***19.5***	***15.5***	***11.8***	***11.6***	***11.8***	***11.1***

*Including Karish North

**Net of Existing ORRI net of Petroleum Tax

Year	Unit	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Production											
Gas production - Karish*	bcm/y	3.04	3.13	3.31	3.12	2.45	2.13	1.81	1.68	1.60	1.36
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	4.09	3.11	2.68	2.01	1.80	1.45	1.36	1.29	1.20
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$	4.32	4.34	4.20	4.03	4.03	4.03	4.05	4.05	4.05	4.05
Condensate Price	US$	66.41	66.16	65.90	65.65	65.39	65.14	64.89	64.63	64.38	64.14
Revenues											
Karish - Revenues*											
Natural Gas Revenues	US$ MM	488.1	504.2	517.6	467.5	367.4	319.5	272.8	252.6	241.1	204.8
Condensate Revenues	US$ MM	336.4	270.7	204.8	176.2	131.3	117.5	93.8	87.9	82.9	76.8
Total Gross Revenues	US$ MM	824.5	774.9	722.4	643.7	498.7	436.9	366.7	340.6	324.0	281.7
Tanin - Revenues											
Natural Gas Revenues	US$ MM	346.7	292.8	349.5	467.6	556.9	524.3	446.5	385.5	87.1	-
Condensate Revenues	US$ MM	24.5	20.5	25.2	34.9	41.5	39.0	32.8	28.3	6.4	-
Total Gross Revenues	US$ MM	371.3	313.3	374.7	502.5	598.4	563.3	479.3	413.8	93.6	-
K&T - Total Gross Revenues	US$ MM	1,195.7	1,088.2	1,097.1	1,146.2	1,097.1	1,000.2	846.0	754.4	417.6	281.7
New-Med Energy - Transaction Revenues											

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Year	Unit	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
*Karish ORRI, Net**	*US$ MM*	*12.5*	*11.7*	*11.0*	*9.8*	*7.6*	*6.6*	*5.6*	*5.2*	*4.9*	*4.3*
Tanin ORRI Net	*US$ MM*	*16.8*	*14.2*	*17.0*	*13.9*	*14.6*	*10.2*	*7.5*	*6.3*	*1.4*	-
Transaction ORRI, Net*	*US$ MM*	***29.3***	***25.9***	***27.9***	***23.7***	***22.1***	***16.9***	***13.1***	***11.4***	***6.3***	***4.3***
*Karish Discounted Transaction Revenues**	*US$ MM*	*4.7*	*4.0*	*3.3*	*2.7*	*1.9*	*1.5*	*1.1*	*0.9*	*0.8*	*0.6*
Tanin Discounted Transaction Revenues	*US$ MM*	*6.3*	*4.8*	*5.2*	*3.9*	*3.6*	*2.3*	*1.5*	*1.1*	*0.2*	-
Total Discounted Transaction Revenues	*US$ MM*	***11.0***	***8.8***	***8.5***	***6.6***	***5.5***	***3.8***	***2.6***	***2.1***	***1.0***	***0.6***

*Including Karish North

**Net of Existing ORRI net of Petroleum Tax

Annex B – 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 Plc. 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	Liquid Natural Gas
MMBTU	A Million BTU – an energy unit used as a basis for the determination of natural gas prices