
Delek Drilling

# 2018

# FINANCIAL STATEMENTS AS OF 31.12.2018 UNAUDITED




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Delek Drilling

# Partnership Description

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# Chapter A – Description of the Partnership's Business

***This report is a translation of Delek Drilling - Limited Partnership's Hebrew-language Description of the General Development of the Partnership's Business, and 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.***

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

## 1.1. The Partnership's operations and a description of its business development

1.1.1. Delek Drilling – Limited Partnership (the "**Partnership**"), is a public limited partnership, within the meaning thereof in the Partnerships Ordinance [New Version], 5735-1975 (the "**Partnerships Ordinance**"), engaged in the exploration, development and production of natural gas, condensate and oil. The Partnership was established under a partnership agreement signed on July 1, 1993 (as amended from time to time) (the "**Partnership Agreement**"), between Delek Drilling Management (1993) Ltd. (the "**General Partner**") of the first part, as general partner, and Delek Drilling Trusts Ltd. as limited partner, of the second part (the "**Limited Partner**"). The Partnership was registered on July 25, 1993, under the Partnerships Ordinance.

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

1.1.3. The current management of the Partnership is performed by the General Partner under the supervision of the supervisors, Fahn Kanne & Co., Accountants, and CPA Micah Blumenthal, together with Gissin & Keidar (jointly: the "**Supervisor**").

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

1.1.5. The General Partner and the Limited Partner are subsidiaries of Delek Energy Systems Ltd. ("**Delek Energy**"), a private company wholly owned by Delek Group Ltd. ("**Delek Group**"), the controlling shareholder of which is Mr. Yitzhak Sharon (Tshuva)[2].

1.1.6. On May 17, 2017, a merger was closed between the Partnership and Avner Oil Exploration, Limited Partnership ("**Avner**" or the "**Avner**

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

[2] As of the report release date, Mr. Yitzhak Sharon (Tshuva) holds approx. 60.77% of the issued capital and approx. 62.03% of the voting rights in Delek Group. It is noted, that on October 16, 2018, the shares of Delek Energy were delisted from the TASE following a full exchange tender offer submitted by the Delek Group, in the context of which it offered, *inter alia*, participation units in the Partnership. See the Partnership's shelf offering report dated September 16, 2018 (Ref.: 2018-01-084490) and immediate report dated September 10, 2018 (Ref.: 2018-01-090619), the information in which is hereby included by way of reference. It is further noted that Delek Energy became a private company on December 2, 2018 in view of the full prepayment of its bonds that were listed on the TASE.

**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**" or the "**Merger of the Partnerships**").

1.1.7. <u>The structure of principal holdings of the Partnership</u>[3]


(a) Delek and Avner (Tamar Bond) Ltd. is a special purpose company (SPC), which was established for the purpose of the issue of bonds to the institutional market in Israel and overseas. For further details, see Section 7.22.1(d) below.

(b) Delek Drilling (Leviathan Financing) Ltd. is a special purpose company (SPC) which was established for the purpose of raising financing for the share of the Partnership in the costs of development of the Leviathan project. For further details, see Section 7.22.1(a) below.

(c) 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 (AOT) (the "**Terminal**"), as mandated by the provisions of the Natural Gas Sector Law, 5760-2000 ("**Natural Gas Sector Law**").

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

(d) Tamar 10-Inch Pipeline Ltd. is a special purpose company (SPC) whose shareholders are the partners in the Tamar reservoir in the area of the I/12 Tamar lease (the "**Tamar Lease**", the "**Tamar Project**" and the "**Tamar Partners**", respectively), which hold the shares of the company according to the rate of their holdings

[3] As of the report release date, the Participation Units issued by the Limited Partner are held, *inter alia*, by Delek Group (directly and through Delek Energy and the General Partner) (59.1%), and Yossi Abu (0.05%).

in the Tamar Lease. The company was established for the purpose of obtaining a license for the transmission of natural gas from the production platform of the Tamar project to the Terminal, as mandated by the provisions of the Natural Gas Sector Law.

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

(f) NBL Jordan Marketing Limited is a company whose shareholders are the Leviathan Partners, which hold the shares of the company according to the rate of their holdings in the Leviathan Leases. The company was established in connection with the engagement of the Leviathan Partners in a gas supply agreement with the national electric company of Jordan – The National Electric Power Company ("**NEPCO**"), whereby it will purchase the natural gas from the Leviathan Partners at the entry point to INGL's transmission system and shall sell it to NEPCO at the delivery point near the Israel-Jordan border under the same terms and conditions set forth in the said gas supply agreement (back-to-back). For further details, see Section 7.13.5(b)(1) below.

(g) Tamar Petroleum Ltd. ("**Tamar Petroleum**") is a public company. On July 20, 2017, upon fulfillment of all of the conditions precedent, a sale transaction was closed according to an agreement of July 2, 2017, which was signed between the Partnership and Tamar Petroleum, in the context of which the Partnership transferred to Tamar Petroleum interests at a rate of 9.25% (out of 100%) in the Tamar Lease and in the I/13 Dalit lease (the "**Dalit Lease**"), *inter alia*, in consideration for 40% of the share capital of Tamar Petroleum (after the allotment). According to an irrevocable letter of waiver produced by the Partnership to Tamar Petroleum, the Partnership unilaterally waived all the voting rights associated with all the shares held thereby, except with respect to a specific quantity that was determined in the 'Sale and Purchase Agreement' for the Sale of the Rights to Tamar Petroleum. For additional details see Section

7.27.17 below. During 2018, Tamar Petroleum engaged with Noble Energy Mediterranean Ltd. ("**Noble**") in an agreement whereby it purchased from Noble another 7.5% (out of 100%) of the Tamar and Dalit leases, *inter alia*, in consideration for an allotment of shares. As of the report release date, the Partnership holds 22.6% of the equity interests and 13.42% of the voting rights in Tamar Petroleum. According to the provisions of the Gas Framework (as defined in Section 7.25.1 below) pertaining to the Partnership's obligation to sell all of its interests in the Tamar and Dalit leases, the Partnership will be required to sell its holdings in Tamar Petroleum by December 17, 2021. For details see Section 7.25.1 below.

(h) EMED Pipeline B.V. ("**EMED**") is an SPC, established for the EMG Transaction (as defined in Section 7.27.7 below) and registered in the Netherlands, whose shares are held as follows: EMED Pipeline Holding Limited, a wholly owned subsidiary (100%) of the partnership that is registered in Cyprus – 25%; Noble Energy International Ltd. ("**Noble Cyprus**") – 25%; and Sphinx EG BV, a wholly owned subsidiary (100%) of East Gas Company S.A.E., which holds, *inter alia*, a gas pipeline and infrastructures in Egypt (the "**Egyptian Partner**") – 50%.

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

2. **<u>Operating Sector</u>**

2.1. The Partnership has holdings in petroleum assets as specified in Sections 7.2-7.9 below, and in this context, a number of significant gas discoveries in the Mediterranean Sea region, which include, *inter alia*, the Tamar reservoir, the Leviathan reservoir and the Aphrodite reservoir in Cyprus. Furthermore, the Partnership is entitled to receive overriding royalties from the Karish and Tanin leases, as specified in Section 7.10 below. The Tamar reservoir, from which the piping of gas commenced in March 2013, currently supplies almost all of the natural gas that is supplied to the Israeli market, and its prominent customers include the Israel Electric Corporation Ltd. (the "**IEC**"), private power plants and a number of industrial enterprises.

2.2. As of the report release date, the Partnership's primary business is exploration, development and production of natural gas, condensate and oil, promotion of use of infrastructures for the export of natural gas and promotion of various natural gas-based projects, with the aim of increasing the volume of natural gas sales.

2.3. Pursuant to the Gas Framework (as defined in Section 7.25.1 below), the Partnership is required to transfer all of its interests in the Tamar and Dalit leases by December 17, 2021. Therefore, as of the date hereof, the Partnership is promoting several alternatives for the sale of its remaining direct holdings in the Tamar and Dalit leases (22% out of 100%), in accordance with the Gas Framework, including the establishment of an SPC which will offer debt and equity, to be listed on a foreign stock exchange and/or on TASE, and/or sale to a third party and/or through split of the Partnership's assets, such that all of the Partnership's assets and liabilities, other than the assets and liabilities attributed to the Tamar and Dalit leases, shall be transferred to a foreign SPV whose shares will be distributed by the Partnership as a distribution in kind to the Partnership's participation unit holders.. For further details, see the Partnership's immediate report dated March 18, 2019 (Ref.: 2019-01-022080), the information appearing in which is incorporated herein by reference. It is noted that as of the Report Release Date, the Partnership has received several preliminary inquiries from potential investors (third parties), including foreign entities, who wish to explore the possibility of acting as anchor investors under the split plan on the London Stock Exchange. For the avoidance of doubt it is clarified that these are preliminary inquiries only. As of now, no decision has yet been made as to whether the split will be combined with a share offering, and there is no certainty that the said inquiries will lead to any binding engagements. For further details on the Gas Framework, see Section 7.25.1 below.

2.4. In accordance with the TASE directives, the Partnership has undertaken to only carry out projects of exploration, development and production, which were defined in the Partnership Agreement or in the amendment thereto to be approved by the meeting of the Participation Unit holders. The Partnership Agreement defines the geographical areas included in the Partnership's existing petroleum assets, which are specified in Section 2.6 below[4].

2.5. It is further provided in the Partnership Agreement that the principal part of the Partnership's expenses would be "Exploration and Development Expenses", within the meaning of such term in the Income Tax Regulations (Rules for the Calculation of Tax due to the Holding and Selling of Participation Units in an Oil Exploration Partnership), 5749-1988[5] (the "**Income Tax Regulations (Participation Units**")).

2.6. The following tables present details with respect to the petroleum assets in which the Partnership has rights, and details with respect to the optimal evaluation of the quantities of the reserves, contingent resources and prospective resources in such assets which are not negligible (in 100% terms)[6]. For further details with respect to these assets, see Sections 7.2-7.9 below[7].

[4] It is noted that in November 2017, the TASE Rules were amended (Chapter Q of Part Two of the Rules) regarding oil or gas exploration, development or production which are performed outside of Israel in the framework of the definition of "project" in a limited partnership that engages in oil and gas exploration, whose securities are listed on TASE.

[5] It is noted, that said regulations were valid up to June 30, 2015, and as of the report release date, they have not yet been extended.

[6] In all of the assets for which data of the appraisal of quantities of reserves and/or resource are presented, the data are as of December 31, 2018.

[7] For details about the exercise of the option to purchase 24.99% of the 399/"Roy" license, see Sections 7.5 and 7.27.14 below. For details about the agreement for the purchase of a 25% interest (out of 100%) in the 405/"New Ofek" license and the 406/"New Yahel" license, see Sections 7.6, 7.7 and 7.27.15 below.

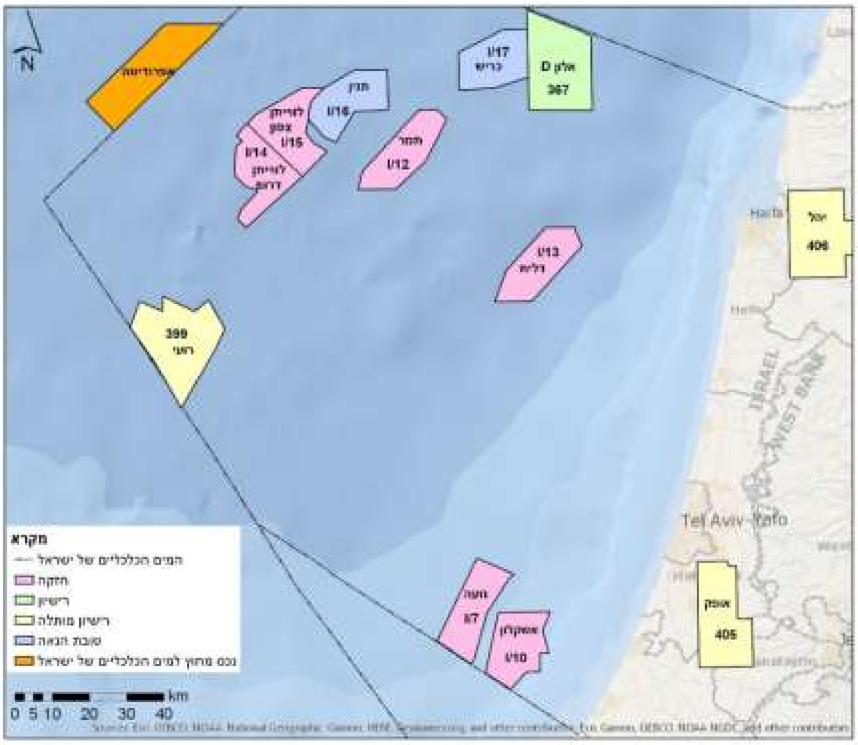
| Petroleum assets in which the Partnership has a direct and indirect holding | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Name of Project** | **Name of Petroleum Assets** | **Type of Right** | **Rate of Partnership's Rights in the Petroleum Assets** | **Reservoirs Discovered in the Area of the Petroleum Asset/s** | **Optimal Evaluation of the Total Quantity of Prospective Resources[8] (100%)** | | | **Optimal Evaluation (2C) of the Quantity of Contingent Resources (100%)** | | | **Optimal Evaluation (2P) of the Total Quantity of Reserves (100%)** | | |
| | | | | | **Natural Gas BCF** | **Conde-nsate Million barrels** | **Oil Million barrels** | **Natural Gas BCF** | **Conde-nsate Million barrels** | **Oil Million barrels** | **Natural Gas BCF** | **Conde-nsate Million barrels** | **Oil Million barrels** |
| Yam Tethys[9] | I/7 Noa I/10 Ashkelon (the "**Noa Lease**" and the "**Ashkelon Lease**", respectively) | Lease | 48.5% | Noa, Mari B and the Pinnacles | - | - | - | - | - | - | - | - | - |
| Tamar | Tamar Lease | Lease | 25.7855%[10] | Tamar and Tamar South-West ("**Tamar SW**")[11] | - | - | - | - | - | - | 11,139 | 14.5 | - |
| Dalit | Dalit Lease | Lease | 25.7855%[12] | Dalit | 267.6 | - | - | 270.7 | - | - | - | - | - |
| Leviathan & Deep Leviathan | Leviathan Leases | Lease | 45.34% | Leviathan | 3,950 | - | 559.7 | 8,110.1 | 14.6 | - | 13,385.1 | 24.0 | - |
| Block 12 in Cyprus | Block 12 | Production sharing | 30% | Aphrodite | 1,018.5 | 1.9 | - | 3,527.2 | 7.1 | - | - | - | - |
| - | 367/Alon D (the "**Alon D License**") | License | 52.941%[13] | - | - | - | - | - | - | - | - | - | - |

[8] The prospective resources noted below are situated in several fault blocks and/or various prospects, and the chances that they exist vary.
[9] For details regarding classification of the Yam Tethys project as a petroleum asset that is negligible to the Partnership's results of operations, see Section 7.2 below.
[10] This rate includes the rate of the Partnership's holding directly in the Tamar Lease (22%) and indirectly in the Tamar Lease, through the Partnership's holding of the shares of Tamar Petroleum at a rate of 22.6%.
[11] Some of the reserves in the Tamar SW well overflow into the area of the Eran/353 license (the "**Eran License**"), which expired on June 14, 2013 and is the subject matter of a legal proceeding. Therefore, the figures in the above table do not include the resources which have been proven by such drilling as part of the Tamar SW reservoir, which overflow into the Eran License. For further details in regards to the Eran License, see Section 7.11 below.
[12] See Footnote 10 above.
[13] For details regarding the transfer of Noble's rights in the license to the Partnership at a rate of 22.059%, see Section 7.9 below

| Petroleum assets in which the Partnership has a benefit[14] | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Name of Project** | **Name of Petroleum Assets** | **Type of Benefit** | **Rate of Partnership's Rights in the Benefit in the Petroleum Assets** | **Reservoirs Discovered in the Area of the Petroleum Asset/s** | **Optimal Evaluation of the Total Quantity of Prospective Resources[15] (100%)** | | | **Optimal Evaluation (2C) of the Quantity of Contingent Resources (100%)** | | | **Optimal Evaluation (2P) of the Total Quantity of Reserves (100%)** | | | |
| | | | | | **Natural Gas BCF** | **Conde-nsate Million barrels** | **Oil Million barrels** | **Natural Gas BCF** | **Conde-nsate Million barrels** | **Oil Million barrels** | **Natural Gas BCF** | **Conde-nsate Million barrels** | **Oil Million barrels** | |
| Tanin[16] | I/16 lease (the "**Tanin Lease**") | Right to royalty | 5.12% before payment of a petroleum profit levy under the Taxation of Profits from Natural Resources Law, 5771-2011 (the "**Levy**") and before the Investment Recovery Date; 2.47% before payment of the Levy and after the Investment Recovery Date; and 3.22% upon commencement of payment of the Levy and after the Investment Recovery Date | Tanin | - | - | - | - | - | - | - | - | - | |
| Karish[17] | I/17 lease (the "**Karish Lease**") | Right to royalty | 5.12% before payment of the Levy and before the Investment Recovery Date; 2.47% before payment of the Levy and after the Investment Recovery Date; 3.22% upon commencement of payment of the Levy and after the Investment Recovery Date | Karish | - | - | - | - | - | - | - | - | - | |

[14] For details, see Section 7.27.16 below.
[15] The prospective resources stated below are situated in several fault blocks and/or various prospects, and the chances of success in respect of their existence vary.
[16] For details regarding classification of the Tanin and Karish leases as petroleum assets that are negligible to the results of operations of the Partnership, see Section 7.10.1 below.
[17] See Footnote 16 above.

2.7. <u>A map that includes the Partnership's petroleum assets, as of the report release date</u>




For further details with respect to licenses whose validity was not extended and which are the subject matter of legal proceedings, see Section 7.11 below.

## 3. **<u>Investments in the Partnership's Capital and Transactions in Participation Units</u>**

During the last two years, there have been no investments in the Partnership's capital and/or material off-exchange transactions in Participation Units, by interested parties in the Partnership, and of which the Partnership is aware, except as specified below[18]:

| Name of interested party | Date of performance of transaction | Type of transaction | Type of securities | Quantity of securities | Price per participation unit (in ILS) | Consideration (in ILS) |
|---|---|---|---|---|---|---|
| Yossi Abu | September 28, 2017 | Sale | Participation units | 511,954 | 11.16 | 5,713,406 |
| Delek Energy | September 28, 2017 | Purchase | Participation units | 511,954 | 11.16 | 5,713,406 |

[18] In the context of a change in the issued capital, it is noted that on May 17, 2017, an allotment of 626,847,903 participation units was performed to all of the holders of the participation units in the Avner Partnership as a result of the Merger of the Partnerships.

4. **Distribution of Profits**

4.1. In the period from January 1, 2017 until December 31, 2018, the Partnership declared profit distributions (as defined in the Partnership Agreement), as specified below:[19]

| Declaration Date | Distribution Date | Distribution Amount per Participation Unit | | Total Distribution Amount (in millions) | |
|---|---|---|---|---|---|
| | | The Partnership | Avner | The Partnership | Avner |
| January 16, 2017 | February 9, 2017 | $0.16866 | 0.03231$ | Approx. $92.3 | Approx. $107.7 |
| May 25, 2017 | June 20, 2017 | $0.15335 | | $180 | |
| August 15, 2017 | Sept. 7, 2017 | $0.25558 | | $300 | |
| Dec. 21, 2017 | January 18, 2018 | ILS 0.1783416 | | Approx. ILS 209 | |
| Dec. 24, 2018 | January 14, 2019 | ILS 0.1107500 | | ILS 130 | |

As of December 31, 2018, the Partnership has profits available for distribution in the amount of approx. 679,303 million U.S. Dollars ("**Dollars**" or "**$**"), subject to the provisions of Sections 4.2.4 to 4.2.6 below and to any law.

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

4.2.1. 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.

4.2.2. Once a year, on or about the end of the year, the General Partner, in consultation with the Partnership's accountants, will perform an estimation of the Partnership's annual taxable income. Based on such estimation, the General Partner will determine the amount for first distribution (the "**First Distribution Amount**"). The First Distribution Amount will be published by the General Partner before the year-end and thereafter distributed to the partners (as being at the year-end). The balance of the Profits remaining for distribution (if any) due to the same year will be determined by the General Partner and published shortly after

[19] In this context it is noted that as of May 2017, the distribution amounts specified in the table are after the completion of the Merger of the Partnerships.

the release of the Partnership's audited financial statements for the same year (the "**Second Distribution**"). The Partnership Agreement clarifies that in the event that after the Second Distribution it transpires, following a change of circumstances, that additional amounts may be distributed for the same year, the General Partner may perform additional distributions for the same year, and the General Partner will be obligated to do so if the additional distributable amounts exceed $3 million. For further details with regards to the tax arrangement that currently applies, see Sections 4.3 to 4.7 below.

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

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

4.2.5. On December 30, 2013, a meeting of the Participation Unit holders was held, in which it was resolved, *inter alia*, to approve refraining from distribution of profits (within the meaning thereof in the Partnership Agreement), for the purpose of investment thereof in the development of the Leviathan reservoir according to the work plan and budgets approved and/or to be approved under the joint operating agreements that apply to the Leviathan Leases, and also to approve use of the surplus cash accumulated and to be accumulated by December 31, 2014, for the purpose of investment thereof in activities of exploration and evaluation in the Leviathan Leases and in Block 12 which is situated in the EEZ of Cyprus, according to a work plan and budgets approved and/or to be approved under the joint operating agreements that apply to the aforesaid petroleum assets. It is clarified that profits of which no actual use is made for the aforesaid purposes will be distributed to the Participation Unit holders, unless otherwise resolved by the meeting of the Unit holders.

4.2.6. On July 1, 2018, a meeting of the Participation Unit holders was held, in which it was resolved to approve refraining from distribution of profits (within the meaning thereof in the Partnership Agreement), for the purpose of investment thereof in the purchase of rights in East Mediterranean Gas Limited ("**EMG**") only in order to enable engagement with EMG in connection with the use of the existing gas pipeline between Israel and Egypt and the facilities owned thereby for the purpose of piping of natural gas only. For details, see the Partnership's immediate reports as of June 11, 2018, June 28, 2018 and July 1, 2018 (Ref.: 2018-01-049728, 2018-01-062350, and 2018-01-063043, respectively), the details of which for the purpose of this resolution are incorporated herein by reference. For details on the EMG Transaction (as defined below), see Section 7.27.7 below.

4.3. <u>The provisions of the Taxation of Profits from Natural Resources Law, 5771-2011[20]</u>

4.3.1. According to the provisions of Section 19 of the Taxation of Profits from Natural Resources Law, 5771-2011 ("**Section 19**" and the "**Taxation of Profits from Natural Resources Law**", respectively), the general partner is obligated to file to the assessing officer a report (certified by an accountant) on the taxable income of the Partnership. Section 19 prescribes, that upon the filing of the report, the General Partner is required to pay the tax deriving therefrom, on account of the tax owed by the partners in the Partnership in the tax year for which the report was filed (i.e. on the account of the eligible participation unit holders, as they will be on December 31 of each tax year) (the "**Entitled Holders**"). According to the provisions of Section 19, the tax that the General Partner is due to pay upon the filing of the report, on account of the tax owed by the Entitled Holders, shall be calculated according to the pro rate share in the Partnership of the Entitled Holders who are corporations and the pro rate share in the Partnership of the Entitled Holders who are individuals (the "**Weighted Tax Rate**"). For such purpose, the taxable income of the individuals shall be deemed to be subject to the maximal tax rate, unless it was proven to the assessing

[20] On November 7, 2017 the Ministry of Finance published the Taxation of Profits from Natural Resources Legislative Memorandum, 5778-2017 (Amendment No. _____) (the "**Memorandum**") which included several proposed amendments to the provisions of the Taxation of Profits from Natural Resources Law, pursuant to the Gas Framework. The subject matter of the amendments contemplated in the Memorandum is, *inter alia*, the amendment of the term "Revenues" in the Taxation of Profits from Natural Resources Law, such that it shall also include payments for components related to the sale as set forth in the Gas Framework, determination of several provisions that increase the ability to audit and enforce the Taxation of Profits from Natural Resources Law by the tax authority, and granting of incentives to specific holders of rights in petroleum enterprises whose size is up to 50 BCM. On July 15, 2018, the Ministerial Committee for Legislation approved the draft law, based on the Memorandum, for a first reading at the Knesset.

officer that the tax rate applying to such individual is lower than said rate.

4.3.2. On October 30, 2016, the supervisor filed a motion for instructions with the court, with respect to the interpretation and implementation of Section 19 (hereinafter in this Section 4: the "**Motion**"). On November 1, 2017, the judgment of the District Court was received in the Motion. To the Partnership's understanding, the judgment determines as follows: (a) Section 19(a) of the Taxation of Profits from Natural Resources Law ("**Section 19(a)**") does not concern regulation of the internal relationship among the holders of the Partnership's participation units themselves, but rather only the manner of collection of the tax. Hence, payment of the tax pursuant to Section 19(a) should not be deemed as a distribution, and payment of the tax is not subject to the distribution tests; (b) The General Partner's proposal that alongside payment of the tax, the holders will be issued with a tax certificate in which the attribution of the payment shall be uniform for each holder, without taking into account his status, cannot be accepted since this proposal entails underpayment of tax with respect to "individuals", which will necessitate additional collection actions and will prejudice the purpose of Section 19(a), which is streamlining the tax collection; (c) The court sees no justification for intervening in the management of the Partnership's affairs and requiring the Partnership to pay an amount exceeding the amount mandated by the provisions of Section 19(a)(6) to the holders of the participation units or to Income Tax; (d) So long as the collection arrangement set forth in Section 19(a) is in effect, the Partnership and/or the General Partner is required to find the proper method to balance between the additional expense entailed by the tax rate that applies to individuals who hold the participation units and the expense entailed by the tax rate that applies to companies that hold participation units. One of the methods is that on the date of payment of the tax by the General Partner, the General Partner will determine a balancing distribution that may be "notional" (a credit on the books until the actual distribution and accounting) to those holders of participation units whose tax rate is lower than the tax rate that applies to individuals. The court does not substitute itself for the General Partner, and if it finds another arrangement that meets the requirements of the law (the partnership agreements and partnerships law) that apply to the Partnership and thereto, it may do so. On December 31, 2017, the Partnership's General Partner filed an appeal from the District Court's judgment (hereinafter in this Section 4: "**Partnership's Appeal**"), in which the Supreme Court was moved to rule on the proper interpretation of Section 19, so as to determine a fixed, known and industry-wide method for taxing the liable income of petroleum partnerships, whereby the petroleum partnerships will all be able to act with certainty, *inter* *alia* while allocating the tax payment among the holders in an equal manner which will prevent discrimination of holders that are liable for a lower rate than the maximum tax rate that applies to an individual. The Supreme Court was further moved to rule that: (a) the tax payment that a petroleum partnership pays pursuant to the provisions of Section 19 shall be equally allocated among all of the units in the Partnership; (b) accordingly, the Partnership is required to issue to the unit holders equal tax certificates, such that the tax that the Partnership paid on account of the tax owed by the partners in the Partnership is recorded on the tax certificate in a uniform amount for individuals and for a body corporate, without distinguishing between them, and each partner will be able to make use of this certificate, insofar as he requires, whether for the purpose of supplementation of the tax payment required of him, or for receipt of a tax refund; (c) alternatively, to rule that the District Court's decision, whereby the tax should be allocated to the partners differentially, shall apply prospectively only, while in relation to the past, the petroleum partnerships will be able to allocate the tax paid in an equal manner to the relevant holders, and accordingly they will be entitled to issue equal tax certificates; (d) alternatively, and insofar as it is determined that the tax payment in accordance with Section 19 does not constitute a distribution within the meaning thereof in the Companies Law, 5759-1999 (the "**Companies Law**"), it shall be ruled that also a balancing payment that shall be made to holders of participation units which are a body corporate (in order to prevent subsidization among holders of units in the Partnership in the payment of the tax) does not constitute a distribution, in order to prevent discrimination of holders that are liable for a rate lower than the maximum tax rate that applies to an individual (such as companies or institutional bodies).

Since also in the matter of another petroleum partnership - Isramco Negev 2 ("**Isramco**") – an appeal was filed with the Supreme Court against a similar decision of the District Court regarding the manner of attribution of the tax paid by the Partnership on account of the holders (hereinafter in this Section 4, "**Isramco's Appeal**"), and per Isramco's and the Partnership's request, the Supreme Court ruled on April 17, 2018 that Isramco's Appeal and the Partnership's Appeal shall be scheduled to be heard on the same date and before the same panel. A hearing for supplementary oral arguments was scheduled for July 25, 2019.

4.3.3. On May 8, 2018, the Supervisor filed with the Tel Aviv District Court a petition for instructions (hereinafter in this Section 4: the "**Supervisor's Petition**", in which the court was moved to order the General Partner, *inter alia*, to bear the Supervisor's expenses in the framework of the petition and in the framework of the

Partnership's Appeal. On June 17, 2018, the General Partner in the Partnership filed its response to the Supervisor's Petition in which framework moved the court to order to dismiss the petition with prejudice. On September 6, 2018, a hearing was held in the Tel Aviv District Court on the General Partner's motion as aforesaid. In accordance with the court's position, as was expressed at the said hearing, and following its recommendation, the Supervisor and the General Partner signed a settlement agreement, whereby at the general meeting of the holders of the Participation Units in the Partnership, the Supervisor's legal fees in the petition and in the appeal would be presented for approval, such that the payment will be made out of the Partnership's funds. Such agreement was sanctioned as a judgment on October 31, 2018. As of the report date, the issue of the legal fees of the supervisor in the Motion and the appeal as aforesaid was added to the agenda of the meeting of the holders of the Partnership's participation units which was held on December 27, 2018, but was removed therefrom prior to the meeting at the supervisor's request, and in view of the request of advisory bodies for institutional investors. In this regard, see the Partnership's immediate reports of December 26, 2018 and November 21, 2018 (Ref.: 2018-01-119173 and 2018-01-106297, respectively).

4.4. <u>Year 2014</u>

In October 2018, final tax certificates were received for an Entitled Holder for the holding of a Participation Unit of the Partnership and of Avner Partnership, for the tax year 2014 (in this section: "**Entitled Holder**").[21]

The table below specifies the data (in ILS), as stated in the final tax certificates for the purpose of calculating the deduction for an Entitled Holder of one Participation Unit of par value ILS 0.1 of the Partnership and of one Participation Unit of par value ILS 0.01 of Avner[22] in 2014:

[21] It is noted that due to the merger of Avner with and into the Partnership, the tax certificate for an Entitled Holder for the holding of a Participation Unit in Avner is published in the Partnership's immediate reports.

[22] The calculation for one unit is based on 546,966,871 issued units of par value ILS 1 each, as of December 31, 2014. The calculation for a participation unit of Avner is calculated on 3,334,830,628 issued units of par value ILS 0.01 each, as of December 31, 2014.

| Loss from business for tax purposes | | Interest from marketable securities overseas taxable at 25% for an individual and 26.5% for a body corporate | | Income from dividend received from a body corporate which is not an Israeli resident taxable at 25% for an individual and 26.5% for a body corporate | | Credit for foreign tax paid overseas on income from dividends overseas[23] | |
|---|---|---|---|---|---|---|---|
| **The Partnership** | **Avner** | **The Partnership** | **Avner** | **The Partnership** | **Avner** | **The Partnership** | **Avner** |
| (0.00766) | (0.00126) | 0.00479 | 0.00079 | 0.00287 | 0.00047 | 0.00029 | 0.00005 |

For further details, see final tax certificates for an Entitled Holder for the holding of a Participation Unit of the Partnership and of Avner for the tax year 2014, attached to the Partnership's immediate report as of October 4, 2018 (Ref: 2018-01-088264), the information appearing in which is incorporated herein by reference.

4.5. Tax years 2015-2016

4.5.1. On December 13, 2017, temporary tax certificates were received for Entitled Holders for the holding of Participation Units of the Partnership in respect of the 2015 tax year and the 2016 tax year (in this section: "**Entitled Holder**"). It is hereby emphasized and clarified as follows:

(a) Holders of Participation Units of the Partnership shall be **permitted (but not obligated)** to include in their tax statements for 2015 and 2016, their share in the Partnership's taxable income, and their share in the tax amount paid by the Partnership, for the Participation Units that were held by them for such years, in accordance with the temporary tax certificates.

(b) The temporary certificate shall allow the Participation Unit holders who are "Entitled Holders" and who have losses for tax purposes or a tax exemption in any of the said tax years, to receive tax refunds for the tax that was paid by the Partnership and was attributed to them.

(c) In accordance with the agreements with the Tax Authority, this is merely a temporary tax certificate and the final tax certificate for each said tax year shall only be issued upon the completion of the Tax Authority's audit. The final tax calculation for each "Entitled Holder" shall be made in accordance with the Partnership's final

[23] In the event that it is possible to offset deductible losses against income of Israeli residents, such losses must be offset as aforesaid and cannot be postponed to the following years, other than in exceptional cases specifically permitted by the Ordinance. Even if such setoff prevents another benefit, such as foreign tax credits. Namely, where there is a deductible loss in Israel and a taxable foreign income, the loss setoff rules in the Ordinance require setoff prior to the credit rules.

assessment and the final certificate for the purpose of calculating the Entitled Holder's tax. Additionally, the final certificate may be changed following the results of the appeal that was filed by the Partnership from the District Court's judgment as mentioned in Section 4.3.2 above.

(d) Unit holders who act in accordance with Section (a) above, shall be required to amend their statements in accordance with the final tax certificate which shall be published by the Partnership. In such case, the amount of the refund owing to or the payment owed by the Entitled Holder may decrease or increase as a result of the aforesaid and accordingly, Unit holders may even be required to repay the Tax Authority amounts that were received thereby based on the temporary certificate.

(e) The following table specifies the figures that were stated in the temporary tax certificates for the purpose of calculation of the profit (deduction) for an Entitled Holder of one participation unit of ILS 1 par value (in ILS) in the years 2015-2016:

| Tax Year | Profit from a Business for Tax Purposes | | Capital Gain from Negotiable Securities | | Interest from Negotiable Securities | | Tax Paid on Account of the Tax of Entitled Holders who are Individuals[24] | | Tax Paid on Account of the Tax for which Entitled Holders who are a Body Corporate are Liable[25] | |
|---|---|---|---|---|---|---|---|---|---|---|
| | The Partnership | Avner | The Partnership | Avner | The Partnership | Avner | The Partnership | Avner | The Partnership | Avner |
| 2015 | 0.36424 | 0.05335 | 0.05220 | 0.00925 | 0.03006 | 0.00493 | 0.19409 | 0.02894 | 0.11698 | 0.01768 |
| 2016 | 0.71042 | 0.10373 | - | - | 0.01568 | 0.00213 | 0.34492 | 0.05033 | 0.18152 | 0.02647 |

(f) It is noted that the Partnership is not a taxpayer under the Income Tax Ordinance (New Version), 5721-1961 (the "**Income Tax Ordinance**"), and revenues, expenses, profits and losses of the Partnership are attributed to the Unit holders who are an "Entitled Holder", as per the definition thereof in the Income Tax Regulations (Participation Units), per the rate of their holdings in the Partnership. An "Entitled Holder" is a person who held Participation Units at the end of the day of December 31 of the tax year.

(g) For further details, see temporary tax certificates for an Entitled Holder for the holding of a Participation Unit of the Partnership and of Avner, for the 2015 and 2016 tax years, which were attached to the Partnership's immediate report dated December 13, 2017 (Ref.: 2017-

[24] Individual – including a liable mutual fund and a partnership.
[25] Body corporate – including a company, provident fund, public institute and an exempt mutual fund.

01-116190), the information appearing in which is incorporated herein by reference.

4.5.2. It is noted that, although as of the date of this report, the Tax Authority's audit of the Partnership's and the Avner Partnership's tax statements for the 2015 tax year has been completed and tax assessment agreements have been signed with the Tax Authority, final tax certificates for the 2015 tax year have not yet been issued since the Income Tax Regulations (Participation Units ) were effective until June 30, 2015 and their effect has not yet been extended to a later date. In accordance with the aforesaid tax assessment agreements, final tax certificates will be issued and released accordingly only after extension of the force and effect of the regulations. In accordance with the aforesaid tax assessment agreements, the taxable income of the Partnership and of the Avner Partnership in 2015 was approx. ILS 317.4 million and approx. ILS 293.3 million, respectively, and in respect thereof the Partnership and the Avner Partnership paid tax on account of the holders of participation units in the Partnership and in the Avner Partnership, in the sum of approx. ILS 92 million and approx. ILS 88 million, respectively.

4.5.3. It is further noted that, given the disputes that have arisen between the Partnership and the Tax Authority and disagreements with respect to the amount of the partnerships' taxable income in respect of 2016, on November 22, 2018, best-judgment assessments were received from the Tax Authority under Section 145(a)(2)(b) of the Income Tax Ordinance (in this section: the "**Tax Assessment**"), according to which the taxable business income of the Partnership and of the Avner Partnership for 2016 was approx. $130 million and approx. $118 million, respectively (*in lieu* of the sums of approx. $108 million and approx. $96 million, respectively, as included in the partnerships' tax statements that had been submitted to the Tax Authority) and the capital gains of the Partnership and of the Avner Partnership for 2016 was approx. $47 million and approx. $62 million, respectively (*in lieu* of sums of approx. $6 million and approx. $15 million, respectively, as included in the partnerships' tax statements that had been submitted to the Tax Authority).

The dispute primarily pertains to the interpretation of the manner of recognition of financial expenses actually borne by the partnerships and the manner of calculation of the capital gains from the sale of the Karish and Tanin leases. According to the tax assessments, and insofar as all of the Tax Authority's arguments are accepted, the Partnership will be required to pay additional advance tax payments (including interest) on account of the tax for which holders of Participation Units of the partnerships are liable in the sum of approx. $40 million. It is noted that, in view of the aforesaid, there may be a delay in the issuance of a final tax certificate to an Entitled Holder in respect of the holding of a Participation Unit of the Partnership and of the Avner Partnership for the tax year 2016, until completion of the proceedings required for the determination of the final assessment. On March 14, 2019, the Partnership filed administrative appeals with respect to the said tax assessments. In the Partnership's estimation, based on the opinion of its professional advisors and past experience, the chances of the Partnership's key arguments being accepted are higher than 50%.

4.6. Tax year 2017

4.6.1. On November 8, 2018, a temporary tax certificate was received for Entitled Holders for the holding of Participation Units of the Partnership in respect of the 2017 tax year (in this section: "**Entitled Holder**"). It is hereby emphasized and clarified as follows:

(a) Holders of Participation Units of the Partnership shall be **permitted (but not obligated)** to include in their tax statements for the year 2017, their share in the Partnership's taxable income, and their share in the tax amount paid by the Partnership, including tax withheld in the context of the distribution of profit carried out by the Partnership on January 18, 2018 in respect of the 2017 tax year, for the Participation Units that were held by them at the end of the day of December 31, 2017, in accordance with the temporary tax certificate.

(b) The temporary certificate shall allow the Participation Unit holders who are "Entitled Holders" and who have losses for tax purposes or a tax exemption for the 2017 tax year, to receive tax refunds for the tax that was paid by the Partnership and was attributed to them.

(c) In accordance with the agreements with the Tax Authority, this is merely temporary tax certificate and the final tax certificate for 2017 shall only be issued upon the completion of the Tax Authority's audit. The final tax calculation for each "Entitled Holder" shall be made in accordance with the Partnership's final assessment and the final certificate for the purpose of calculating the Entitled Holder's tax, which may materially differ from the temporary tax certificate. Additionally, the final certificate may be changed following the results of the appeal that was filed by the Partnership from the District Court's judgment as mentioned in Section 4.3.2 above.

(d) Unit holders who act in accordance with Section (a) above, shall be required to amend their statements in accordance with the final tax certificate which shall be published by the Partnership. In such case, the amount of the refund owing to or the payment owed by the Entitled Holder may decrease or increase as a result of the aforesaid and accordingly, Unit holders may even be required to repay the Tax Authority amounts that were received thereby based on the temporary certificate.

(e) The following table specifies the figures that were stated in the temporary tax certificate for the purpose of calculation of the profit (deduction) for an Entitled Holder of one Participation Unit of ILS 1 par value (in ILS) in Y2017:

| **Taxable Business Income** | **Business Capital Gains** | **Capital Loss from Marketable Securities Abroad** | **Interest from Marketable Securities** | | **Income from Dividend from Abroad** | **Tax Paid on Account of the Tax owed by Entitled Holders who are Individuals** [26] | **Tax Paid on Account of the Tax owed by Entitled Holders who are Bodies Corporate** [27] | **Credit from Foreign Tax Paid Abroad** [28] | |
|---|---|---|---|---|---|---|---|---|---|
| | | | **Abroad** | **In Israel** | | | | **For Income from Interest Abroad** | **For Income from Dividend Abroad** |
| 0.62266 | 1.61050 | (0.02665) | 0.01167 | 0.00008 | 0.00035 | 0.54832 | 0.53236 | 0.00002 | 0.00056 |

(f) For further details, see temporary tax certificate for Entitled Holders for the holding of Participation Units of the Partnership in respect of 2017, which was attached to the Partnership's immediate report of November 8, 2018 (Ref.: -2018-01101494), the information included in which is incorporated herein by reference.

4.6.2. In accordance with the provisions of Section 19 as aforesaid, until the report release date, the Partnership paid the Income Tax Authorities, on account of the tax for which the partners will be liable in the tax year 2017, advance payments in an aggregate amount of approx. ILS 764 million, i.e. approx. ILS 0.65128 per Participation Unit. It is clarified that such advance payments do not include the withholding tax that was withheld from the

[26] Individual – including a liable mutual fund and a partnership.
[27] Body corporate – including a company, provident fund, public institution and exempt mutual fund.
[28] See Footnote 23 above.

profits that were distributed in the framework of an agreement for the collection of tax for the tax year 2017, which was signed between the Partnership and the Tax Assessor for Large Enterprises (the "**Tax Agreement**") (for details see the immediate reports dated December 21, 2017 and December 24, 2017 (Ref..: 2017-01-118860 and 2017-01-119130) the information included in which is incorporated herein by reference). It is noted that following the filing of the Partnership's tax statement for 2017, the Partnership received a refund from the Tax Authority in respect of advance tax payments made thereby in the sum of approx. ILS 121 million. It is noted that if, after completion of the audit by the Tax Authority, it transpires that the Partnership made advance tax payments in amounts that exceed the amounts required by the law, the balance will be paid back to the Partnership; if it transpires that the final tax assessment is higher than the amounts paid by the Partnership (net of refunds paid thereto), the Partnership will be required to act in accordance with the provisions of Section 19, and pay the tax balance deriving therefrom according to the rate of the share in the Partnership of the Entitled Holders who are bodies corporate and the rate of the share in the Partnership of the Entitled Holders who are individuals, for which purpose the taxable income of the individuals shall be deemed as being subject to the maximum tax rate, unless it is proven to the assessing officer that the tax rate that applies to such individual is lower than the said rate. In addition, the Partnership shall act in accordance with the aforesaid judgment of the District Court, insofar as the Supreme Court does not rule otherwise in its decision on the appeal filed by the Partnership as aforesaid.

On January 18, 2018, a profit distribution was performed in the sum of approx. ILS 209 million in the context of the Tax Agreement.

4.7. Tax year 2018

4.7.1. In accordance with the provisions of the Partnership Agreement and the Trust Agreement of July 1, 1993 (as amended from time to time), and after consulting with the Partnership's accountants, in the estimation of the General Partner, according to an estimate prepared thereby (subject to the restrictions and reservations that follow), according to estimated unaudited data and based on various assessments and assumptions, including with respect to the estimate of revenues and expenses expected by December 31, 2018, the Partnership's taxable income for 2018 is expected to amount to a total of approx. ILS 471 million, i.e. approx. ILS 0.40409 per Participation Unit. The revenues from dividend and interest from securities, after deduction of the (net) capital loss from the sale of securities, for the year 2018, are expected to amount to a total of approx. ILS 58 million, i.e., approx. 0.04911 per Participation Unit.

It is clarified that such estimate is a preliminary estimate and constitutes a mere assessment, and that the amount of the taxable income per Entitled Holder in respect of the holding of a Participation Unit for the 2018 tax year as not yet been determined, due to the fact that the proceeding of audit of the Partnership's tax statements by the Partnership's auditors and by the Tax Authority for the year 2018 has not yet been conducted. Furthermore, the final determination of the Partnership's taxable income for the tax years 2016 and 2017 may have a material effect on the amount of the Partnership's taxable income for the year 2018. After the proceeding of the audit by the auditors and the Tax Authority is completed, as aforesaid, and upon the determination of the amount of the taxable income per Entitled Holder in respect of the year 2018, a certificate for the purpose of calculation of the taxable income per Entitled Holder will be issued. It is noted that the Income Tax Regulations (Participation Units) were effective until June 30, 2015 and as of the report release date, their force and effect has not yet been extended. In accordance with the provisions of Section 19 as aforesaid, until the report release date, the Partnership paid the Income Tax Authorities, on account of the tax for which the partners will be liable in the tax year 2018, advance payments in an aggregate amount of approx. ILS 110 million, i.e. approx. ILS 0.0937 per Participation Unit. It is clarified that such advance payments do not include the tax withheld, if any, from the profits that were distributed in on January 14, 2019. It is noted that if, after completion of the audit by the Tax Authority, it transpires that the Partnership made advance tax payments in amounts that exceed the amounts required by the law, the balance will be paid back to the Partnership; if it transpires that the final tax assessment is higher than the amounts paid by the Partnership, the Partnership will be required to act in accordance with the provisions of Section 19 of the law, and pay the tax balance deriving therefrom according to the rate of the share in the Partnership of the Entitled Holders who are bodies corporate and the rate of the share in the Partnership of the Entitled Holders who are individuals, for which purpose the taxable income of the individuals shall be deemed as being subject to the maximum tax rate, unless it is proven to the assessing officer that the tax rate that applies to such individual is lower than the said rate. In addition, the Partnership shall act in accordance with the aforesaid judgment of the District Court, insofar as the Supreme Court does not rule otherwise in its decision on the appeal filed by the Partnership as stated in Section 4.3.2 above.

On January 14, 2019, a profit distribution was performed in the sum of approx. ILS 130 million. For further details, see the

Partnership's immediate report dated December 24, 2018 (Ref.: 2018-01-118024), the information appearing in which is incorporated herein by reference.

**Every Holder should, examine through professional advisors, his taxation situation and the need to take preparatory measures pursuant to the recommendations of his professional advisors. The Partnership is not liable and shall bear no responsibility in relation to the statements of the Unit holders and/or amendment thereof and/or the implications of amendment thereof.**

**Caution concerning forward looking information – the Partnership's assessment on the amount of the Partnership's taxable income in respect of the year 2018 and with respect to the payments paid by the Partnership to Income Tax for the tax year 2018, is forward looking information within the meaning thereof in the Securities Law, 5728-1968 (the "Securities Law"), since the amount of the taxable income of an Entitled Holder for the holding of any of the Participation Units in respect of the 2018 tax year has not yet been determined, due to the fact that an audit of the Partnership's books was not yet performed by the auditors of the Partnership and by the Tax Authority for 2018. It is clarified that this is merely an assessment by the General Partner and a preliminary estimate, and that the final determination of the Partnership's taxable income in respect of 2018 may be materially different from such assessment, and may be affected, *inter alia*, by the total revenues and total expenses of the Partnership for tax purposes in respect of 2018, which have not yet been audited, as of the report release date, by the accounting and tax implications which are unknown as of this time, by the final determination of the Partnership's taxable income for the tax years 2016 and 2017 and by changes in the exchange rate of the USD in relation to the ILS.**

5. <u>Financial Information regarding the Partnership's Operating Sector</u>

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

5.2. For details with respect to the total assets and liabilities of the Partnership as of December 31, 2018 and December 31, 20162017, 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 General Partner's board of directors' report (Chapter B hereof).

6. **General Environment and the Effect of External Factors**

6.1. The Petroleum Law, 5712-1952 (the "**Petroleum Law**") governs the regulation in the sector of oil and natural gas exploration and production in Israel and prescribes, *inter alia*, that oil and gas exploration activities in Israel can be conducted in geographical areas in which the exploring entity was granted a gas and petroleum right under the Petroleum Law. In addition, the Natural Gas Sector Law mainly governs the issue of transmission, distribution, marketing and storage of natural gas and/or LNG within the State of Israel. For further details with respect to the Petroleum Law and the Natural Gas Sector Law, see Sections 7.25.3(f) and 7.25.3(i) below, respectively.

6.2. The economic merit of investments in exploration and development of natural gas reservoirs, is greatly affected by the prices of petroleum and gas in the world, by demands for natural gas in the global, regional and local markets and the ability to export natural gas (whether by pipes, in compressed form or in liquid form), which requires, *inter alia*, gas resources of considerable volumes and engagements in long term agreements for the sale of natural gas in substantial amounts, to justify the high investments required for construction of the appropriate infrastructures. The sale of petroleum, if found and where found, may be made to various consumers in Israel and across the world based on the global oil prices at such time.

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

6.4. In recent years, the natural gas sector in Israel has been undergoing significant changes (which include, *inter alia*, regulatory, economic and environmental changes). Within a few years, natural gas has become the primary component in the Israeli economy in the range of fuels for electricity production and a significant energy source for industry in Israel. The natural gas resources that were discovered in Israel can provide all of the gas needs of the local economy during the upcoming decades and most of its energy needs, and thus substantially reduce the dependence of the State of Israel on foreign energy sources.

6.5. According to the data of the Ministry of Energy[29], the scope of use of natural gas in Israel increased from approx. 7.6 BCM in 2014 to approx.

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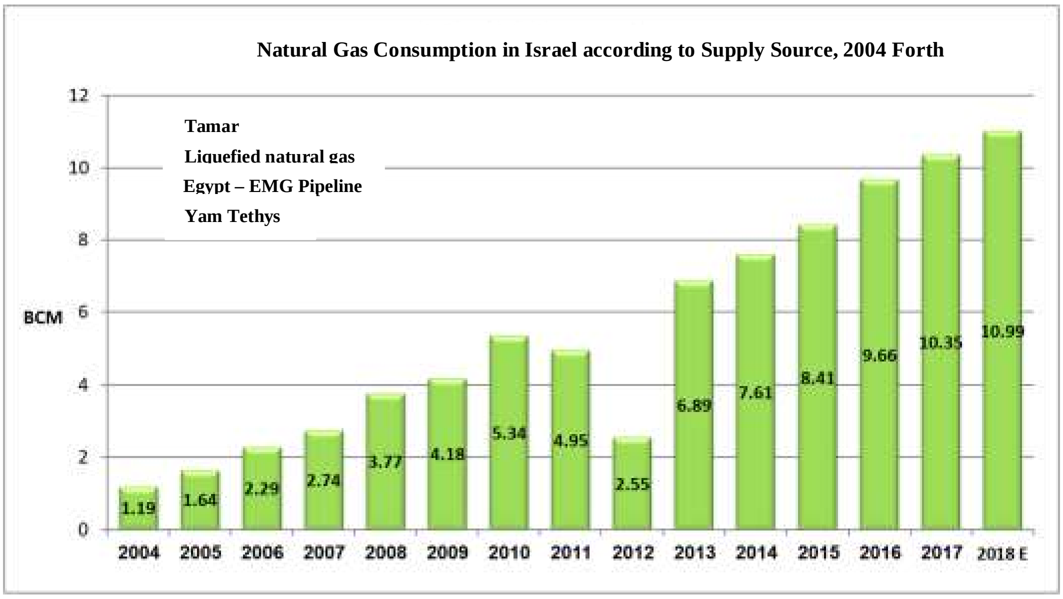
[29] Taken from the Ministry of Energy, Natural Gas Authority, **Review of the Natural Gas Sector in 2017**, https://www.gov.il/BlobFolder/guide/natural_gas_basics/he/ng_2017.pdf.

10.3 BCM in 2017, while in 2018 it is estimated at approx. 11 BCM, all as specified in the graph below[30]:




In addition, in 2017, the export of natural gas from the Tamar reservoir to Jordan began for the first time, at a volume of approx. 0.07 BCM (approx. 0.14 BCM in 2018). It is further noted that from 2013 (the year in which the flow of gas from the Tamar Project began), mainly at peak demand hours for electricity in the winter and summer seasons, the demand for natural gas in the Israeli market was higher than the maximum hourly production capacity of the Tamar Project, and therefore, the Tamar Partners were unable to supply the entire demand at such times.

6.6. In the Partnership's estimation, natural gas consumption in Israel is expected to double by the end of the next decade, *inter alia*, given the connection of additional gas suppliers to the national transmission system, the Government's policy with regard to increasing the use of natural gas for the production of electricity and reducing the production of electricity via polluting coal-fired plants, introducing the uses of compressed natural gas in some of the transportation sectors (such as conversion of buses and heavy vehicles to using natural gas), making natural gas accessible to additional industrial enterprises throughout Israel, *inter alia*, through a government-sponsored program to support companies that received a government franchise to lay a distribution pipeline for the purpose of upgrading the distribution systems, entry of electric vehicles and train electrification, building additional facilities for seawater desalination, developing and tapping of industries based on natural gas as a raw material (such as development of petrochemical plants that use natural gas), and policy actions taken in favor of the matter, all over and above the natural increase in demand for natural gas and for electricity in the Israeli economy due to increase in population

[30] Source for the chart: figures of the Natural Gas Authority at the Ministry of Energy, and the Partnership's processing. Y2018: merely an estimate.

and standard of living. In addition, in the Partnership's estimation, conditions exist in Israel for the development of additional energy-intensive industries, such as primary aluminum production, but they are in too early stages for it to be possible to include them in the present demand forecasts. With respect to the decision of the Minister of Energy to reduce the use of coal and the reform at the IEC and in the electricity sector, and the Minister of Energy's plan to save Israel from polluting energy, see Sections 7.25.5(f), and 7.25.5(g) below, respectively. With respect to orders in relation to increasing the excise tax on coal and on CNG, see Section 7.25.5(h) below.

6.7. An additional operation of the Partnership's is conducted in Cyprus – for a description of the general environment and the competition in the market in Cyprus, see Section 0 below.

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

6.8.1. <u>Fluctuations in the US CPI, in the Electricity Production Tariff, and the price of a Brent-type oil barrel</u>

The gas prices set in the agreements for the sale of natural gas from the Tamar and Leviathan projects are based on various pricing formulas including, *inter alia* linkage to the US CPI, to the electricity production tariff as determined from time to time by the Public Utility Authority-Electricity (the "**Electricity Production Tariff**" and "**PUA-E**", respectively), and the price of a Brent-type oil barrel. Notwithstanding the aforesaid, the exposure of the Partnership to fluctuations in the electricity production tariff and in the Brent oil barrel price in agreements for the sale of natural gas from the Tamar Project is defined in a bottom threshold determined in agreements for the sale of natural gas since all the agreements which are linked to such components include a 'floor price'. Therefore, an additional drop in the Brent oil barrel price or the electricity production tariff as aforesaid, has a hedged effect which is limited to a 'floor price' as aforesaid, on the Partnership's income, by virtue of the agreements to which it is a party.

However, a change in each one of the said linkage components and/or in the prices of the alternative fuels as aforesaid may affect the economic merit of development or expansion of existing and/or new reservoirs discovered and/ or to be discovered in the future (if any) by the Partnership and on the scope of production therefrom, and as a consequence thereof, on the Partnership's decisions in connection with the foregoing.

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

6.8.2. Regulation

Exploration, development and production of oil and natural gas are subject to regulation in the countries in whose territories the activity is conducted. The sector of exploration, development and production of oil and natural gas in Israel is subject to extensive regulation with respect to petroleum assets (including rules for granting, transferring and pledging the same), conditions for development, production and supply (including the construction of transmission and distribution and consumer connection infrastructures), royalties, taxation, environmental regulation, restrictive trade practices and so forth. In recent years, following the gas discoveries which were discovered by the Partnership and its partners in the various petroleum assets, in the State of Israel's EEZ, there has been a significant increase in the extent of regulation of the energy sector in Israel, as a consequence of a series of significant regulatory moves taken by the Government and the state authorities. Prominent examples of this are: the enactment of the Taxation of Profits from Natural Resources Law, the Government's decisions regarding adoption of recommendations of the Committees for Examination of the Government Policy on the Natural Gas Sector (collectively: the "**Government Resolution on Export**"), the declaration by the Competition Commissioner (the "**Competition Commissioner**") of the Partnership together with the other Tamar Partners as monopoly holders in natural gas supply to Israel, the release of various directives by the Petroleum Commissioner at the Ministry of Energy (the "**Petroleum Commissioner**"), (for further details, see Section 7.25.4 below), the release of the Marine Zones Bill, 5778-2017 (the "**Marine Zones Bill**"), the government resolution in the matter of the Gas Framework as specified in Section 7.25.1(c)6 below, the national outline plan on the reception and processing of natural gas, and so forth.

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 Section 7.25 below.

## 7. Description of the Partnership's Business per Operating Segment

7.1. General information about the operating segment

7.1.1. Structure of the operating segment and changes occurring therein

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

Activities of exploration, development and production of oil and natural gas are usually conducted in the framework of joint ventures between several partners who sign a joint operating agreement (JOA), whereby one of the partners is appointed as the operator of the joint venture (for a description of a joint operating agreement, see, for example, an operating agreement that applies to the Tamar Project, which is described in Section 7.27.8 below).

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

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

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

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

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

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

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

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

(h) Performance of production tests (in certain cases).

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

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

(k) A final analysis of the data and a decision as to whether the finding (the discovery) is commercial.

(l) The projects for the development of the findings of natural gas require the execution of long-term binding agreements for the sale of natural gas, in appropriate quantities and prices, with customers that have the financial capability allowing the raising of project financing.

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

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

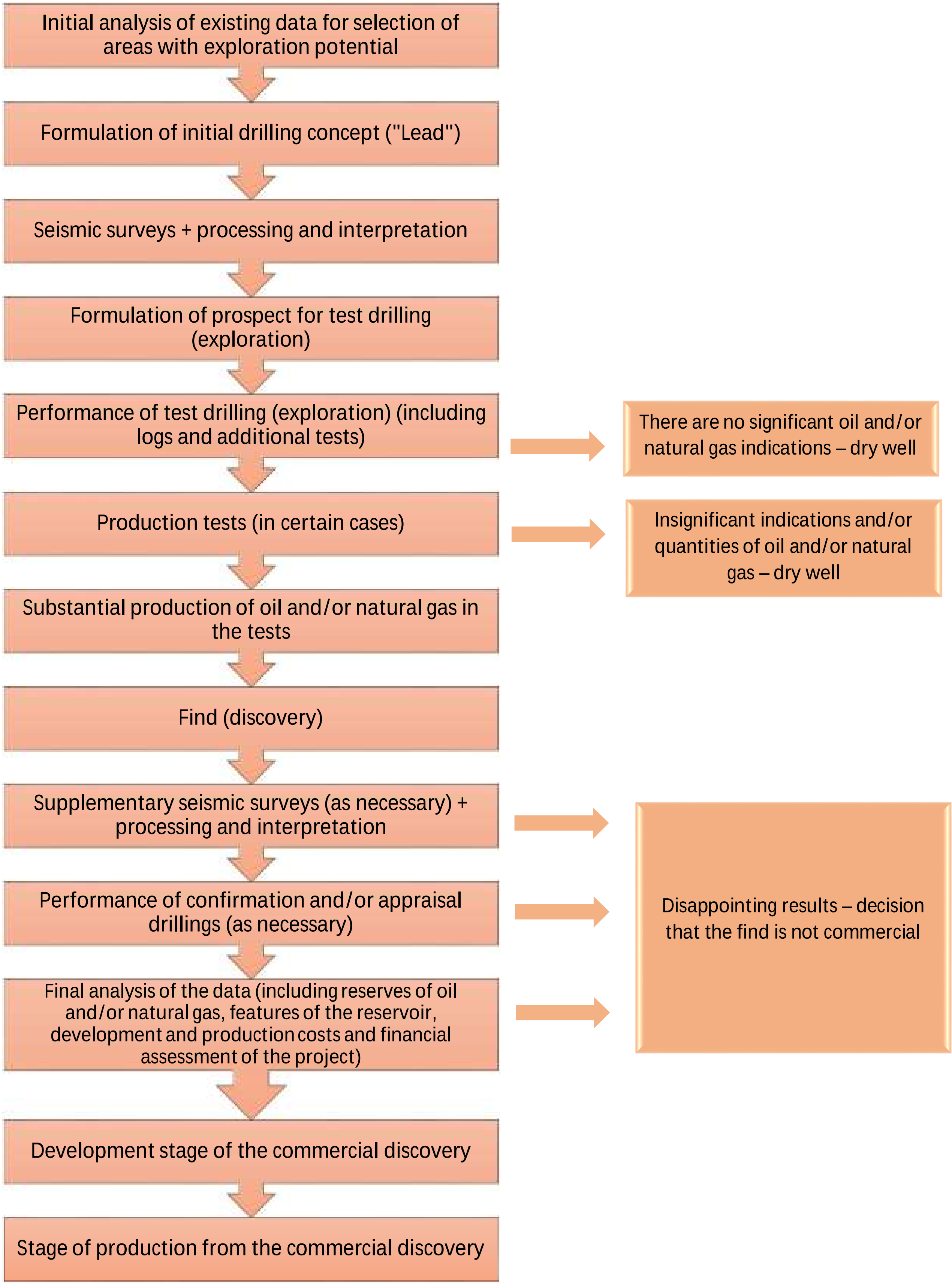
(o) When the reservoir is exhausted, and after weighing various technical, economic and regulatory parameters, abandonment in accordance with the local accepted standards.

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

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

It is noted that the commerciality of oil and/or natural gas findings is complex and dependent upon numerous and various factors. In this context, there are material differences between an offshore finding, the development of which requires financial input and use of unique technologies, such as drilling at a considerable water depth or laying subsea facilities and pipelines which are able to operate at a high level of reliability in the sea depths, and an onshore discovery, whose development costs may be substantially lower. In addition, the financial, logistical and technical inputs required to develop a natural gas reservoir which is intended, in part, for export to the international market, are generally immeasurably more significant compared to those required for development and production from a natural gas reservoir which is designated solely for the local domestic market. An additional key parameter is the demand and the price at the target markets. There is great difficulty in developing a project of significant scope when the demand and prices of natural gas do not allow the raising of project finance. Furthermore, there are substantial technological, marketing and financial differences between oil reservoirs and natural gas reservoirs. For example, the economic merit of a natural gas reservoir derives from the ability to market it to a destination that is attractive and guaranteed for years, due to the fact that natural gas, unlike oil, is not a commodity which is sold for similar prices all around the world, nor is it easy to transport. Moreover, the commerciality of an oil reservoir is highly impacted by global oil prices, thus, for example, a reservoir which is not commercial when the price of an oil barrel is X Dollars, may become commercial when the price of an oil barrel rises to 1.5X Dollars and vice versa. In light of the aforesaid, naturally, oil and/or natural gas reservoirs, which are not commercial under certain market conditions, may become, upon the occurrence of material changes in the regulation and market conditions, commercial reservoirs, and vice versa.

<u>A generic exploration and development process may be presented as follows</u>:


Initial analysis of existing data for selection of areas with exploration potential
Formulation of initial drilling concept ("Lead")
Seismic surveys + processing and interpretation
Formulation of prospect for test drilling (exploration)
Performance of test drilling (exploration) (including logs and additional tests)
There are no significant oil and/or natural gas indications – dry well
Production tests (in certain cases)
Insignificant indications and/or quantities of oil and/or natural gas – dry well
Substantial production of oil and/or natural gas in the tests
Find (discovery)
Supplementary seismic surveys (as necessary) + processing and interpretation
Performance of confirmation and/or appraisal drillings (as necessary)
Final analysis of the data (including reserves of oil and/or natural gas, features of the reservoir, development and production costs and financial assessment of the project)
Disappointing results – decision that the find is not commercial
Development stage of the commercial discovery
Stage of production from the commercial discovery

**It is emphasized that the chart presented above is general and presented for illustration only. It is further emphasized that some of the stages stated in the chart will not be included in the process and/or will be included in a different order, and that stages which are not specified in the chart at all will be implemented.**

7.1.2. Restrictions, legislation, standardization and special constraints applicable to the operating segment

For details, see Section 7.25 below.

7.1.3. Developments in markets or changes in customer characteristics

(a) As of the report release date, the Partnership supplies natural gas from the Tamar Project to various customers in the local market, the most important of which being the IEC, and in addition it exports natural gas from the Tamar Project to Jordan. In addition, the Partnership has signed agreements for exporting of natural gas, in significant amounts, to customers in Jordan and Egypt, as specified in Section 7.13.5 below. The Partnership also supplies condensate from the Tamar Project to Paz Ashdod Refinery Ltd. ("**PAR**"). For a description of the Partnership's agreements with its customers, see Sections 7.13.4 and 7.13.5 below.

In light of the significant volume of resources discovered off the shores of the State of Israel, mainly in the Tamar and Leviathan natural gas reservoirs, the Partnership is acting to identify markets and customers, in the domestic market and in neighboring countries and/or markets in Europe and in Asia, subject to restrictions on gas export, as specified in Section 7.25.1(c)2 below. The Partnership is also promoting use of infrastructures now in existence and/or that will exist in the foreseeable future and/or that will be built especially for natural gas export purposes. For further details in this matter, see Sections 7.13.5 and 7.14.2(b) below.

(b) Demand for natural gas

The volume of natural gas sales is affected *inter alia* by the rate of penetration and/or conversion of alternative energy sources. The Ministry of Energy's policy for encouragement and promotion of production of electricity using renewable energy, *inter alia* by using solar technologies, may affect the market share of natural gas in the mix of electricity production sources in the economy.

In this regard, see also Section 6.6 above. In addition, for further details regarding projects of the Partnership for increasing the demand for natural gas, see Section 7.29.6 below.

7.1.4. Material technological changes

The last decades saw technological changes in the field of oil and natural gas exploration, development and production, both in the area of information collection and analysis and in the drilling and production methods. These changes have improved the quality of the data available to oil and natural gas explorers and have allowed for more advanced identification of potential oil and natural gas reservoirs, and therefore may also reduce the risks of drilling. Furthermore, the technological improvements have increased the efficiency of the drilling and production work and also presently allow the performance of activities in rougher conditions than before, including at significant water depths. Accordingly, corporations exploring for oil and natural gas, are able to invest exploration efforts in areas where drillings were not feasible in the past, or were feasible but at very high costs and at greater risks. Furthermore, technological changes in the natural gas production and marketing segment, such as technologies for converting natural gas into liquefied natural gas ("**LNG**"), through an onshore or offshore facility (FLNG), compressed natural gas (CNG) and liquid (GTL) may facilitate more efficient transportation and commercialization of natural gas.

7.1.5. Critical success factors in the operating segment

(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 (such as 3D seismic surveys and advanced information processing) for the purpose of identification and preparation of prospects for drilling, for the purpose of evaluation of the results of the drilling and for the purpose of formulating a development plan.

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

(e) Success of the exploration activity.

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

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

7.1.6. Changes in the suppliers and raw materials layout

For details, see Section 7.19 below.

7.1.7. Entry and exit barriers

The main entry barriers in the operating sector are the need for permits and licenses for the performance of oil and natural gas exploration, development and production, meeting the requirements of the law and regulation, including directives and criteria determined by the Petroleum Commissioner (and, in Cyprus, directives and criteria set forth in legislation and in arrangements under a production sharing contract (in this section: "**PSC**")), the ability to transfer and/or purchase rights in petroleum assets, including in respect of presenting 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 extensive investments at a relatively high risk level, which are involved in the performance of the exploration, development and production activities.

The significant barriers to exit the operating sector in Israel are mainly undertakings by virtue of long-term gas supply agreements in which the Partnership has engaged. In addition, both in Israel and in Cyprus, there is a duty to plug and abandon wells and to dismantle production facilities before abandoning lease areas, as specified in the lease deeds, the provisions of the law regarding abandoning offshore oil and gas wells, or in the PSC, as the case may be. Aside from the above, there are no significant barriers to exit the operating sector in Cyprus, apart from the conditions set forth in the PSC in respect of the transfer of rights to third parties.

It shall be noted, that in everything relating to exiting existing projects by way of partial or full sale, exit barriers may exist which derive from regulatory requirements that will apply to the purchaser, and from the substantial monetary amount of such sale.

7.1.8. Substitutes for the products of the operating segment

Natural gas is mainly used as an energy production raw material and is sold in Israel mainly to electricity producers and industrial customers. In general, the substitutes for use of natural gas are other fuels, the main ones of which are: diesel oil, mazut, coal, LPG, LNG, petcoke, as well as energy from renewable sources, such as solar energy, wind energy and so forth. Each of the aforesaid substitute fuels and the substitute energy production methods has advantages and disadvantages and they are subject to price volatility, availability, technical constraints and more. The shift from using one type of energy to using another type of energy usually involves large investments. The principal advantages of natural gas, compared with coal and liquid fuels, are the fact that the energy efficiency of power plants operated using natural gas is significantly higher than that of power plants operated using coal and fuel oil, and the fact that the emission of particles and nitrogen and sulfur oxides from the burning of natural gas is significantly lower than that of coal and fuel oil.

7.1.9. Structure of competition in the operating segment

For details, see Section 0 below.

Set forth below are details regarding the Partnership's petroleum assets:

7.2. The Yam Tethys project

As of the report release date, the Partnership deems the Yam Tethys project in the area of the Noa Lease and the Ashkelon Lease as a petroleum asset negligible to the results of operations of the Partnership and to its business, after examination of the qualitative and quantitative parameters, which are primarily: (1) although natural gas is still produced from the Yam Tethys project, as of the report release date, the scope of production is negligible to the Partnership's operations and the main uses of the assets of the project are the supply of infrastructure services to the Tamar reservoir[31]. During 2018, approx. 0.19 BCM of natural gas was produced from the Yam Tethys project, out of total production of approx. 10.5 BCM from the Tamar and Yam Tethys projects; (2) The Partnership's share in the contingent resources and reserves located in the Yam Tethys project is negligible relative to all the contingent resources and reserves attributed to the Partnership in its petroleum assets; (3) The estimates and assessments of the Partnership with regard to the discounted cash flow data of the reservoirs of the Yam Tethys project are negligible relative to the market value of the Partnership on the stock market, as of the same date; (4) The total income from the reservoir in 2018 out of the Partnership's total income during the same period and the total projected income from the reservoir

[31] The Gas Framework determined that the holders of the rights in the Tamar Lease may use the Mari B rig for the entire period of the Tamar Lease, for the purpose of export or supply to the domestic natural gas market from the Tamar reservoir, subject to the conditions determined in the Gas Framework.

in the coming year is negligible relative to the Partnership's total projected income.

In view of the classification of the said project as negligible, following is a more limited description of the Yam Tethys project:

7.2.1. General

| General Details with respect to the Petroleum Asset | |
|---|---|
| **Name of the petroleum assets:** | Noa Lease[32]<br>Ashkelon Lease[33] |
| **Location:** | Ashkelon Lease – approx. 25 km west of the shores of Ashkelon.<br>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;<br>Permitted activities under the Petroleum Law – exploration and production. |
| **Original granting date of the petroleum asset:** | Ashkelon Lease – June 11, 2002.<br>Noa Lease – February 10, 2000. |
| **Original expiration date of the petroleum asset:** | Ashkelon Lease – June 10, 2032.<br>Noa Lease – January 1, 2030. |
| **Dates on which an extension of the term of the petroleum asset was decided:** | - |
| **Current expiration date of the petroleum asset:** | Ashkelon Lease – June 10, 2032.<br>Noa Lease – January 1, 2030. |
| **Note on whether there is an additional option to extend the term of the petroleum asset; if such option exists – the optional extension term should be noted:** | Subject to the Petroleum Law, by 20 additional years. |
| **The name of the operator:** | Noble |
| **The names of the direct partners in the petroleum asset and their direct share in the petroleum asset, and, to the best of the Partnership's knowledge, the names of the controlling shareholders of such partners:** | ▪ Noble (47.059%). Noble is a wholly owned subsidiary of Noble Energy Inc. (in this section: "**Noble**"), a public company whose stocks are traded on the NYSE. According to Noble's reports, there is no shareholder holding more than 10% of its issued capital.<br>▪ The Partnership (48.5%).<br>▪ Delek Group (4.441%). |

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

Below is a concise description of the main activities actually performed in the Noa Lease and in the Ashkelon Lease, from January 1, 2016 and until the report release date, and a concise description of planned activities:

[32] The Noa gas reservoir was discovered in the area of the Noa Lease in June 1999.
[33] The Mari B natural gas reservoir was discovered in the area of the Ashkelon Lease in 2000 and the Pinnacles natural gas reservoir was discovered in 2012.

| Period | Concise Description of Activities Actually Performed for the Period or of the Planned Work Plan | Total Estimated Budget for Activity at the Petroleum Asset Level (Dollars in thousands)[34] | Amount of Actual Participation in the Budget by the Holders of the Equity Interests of the Partnership (Dollars in thousands)[35] |
|---|---|---|---|
| 2016 | • Production from the Mari B reservoir, ongoing operation and maintenance.<br>• Performance of engineering feasibility tests for renewal of production from the Noa reservoir.<br>• Preparation for future abandonment of wells in the Yam Tethys project's reservoirs.<br>• Continued update of the geological model and the flow model, *inter alia* according to the production data.<br>• Evaluation of prospectivity in the area of the Ashkelon Lease and the Noa Lease. | - | - |
| 2017 | • Production from the Mari B reservoir, ongoing operation and maintenance.<br>• Examination of uses of existing infrastructures and preservation or increase of the production capacity.<br>• Examination of development works at the Noa reservoirs, including the refurbishment of existing wells, conversion of existing wells into production wells, drilling of new wells, and examination of uses of existing infrastructure. .<br>• Preparation for future abandonment of wells and facilities in the Yam Tethys project's reservoirs.<br>• Continued update of the geological model and the flow model, *inter alia* according to the drilling and production data.<br>• Mapping out and definition of additional prospects in the area of the petroleum asset, including a deep-water target prospect in the area of the petroleum asset. | - | - |
| 2018 | • Production from the Mari B reservoir, ongoing operation and maintenance.<br>• Examination of uses of existing infrastructures and preservation or increase of the production capacity.<br>• Preparation for future abandonment of wells and facilities in the Yam Tethys project's reservoirs.<br>• Continued update of the geological model and the flow model, *inter alia* according to the drilling and production data.<br>• Mapping out and definition of additional prospects in the area of the petroleum asset, including a deep-water target prospect in the area of the petroleum asset. | - | - |
| 2019 forth | • Production from the Mari B reservoir, ongoing operation and maintenance.<br>• Examination of uses of existing infrastructures and preservation or increase of the production capacity.<br>• Future abandonment of production facilities and wells.<br>• Continued update of the geological model and the flow model, *inter alia* according to the drilling and | Approx. 77,000[36] | Approx. 35,266 |

[34] The amounts for 2016-2018 are amounts actually expended and audited in the framework of the financial statements.
[35] The costs in the table reflect the Partnership's holding in the Yam Tethys project after the Merger, i.e. 48.5%.
[36] The aforesaid budget has not yet been approved by the partners in the Yam Tethys project.

| Period | Concise Description of Activities Actually Performed for the Period or of the Planned Work Plan | Total Estimated Budget for Activity at the Petroleum Asset Level (Dollars in thousands)[34] | Amount of Actual Participation in the Budget by the Holders of the Equity Interests of the Partnership (Dollars in thousands)[35] |
|---|---|---|---|
| | production data.<br>• Mapping out and definition of additional prospects in the area of the petroleum asset, including a deep-water target prospect in the area of the petroleum asset. | | |

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

## 7.3. The Tamar and Dalit project

### 7.3.1. General

| **The Tamar Lease** | |
|---|---|
| **General Details with respect to the Petroleum Asset** | |
| **Name of the petroleum asset:** | Tamar Lease |
| **Location:** | An offshore asset approx. 90 km west of the shores of Haifa, at a water depth of 1,670 meters. |
| **Area:** | Approx. 250 $km^2$. |
| **Type of petroleum asset and description of the activities permitted for such type:** | Lease;<br>Permitted activities under the Petroleum Law – exploration and production. |
| **Original granting date of the petroleum asset:** | December 2, 2009 |
| **Original expiration date of the petroleum asset:** | December 1, 2038 |
| **Dates on which an extension of the term of the petroleum asset was decided:** | - |
| **Current expiration date of the petroleum asset:** | December 1, 2038 |
| **Note on whether there is an additional option to extend the term of the petroleum asset; if such option exists – the optional extension term should be noted:** | Subject to the Petroleum Law, by 20 additional years. |
| **The name of the operator:** | Noble |
| **The names of the direct partners in the petroleum asset and their direct share in the petroleum asset, and, to the best of the Partnership's knowledge, the names of the controlling shareholders of such partners:** | ▪ Noble[37] (25%).<br>▪ Isramco Negev 2, Limited Partnership ("**Isramco**") (28.75%). To the best knowledge of the Partnership, the general partner of Isramco, Isramco Oil & Gas Ltd., is a private company indirectly controlled by Mr. Haim Tsuff[38].<br>▪ The Partnership[39] (22%).<br>▪ Tamar Petroleum[40] (16.75%).<br>▪ Dor Gas Exploration, Limited Partnership ("**Dor**") (4%). To the best knowledge of the Partnership, the general partner of Dor Exploration is Alon Gas Exploration Management Ltd., a private company controlled by Alon Natural Gas Exploration Ltd., which is a public company, the controlling shareholder of which is "Alon" Israeli Fuel Company Ltd., which is a private company.<br>▪ Everest Infrastructures Limited Partnership ("**Everest**") 3.5%. To the best of the Partnership's knowledge, Everest is a limited partnership, in which Harel Insurance Co. Ltd. and other institutional bodies owned thereby are partners, as well as partners from the Israel Infrastructure Fund group. |

[37] As specified in Section 1.1.7(g) above, on March 14, 2018 Tamar Petroleum closed a deal for the purchase of participation rights at a rate of 7.5% (of 100%) in the Tamar and Dalit leases from Noble.
[38] As of the report release date, corporations controlled by Mr. Haim Tsuff hold approx. 22.26% of the participation units issued by Isramco Management (1988) Ltd. (the limited partner in Isramco). In addition, Mr. Haim Tsuff holds approx. 0.43% of the participation units issued by the limited partner in Isramco.
[39] According to the Gas Framework (as defined below), the Partnership is required to sell all of its rights in the Tamar and Dalit leases to an unrelated third party until December 2021.
[40] For details on the Partnership's holdings in Tamar Petroleum as of the report date, see in Section 1.1.7(g) above.

| The Tamar Lease | |
|---|---|
| **General Details with respect to the Partnership's Share in the Petroleum Asset** | |
| **For a holding in a purchased petroleum asset – the purchase date:** | -[41] |
| **Description of the nature and manner of the Partnership's holding in the petroleum asset:** | The Partnership directly holds 22% of the Lease and indirectly holds 3.7855% of the Lease through its holding of Tamar Petroleum shares[42]. |
| **The actual share in the revenues from the petroleum asset attributable to the holders of the equity interests of the Partnership[43]:** | 20.1725% (this figure is after the Investment Recovery Date)[44]. |
| **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. $310,772 thousand[45]. |

| The Dalit Lease | |
|---|---|
| **General Details with respect to the Petroleum Asset** | |
| **Name of the petroleum assets:** | Dalit Lease[46] |
| **Location:** | An offshore asset approx. 50 km west of the shores of Haifa. |
| **Area:** | Approx. 250 km$^2$. |
| **Type of petroleum asset and description of the activities permitted for such type:** | Lease;<br>Permitted activities under the Petroleum Law – exploration and production. |
| **Original granting date of the petroleum asset:** | December 2, 2009 |
| **Original expiration date of the petroleum asset:** | December 1, 2038 |
| **Dates on which an extension of the term of the petroleum asset was decided:** | - |
| **Current expiration date of the petroleum asset:** | December 1, 2038 |
| **Note on whether there is an additional option to extend the term of the petroleum asset; if such option exists – the optional extension term should be noted:** | Subject to the Petroleum Law, by 20 additional years. |
| **The name of the operator:** | Noble |
| **The names of the direct partners in the petroleum asset and their direct share in the petroleum asset, and, to the best of the Partnership's knowledge, the names of the controlling shareholders of such partners:** | ▪ Noble (25%)[47].<br>▪ Isramco (28.75%).<br>▪ The Partnership[48] (22%).<br>▪ Tamar Petroleum[49] (16.75%).<br>▪ Dor (4%).<br>▪ Everest (3.5%) |

[41] The lease was granted to the Partnership on December 2, 2009, following the Tamar natural gas finding, which was discovered in 2009 in the area of the Matan/309 license.
[42] See Footnote 10 above.
[43] See Footnote 10 above.
[44] For further details on this matter, see Sections 7.27.12 and 7.28.6 below.
[45] The costs in the table reflect the Partnership's holding of 25.7855% of the Tamar Lease. For details see Footnote 10 above.
[46] The Dalit gas reservoir was discovered in the area of the Dalit Lease in 2009.
[47] See Footnote 37 above.
[48] See Footnote 39 above.
[49] See Footnote 40 above.

| The Dalit Lease | |
|---|---|
| **General Details with respect to the Partnership's Share in the Petroleum Asset** | |
| **For a holding in a purchased petroleum asset – the purchase date:** | [50] |
| **Description of the nature and manner of the Partnership's holding in the petroleum asset:** | The Partnership directly holds 22% of the Lease and indirectly holds 3.7855% of the Lease through its holding of Tamar Petroleum shares[51]. |
| **The actual share in the revenues from the petroleum asset attributable to the holders of the equity interests of the Partnership[52]:** | Pre Investment-Recovery – 21.377%.<br>Post Investment-Recovery – 20.1725%. |
| **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. $192 thousand[53]. |

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

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

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

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

[50] The lease was granted to the Partnership on December 2, 2009, following the Dalit natural gas finding, which was discovered in 2009 in the area of the Michal/308 license.
[51] See Footnote 10 above.
[52] See Footnote 10 above.
[53] The costs in the table reflect the Partnership's holding of 25.7855% of the Dalit Lease, and do not include a budget update (decrease) in the sum of $462 thousand. For details see Footnote 10 above.

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

2. At the lease holder's sole responsibility, the lease holder will plan, finance, construct and operate the lease holder's production system and the transmission system and will maintain them for the purpose of their ongoing operation, all through the Operator, contractors, planners and consultants who have knowledge and experience in their fields, in such manner so as to enable the regular, proper and safe supply of oil and natural gas from the reservoir.

(e) Term of the lease

1. The term of the lease will be divided into two sub-terms:

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

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

2. If the term of the lease ends or if the lease is revoked under the provisions of the Petroleum Law, including Section 29 of the Petroleum Law, 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

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

(g) Construction of facilities

1. The lease holder will only construct the production system after the Petroleum Commissioner shall have

granted the lease holder a construction approval and subject to the terms and conditions of the approval.

2. The lease holder will construct the production system and the transmission system in a manner enabling a total commercial production capacity from the area of the Tamar Lease and the area of the Dalit Lease, of no less than 7 billion standard cubic meters of natural gas in the year commencing on the beginning of the commercial production period, subject to approval of the northern terminal[54].

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

(h) Supervision company

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

(i) The commercial production

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

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

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

[54] Production is conducted through a platform set-up off the shores of Ashkelon and through the Terminal.

to time, considering the data and features of the reservoir.

c. The lease holder will be required to maintain the quality of the gas piped thereby into the national transmission system, in accordance with the gas specification to be determined.

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

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

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

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

(j) Natural gas storage

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

2. If the lease holder, on its own initiative, requests to store gas in permitted storage reservoirs, it shall be done at the

expense of the lease holder and in accordance with the provisions of any law and the criteria, if any.

(k) Revocation or restriction of the lease

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

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

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

(l) Abandonment plan

1. Within 30 days of the date of commencement of the production period, the lease holder will submit for approval by the Petroleum Commissioner, a general plan for abandonment of the production system's facilities and for the sealing of wells, when use thereof ends, whether during the term of the lease or thereafter (the "**General Abandonment Plan**").

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

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

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

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

(m) Guarantees

The lease deed prescribes provisions for the furnishing of an irrevocable unconditional autonomous bank guarantee by the lease holders, in order to secure compliance with the terms and conditions of the lease deed, the term thereof and causes for forfeiture of the guarantee. For details regarding the guarantee furnished as aforesaid for securing compliance with the terms and conditions of the lease deed and the directives of the Petroleum Commissioner, see Section 7.25.4(a) below.

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

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

7.3.3. Compliance with the conditions of the work plan for the Tamar Project[55]

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

[55] As of the report release date, a detailed development plan has only been submitted with respect to the Tamar Lease.

### 7.3.4. Work plan for the Tamar Project – actual and planned[56]

(a) Below is a concise description of the main activities actually performed in the Tamar Project, from January 1, 2016 and until the report release date, and a concise description of planned activities:

| **The Tamar Lease** | | | |
|---|---|---|---|
| **Period** | **Concise Description of Activities Actually Performed for the Period or of the Planned Work Plan** | **Total Estimated Budget for Activity at the Petroleum Asset Level (Dollars in thousands)[57]** | **Amount of Actual Participation in the Budget by the Holders of the Equity Interests of the Partnership (Dollars in thousands)[58]** |
| 2016 | • Continued production from the Tamar Project, ongoing operation and maintenance.<br>• Completion of the operational running-in of three compressors and related auxiliary systems (the "**Compressors Project**") during Q2/2016. | - | - |
| | • Drilling of an additional development and production well, "Tamar-8", and construction of related infrastructure for connecting the well to the existing subsea production system of the Tamar Project. | Approx. 101,884[61] | Approx. 26,271 |
| | • Upgrade and improvement of the production set-up in the Tamar Platform and in the Terminal, including procurement of equipment and spare parts and improvement of the operating and maintenance systems[59] and performance of actions in connection with the expansion of the supply capacity from the Tamar Project, including planning and preparations for the drilling of additional wells and examination of alternatives to the export of gas from the Tamar Project to neighboring countries.<br>• Preparation of the Tamar 10-inch pipeline for transmission of natural gas and receipt of a transmission license for such pipe.[60]<br>• Continued update of the geological model and flow model, *inter alia*, according to the data of the wells and the production, and planning and preparations for the drilling of additional wells.<br>• Mapping out and definition of additional prospects, including a deep-water target prospect in the area of the lease. | Approx. 38,403[62] | Approx. 9,921 |

[56] The costs specified in 2016-2018 in the work plan below do not include current operating and maintenance costs and abandonment costs of the Tamar Project, which were included in Section 7.3.10 below.
[57] The amounts for 2016-2018 are amounts that were audited in the framework of the financial statements.
[58] The costs in the table reflect the Partnership's holding of 25.7855% of the Tamar Lease, for details see Footnote 10 above.
[59] The budget includes a sum of approx. $19.1 million (100%) (the Partnership's share - approx. $4.9 million), according to an agreement executed between the Tamar Partners and the Operator in connection with the Operator's indirect expenses in the Tamar and Dalit leases for previous years, for further details see Section 7.27.8(b) below.
[60] The transmission license was granted to Tamar 10 Inch Ltd., a company owned by the holders of the rights in the lease ("**Tamar 10 Inch**").
[61] The budget does not include costs of equipment that was purchased in 2015 for the development of Tamar SW in the amount of approx. $33.4 million (100%) (the Partnership's share - approx. $8.6 million), which was used in part for the Tamar-8 well.
[62] The costs specified for 2016 do not include a budget update (decrease) in the sum of approx. $41.4 million (100%) (the Partnership's share - approx. $10.7 million).

| The Tamar Lease | | | |
|---|---|---|---|
| **Period** | **Concise Description of Activities Actually Performed for the Period or of the Planned Work Plan** | **Total Estimated Budget for Activity at the Petroleum Asset Level (Dollars in thousands)[57]** | **Amount of Actual Participation in the Budget by the Holders of the Equity Interests of the Partnership (Dollars in thousands)[58]** |
| 2017[63] | • Continued production from the Tamar Project, ongoing operation and maintenance. | - | - |
| | • Completion of the Tamar-8 well and connection thereof to the production system and commencement of piping of the natural gas therefrom. | Approx. 101,094 | Approx. 26,068 |
| | • Upgrade and improvement of the Tamar Platform and the Terminal, including addition of structures and replacement of the main disconnection valves in the platform with new valves of a different type in order to improve the functioning thereof. | Approx. 28,012 | Approx. 7,223 |
| | • Reprocessing of seismic surveys.<br>• Commencement of project of installation of systems for reducing emissions from the Tamar Platform.<br>• Continued update of the geological model and flow model, *inter alia*, according to the data of the wells and the production, and planning and preparations for drilling additional of wells.<br>• Mapping out and definition of additional prospects, including a deep-water target prospect in the area of the lease. | Approx. 1,083 | Approx. 279 |
| 2018 | • Continued production from the Tamar Project, ongoing operation and maintenance.<br>• Continuance of the project of installing systems for reducing emissions from the Tamar Platform. | Approx. 28,894 | Approx. 6,706 |
| | • Continued upgrade and improvement of the production set-up in the Tamar Platform and in the Terminal, including improvement of the operating systems, and upgrade of the stainless steel pipeline for the prevention of corrosion.<br>• Continued update of the geological model and flow model, *inter alia*, according to the data of the wells and the production, and planning and preparations for the additional drilling of wells and performance of completions.<br>• Mapping out and definition of additional prospects, including a deep-water target prospect in the area of the lease.<br>• Continuance of the reprocessing of seismic surveys project. | Approx. 24,845[64] | Approx. 5,767 |
| 2019 forth | • Continued production from the Tamar Project, | | |

[63] The costs specified in 2017 do not include a budget update in the amount of approx. $12.4 million (100%) (the Partnership's share is approx. $3.2 million).

[64] The aforesaid budget has not yet been approved by the Tamar Partners. The specified costs do not include decrease in the scope of the investments in the sum of $33.6 million (100%) (the Partnership's share is approx. $8.7 million). The decrease derives, *inter alia*, from the sale of drilling equipment, depreciation of pipeline and decrease in the investment in the Tamar SW well.

| The Tamar Lease | | | |
|---|---|---|---|
| **Period** | **Concise Description of Activities Actually Performed for the Period or of the Planned Work Plan** | **Total Estimated Budget for Activity at the Petroleum Asset Level (Dollars in thousands)**[57] | **Amount of Actual Participation in the Budget by the Holders of the Equity Interests of the Partnership (Dollars in thousands)**[58] |
| | ongoing operation and maintenance[65] [66].<br>• Completion of the reprocessing of seismic surveys project and interpretation of the processed surveys.<br>• Completion of the development of Tamar SW and connection thereof to the subsea production system in the Tamar field. For further details, see Section 7.3.4(d) below.<br>• Continued update of the geological model and flow model, *inter alia*, according to the data of the wells and the production, and planning and preparations for the additional drilling of wells and performance of completions.<br>• Drilling and completion of additional wells, as required, in accordance with the actual production data and market demands.<br>• Mapping out and definition of additional prospects, including a deep-water target prospect in the area of the lease.<br>• Completion of running-in and operation of the project for the reduction of emissions from the Tamar Platform.<br>• Continued upgrade and improvement of the production set-up in the Tamar Platform and in the Terminal, including improvement of the operating systems, adding buildings, upgrade of the stainless steel pipeline for the prevention of corrosion, dyeing equipment and pipeline and continued upgrade of the valve set-up.<br>• Placement of a third pipe from the Tamar field to the platform.<br>• Payment in respect of gas flow in the EMG Pipeline (as defined below). | Approx. 247,900<br>Approx. 586,000[67]<br>Approx. 10,000[68]<br>Approx. 44,000<br>Approx. 370,000[69]<br>Approx. 50,000[70] | Approx. 63,922<br>Approx. 151,103<br>Approx. 2,579<br>Approx. 11,346<br>Approx. 95,406<br>Approx. 12,893 |

[65] For details regarding operation costs in the Tamar Project that are attributed to the Partnership, see the discounted cash flow figures that are attributed to the Partnership's share from the reserves in the Tamar Project, as specified in Section 7.3.11(a)3 below.

[66] During the month of April 2019, over the Passover holiday, the operator in the Tamar project is expected to carry out upgrade and improvement work on the Tamar platform, including upgrade of the main disconnection valves on the Tamar platform (in this footnote: the "**Upgrade Work**") over an estimated period of about one week, in two time frames, in each one of which time frames natural gas will flow from the Tamar field to the Tamar project production platform, through only one of the two pipelines, and at a volume of one half the maximum production capacity. The Partnership estimates that the Upgrade Work will not have a material effect on the Partnership's income from the sale of natural gas in Q2/2019.

[67] The aforesaid budget is yet to be approved by the Tamar Partners. It is noted that the said budget does not include abandonment costs.

[68] The aforesaid budget is yet to be approved by the Tamar Partners.

[69] The aforesaid budget is yet to be approved by the Tamar Partners.

[70] The aforesaid budget is yet to be approved by the Tamar Partners.

| The Dalit Lease | | | |
|---|---|---|---|
| **Period** | **Concise Description of Activities Actually Performed for the Period or of the Planned Work Plan** | **Total Estimated Budget for Activity at the Petroleum Asset Level (Dollars in thousands)** | **Amount of Actual Participation in the Budget by the Holders of the Equity Interests of the Partnership (Dollars in thousands)[71]** |
| 2016[72] | • Examination of development alternatives, considering the development plans of the adjacent reservoirs and the production data from the Tamar reservoir.<br>• Update of mapping and analysis of the Dalit reservoir based on the seismic survey as aforesaid and on data from adjacent reservoirs, including production data from the Tamar reservoir.<br>• Mapping out and definition of additional prospects in the area of the lease, including a deep-water target prospect in the area of the lease. | - | - |
| 2017 | • Examination of development alternatives, considering the development plans of the adjacent reservoirs and the production data from the Tamar reservoir.<br>• Update of mapping and analysis of the Dalit reservoir based on the seismic survey as aforesaid and on data from adjacent reservoirs, including production data from the Tamar reservoir.<br>• Mapping out and definition of additional prospects in the area of the lease, including a deep-water target prospect in the area of the lease. | - | - |
| 2018 | • Examination of development alternatives, considering the development plans of the adjacent reservoirs and the production data from the Tamar Reservoir.<br>• Update of mapping and analysis of the Dalit Reservoir based on the seismic survey as aforesaid and on data from adjacent reservoirs, including production data from the Tamar Reservoir.<br>• Mapping out and definition of additional prospects in the area of the lease, including a deep-water target prospect in the area of the lease. | - | - |
| 2019 forth | • Examination of development alternatives, considering the development plans of the adjacent reservoirs and the production data from the Tamar reservoir.<br>• Update of mapping and analysis of the Dalit reservoir based on the seismic survey as aforesaid and on data from adjacent reservoirs, including production data from the Tamar reservoir. | - | - |

[71] The costs in the table reflect the Partnership's holding at a rate of 25.7855% of the Dalit Lease, for details see Footnote 10 above.
[72] In 2016, the Operator was paid indirect expenses in the sum of approx. $270 thousand (in 100% terms) for previous years, the Partnership's share is approx. $70 thousand.

| The Dalit Lease | | | |
|---|---|---|---|
| **Period** | **Concise Description of Activities Actually Performed for the Period or of the Planned Work Plan** | **Total Estimated Budget for Activity at the Petroleum Asset Level (Dollars in thousands)** | **Amount of Actual Participation in the Budget by the Holders of the Equity Interests of the Partnership (Dollars in thousands)[71]** |
| | • Mapping out and definition of additional prospects in the area of the lease, including a deep-water target prospect in the area of the lease.<br>• Completion of the Dalit-1 well, drilling additional wells as required, and connecting the reservoir to the subsea production system of the Tamar project. | | |

(b) Development plan for the Tamar Project[73]

At present, the Tamar Project includes 6 subsea production wells, each of which is able to produce approx. 250 MMCF per day. Gas flows through two 16-inch pipes (the double pipeline) from the wells of the Tamar field to a processing platform which has been set up off the Ashkelon shores (the "**Tamar Platform**"), approx. 2 km north of the platform of the Yam Tethys project. Natural gas and condensate flow from the Tamar Platform through 30-inch and 6-inch pipes, respectively, to the Terminal for the completion of processing thereof, and therefrom the natural gas is piped to INGL's national transmission system and the condensate is piped to the nearby PAR.

On August 29, 2016, the Minister of Energy granted the Tamar Partners[74] a license for the operation of a pipe with a diameter of 10 inches, which was originally designated for transmission of condensate from the Tamar Platform, for the transfer of natural gas in order to increase the gas supply capacity.

In April 2017, piping of natural gas began from the "Tamar-8" well, which was drilled and completed in 2017, in order, *inter alia*, to increase the redundancy of the production system and allow for maximum supply from the Tamar reservoir at times of peak demand.

The gas supply capacity from the Tamar Project (which includes the Tamar Project's facilities, the compressor systems and the transmission and treatment systems of the Yam Tethys project, which have been upgraded and adapted for use in the Tamar Project) to the transmission system of INGL is approx. 1.1 BCF per day at maximum production.

[73] The Tamar reservoir development plan that was submitted to the Petroleum Commissioner by the Operator on behalf of the partners in the Tamar and Dalit leases included, *inter alia*, reference to the development of the Dalit Lease.

[74] The license was granted to Tamar 10 Inch.

For details regarding the average daily production in the past two years, see Footnote 103 below.

The production system of the Tamar Project, since the commercial operation thereof, has very high operational reliability of over 99% up-time).

The total cost invested in the Tamar Project, as described above, as of December 31, 2018, is approx. $4.4 billion (100%) (including exploration costs, and excluding retirement and abandonment costs and exploration costs in the Dalit Lease).

(c) Examination of the possibility of expanding the supply capacity of the Tamar project

The overall supply capacity of the Tamar facilities is currently limited to the flow capacity of the Double Piping (as defined in Section 7.18 below). As of the date of release of this report, the Tamar Partners are examining options for expansion of the supply capacity of the Tamar Project, insofar as required, according to the scope of forecasted demands in the domestic market and for export.

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

(d) Development of the Tamar SW reservoir

According to the development plan of the Tamar SW reservoir, which was approved by the Petroleum Commissioner in January 2019, considering the provisions of the Gas Framework specified in Section 7.25.1(c)3 below, the Tamar SW reservoir will be developed and subsequently connected to the subsea facilities of the Tamar Project. The cost of development of the Tamar SW reservoir has been partly approved by the Tamar Partners.

In the Partnership's estimation, the completion of the Tamar SW reservoir and the connection thereof to the production system are expected to be take place in 2021.

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

(e) <u>Commercial arrangement of the operation and production from the Yam Tethys project and from the Tamar Project</u>

Since the beginning of October 2017, the Yam Tethys partners are supplying natural gas according to the gas supply agreements between the Yam Tethys partners and their customers, only from the Yam Tethys reservoir. In May 2018, the Yam Tethys partners engaged with the Tamar Partners (which are not common to the Yam Tethys project) in a spot agreement (which was updated in September 2018) for the sale of the surplus production from the Yam Tethys reservoir (which is immaterial) to the Tamar Partners (which are not common to the Yam Tethys project), for the sale thereof to the Tamar Project's customers for a period of 24 months from October 1, 2017.

**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 possibility of expansion of the supply capacity and production rates in the Tamar Project, constitute forward-looking information as defined in the Securities Law, which is based on the estimations of the General Partner of the Partnership with respect to the planned activities, costs, timetables and actual performance of the planned activities and production rates, which are all based on estimations that the General Partner of the Partnership received from the Operator. In actuality, the planned activities, costs, timetables and production rates may materially differ from the aforesaid estimations and are contingent, *inter alia*, on the adoption of fitting decisions by the Tamar Partners, receipt of the approvals required pursuant to any law, completion of the detailed planning of the components of the activities, receipt of proposals from contractors, changes in the suppliers market and raw material around the world, the applicable regulation, technical abilities and economic merit.**

7.3.5. Actual participation rate in the expenses and revenues of the Tamar Project (the figures in the table are after the Investment Recovery Date[75])

| **Participation Rate** | **Percentage** | **Rate Grossed-Up to 100%** | **Explanations** |
|---|---|---|---|
| Actual rate in the petroleum asset attributable to the holders of the equity interests of the Partnership[76]. | 25.7855% | 100% | See the description of the chain of holdings in Section 7.3.1 above. |
| Actual rate in the **revenues** from the petroleum asset attributable to the holders of the equity interests of the Partnership. | 20.1725% | 77.23% | See the calculation in Section 7.3.7 below. |
| Actual participation rate in the **expenses** involved in exploration, development or production activities in the petroleum asset attributable to the holders of the equity interests of the Partnership. | 26.0434% | 101% | See the calculation in Section 7.3.9 below. |

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

| **Participation Rate** | **Percentage Pre Investment-Recovery** | **Percentage Post Investment - Recovery** | **Rate Grossed-Up to 100% Pre Investment-Recovery** | **Rate Grossed-Up to 100% Post Investment-Recovery** | **Explanations** |
|---|---|---|---|---|---|
| Actual rate in the petroleum asset attributable to the holders of the equity interests of the Partnership[77]. | 25.7855% | 25.7855% | 100% | 100% | See the description of the chain of holdings in Section 7.3.1 above. |
| Actual rate in the **revenues** from the petroleum asset attributable to the holders of the equity interests of the Partnership. | 21.377% | 20.1725% | 82.90% | 78.23% | See the calculation in Section 7.3.8 below. |
| Actual participation rate | 26.0434% | 26.0434% | 101% | 101% | See the calculation in |

[75] See Footnote 44 above.
[76] See Footnote 10 above.
[77] See Footnote 10 above.

| | | | | | |
|---|---|---|---|---|---|
| in the **expenses** involved in exploration, development or production activities in the petroleum asset attributable to the holders of the equity interests of the Partnership. | | | | | Section 7.3.9 below. |

7.3.7. <u>Participation rate of holders of the equity interests of the Partnership in revenues from the Tamar Project (the figures in the table are after the Investment Recovery Date[78])</u>

| **<u>Item</u>** | **<u>Percentage</u>** | **<u>Concise Explanation as to How Royalties or Payments are Calculated</u>** |
|---|---|---|
| Projected annual revenues of petroleum asset | 100% | |
| **<u>Specification of the royalties or payment (deriving from revenues post-finding) at the petroleum asset level:</u>** | | |
| The State | (12.50%) | In accordance with the Petroleum Law, royalties are calculated according to market value at the wellhead. The actual royalty rate is lower, as a result of the deduction of expenses due to the gas treatment and transmission systems from the wellhead up to the onshore gas delivery location. For further details, see Section 7.27.12(c) below. |
| Adjusted revenues at the petroleum asset level | 87.50% | |
| Share in the adjusted revenues deriving from the petroleum asset attributable to the holders of the equity interests of the Partnership (indirect holdings) | 25.7855% | |
| Total share of the holders of the equity interests of the Partnership in the actual amount of revenues, at the petroleum asset level (and before other payments at the Partnership level) | 22.5623% | |
| **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 | (2.2886%) | Overriding royalty in respect of the Partnership's share at a 9.5% rate Post- |

[78] See Footnote 44 above.

| Item | Percentage | Concise Explanation as to How Royalties or Payments are Calculated |
|---|---|---|
| | | Investment-Recovery, is calculated according to market value at the wellhead.[79] Calculation of the aforesaid rate was made according to the principles under which the State's royalties in the Tamar Project are calculated, and therefore such rate may change, insofar as the manner of calculation of the State's royalties is changed. For further details with respect to the manner of calculation of the royalty rate, see Section 7.27.12 below. |
| Rate of the holders of the equity interests of the Partnership in the payment to Dor Chemicals Ltd.[80] | (0.1012%) | Overriding royalty at a rate of 6% for 2.5% (out of 100%) of the rights in the petroleum asset paid to the royalty holder, after deduction of the royalty to the State and calculated according to market value at the wellhead.[81] The said rate is calculated in accordance with the principles by which the State's royalties in the Tamar Project are calculated and therefore the said rate may change if and to the extent the manner of calculating the State's royalties shall change. For further details regarding the manner of calculating the rate of the royalties, see Section 7.27.12 below. |
| Actual rate in revenues from the petroleum asset attributable to the holders of the equity interests of the Partnership. | 20.1725% | |

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

| Item | Pre Investment-Recovery | Post Investment-Recovery | Concise Explanation as to How Royalties or Payments are Calculated |
|---|---|---|---|
| Projected annual revenues of petroleum asset. | 100% | 100% | |
| **Specification of the royalties or payment (deriving from revenues post-finding) at the petroleum asset level:** | | | |

[79] As of the report date, the parties entitled to royalties are Delek Royalties (2012) Ltd. ("**Delek Royalties**"), Delek Group, Cohen Developments and others which are not related parties. For further details, see Section 7.27.12 below.
[80] On January 21, 2007, the Partnership and Avner entered into an agreement with Dor Chemicals Ltd. for the purchase of 2.5% (out of 100%) of the rights in the Michal and Matan Licenses (in whose place the Tamar and Dalit leases were granted, respectively). In consideration for such sale of rights, Dor Chemicals Ltd. is entitled to overriding royalty as specified in the table. The figure in the table refers to royalties post-sale to Tamar Petroleum, as specified in Footnote 10 above.
[81] It is noted that upon the transfer of the rights to Tamar Petroleum in the framework of the agreement of the sale of rights to Tamar Petroleum, as described in Section 1.1.7(g) above, Tamar Petroleum was transferred a proportionate share of the obligation to pay a royalty for 2.5% of the rights in the petroleum asset.

| **Item** | **Pre Investment-Recovery** | **Post Investment-Recovery** | **Concise Explanation as to How Royalties or Payments are Calculated** |
|---|---|---|---|
| The State. | (12.50%) | (12.50%) | In accordance with the Petroleum Law, royalties are calculated according to market value at the wellhead. The actual royalty rate is lower, as a result of the deduction of expenses due to the gas treatment and transmission systems from the wellhead up to the onshore gas delivery location. For further details, see Section 7.27.12(c) below. |
| Adjusted revenues at the petroleum asset level | 87.50% | 87.50% | |
| Share in the adjusted revenues deriving from the petroleum asset attributable to the holders of the equity interests of the Partnership (indirect holdings) | 25.7855% | 25.7855% | |
| Total share of the holders of the equity interests of the Partnership in the actual amount of revenues, at the petroleum asset level (and before other payments at the Partnership level) | 22.5623% | 22.5623% | |
| **Specification of royalties or payments (deriving from revenues post-finding) in connection with the petroleum asset at the Partnership level (the following percentage will be calculated according to the rate of the holders of the equity interests of the Partnership in the petroleum asset):** | | | |

| **Item** | **Pre Investment-Recovery** | **Post Investment-Recovery** | **Concise Explanation as to How Royalties or Payments are Calculated** |
|---|---|---|---|
| The rate of the holders of the equity interests of the Partnership in payment to related and third parties | (1.0841%) | (2.2886%) | 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[82]. Calculation of the aforesaid rate was made according to the principles under which the State's royalties in the Tamar Project are calculated, and therefore such rate may change, insofar as the manner of calculation of the State's royalties is changed.<br>For further details with respect to the manner of calculation of the royalty rate, see Section 7.27.12 below. |
| Rate of the holders of the equity interests of the Partnership in the payment to Dor Chemicals Ltd.[83] | (0.1012%) | (0.1012%) | Overriding royalty at a rate of 6% for 2.5% (out of 100%) of the rights in the petroleum asset paid to the royalty holder, after deduction of the royalty to the State and calculated according to market value at the wellhead[84]. The said rate is calculated in accordance with the principles by which the State's royalties in the Tamar Project are calculated and therefore the said rate may change if and to the extent the manner of calculating the State's royalties shall change.<br>For additional details regarding the manner of calculating the rate of the royalties, see Section 7.27.12 below. |
| Actual rate in revenues from the petroleum asset attributable to the holders of the equity interests of the Partnership. | 21.377% | 20.1725% | |

[82] As of the report date, the parties entitled to royalties are Delek Royalties, Delek Group, Cohen Developments and others which are not related parties.. For further details, see Section 7.27.12 below.
[83] See Footnote 80 above.
[84] See Footnote 81 above.

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

| **Item** | **Percentage** | **Concise Explanation as to How Royalties or Payment are Calculated** |
|---|---|---|
| Theoretical expenses of the petroleum asset (without the aforesaid royalties) | 100% | |
| **Specification of the payments (derived from the expenses) at the petroleum asset level:** | | |
| The Operator | 1% | The Operator is entitled to reimbursement of its direct and indirect expenses in relation to its capacity as Operator. On June 30, 2016, an amendment was signed to the JOA in the Tamar Project, whereby it was agreed that from January 1, 2016, the Operator shall be entitled to reimbursement of its indirect expenses at a rate of 1% out of the total direct expenses in relation to development and production activities, subject to certain exclusions, such as marketing activity. |
| Total actual expense rate at the petroleum asset level | 101% | |
| Rate of the holders of the equity interests of the Partnership in the expenses of the petroleum asset (indirect holdings) | 25.7855% | |
| Total actual rate of the holders of the equity interests of the Partnership in the expenses, at the petroleum asset level (before other payments at the Partnership level) | 26.0434% | |
| **Specification of payments (derived from the expenses) in connection with the petroleum asset and at the Partnership level (the following percentage will be calculated according to the rate of the holders of the equity interests of the Partnership in the petroleum asset):** | | |
| Actual rate in the expenses involved in exploration, development and production activities in the petroleum asset, attributable to the holders of the equity interests of the Partnership | 26.0434% | The Partnership pays management fees to the General Partner, which are comprised of a fixed amount and a variable amount that is calculated as a rate of the exploration expenses (for details see Section (b)7 of Regulation 21 in Chapter D of this report). Such amounts were not taken into account in this table. |

7.3.10. Fees and payments made during the exploration, development and production activities in the petroleum asset (Dollars in thousands)[85]

| Item | Total Rate of the Holders of the Equity Interests of the Partnership in the Investment in the Petroleum Asset in this Period (including costs for which no payments are made to the Operator) | Out of which, the Share of the Holders of the Equity Interests of the Partnership in Payments to the General Partner | Out of which, the Share of the Holders of the Equity Interests of the Partnership in Payments to the Operator (beyond the reimbursement of its direct expenses) |
|---|---|---|---|
| Budget actually invested in 2016 | Approx. 61,076 | Approx. (3) | Approx. 5,164[86] |
| Budget actually invested in 2017 | Approx. 58,859 | - | Approx. 606 |
| Budget actually invested in 2018 | Approx. 39,865 | - | Approx. 410 |

| Item | Total Rate of the Holders of the Equity Interests of the Partnership in the Investment in the Petroleum Asset in this Period (including costs for which no payments are made to the Operator) | Out of which, the Share of the Holders of the Equity Interests of the Partnership in Payments to the General Partner | Out of which, the Share of the Holders of the Equity Interests of the Partnership in Payments to the Operator (beyond the reimbursement of its direct expenses) |
|---|---|---|---|
| Budget actually invested in 2016 | Approx. 72 | Approx. 2 | Approx. 72 |
| Budget actually invested in 2017 | Approx. (2) | - | Approx. 0 |
| Budget actually invested in 2018 | Approx. 0 | - | Approx. 0 |

[85] The costs in the table reflect the Partnership's holding of 25.7855% of the Tamar and Dalit leases, for details see Footnote 10 above.

[86] Including indirect expenses paid to the Operator for previous years. See Section 7.27.8(b) below.

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

(a) Reserves in the Tamar Lease[87]

1. Quantity data

According to a report the Partnership received from Netherland, Sewell & Associates, Inc. ("**NSAI**" or the "**Evaluator**"), which was prepared in accordance with the rules of the Petroleum Resources Management System (SPE-PRMS), as of December 31, 2018 (the "**Reserves Report**"), the natural gas and condensate reserves at the Tamar Project (which includes, as aforesaid, the Tamar and Tamar SW reservoirs), which are classified as reserves "On Production", are as specified below:

[87] The table does not include resources situated in the area of the Eran License. See also Section 7.28.7(a) below.

| Reserves Category | Total (100%) in the Petroleum Asset (gross) | | | | | | Total (Tamar and Tamar SW Reservoirs) Rate Attributable to the Holders of the Equity Interests of the Partnership (Net)[88] | |
|---|---|---|---|---|---|---|---|---|
| | The Tamar Reservoir | | The Tamar SW Reservoir | | Total (Tamar and Tamar SW Reservoirs) | | | |
| | Natural Gas BCF | Condensate Million Barrels | Natural Gas BCF | Condensate Million Barrels | Natural Gas BCF | Condensate Million Barrels | Natural Gas BCF | Condensate Million Barrels |
| Proved Reserves 1P | 7,312.4 | 9.5 | 796.4 | 1.0 | 8,108.9 | 10.5 | 1,635.8 | 2.1 |
| Probable Reserves | 2,871.0 | 3.7 | 159.1 | 0.2 | 3,030.1 | 3.9 | 611.2 | 0.8 |
| Total 2P Reserves (Proved + Probable Reserves) | 10,183.4 | 13.2 | 955.6 | 1.2 | 11,139.0 | 14.5 | 2,247.0 | 2.9 |
| Possible Reserves | 2,366.0 | 3.1 | 102.2 | 0.1 | 2,468.3 | 3.2 | 497.9 | 0.6 |
| Total 3P Reserves (Proved + Probable + Possible Reserves) | 12,549.5 | 16.3 | 1,057.8 | 1.4 | 13,607.3 | 17.7 | 2,744.9 | 3.5 |

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

[88] The Reserves Report does not state the Partnership's net share, but rather the Partnership's gross share. The Partnership's share in the table above is after payment of royalties to the State, related parties and third parties. The rate of the royalty to Delek Group Ltd. and to Delek Royalties, which was taken into account in the above data, is 6.5% (at the wellhead), i.e., the royalty rate after the Investment Recovery Date. The rate attributed to the holders of the Partnership's equity interests was calculated according to the Partnership's (direct and indirect) holdings in the Tamar Project as of December 31, 2018 and under the assumption that the rate of the royalty to the State is 12.5% (at the wellhead). For further details regarding the Investment Recovery Date, see Sections 7.27.12 and 7.28.6 below.

2. In the Reserves Report, NSAI noted, among other things, several assumptions and reservations, including that: (a) as is common practice in reserve evaluation under the rules of SPE-PRMS, the estimations are not adjusted to risks; (b) NSAI did not visit the oil field and did not examine the mechanical operation of the facilities and wells or their condition; (c) NSAI did not examine possible exposure stemming from environmental protection issues. However, NSAI noted that, as of the date of the Reserves Report, it is not aware of a possible liability pertaining to environmental protection issues, which might materially affect the estimated quantity of reserves in the Reserves Report or the commerciality thereof, and therefore did not include in the Reserves Report costs that might stem from such liability (d) NSAI assumed that the reservoirs will be developed according to the existing development plans[89], will be reasonably operated, that no regulation shall be determined which affects the ability of a holder of the petroleum rights to produce the reserves and that its forecasts with respect to future production will be similar to the actual functioning of the reservoirs.

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

[89] With respect to a future development plan of the Tamar field, see Section (2) below.

3. Discounted cash flow data

With respect to the discounted cash flow calculation specified below, it is noted as follows: (a) The discounted cash flow was calculated, *inter alia*, based on a weighted average of the gas prices stated in the existing gas sale agreements, which are based on various price formulas, which include, among others, linkage to the U.S. CPI, to the Brent barrel price or to the Electricity Production Tariff[90]. It is noted that a change in the gas prices may arise, *inter alia*, due to price adjustment in accordance with the mechanism set forth in the agreement with the IEC, as specified in Section 7.13.4(a)4 below, and changes in indices on which the linkages in the gas supply agreements are based[91]. It is clarified that since, as of the date of release of this report, it is not possible to estimate the scope of the price adjustment that shall be effected (if and insofar as effected) at the first adjustment date (i.e., on July 1, 2021), as set forth in the agreement with the IEC, it has been assumed that a reduction of 50% of the maximum adjustment rate shall be effected, i.e., a reduction of 12.5%. It shall be noted that in the discounted cash flow it was assumed that there shall be no price change at the second adjustment date (i.e., on July 1, 2024). For details regarding changes in the discounted cash flow as a result of a change in price, including as a result of a change in the price adjustment rate as aforesaid, see the sensitivity tables in Sections 7.3.11(a)4 and 7.3.11(a)7 below. It is clarified that such sensitivity analyses are based on the assumption of a price reduction, as aforesaid. It is further noted that a change in the price as a result of the class action certification motion filed by an IEC consumer against the partners in the Tamar Project, as specified in Section 7.28.1 below, was not taken into account. In the estimation of the Partnership's legal counsel, chances of the certification motion being granted are lower than 50%. As aforesaid, at this time, the parties are at the stage of adjudication of the motion for class action certification. Insofar as a final non-appealable decision is issued in the context of the grant of such class action (i.e. after the motion for class action certification is granted (if granted) and a non-appealable decision is issued on the actual class action (if issued)), this may have an adverse effect on the Partnership's business, including on the discounted cash flow figures and the prices at which the Partnership, together with the other Tamar Partners, sells natural gas to its customers, the extent of which shall derive from the outcome of the action. The data with

[90] The weighted electricity production tariff (the "**Electricity Production Tariff**") is the tariff that is supervised by the PUA-E, and reflects the costs of the IEC's electricity production segment, including the IEC's fuels costs, the operational and capital costs that are attributed to the production segment and the cost of purchasing electricity from private electricity producers.

[91] The discounted cash flow was calculated based on the contractual price that shall apply from January 2019 until the first adjustment date, in accordance with the amendment to the IEC agreement (if and insofar as signed), as specified in Section 7.13.4(a)4 below.

respect to such gas prices was provided to NSAI by the Partnership[92]; (b)The demand forecast for the domestic market in Israel, which was used in order to estimate the projected future volume of natural gas sales in the domestic market in Israel, was prepared by an outside consultant, BDO Consulting Group; (c) The discounted cash flow was calculated based on the condensate price which is based on Brent Crude prices. For the purpose of calculation of the Brent price, use was made of the average of oil price forecasts by third parties that provide long-term price forecasts, including World Bank and others, for the price of the NYMEX ICE Brent Crude and adjusted to quality differences, transport costs and the price for which condensate is sold in the region; (d) The operating costs taken into account are costs provided to NSAI by the Partnership. Such costs include direct costs at the project level, insurance costs, production well maintenance costs and estimated G&A and overhead expenses of the operator, which may be directly attributed to the project and together represent the project's operating costs. These costs are divided into expenses at the field level and expenses per output unit. The operating costs provided to NSAI by the Partnership are deemed reasonable thereby, based, *inter alia*, on NSAI's additional knowledge from similar projects. Such costs are not adjusted to inflation changes; (e) The amount of the capital expenditures taken into account for the purpose of preparing the discounted cash flow exceeds the costs approved by the Partnership, and it also includes a cost estimation of future expenses to be incurred during production for the purpose of preserving and expanding the production capacity. The capital expenditures taken into account are capital expenditures which may be required, such as the drilling, development and connection of new wells and the placement of additional production equipment and infrastructures. The capital expenditures provided to NSAI are deemed reasonable thereby, based, *inter alia*, on development plans for the Tamar Project and on NSAI's additional knowledge from similar projects and are not adjusted to inflation changes; (f) The abandonment costs taken into account are costs provided to NSAI by the Partnership, in accordance with its estimations of the cost of abandonment of the wells, platform and production facilities. These costs do not take into account the salvage value of the Tamar Lease and the facilities at the Tamar Project and are not adjusted to inflation changes; (g) The tax calculations take into account corporate tax rates in accordance with the law. The tax payments

[92] For the purpose of calculating the price forecast, use was made of assumptions based on data received from a consulting company, which are based on a weighting of data of several public and private bodies: (1) an annual increase in the U.S. CPI at an average rate of approx. 2% per annum; (2) a Brent barrel price of approx. $67 per barrel in 2019, rising to approx. $80 per barrel in 2024, and to approx. $92 per barrel in 2029, and a gradual increase at an average rate of approx. 2.9% per annum thereafter; (3) a forecast of the Electricity Production Tariff based, *inter alia*, on an shekel-dollar exchange rate forecast and on the fuel price forecast which is based on the price of the gas for the IEC.

and their rate, which are included within the discounted cash flow, were calculated from the perspective of the holder of the Partnership's Participation Units, which is a company holding the Partnership's Participation Units since the project's launch date. It is noted that tax payments that shall actually be made by the Partnership in the future on account of the tax for which the holders of the Partnership's Participation Units are liable in each of the relevant tax years, according to the provisions of the Taxation of Profits from Natural Resources Law (in this section: the "**Law**"), may be materially different; (h) The actual production rate for each of the reserve categories specified above may be lower or higher than the production rate used for the purpose of estimating the discounted cash flow. Moreover, NSAI did not conduct a sensitivity analysis with respect to the wells' production rate; (i) The discounted cash flow assumes projected sale quantities in each of the project's years based on the reservoirs' production capacity[93] and a forecast of the scope of supply and demand in the domestic market and in the export markets in each of the project's years, based on the Partnership's estimates which rely on demand forecasts of independent consulting companies; (j) The calculation of the discounted cash flow assumes revenues from the export of gas to the local markets in Egypt and Jordan in a total aggregate amount of approx. 42 BCM, until 2040, *inter alia* based on the Partnership's forecasts as to the performance of the agreements for export to Egypt and Jordan specified in Section 7.13.5 below. Furthermore, it assumes a capital payment by the Tamar Partners in respect of the piping of natural gas through the EMG Pipeline (see Section 7.27.7 below). The price under the Tamar-Dolphinus export agreement (as defined below) (for details see Section 7.13.5(a)2 below) was adjusted to the point of delivery, as determined in the agreement; (k) The calculation of the discounted cash flow takes into account the actual rate of royalties to the State, related parties and third parties which shall be paid by the Partnership, at the rate of approx. 11.5% and approx. 9.13%, respectively. As of the date of release of this report, the Tamar Partners are in discussions with the Ministry of Energy as to the manner of calculation of the actual rate of the royalties that shall be paid to the State by the Partnership. Therefore, the actual rate of such royalties is not final and may change and there is no certainty that the Partnership will succeed in the negotiations for the determination of a lower royalty rate in the future. For further details on this issue, see Section 7.27.12(c) below; (l) The calculation of the discounted cash flow takes into account the petroleum profit levy applicable to the Partnership under the provisions of the Law. It should be emphasized that the levy calculations were made according to the definitions, formulas and

[93] For details regarding the production capacity of the Tamar Project, see Section 7.3.4(b) above.

mechanisms defined in the Law as understood and interpreted by the Partnership, which were reflected in the reports of the Tamar venture to 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. It is noted that, as of the date of release of this report, several interpretive disagreements are being clarified with respect to the implementation of the Law in the reports of the Tamar venture to the Tax Authority, in the framework of the objection and appeal proceedings prescribed by the Law. The issues to which the disagreements pertain have not yet been addressed in the case law of the Israeli courts. The levy calculations were made according to the transitional provisions prescribed by the Law with respect to a venture, the date of commercial production commencement of which occurred between the date of commencement of the Law and January 1, 2014, and based on the following assumptions: the venture will choose to report in dollars, according to Section 13(b) of the Law, all payments of the venture (production costs, investments, royalties, etc.) will be recognized by the Tax Authorities for the purpose of calculating the levy and for the purpose of calculating the venture's revenues the actual gas sale prices will be taken into account; (m) The calculation of the discounted cash flow takes into account expenses and investments actually paid and expected to be paid by the Partnership from January 1, 2019 as well as revenues deriving from sales of natural gas and condensate that were produced from January 1, 2019. It is clarified that revenues received in 2019 in respect of sales of natural gas and condensate that were produced in 2018 were not included in the discounted cash flow.

<u>It is noted that the discounted cash flow was revised in relation to the discounted cash flow as of December 31, 2017 (the **"Previous Discounted Cash Flow"**) primarily for the following reasons[94]:</u>

(1) In view of the update of the forecasts of the Electricity Production Tariff, the U.S. C.P.I. and the Brent barrel price, the forecasts of the relevant sale prices (natural gas and condensate) that are linked thereto have been revised.

(2) In view of the update of the venture's expenditure forecast, including the update of the venture's capital expenditure forecast, which chiefly derives from the update of the forecast

[94] It is noted that the Partnership's holdings in the Tamar Project (directly and indirectly through Tamar Petroleum) total 25.7855% (compared with a rate of 25.7% in the Previous Discounted Cash Flow).

for the future development plan of the Tamar field, including changes in the dates of drilling of future wells and a change in the cost estimates in respect thereof, along with the addition of a third flowline from the Tamar field to the Tamar platform, the investments in respect of which are expected to be made between the years 2024-2026, with an estimated budget of approx. $370 million (in 100% terms) that is not adjusted to inflation changes, which will allow the gas supply capacity of the Tamar Project to increase to approx. 1.2 BCF per day (approx. 12 BCM per annum), at maximum production. It is noted that such third flowline, construction and placement of which are yet to receive final approval from the Tamar partners, will, subject to associated investments, allow for further expansions of the gas supply capacity of the Tamar Project even beyond a maximum production of 12 BCM per annum.

(3) In view of the update of the blend of domestic market and export in the forecast of quantities to be sold, and in view of the possible addition of a third flowline as specified in Section 2 above and in view of the EMG transaction (see Section 7.27.7 below), which increases the certainty of performance of the Dolphinus Agreement, the projected quantities for sale were revised as of 2027.

(4) For changes that occurred in relation to the quantity of reserves attributed to the petroleum asset, see Section 7.3.11(a)8 below.

In accordance with various assumptions, the principal amount which assumptions are specified above, the following table shows the estimated discounted cash flow as of December 31, 2018 in thousands of dollars (after levy and income tax), attributed to the Partnership's share (directly and indirectly, through its holding in Tamar Petroleum), from the reserves in the Tamar Project, for each of the reserve categories specified above:

**Total discounted cash flow from proved reserves as of December 31, 2018 (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) | 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%[95] | Discounted at 10% | Discounted at 15% | Discounted at 20% |
| **31.12.2019** | 489 | 10.65 | 543,380 | 108,842 | - | 44,046 | 31,018 | - | 359,474 | - | 60,543 | 298,931 | 291,727 | 288,315 | 285,020 | 278,755 | 272,886 |
| **31.12.2020** | 489 | 10.65 | 528,307 | 105,823 | - | 40,848 | 63,546 | - | 318,091 | 11,141 | 71,510 | 235,440 | 218,825 | 211,236 | 204,076 | 190,912 | 179,105 |
| **31.12.2021** | 475 | 10.34 | 521,631 | 104,486 | - | 39,959 | 208 | - | 376,977 | 102,351 | 47,938 | 226,688 | 200,658 | 189,194 | 178,627 | 159,840 | 143,706 |
| **31.12.2022** | 489 | 10.65 | 540,522 | 108,270 | - | 40,056 | 74,704 | - | 317,492 | 112,337 | 49,579 | 155,577 | 131,155 | 120,786 | 111,448 | 95,390 | 82,189 |
| **31.12.2023** | 489 | 10.65 | 546,903 | 109,548 | - | 40,056 | 69,796 | - | 327,503 | 136,019 | 47,927 | 143,557 | 115,259 | 103,678 | 93,489 | 76,539 | 63,199 |
| **31.12.2024** | 490 | 10.67 | 552,028 | 110,575 | - | 40,056 | - | - | 401,398 | 186,497 | 36,432 | 178,470 | 136,466 | 119,900 | 105,659 | 82,742 | 65,474 |
| **31.12.2025** | 489 | 10.65 | 553,775 | 110,925 | - | 40,056 | - | - | 402,795 | 188,508 | 36,296 | 177,991 | 129,619 | 111,235 | 95,796 | 71,757 | 54,415 |
| **31.12.2026** | 489 | 10.65 | 559,641 | 112,099 | - | 40,056 | - | - | 407,486 | 190,703 | 37,412 | 179,371 | 124,403 | 104,277 | 87,762 | 62,881 | 45,697 |
| **31.12.2027** | 534 | 11.64 | 624,461 | 125,083 | - | 40,056 | - | - | 459,322 | 214,963 | 45,143 | 199,216 | 131,588 | 107,734 | 88,611 | 60,729 | 42,294 |
| **31.12.2028** | 536 | 11.67 | 631,608 | 126,515 | - | 40,056 | - | - | 465,038 | 217,638 | 48,533 | 198,867 | 125,102 | 100,042 | 80,414 | 52,715 | 35,184 |
| **31.12.2029** | 534 | 11.64 | 635,059 | 127,206 | - | 40,056 | - | - | 467,797 | 218,929 | 49,078 | 199,790 | 119,698 | 93,494 | 73,443 | 46,052 | 29,456 |
| **31.12.2030** | 534 | 11.64 | 649,909 | 130,181 | - | 40,056 | - | - | 479,673 | 224,487 | 51,233 | 203,953 | 116,373 | 88,783 | 68,158 | 40,879 | 25,058 |
| **31.12.2031** | 534 | 11.64 | 668,438 | 133,892 | - | 40,056 | - | - | 494,490 | 231,422 | 54,942 | 208,127 | 113,100 | 84,279 | 63,229 | 36,275 | 21,309 |

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

**Total discounted cash flow from proved reserves as of December 31, 2018 (in dollars in thousands in relation to the Partnership's share)**

| 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%) | Taxes | | Total discounted cash flow after tax | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cash flow components | | | | | | | | | | Levy | Income Tax | Discounted at 0% | Discounted at 5% | Discounted at 7.5%[95] | Discounted at 10% | Discounted at 15% | Discounted at 20% |
| **31.12.2032** | 536 | 11.67 | 692,393 | 138,690 | - | 40,056 | - | - | 513,647 | 240,387 | 57,285 | 215,975 | 111,776 | 81,356 | 59,649 | 32,733 | 18,427 |
| **31.12.2033** | 534 | 11.64 | 712,656 | 142,749 | - | 40,056 | 52,087 | - | 477,765 | 223,594 | 65,962 | 188,208 | 92,767 | 65,950 | 47,255 | 24,804 | 13,382 |
| **31.12.2034** | 519 | 11.30 | 703,289 | 140,873 | - | 40,056 | - | - | 522,360 | 244,465 | 60,507 | 217,389 | 102,048 | 70,861 | 49,619 | 24,913 | 12,880 |
| **31.12.2035** | 419 | 9.12 | 576,059 | 115,388 | - | 40,056 | - | - | 420,615 | 196,848 | 48,484 | 175,283 | 78,364 | 53,150 | 36,371 | 17,467 | 8,655 |
| **31.12.2036** | 285 | 6.22 | 398,227 | 79,767 | - | 40,056 | - | - | 278,404 | 130,293 | 31,651 | 116,460 | 49,587 | 32,850 | 21,969 | 10,092 | 4,792 |
| **31.12.2037** | 285 | 6.20 | 402,450 | 80,613 | - | 40,056 | - | - | 281,782 | 131,874 | 32,067 | 117,841 | 47,785 | 30,920 | 20,208 | 8,879 | 4,041 |
| **31.12.2038** | 279 | 6.08 | 399,767 | 80,076 | - | 40,056 | - | - | 279,636 | 130,870 | 31,829 | 116,938 | 45,161 | 28,542 | 18,230 | 7,662 | 3,341 |
| **31.12.2039** | 270 | 5.87 | 390,468 | 78,213 | - | 40,056 | - | - | 272,200 | 127,389 | 30,959 | 113,851 | 41,875 | 25,850 | 16,136 | 6,487 | 2,711 |
| **31.12.2040** | 253 | 5.52 | 370,847 | 74,283 | - | 40,056 | - | - | 256,508 | 120,046 | 29,109 | 107,354 | 37,605 | 22,674 | 13,832 | 5,319 | 2,130 |
| **31.12.2041** | 174 | 3.79 | 258,160 | 51,711 | - | 40,056 | - | - | 166,394 | 77,872 | 18,419 | 70,102 | 23,387 | 13,773 | 8,211 | 3,020 | 1,159 |
| **31.12.2042** | 143 | 3.12 | 215,082 | 43,082 | - | 40,056 | - | - | 131,944 | 61,750 | 12,635 | 57,559 | 18,288 | 10,520 | 6,129 | 2,156 | 793 |
| **31.12.2043** | 98 | 2.12 | 148,014 | 29,648 | - | 40,056 | - | - | 78,310 | 36,649 | 6,268 | 35,393 | 10,710 | 6,017 | 3,426 | 1,153 | 406 |
| **31.12.2044** | 78 | 1.70 | 119,850 | 24,007 | - | 40,056 | - | 16,412 | 39,375 | 18,428 | 6,560 | 14,388 | 4,146 | 2,275 | 1,266 | 408 | 138 |
| **31.12.2045** | 65 | 1.42 | 101,088 | 20,248 | - | 40,056 | - | 16,412 | 24,372 | 11,406 | 4,780 | 8,186 | 2,247 | 1,204 | 655 | 202 | 65 |

**Total discounted cash flow from proved reserves as of December 31, 2018 (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) | 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%[95] | Discounted at 10% | Discounted at 15% | Discounted at 20% |
| **31.12.2046** | 33 | 0.71 | 51,462 | 10,308 | - | 40,056 | - | 16,412 | (15,314) | (7,167) | 61 | (8,208) | (2,146) | (1,123) | (597) | (176) | (55) |
| **31.12.2047** | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **31.12.2048** | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **31.12.2049** | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **31.12.2050** | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **31.12.2051** | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **31.12.2052** | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **31.12.2053** | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **31.12.2054** | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **31.12.2055** | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **31.12.2056** | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **31.12.2057** | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **Total** | **10,542** | **230** | **13,095,475** | **2,623,103** | - | **1,126,242** | **291,359** | **49,236** | **9,005,535** | **3,779,697** | **1,073,141** | **4,152,697** | **2,617,571** | **2,167,774** | **1,838,089** | **1,400,583** | **1,132,838** |

| Total discounted cash flow from probable reserves as of December 31, 2018 (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) | Sales volume (BCM) (100% of the petroleum asset) | Income | Royalties to be paid | Royalties to be received | Operation costs | Development costs[96] | 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%[97] | Discounted at 10% | Discounted at 15% | Discounted at 20% |
| **31.12.2019** | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **31.12.2020** | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **31.12.2021** | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **31.12.2022** | - | - | - | - | - | - | (75,526) | - | 75,526 | 30,812 | (7,087) | 51,801 | 43,669 | 40,217 | 37,107 | 31,761 | 27,365 |
| **31.12.2023** | - | - | - | - | - | - | (69,796) | - | 69,796 | 38,528 | (7,779) | 39,047 | 31,350 | 28,200 | 25,429 | 20,819 | 17,190 |
| **31.12.2024** | - | - | - | - | - | - | 75,526 | - | (75,526) | (33,988) | 11,098 | (52,635) | (40,247) | (35,361) | (31,161) | (24,403) | (19,310) |
| **31.12.2025** | - | - | - | - | - | - | 26,043 | - | (26,043) | (12,188) | 4,940 | (18,795) | (13,687) | (11,746) | (10,116) | (7,577) | (5,746) |
| **31.12.2026** | - | - | - | - | - | - | 43,753 | - | (43,753) | (20,476) | 6,840 | (30,117) | (20,888) | (17,508) | (14,735) | (10,558) | (7,673) |
| **31.12.2027** | - | - | - | - | - | - | - | - | - | - | (62) | 62 | 41 | 33 | 28 | 19 | 13 |
| **31.12.2028** | - | - | - | - | - | - | - | - | - | - | (62) | 62 | 39 | 31 | 25 | 16 | 11 |
| **31.12.2029** | - | - | - | - | - | - | - | - | - | - | (62) | 62 | 37 | 29 | 23 | 14 | 9 |

[96] Since the degree of certainty required for production of the probable reserves (50%) is lower than the degree of certainty required for the production of the proved reserves (90%), the date of performance of the capital investments required for production of the probable reserves was postponed relative to the date of performance of the capital investments required for production of the proved reserves, in accordance with the production profile. Thus, development costs which are stated as negative in certain years in the table of discounted cash flow figures from probable reserves, are stated as positive in later years in the same table, relative to the development costs in the table of discounted cash flow figures from proved reserves. For details regarding the total capital investments required, see the table of discounted cash flow figures from 2P (proved (1P) + probable) reserves.

[97] See Footnote 95 above.

**Total discounted cash flow from probable reserves as of December 31, 2018 (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) | Sales volume (BCM) (100% of the petroleum asset) | Income | Royalties to be paid | Royalties to be received | Operation costs | Development costs[96] | 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%[97] | Discounted at 10% | Discounted at 15% | Discounted at 20% |
| **31.12.2030** | - | - | - | - | - | - | - | - | - | - | (62) | 62 | 35 | 27 | 21 | 12 | 8 |
| **31.12.2031** | - | - | - | - | - | - | - | - | - | - | (62) | 62 | 34 | 25 | 19 | 11 | 6 |
| **31.12.2032** | - | - | - | - | - | - | - | - | - | - | (62) | 62 | 32 | 23 | 17 | 9 | 5 |
| **31.12.2033** | - | - | - | - | - | - | (52,087) | - | 52,087 | 24,377 | (6,751) | 34,461 | 16,986 | 12,075 | 8,652 | 4,542 | 2,450 |
| **31.12.2034** | 16 | 0.34 | 21,367 | 4,280 | - | - | - | - | 17,087 | 7,997 | (54) | 9,144 | 4,292 | 2,981 | 2,087 | 1,048 | 542 |
| **31.12.2035** | 116 | 2.53 | 159,583 | 31,965 | - | - | 52,087 | - | 75,531 | 35,348 | 20,815 | 19,368 | 8,659 | 5,873 | 4,019 | 1,930 | 956 |
| **31.12.2036** | 250 | 5.46 | 349,352 | 69,977 | - | - | - | - | 279,375 | 130,748 | 31,399 | 117,229 | 49,914 | 33,066 | 22,114 | 10,158 | 4,823 |
| **31.12.2037** | 250 | 5.44 | 353,097 | 70,727 | - | - | - | - | 282,370 | 132,149 | 34,551 | 115,670 | 46,905 | 30,350 | 19,836 | 8,716 | 3,966 |
| **31.12.2038** | 255 | 5.56 | 365,897 | 73,291 | - | - | - | - | 292,605 | 136,939 | 35,803 | 119,863 | 46,291 | 29,256 | 18,686 | 7,854 | 3,425 |
| **31.12.2039** | 265 | 5.77 | 383,588 | 76,835 | - | - | 49,482 | - | 257,271 | 120,403 | 42,861 | 94,007 | 34,577 | 21,345 | 13,323 | 5,356 | 2,238 |
| **31.12.2040** | 283 | 6.16 | 413,777 | 82,882 | - | - | - | - | 330,895 | 154,859 | 39,350 | 136,686 | 47,880 | 28,870 | 17,611 | 6,772 | 2,712 |
| **31.12.2041** | 348 | 7.59 | 516,282 | 103,414 | - | - | - | - | 412,868 | 193,222 | 49,380 | 170,265 | 56,802 | 33,453 | 19,943 | 7,335 | 2,815 |
| **31.12.2042** | 304 | 6.61 | 455,481 | 91,236 | - | - | - | - | 364,246 | 170,467 | 45,131 | 148,648 | 47,229 | 27,168 | 15,828 | 5,569 | 2,048 |
| **31.12.2043** | 336 | 7.31 | 509,333 | 102,022 | - | - | - | - | 407,310 | 190,621 | 50,401 | 166,289 | 50,318 | 28,272 | 16,097 | 5,417 | 1,910 |
| **31.12.2044** | 341 | 7.43 | 524,124 | 104,985 | - | - | - | (16,412) | 435,551 | 203,838 | 48,883 | 182,830 | 52,689 | 28,916 | 16,089 | 5,179 | 1,750 |

| Total discounted cash flow from probable reserves as of December 31, 2018 (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) | Sales volume (BCM) (100% of the petroleum asset) | Income | Royalties to be paid | Royalties to be received | Operation costs | Develop-ment costs[96] | 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%[97] | Discounted at 10% | Discounted at 15% | Discounted at 20% |
| 31.12.2045 | 246 | 5.35 | 382,301 | 76,577 | - | - | - | (16,412) | 322,136 | 150,760 | 35,006 | 136,371 | 37,429 | 20,063 | 10,910 | 3,359 | 1,087 |
| 31.12.2046 | 244 | 5.32 | 384,201 | 76,958 | - | - | - | (16,412) | 323,655 | 151,471 | 34,690 | 137,495 | 35,940 | 18,817 | 10,000 | 2,945 | 914 |
| 31.12.2047 | 273 | 5.94 | 434,419 | 87,017 | - | 40,056 | - | - | 307,347 | 143,838 | 34,769 | 128,740 | 32,049 | 16,390 | 8,512 | 2,398 | 713 |
| 31.12.2048 | 218 | 4.75 | 351,877 | 70,483 | - | 40,056 | - | 17,524 | 223,814 | 104,745 | 28,578 | 90,491 | 21,455 | 10,717 | 5,439 | 1,466 | 418 |
| 31.12.2049 | 130 | 2.83 | 212,171 | 42,499 | - | 40,056 | - | 17,524 | 112,092 | 52,459 | 14,908 | 44,725 | 10,099 | 4,927 | 2,444 | 630 | 172 |
| 31.12.2050 | 64 | 1.40 | 106,468 | 21,326 | - | 40,056 | - | 17,524 | 27,562 | 12,899 | 5,703 | 8,960 | 1,927 | 918 | 445 | 110 | 29 |
| 31.12.2051 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 31.12.2052 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 31.12.2053 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 31.12.2054 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 31.12.2055 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 31.12.2056 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 31.12.2057 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **Total** | **3,939** | **86** | **5,923,318** | **1,186,476** | **-** | **160,222** | **49,482** | **3,335** | **4,523,802** | **2,119,826** | **553,063** | **1,850,913** | **601,855** | **357,426** | **218,691** | **90,907** | **44,848** |

| Total discounted cash flow from 2P (proved + probable) reserves as of December 31, 2018 (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) | Sales volume (BCM) (100% of the petroleum asset) | Income | Royalties to be paid | Royalties to be received | Operation costs | Develop-ment 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%[98] | Discounted at 10% | Discounted at 15% | Discounted at 20% |
| 31.12.2019 | 489 | 10.65 | 543,380 | 108,842 | - | 44,046 | 31,018 | - | 359,474 | - | 60,543 | 298,931 | 291,727 | 288,315 | 285,020 | 278,755 | 272,886 |
| 31.12.2020 | 489 | 10.65 | 528,307 | 105,823 | - | 40,848 | 63,546 | - | 318,091 | 11,141 | 71,510 | 235,440 | 218,825 | 211,236 | 204,076 | 190,912 | 179,105 |
| 31.12.2021 | 475 | 10.34 | 521,631 | 104,486 | - | 39,959 | 208 | - | 376,977 | 102,351 | 47,938 | 226,688 | 200,658 | 189,194 | 178,627 | 159,840 | 143,706 |
| 31.12.2022 | 489 | 10.65 | 540,522 | 108,270 | - | 40,056 | (821) | - | 393,018 | 143,149 | 42,492 | 207,378 | 174,823 | 161,002 | 148,555 | 127,151 | 109,554 |
| 31.12.2023 | 489 | 10.65 | 546,903 | 109,548 | - | 40,056 | - | - | 397,300 | 174,547 | 40,147 | 182,605 | 146,609 | 131,879 | 118,917 | 97,358 | 80,389 |
| 31.12.2024 | 490 | 10.67 | 552,028 | 110,575 | - | 40,056 | 75,526 | - | 325,872 | 152,508 | 47,530 | 125,834 | 96,218 | 84,538 | 74,497 | 58,339 | 46,164 |
| 31.12.2025 | 489 | 10.65 | 553,775 | 110,925 | - | 40,056 | 26,043 | - | 376,752 | 176,320 | 41,236 | 159,196 | 115,932 | 99,489 | 85,680 | 64,179 | 48,669 |
| 31.12.2026 | 489 | 10.65 | 559,641 | 112,099 | - | 40,056 | 43,753 | - | 363,733 | 170,227 | 44,252 | 149,254 | 103,516 | 86,769 | 73,027 | 52,323 | 38,025 |
| 31.12.2027 | 534 | 11.64 | 624,461 | 125,083 | - | 40,056 | - | - | 459,322 | 214,963 | 45,081 | 199,278 | 131,629 | 107,767 | 88,638 | 60,747 | 42,308 |
| 31.12.2028 | 536 | 11.67 | 631,608 | 126,515 | - | 40,056 | - | - | 465,038 | 217,638 | 48,472 | 198,928 | 125,141 | 100,073 | 80,439 | 52,731 | 35,195 |
| 31.12.2029 | 534 | 11.64 | 635,059 | 127,206 | - | 40,056 | - | - | 467,797 | 218,929 | 49,016 | 199,852 | 119,735 | 93,523 | 73,466 | 46,066 | 29,465 |
| 31.12.2030 | 534 | 11.64 | 649,909 | 130,181 | - | 40,056 | - | - | 479,673 | 224,487 | 51,171 | 204,015 | 116,408 | 88,810 | 68,178 | 40,892 | 25,066 |
| 31.12.2031 | 534 | 11.64 | 668,438 | 133,892 | - | 40,056 | - | - | 494,490 | 231,422 | 54,880 | 208,188 | 113,133 | 84,305 | 63,248 | 36,286 | 21,315 |
| 31.12.2032 | 536 | 11.67 | 692,393 | 138,690 | - | 40,056 | - | - | 513,647 | 240,387 | 57,223 | 216,037 | 111,808 | 81,379 | 59,666 | 32,742 | 18,432 |
| 31.12.2033 | 534 | 11.64 | 712,656 | 142,749 | - | 40,056 | - | - | 529,851 | 247,970 | 59,212 | 222,669 | 109,753 | 78,026 | 55,907 | 29,346 | 15,832 |

| | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **31.12.2034** | 534 | 11.64 | 724,656 | 145,153 | - | 40,056 | - | - | 539,447 | 252,461 | 60,453 | 226,533 | 106,340 | 73,841 | 51,706 | 25,961 | 13,422 |
| **31.12.2035** | 534 | 11.64 | 735,641 | 147,353 | - | 40,056 | 52,087 | - | 496,146 | 232,196 | 69,299 | 194,651 | 87,023 | 59,022 | 40,390 | 19,397 | 9,611 |
| **31.12.2036** | 536 | 11.67 | 747,579 | 149,745 | - | 40,056 | - | - | 557,779 | 261,041 | 63,049 | 233,689 | 99,501 | 65,916 | 44,083 | 20,250 | 9,615 |
| **31.12.2037** | 534 | 11.64 | 755,547 | 151,341 | - | 40,056 | - | - | 564,151 | 264,023 | 66,618 | 233,510 | 94,690 | 61,270 | 40,044 | 17,595 | 8,007 |
| **31.12.2038** | 534 | 11.64 | 765,664 | 153,367 | - | 40,056 | - | - | 572,241 | 267,809 | 67,632 | 236,801 | 91,452 | 57,799 | 36,917 | 15,516 | 6,766 |
| **31.12.2039** | 534 | 11.64 | 774,057 | 155,048 | - | 40,056 | 49,482 | - | 529,470 | 247,792 | 73,820 | 207,859 | 76,452 | 47,195 | 29,459 | 11,843 | 4,949 |
| **31.12.2040** | 536 | 11.67 | 784,624 | 157,165 | - | 40,056 | - | - | 587,403 | 274,905 | 68,459 | 244,040 | 85,485 | 51,544 | 31,443 | 12,091 | 4,842 |
| **31.12.2041** | 523 | 11.38 | 774,442 | 155,125 | - | 40,056 | - | - | 579,261 | 271,094 | 67,800 | 240,367 | 80,189 | 47,226 | 28,154 | 10,356 | 3,975 |
| **31.12.2042** | 447 | 9.74 | 670,563 | 134,318 | - | 40,056 | - | - | 496,190 | 232,217 | 57,766 | 206,207 | 65,517 | 37,688 | 21,957 | 7,725 | 2,841 |
| **31.12.2043** | 433 | 9.43 | 657,347 | 131,671 | - | 40,056 | - | - | 485,621 | 227,270 | 56,669 | 201,681 | 61,028 | 34,289 | 19,523 | 6,570 | 2,316 |
| **31.12.2044** | 419 | 9.13 | 643,974 | 128,992 | - | 40,056 | - | - | 474,926 | 222,265 | 55,443 | 197,217 | 56,835 | 31,191 | 17,355 | 5,587 | 1,887 |
| **31.12.2045** | 311 | 6.77 | 483,389 | 96,826 | - | 40,056 | - | - | 346,508 | 162,166 | 39,785 | 144,557 | 39,675 | 21,267 | 11,565 | 3,561 | 1,153 |
| **31.12.2046** | 277 | 6.03 | 435,663 | 87,266 | - | 40,056 | - | - | 308,342 | 144,304 | 34,751 | 129,287 | 33,795 | 17,694 | 9,403 | 2,769 | 859 |
| **31.12.2047** | 273 | 5.94 | 434,419 | 87,017 | - | 40,056 | - | - | 307,347 | 143,838 | 34,769 | 128,740 | 32,049 | 16,390 | 8,512 | 2,398 | 713 |
| **31.12.2048** | 218 | 4.75 | 351,877 | 70,483 | - | 40,056 | - | 17,524 | 223,814 | 104,745 | 28,578 | 90,491 | 21,455 | 10,717 | 5,439 | 1,466 | 418 |
| **31.12.2049** | 130 | 2.83 | 212,171 | 42,499 | - | 40,056 | - | 17,524 | 112,092 | 52,459 | 14,908 | 44,725 | 10,099 | 4,927 | 2,444 | 630 | 172 |
| **31.12.2050** | 64 | 1.40 | 106,468 | 21,326 | - | 40,056 | - | 17,524 | 27,562 | 12,899 | 5,703 | 8,960 | 1,927 | 918 | 445 | 110 | 29 |
| **31.12.2051** | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |

[98] See Footnote 95 above.

| | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **31.12.2052** | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **31.12.2053** | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **31.12.2054** | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **31.12.2055** | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **31.12.2056** | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **31.12.2057** | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **Total** | **14,478** | **315** | **19,018,792** | **3,809,579** | **-** | **1,286,477** | **340,842** | **52,572** | **13,529,335** | **5,899,523** | **1,626,205** | **6,003,608** | **3,219,427** | **2,525,199** | **2,056,780** | **1,491,492** | **1,177,686** |

| Total discounted cash flow from possible reserves as of December 31, 2018 (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) | 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%[99] | Discounted at 10% | Discounted at 15% | Discounted at 20% |
| 31.12.2019 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 31.12.2020 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 31.12.2021 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 31.12.2022 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 31.12.2023 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 31.12.2024 | - | - | - | - | - | - | (75,526) | - | 75,526 | 35,346 | (8,130) | 48,309 | 36,939 | 32,455 | 28,600 | 22,397 | 17,723 |
| 31.12.2025 | - | - | - | - | - | - | - | - | - | - | 1,144 | (1,144) | (833) | (715) | (616) | (461) | (350) |
| 31.12.2026 | - | - | - | - | - | - | 75,526 | - | (75,526) | (35,346) | 9,274 | (49,453) | (34,299) | (28,750) | (24,196) | (17,337) | (12,599) |
| 31.12.2027 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 31.12.2028 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 31.12.2029 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 31.12.2030 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |

99 See Footnote 95 above.

| Total discounted cash flow from possible reserves as of December 31, 2018 (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) | 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%[99] | Discounted at 10% | Discounted at 15% | Discounted at 20% |
| 31.12.2031 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 31.12.2032 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 31.12.2033 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 31.12.2034 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 31.12.2035 | - | - | - | - | - | - | (52,087) | - | 52,087 | 24,377 | (7,344) | 35,054 | 15,672 | 10,629 | 7,274 | 3,493 | 1,731 |
| 31.12.2036 | - | - | - | - | - | - | - | - | - | - | 647 | (647) | (275) | (183) | (122) | (56) | (27) |
| 31.12.2037 | - | - | - | - | - | - | 52,087 | - | (52,087) | (24,377) | 6,805 | (34,515) | (13,996) | (9,056) | (5,919) | (2,601) | (1,183) |
| 31.12.2038 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 31.12.2039 | - | - | - | - | - | - | (49,482) | - | 49,482 | 23,158 | (5,326) | 31,651 | 11,641 | 7,186 | 4,486 | 1,803 | 754 |
| 31.12.2040 | - | - | - | - | - | - | - | - | - | - | 1,138 | (1,138) | (399) | (240) | (147) | (56) | (23) |
| 31.12.2041 | 12 | 0.26 | 17,486 | 3,503 | - | - | 49,482 | - | (35,499) | (16,614) | 8,175 | (27,061) | (9,028) | (5,317) | (3,170) | (1,166) | (447) |
| 31.12.2042 | 87 | 1.90 | 130,990 | 26,238 | - | - | - | - | 104,752 | 49,024 | 12,817 | 42,911 | 13,634 | 7,843 | 4,569 | 1,608 | 591 |
| 31.12.2043 | 101 | 2.21 | 153,947 | 30,837 | - | - | - | - | 123,110 | 57,616 | 15,064 | 50,431 | 15,260 | 8,574 | 4,882 | 1,643 | 579 |

| Total discounted cash flow from possible reserves as of December 31, 2018 (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) | 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%[99] | Discounted at 10% | Discounted at 15% | Discounted at 20% |
| 31.12.2044 | 117 | 2.55 | 179,573 | 35,970 | - | - | - | - | 143,603 | 67,206 | 17,571 | 58,826 | 16,953 | 9,304 | 5,177 | 1,666 | 563 |
| 31.12.2045 | 224 | 4.87 | 347,734 | 69,653 | - | - | - | - | 278,081 | 130,142 | 34,026 | 113,913 | 31,265 | 16,759 | 9,113 | 2,806 | 908 |
| 31.12.2046 | 258 | 5.61 | 405,551 | 81,234 | - | - | - | - | 324,316 | 151,780 | 40,186 | 132,351 | 34,596 | 18,113 | 9,626 | 2,835 | 880 |
| 31.12.2047 | 262 | 5.70 | 417,006 | 83,529 | - | - | - | - | 333,477 | 156,067 | 41,306 | 136,103 | 33,882 | 17,327 | 8,999 | 2,535 | 754 |
| 31.12.2048 | 318 | 6.92 | 512,396 | 102,636 | - | - | - | (17,524) | 427,284 | 199,969 | 49,952 | 177,363 | 42,051 | 21,005 | 10,661 | 2,873 | 818 |
| 31.12.2049 | 358 | 7.79 | 583,454 | 116,869 | - | - | - | (17,524) | 484,109 | 226,563 | 56,905 | 200,640 | 45,305 | 22,103 | 10,963 | 2,826 | 772 |
| 31.12.2050 | 391 | 8.51 | 645,125 | 129,223 | - | - | - | (17,524) | 533,427 | 249,644 | 60,102 | 223,681 | 48,102 | 22,923 | 11,111 | 2,739 | 717 |
| 31.12.2051 | 390 | 8.50 | 652,024 | 130,604 | - | 40,056 | - | - | 481,364 | 225,278 | 56,061 | 200,024 | 40,967 | 19,068 | 9,033 | 2,130 | 534 |
| 31.12.2052 | 325 | 7.08 | 549,932 | 110,155 | - | 40,056 | - | 17,524 | 382,198 | 178,869 | 50,796 | 152,533 | 29,752 | 13,526 | 6,262 | 1,412 | 339 |
| 31.12.2053 | 228 | 4.96 | 389,612 | 78,042 | - | 40,056 | - | 17,524 | 253,991 | 118,868 | 35,109 | 100,014 | 18,579 | 8,250 | 3,733 | 805 | 185 |
| 31.12.2054 | 140 | 3.05 | 243,061 | 48,687 | - | 40,056 | - | 17,524 | 136,795 | 64,020 | 20,769 | 52,006 | 9,201 | 3,991 | 1,764 | 364 | 80 |
| 31.12.2055 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 31.12.2056 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |

| Total discounted cash flow from possible reserves as of December 31, 2018 (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) | 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%[99] | Discounted at 10% | Discounted at 15% | Discounted at 20% |
| 31.12.2057 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Total | 3,209 | 70 | 5,227,891 | 1,047,178 | - | 160,222 | - | - | 4,020,491 | 1,881,590 | 497,048 | 1,641,853 | 384,970 | 194,796 | 102,082 | 32,259 | 13,300 |

| Total discounted cash flow from 3P (proved + probable + possible) reserves as of December 31, 2018 (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) | 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%[100] | Discounted at 10% | Discounted at 15% | Discounted at 20% |
| **31.12.2019** | 489 | 10.65 | 543,380 | 108,842 | - | 44,046 | 31,018 | - | 359,474 | - | 60,543 | 298,931 | 291,727 | 288,315 | 285,020 | 278,755 | 272,886 |
| **31.12.2020** | 489 | 10.65 | 528,307 | 105,823 | - | 40,848 | 63,546 | - | 318,091 | 11,141 | 71,510 | 235,440 | 218,825 | 211,236 | 204,076 | 190,912 | 179,105 |
| **31.12.2021** | 475 | 10.34 | 521,631 | 104,486 | - | 39,959 | 208 | - | 376,977 | 102,351 | 47,938 | 226,688 | 200,658 | 189,194 | 178,627 | 159,840 | 143,706 |
| **31.12.2022** | 489 | 10.65 | 540,522 | 108,270 | - | 40,056 | (821) | - | 393,018 | 143,149 | 42,492 | 207,378 | 174,823 | 161,002 | 148,555 | 127,151 | 109,554 |
| **31.12.2023** | 489 | 10.65 | 546,903 | 109,548 | - | 40,056 | - | - | 397,300 | 174,547 | 40,147 | 182,605 | 146,609 | 131,879 | 118,917 | 97,358 | 80,389 |
| **31.12.2024** | 490 | 10.67 | 552,028 | 110,575 | - | 40,056 | - | - | 401,398 | 187,854 | 39,400 | 174,144 | 133,158 | 116,993 | 103,097 | 80,736 | 63,887 |
| **31.12.2025** | 489 | 10.65 | 553,775 | 110,925 | - | 40,056 | 26,043 | - | 376,752 | 176,320 | 42,380 | 158,052 | 115,098 | 98,775 | 85,064 | 63,718 | 48,319 |
| **31.12.2026** | 489 | 10.65 | 559,641 | 112,099 | - | 40,056 | 119,279 | - | 288,207 | 134,881 | 53,526 | 99,801 | 69,217 | 58,019 | 48,830 | 34,986 | 25,426 |
| **31.12.2027** | 534 | 11.64 | 624,461 | 125,083 | - | 40,056 | - | - | 459,322 | 214,963 | 45,081 | 199,278 | 131,629 | 107,767 | 88,638 | 60,747 | 42,308 |
| **31.12.2028** | 536 | 11.67 | 631,608 | 126,515 | - | 40,056 | - | - | 465,038 | 217,638 | 48,472 | 198,928 | 125,141 | 100,073 | 80,439 | 52,731 | 35,195 |
| **31.12.2029** | 534 | 11.64 | 635,059 | 127,206 | - | 40,056 | - | - | 467,797 | 218,929 | 49,016 | 199,852 | 119,735 | 93,523 | 73,466 | 46,066 | 29,465 |
| **31.12.2030** | 534 | 11.64 | 649,909 | 130,181 | - | 40,056 | - | - | 479,673 | 224,487 | 51,171 | 204,015 | 116,408 | 88,810 | 68,178 | 40,892 | 25,066 |
| **31.12.2031** | 534 | 11.64 | 668,438 | 133,892 | - | 40,056 | - | - | 494,490 | 231,422 | 54,880 | 208,188 | 113,133 | 84,305 | 63,248 | 36,286 | 21,315 |
| **31.12.2032** | 536 | 11.67 | 692,393 | 138,690 | - | 40,056 | - | - | 513,647 | 240,387 | 57,223 | 216,037 | 111,808 | 81,379 | 59,666 | 32,742 | 18,432 |
| **31.12.2033** | 534 | 11.64 | 712,656 | 142,749 | - | 40,056 | - | - | 529,851 | 247,970 | 59,212 | 222,669 | 109,753 | 78,026 | 55,907 | 29,346 | 15,832 |

[100] See Footnote 95 above.

| | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **31.12.2034** | 534 | 11.64 | 724,656 | 145,153 | - | 40,056 | - | - | 539,447 | 252,461 | 60,453 | 226,533 | 106,340 | 73,841 | 51,706 | 25,961 | 13,422 |
| **31.12.2035** | 534 | 11.64 | 735,641 | 147,353 | - | 40,056 | - | - | 548,232 | 256,573 | 61,955 | 229,704 | 102,694 | 69,651 | 47,664 | 22,890 | 11,342 |
| **31.12.2036** | 536 | 11.67 | 747,579 | 149,745 | - | 40,056 | - | - | 557,779 | 261,041 | 63,696 | 233,042 | 99,225 | 65,733 | 43,960 | 20,194 | 9,589 |
| **31.12.2037** | 534 | 11.64 | 755,547 | 151,341 | - | 40,056 | 52,087 | - | 512,064 | 239,646 | 73,423 | 198,996 | 80,694 | 52,214 | 34,126 | 14,995 | 6,823 |
| **31.12.2038** | 534 | 11.64 | 765,664 | 153,367 | - | 40,056 | - | - | 572,241 | 267,809 | 67,632 | 236,801 | 91,452 | 57,799 | 36,917 | 15,516 | 6,766 |
| **31.12.2039** | 534 | 11.64 | 774,057 | 155,048 | - | 40,056 | - | - | 578,953 | 270,950 | 68,493 | 239,510 | 88,093 | 54,381 | 33,945 | 13,646 | 5,703 |
| **31.12.2040** | 536 | 11.67 | 784,624 | 157,165 | - | 40,056 | - | - | 587,403 | 274,905 | 69,597 | 242,902 | 85,087 | 51,304 | 31,296 | 12,034 | 4,820 |
| **31.12.2041** | 534 | 11.64 | 791,928 | 158,628 | - | 40,056 | 49,482 | - | 543,762 | 254,481 | 75,975 | 213,306 | 71,161 | 41,910 | 24,984 | 9,190 | 3,527 |
| **31.12.2042** | 534 | 11.64 | 801,553 | 160,556 | - | 40,056 | - | - | 600,942 | 281,241 | 70,584 | 249,117 | 79,151 | 45,531 | 26,526 | 9,333 | 3,433 |
| **31.12.2043** | 534 | 11.64 | 811,294 | 162,507 | - | 40,056 | - | - | 608,731 | 284,886 | 71,733 | 252,112 | 76,288 | 42,863 | 24,405 | 8,213 | 2,895 |
| **31.12.2044** | 536 | 11.68 | 823,547 | 164,961 | - | 40,056 | - | - | 618,530 | 289,472 | 73,015 | 256,043 | 73,788 | 40,495 | 22,532 | 7,253 | 2,450 |
| **31.12.2045** | 534 | 11.64 | 831,123 | 166,479 | - | 40,056 | - | - | 624,589 | 292,307 | 73,811 | 258,470 | 70,940 | 38,026 | 20,678 | 6,367 | 2,061 |
| **31.12.2046** | 534 | 11.64 | 841,214 | 168,500 | - | 40,056 | - | - | 632,658 | 296,084 | 74,937 | 261,638 | 68,390 | 35,807 | 19,028 | 5,604 | 1,739 |
| **31.12.2047** | 534 | 11.64 | 851,425 | 170,546 | - | 40,056 | - | - | 640,824 | 299,905 | 76,075 | 264,843 | 65,932 | 33,717 | 17,510 | 4,933 | 1,467 |
| **31.12.2048** | 536 | 11.68 | 864,273 | 173,119 | - | 40,056 | - | - | 651,098 | 304,714 | 78,530 | 267,854 | 63,506 | 31,721 | 16,100 | 4,338 | 1,236 |
| **31.12.2049** | 488 | 10.62 | 795,625 | 159,368 | - | 40,056 | - | - | 596,201 | 279,022 | 71,813 | 245,366 | 55,404 | 27,031 | 13,407 | 3,456 | 944 |
| **31.12.2050** | 455 | 9.91 | 751,593 | 150,549 | - | 40,056 | - | - | 560,989 | 262,543 | 65,804 | 232,642 | 50,029 | 23,841 | 11,556 | 2,849 | 746 |
| **31.12.2051** | 390 | 8.50 | 652,024 | 130,604 | - | 40,056 | - | - | 481,364 | 225,278 | 56,061 | 200,024 | 40,967 | 19,068 | 9,033 | 2,130 | 534 |
| **31.12.2052** | 325 | 7.08 | 549,932 | 110,155 | - | 40,056 | - | 17,524 | 382,198 | 178,869 | 50,796 | 152,533 | 29,752 | 13,526 | 6,262 | 1,412 | 339 |

| | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **31.12.2053** | 228 | 4.96 | 389,612 | 78,042 | - | 40,056 | - | 17,524 | 253,991 | 118,868 | 35,109 | 100,014 | 18,579 | 8,250 | 3,733 | 805 | 185 |
| **31.12.2054** | 140 | 3.05 | 243,061 | 48,687 | - | 40,056 | - | 17,524 | 136,795 | 64,020 | 20,769 | 52,006 | 9,201 | 3,991 | 1,764 | 364 | 80 |
| **31.12.2055** | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **31.12.2056** | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **31.12.2057** | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **Total** | **17,690** | **385** | **24,246,684** | **4,856,758** | - | **1,446,687** | **340,841** | **52,571** | **17,549,827** | **7,781,113** | **2,123,252** | **7,645,463** | **3,604,396** | **2,719,997** | **2,158,862** | **1,523,750** | **1,190,986** |

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

**Caution concerning forward-looking information – The aforesaid discounted cash flow figures 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 sales of natural gas from the project, operating costs, capital expenditure, abandonment expenses, royalty rates and sale prices, including with respect to the price adjustments according to the agreement with the IEC, and there is no certainty that such assumptions will materialize. It is noted that the quantities of natural gas and/or condensate that shall actually be produced, such expenses and such revenues may materially differ from the above estimates and conjectures, *inter alia* as a result of the competition conditions prevailing on the market and/or operating and technical conditions and/or regulatory changes and/or supply and demand conditions on the 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. It is further noted that the price adjustment rate on the first adjustment date as set forth in the agreement with the IEC may materially differ from the Partnership's estimate, *inter alia* as a result of the actual natural gas prices on the domestic market on the first adjustment date and all according to the adjustment mechanism as stipulated in the agreement with the IEC.**

4. Below is a sensitivity analysis in respect of the principal parameters comprising the discounted cash flow (the price of gas and the amount of gas sales[101]) as of December 31, 2018 (Dollars in thousands), which was performed by the Partnership:

| Sensitivity/Category | Total | Current Value Discounted at 10% | Current Value Discounted at 15% | Current Value Discounted at 20% | Sensitivity/Category | Total | Current Value Discounted at 10% | Current Value Discounted at 15% | Current Value Discounted at 20% |
|---|---|---|---|---|---|---|---|---|---|
| **10% Increase in Gas Price** | | | | | **10% Decrease in Gas Price** | | | | |
| Proved Reserves 1P | 4,562,264 | 1,999,453 | 1,518,573 | 1,225,473 | Proved Reserves 1P | 3,744,099 | 1,675,162 | 1,280,206 | 1,037,232 |
| Probable Reserves | 2,045,261 | 240,221 | 98,889 | 47,920 | Probable Reserves | 1,659,148 | 198,814 | 84,343 | 43,003 |
| Total 2P Type Reserves (Proved + Probable Reserves) | 6,607,524 | 2,239,674 | 1,617,462 | 1,273,393 | Total 2P Type Reserves (Proved + Probable Reserves) | 5,403,247 | 1,873,976 | 1,364,550 | 1,080,235 |
| Possible Reserves | 1,813,112 | 111,947 | 34,948 | 14,089 | Possible Reserves | 1,469,749 | 91,720 | 29,181 | 12,203 |
| Total 3P Type Reserves (Proved + Probable + Possible Reserves) | 8,420,636 | 2,351,620 | 1,652,410 | 1,287,482 | Total 3P Type Reserves (Proved + Probable + Possible Reserves) | 6,872,996 | 1,965,696 | 1,393,731 | 1,092,438 |
| **15% Increase in Gas Price** | | | | | **15% Decrease in Gas Price** | | | | |
| Proved Reserves 1P | 4,765,600 | 2,078,329 | 1,575,693 | 1,269,891 | Proved Reserves 1P | 3,537,521 | 1,590,594 | 1,216,778 | 986,156 |
| Probable Reserves | 2,142,758 | 251,236 | 103,099 | 49,649 | Probable Reserves | 1,563,489 | 189,057 | 81,226 | 42,229 |
| Total 2P Type Reserves (Proved + Probable Reserves) | 6,908,358 | 2,329,565 | 1,678,792 | 1,319,540 | Total 2P Type Reserves (Proved + Probable Reserves) | 5,101,010 | 1,779,650 | 1,298,004 | 1,028,385 |
| Possible Reserves | 1,898,741 | 116,879 | 36,292 | 14,484 | Possible Reserves | 1,383,659 | 86,613 | 27,733 | 11,750 |
| Total 3P Type Reserves (Proved + Probable + Possible Reserves) | 8,807,099 | 2,446,443 | 1,715,084 | 1,334,024 | Total 3P Type Reserves (Proved + Probable + Possible Reserves) | 6,484,670 | 1,866,263 | 1,325,738 | 1,040,135 |
| **20% Increase in Gas Price** | | | | | **20% Decrease in Gas Price** | | | | |
| Proved Reserves 1P | 4,968,029 | 2,156,080 | 1,631,645 | 1,313,123 | Proved Reserves 1P | 3,335,739 | 1,509,352 | 1,156,207 | 937,574 |
| Probable Reserves | 2,240,203 | 262,299 | 107,383 | 51,466 | Probable Reserves | 1,467,386 | 179,058 | 77,926 | 41,314 |

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

| Sensitivity/Category | Total | Current Value Discounted at 10% | Current Value Discounted at 15% | Current Value Discounted at 20% | Sensitivity/Category | Total | Current Value Discounted at 10% | Current Value Discounted at 15% | Current Value Discounted at 20% |
|---|---|---|---|---|---|---|---|---|---|
| Total 2P Type Reserves (Proved + Probable Reserves) | 7,208,233 | 2,418,379 | 1,739,027 | 1,364,588 | Total 2P Type Reserves (Proved + Probable Reserves) | 4,803,125 | 1,688,410 | 1,234,133 | 978,887 |
| Possible Reserves | 1,984,371 | 121,811 | 37,637 | 14,879 | Possible Reserves | 1,298,246 | 81,905 | 26,597 | 11,543 |
| Total 3P Type Reserves (Proved + Probable + Possible Reserves) | 9,192,603 | 2,540,190 | 1,776,664 | 1,379,467 | Total 3P Type Reserves (Proved + Probable + Possible Reserves) | 6,101,372 | 1,770,315 | 1,260,730 | 990,431 |

| Sensitivity/Category | Total | Current Value Discounted at 10% | Current Value Discounted at 15% | Current Value Discounted at 20% | Sensitivity/Category | Total | Current Value Discounted at 10% | Current Value Discounted at 15% | Current Value Discounted at 20% |
|---|---|---|---|---|---|---|---|---|---|
| **10% Increase in Gas Sales** | | | | | **10% Decrease in Gas Sales** | | | | |
| Proved Reserves 1P | 4,200,294 | 1,968,492 | 1,514,270 | 1,230,071 | Proved Reserves 1P | 3,755,105 | 1,663,744 | 1,268,918 | 1,026,916 |
| Probable Reserves | 1,792,673 | 241,158 | 102,797 | 50,475 | Probable Reserves | 1,662,544 | 197,838 | 83,699 | 42,553 |
| Total 2P Type Reserves (Proved + Probable Reserves) | 5,992,967 | 2,209,651 | 1,617,067 | 1,280,546 | Total 2P Type Reserves (Proved + Probable Reserves) | 5,417,650 | 1,861,582 | 1,352,617 | 1,069,469 |
| Possible Reserves | 1,581,853 | 117,441 | 38,610 | 15,701 | Possible Reserves | 1,469,965 | 91,256 | 29,070 | 12,208 |
| Total 3P Type Reserves (Proved + Probable + Possible Reserves) | 7,574,821 | 2,327,092 | 1,655,677 | 1,296,247 | Total 3P Type Reserves (Proved + Probable + Possible Reserves) | 6,887,614 | 1,952,838 | 1,381,688 | 1,081,677 |
| **15% Increase in Gas Sales** | | | | | **15% Decrease in Gas Sales** | | | | |
| Proved Reserves 1P | 4,176,652 | 2,021,530 | 1,565,409 | 1,276,064 | Proved Reserves 1P | 3,542,871 | 1,575,756 | 1,202,777 | 973,664 |
| Probable Reserves | 1,779,171 | 256,122 | 111,256 | 54,851 | Probable Reserves | 1,566,872 | 187,976 | 80,463 | 41,655 |
| Total 2P Type Reserves (Proved + Probable Reserves) | 5,955,823 | 2,277,652 | 1,676,665 | 1,330,915 | Total 2P Type Reserves (Proved + Probable Reserves) | 5,109,742 | 1,763,732 | 1,283,241 | 1,015,319 |
| Possible Reserves | 1,559,611 | 127,855 | 43,330 | 17,664 | Possible Reserves | 1,383,819 | 86,063 | 27,537 | 11,676 |
| Total 3P Type Reserves (Proved + Probable + Possible Reserves) | 7,515,434 | 2,405,507 | 1,719,995 | 1,348,579 | Total 3P Type Reserves (Proved + Probable + Possible Reserves) | 6,493,562 | 1,849,795 | 1,310,778 | 1,026,995 |

| Sensitivity/Category | Total | Current Value Discounted at 10% | Current Value Discounted at 15% | Current Value Discounted at 20% | Sensitivity/Category | Total | Current Value Discounted at 10% | Current Value Discounted at 15% | Current Value Discounted at 20% |
|---|---|---|---|---|---|---|---|---|---|
| **20% Increase in Gas Sales** | | | | | **20% Decrease in Gas Sales** | | | | |
| Proved Reserves 1P | 4,181,537 | 2,074,046 | 1,615,048 | 1,320,655 | Proved Reserves 1P | 3,329,873 | 1,486,661 | 1,135,498 | 919,284 |
| Probable Reserves | 1,741,455 | 268,241 | 119,211 | 59,398 | Probable Reserves | 1,470,835 | 177,929 | 77,091 | 40,658 |
| Total 2P Type Reserves (Proved + Probable Reserves) | 5,922,992 | 2,342,287 | 1,734,259 | 1,380,053 | Total 2P Type Reserves (Proved + Probable Reserves) | 4,800,708 | 1,664,590 | 1,212,589 | 959,942 |
| Possible Reserves | 1,538,687 | 138,807 | 48,568 | 19,958 | Possible Reserves | 1,298,121 | 81,173 | 26,255 | 11,351 |
| Total 3P Type Reserves (Proved + Probable + Possible Reserves) | 7,461,679 | 2,481,094 | 1,782,827 | 1,400,011 | Total 3P Type Reserves (Proved + Probable + Possible Reserves) | 6,098,829 | 1,745,763 | 1,238,844 | 971,293 |

5. <u>Below is a sensitivity analysis in respect of the principal linkage components of gas price under the gas sale agreements in which the Tamar Partners have engaged (the U.S. CPI and the Electricity Production Tariff) as of December 31, 2018 (Dollars in thousands), which was performed by the Partnership</u>[102]:

| Sensitivity/Category | Total | Current Value Discounted at 10% | Current Value Discounted at 15% | Current Value Discounted at 20% | Sensitivity/Category | Total | Current Value Discounted at 10% | Current Value Discounted at 15% | Current Value Discounted at 20% |
|---|---|---|---|---|---|---|---|---|---|
| **10% Increase in CPI Forecast** | | | | | **10% Decrease in CPI Forecast** | | | | |
| Proved Reserves 1P | 4,157,036 | 1,840,360 | 1,402,284 | 1,134,138 | Proved Reserves 1P | 4,147,928 | 1,835,498 | 1,398,603 | 1,131,293 |
| Probable Reserves | 1,850,920 | 218,688 | 90,902 | 44,842 | Probable Reserves | 1,850,909 | 218,690 | 90,908 | 44,849 |
| Total 2P Type Reserves (Proved + Probable Reserves) | 6,007,956 | 2,059,048 | 1,493,187 | 1,178,980 | Total 2P Type Reserves (Proved + Probable Reserves) | 5,998,837 | 2,054,188 | 1,489,510 | 1,176,142 |
| Possible Reserves | 1,641,853 | 102,082 | 32,259 | 13,300 | Possible Reserves | 1,641,853 | 102,082 | 32,259 | 13,300 |
| Total 3P Type Reserves (Proved + Probable + Possible Reserves) | 7,649,809 | 2,161,131 | 1,525,446 | 1,192,280 | Total 3P Type Reserves (Proved + Probable + Possible Reserves) | 7,640,690 | 2,156,270 | 1,521,770 | 1,189,442 |
| **10% Increase in Electricity Production Tariff Forecast** | | | | | **10% Decrease in Electricity Production Tariff Forecast** | | | | |
| Proved Reserves 1P | 4,235,794 | 1,886,832 | 1,440,545 | 1,166,761 | Proved Reserves 1P | 4,103,918 | 1,814,325 | 1,382,726 | 1,118,836 |
| Probable Reserves | 1,850,900 | 218,569 | 90,764 | 44,695 | Probable Reserves | 1,850,924 | 218,744 | 90,969 | 44,912 |
| Total 2P Type Reserves (Proved + Probable Reserves) | 6,086,694 | 2,105,400 | 1,531,308 | 1,211,456 | Total 2P Type Reserves (Proved + Probable Reserves) | 5,954,841 | 2,033,069 | 1,473,695 | 1,163,749 |
| Possible Reserves | 1,641,853 | 102,082 | 32,259 | 13,300 | Possible Reserves | 1,641,853 | 102,082 | 32,259 | 13,300 |
| Total 3P Type Reserves (Proved + Probable + Possible Reserves) | 7,728,547 | 2,207,483 | 1,563,568 | 1,224,756 | Total 3P Type Reserves (Proved + Probable + Possible Reserves) | 7,596,695 | 2,135,151 | 1,505,954 | 1,177,048 |

[102] Although the Electricity Production Tariff is affected, *inter alia*, by the CPI, in the analysis of the sensitivity in the table below, this effect was not taken into account.

6. Below is a sensitivity analysis in respect of the sale of quantities over and above the minimal quantities (take-or-pay) under the gas sale agreements in which the Partnership has engaged as of December 31, 2018 (Dollars in thousands), which was performed by the Partnership:

| Sensitivity/Category | Total | Current Value Discounted at 10% | Current Value Discounted at 15% | Current Value Discounted at 20% | Sensitivity/Category | Total | Current Value Discounted at 10% | Current Value Discounted at 15% | Current Value Discounted at 20% |
|---|---|---|---|---|---|---|---|---|---|
| **10% increase in the quantity of gas sales in respect of quantities over and above the take-or-pay** | | | | | **10% decrease in the quantity of gas sales in respect of quantities over and above the take-or-pay** | | | | |
| Proved Reserves 1P | 4,244,034 | 1,921,254 | 1,468,782 | 1,189,387 | Proved Reserves 1P | 4,313,034 | 1,764,169 | 1,331,419 | 1,073,024 |
| Probable Reserves | 1,812,212 | 220,445 | 92,023 | 45,302 | Probable Reserves | 1,869,297 | 212,633 | 88,771 | 44,352 |
| Total 2P Type Reserves (Proved + Probable Reserves) | 6,056,246 | 2,141,699 | 1,560,805 | 1,234,689 | Total 2P Type Reserves (Proved + Probable Reserves) | 6,182,331 | 1,976,802 | 1,420,190 | 1,117,376 |
| Possible Reserves | 1,619,676 | 104,169 | 33,114 | 13,606 | Possible Reserves | 1,660,508 | 97,248 | 30,583 | 12,731 |
| Total 3P Type Reserves (Proved + Probable + Possible Reserves) | 7,675,922 | 2,245,868 | 1,593,919 | 1,248,295 | Total 3P Type Reserves (Proved + Probable + Possible Reserves) | 7,842,839 | 2,074,050 | 1,450,773 | 1,130,107 |

7. Below is a sensitivity analysis for the adjustment of the price determined in the agreement with the IEC as of December 31, 2018 (Dollars in thousands), which was performed by the Partnership:

| Sensitivity/Category | Total | Current Value Discounted at 10% | Current Value Discounted at 15% | Current Value Discounted at 20% | Sensitivity/Category | Total | Current Value Discounted at 10% | Current Value Discounted at 15% | Current Value Discounted at 20% |
|---|---|---|---|---|---|---|---|---|---|
| **0% Price Decrease** | | | | | **25% Price Decrease** | | | | |
| Proved Reserves 1P | 4,225,138 | 1,877,195 | 1,430,528 | 1,156,295 | Proved Reserves 1P | 4,081,890 | 1,799,617 | 1,371,037 | 1,109,630 |
| Probable Reserves | 1,850,927 | 218,620 | 90,819 | 44,751 | Probable Reserves | 1,850,962 | 218,823 | 91,053 | 44,997 |
| Total 2P Reserves (Proved + Probable Reserves) | 6,076,066 | 2,095,815 | 1,521,347 | 1,201,047 | Total 2P Reserves (Proved + Probable Reserves) | 5,932,852 | 2,018,440 | 1,462,090 | 1,154,627 |
| Possible Reserves | 1,641,853 | 102,082 | 32,259 | 13,300 | Possible Reserves | 1,641,830 | 102,069 | 32,249 | 13,291 |
| Total 3P Reserves (Proved + Probable + Possible Reserves) | 7,717,919 | 2,197,898 | 1,553,607 | 1,214,346 | Total 3P Reserves (Proved + Probable + Possible Reserves) | 7,574,682 | 2,120,508 | 1,494,339 | 1,167,918 |

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

The main differences between the present reserve report and the previous reserve report derive from the production of approx. 364 BCF and approx. 477 thousand barrels of condensate from the reservoir in the course of 2018, as well as from the update of the mapping of the reservoir, which indicated an increase in the quantity of reserves in the Tamar Project as follows:

Compared with the previous report, the total quantity of condensate and natural gas reserves in the Tamar Lease has increased in the proved reserves (1P) category by approx. 3.5% (from approx. 7.8 TCF and approx. 10.2 million barrels of condensate in the previous report to approx. 8.1 TCF and approx. 10.5 million barrels of condensate in the present reserve report); in the proved and probable (2P) category by approx. 0.7% (from approx. 11 TCF and approx. 14.4 million barrels of condensate in the previous report to approx. 11.1 TCF and approx. 14.5 million barrels of condensate in the present reserve report); and in the proved, probable and possible (3P) category by approx. 3.7% (from approx. 13.1 TCF and approx. 17.1 million barrels of condensate in the reserve report to approx. 13.6 TCF and approx. 17.7 million barrels of condensate in the present reserve report).

9. Production Data

Production data in respect of the Tamar Project, which are attributable to the Partnership in 2016-2018[103], are presented below:

[103] It is noted that from the date of commencement of the piping of natural gas from the Tamar Project (i.e. March 30, 2013) until December 31, 2018, natural gas was supplied to customers in a total quantity of approx. 50.5 BCM. It is further noted that the average daily production volume of natural gas in the past two years (January 1, 2017 – December 31, 2018) amounted to approx. 0.97 BCF.

| **Natural Gas**[104105] | | Y2016 | Y2017 | Y2018 |
|---|---|---|---|---|
| Total output (attributable to the holders of the equity interests of the Partnership) during the period (in MMCF) | | 103,028 | 97,659 | 92,698 |
| Average price per output unit (attributable to the holders of the equity interests of the Partnership) (Dollars per MCF) [106] | | 5.2 | 5.33 | 5.49 |
| Average royalties (any payment derived from the output of the producing asset, including from the gross revenues from the petroleum asset) paid per output unit (attributable to the holders of the equity interests of the Partnership) (Dollars per MCF) | The State | 0.6 | 0.6 | 0.61 |
| | Third parties | 0.09 | 0.1 | 0.09 |
| | Interested parties | 0.14 | 0.15 | 0.36[107] |
| Average production costs per output unit (attributable to the holders of the equity interests of the Partnership) (Dollars per MCF)[108] | | 0.4 | 0.36 | 0.39 |
| Average net revenues per output unit (attributable to the holders of the equity interests of the Partnership) (Dollars per MCF) | | 3.97 | 4.12 | 4.04 |
| Petroleum and gas profit levy | | - | - | - |
| Average net revenues per output unit after petroleum and gas profit levy (attributable to the holders of the equity interests of the Partnership) (Dollars per MCF) | | 3.97 | 4.12 | 4.04 |
| Depletion amount during the reported period relative to the total amounts of gas in the project (in %)[109] | | 3.2 | 3.44 | 3.29 |

| **Condensate**[110,111] | | Y2016 | Y2017 | Y2018 |
|---|---|---|---|---|
| Total output (attributable to the holders of the equity interests of the Partnership) during the period (in barrels in thousands) | | 140 | 129.4 | 121.51 |
| Average price per output unit (attributable to the holders of the equity interests of the Partnership) (Dollars per barrel) | | 38.1 | 47.1 | 63.01 |
| Average royalties (any payment derived | The State | 4.2 | 5.28 | 7.03 |

[104] The rate attributed to the holders of the equity interests of the Partnership in the output, in the royalties paid, in the production costs and in net revenues, was rounded off to two digits after the decimal point.
[105] The production data include, in addition to the Partnership's direct holding in the Tamar Project, also the Partnership's share in the production data of Tamar Petroleum commencing from July 2017.
[106] The average price per output unit, weights the Partnership's actual price, which includes the outline for the sale of natural gas from the Tamar Project to the Yam Tethys project. In this regard, see Section 7.28.2 below.
[107] For the royalty rate taken into account in 2018, see Footnote 88 above
[108] The data include current production costs only and do not include exploration and development costs of the reservoir and tax payments that shall be paid in the future by the Partnership.
[109] The depletion rate is the amount of natural gas produced in the relevant report period out of the balance of proved and probable reserves as of the beginning of the same report period. The said depletion rate is calculated at the end of the year and not during the year.
[110] See Footnote 104 above.
[111] See Footnote 105 above.

| | | | | |
|---|---|---|---|---|
| from the output of the producing asset, including from the gross revenues from the petroleum asset) paid per output unit (attributable to the holders of the equity interests of the Partnership) (Dollars per barrel) | Third parties | 0.68 | 0.83 | 1.05 |
| | Interested Parties | 1 | 1.37 | 4.18[112] |
| Average production costs per output unit (attributable to the holders of the equity interests of the Partnership) (Dollars per barrel)[113] | | 2.1 | 2 | 2.11 |
| Average net revenues per output unit (attributable to the holders of the equity interests of the Partnership) (Dollars per barrel) | | 30.12 | 37.62 | 48.64 |
| Petroleum and gas profit levy | | - | - | - |
| Average net revenues per output unit after petroleum and gas profit levy (attributable to the holders of the equity interests of the Partnership) (Dollars per barrel) | | 30.12 | 37.62 | 48.64 |
| Depletion rate during the reported period relative to the total quantities of condensate in the project (in %)[114] | | 3.3 | 3.5 | 3.31 |

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

Opinion of the Evaluator

Attached hereto as **Annex B** is a reserves report for the Tamar Project (which includes the Tamar and Tamar SW reservoirs), prepared by NSAI, as of December 31, 2018, and attached as **Annex A** to this chapter is the evaluator's consent to the inclusion of the said report herein.

A letter dated March 21, 2019 that the Partnership received from NSAI regarding the absence of material changes in the Tamar Project, is attached to this chapter as **Annex C**.

Management Statement

(1) Date of statement: March 21, 2019;

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

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

[112] See Footnote 107 above.
[113] See Footnote 108 above.
[114] The quantity of condensate produced from the Tamar Project derives from the quantity of natural gas produced from the project.

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

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

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

(7) We hereby confirm that the data included herein were drafted according to the professional terms listed in Chapter G of the Third Schedule to the Securities Regulations (Details of the Prospectus and the Draft Prospectus – Structure and Form), 5729-1969 and per the meaning ascribed to the same in the Petroleum Resources Management System (2007), as published by the Society of Petroleum Engineers (SPE), the American Association of Petroleum Geologists (AAPG), the World Petroleum Council (WPC) and the Society of Petroleum Evaluation Engineers (SPEE), as effective on the report release date;

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

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

________________________

Assi Bartfeld

(b) Contingent and prospective resources in the Dalit Lease

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

## 7.4. Leviathan project

### 7.4.1. General

| General Details with respect to the Petroleum Asset | |
|---|---|
| **Name of the petroleum assets:** | Leviathan North<br>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;<br>Permitted activities under the Petroleum Law – exploration and production. |
| **Original granting date of the petroleum asset:** | March 27, 2014 |
| **Original expiration date of the petroleum asset:** | February 13, 2044 |
| **Dates on which an extension of the term of the petroleum asset was decided:** | - |
| **Current expiration date of the petroleum asset:** | February 13, 2044 |
| **Note on whether there is an additional option to extend the term of the petroleum asset; if such option exists – the optional extension term should be noted:** | Subject to the Petroleum Law, it may be extended by another 20 years. |
| **The name of the operator:** | Noble |
| **The names of the direct partners in the petroleum asset and their direct share in the petroleum asset, and, to the best of the Partnership's knowledge, the names of the controlling shareholders of such partners:** | ▪ Noble (39.66%).<br>▪ The Partnership (45.34%).<br>▪ Ratio Oil Exploration (1992) – Limited Partnership ("**Ratio**") (15%). To the best of the Partnership's knowledge, the general partner of Ratio, Ratio Oil Explorations Ltd., is a company co-owned by D.L.I.N. Ltd. ("**D.L.I.N.**") (34%), Hiram Landau Ltd. ("**Hiram**") (34%), Eitan Aizenberg Ltd. ("**Aizenberg**") (8.5%), Eyal Zafriri (4.3%), Edo Porat (1.4%), Asher Porat (1.4%), Daniel Soldin (1.4%) and Adv. Boaz Ben-Zur and Adv. Eli Zohar 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 controlled by the estate of the late Yeshayahu Landau. Aizenberg is a private company controlled by Eitan Aizenberg[115]. |

| 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%.<br>After investment recovery – 35.37%. |
| **The total share of the holders of the equity** | Approx. $1,225,834 thousand[116]. |

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

[116] The costs in the table reflect the Partnership's post-merger holding in the Leviathan leases, i.e. 45.34%, and exclude the costs of construction of the Israeli transmission system to the Israel-Jordan border, as specified in Section 7.14.2(b)2.a below.

| | |
|---|---|
| **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):** | |

7.4.2. <u>The principal terms and conditions of the Leviathan leases</u>

(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 7.4.2: 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) <u>Scope of the lease</u>

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) <u>Term of the lease</u>

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

(f) Sale to consumers in Israel and export

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

   The export of gas from the lease will require written approval from the Petroleum Commissioner with the approval of the Minister of Energy (in this Section 7.4.2: the "**Export Approval**") in accordance with the government resolution as detailed in Section 7.25.1(c)2 below. Note that export will not be allowed in practice unless, following the execution of the development program, an amount of 540 BCM will be available to the local economy in accordance with the provisions of the foregoing government resolution. Similarly, export will not be allowed in a manner that harms the lease holder's ability to supply and to pipe, from the Leviathan field to the national transmission system, an amount of at least 1.05 MCM of gas per hour (from the areas leased to Leviathan together). In any event, the actual export will not begin prior to the date of commencement of the piping to the transmission system.

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

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

(g) Construction of facilities and adjustment of the capacity to the needs of the local economy

1. The planning and set up of the production system and transmission system to the shore, in the framework of the development program, will be performed so as to allow the supply and piping of gas to the national transmission

system in an amount of at least 1.4 MCM per hour 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) Commercial production

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

   a. Production will be carried out with proper diligence, without waste, 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) Supervision company

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.

As of the report date, supervision companies have been chosen to accompany the development of the project and to accompany the drillings in the project that have been approved by 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[117] 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. For details in regards to the notice of the Petroleum Commissioner of his intention to postpone the production date as aforesaid, see Section 7.25.1(c)6.b. below.

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

[117] For further details see Section 7.4.4 below.

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 7.4.2(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) Dismantling 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 dismantling of the facilities, and an estimate of the dismantling costs (the "**Dismantling Plan**") to the Petroleum Commissioner for approval. If the lease holder does not submit the foregoing Dismantling Plan on time, or the Petroleum Commissioner finds that the Dismantling Plan that was submitted is not suitable for approval, and the parties did not succeed in agreeing on a Dismantling Plan, the Petroleum Commissioner will determine the Dismantling Plan in accordance with the accepted international standards.

2. On the date of approval of the Dismantling 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 Dismantling Plan.

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

(n) <u>Guarantees</u>[118]

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 7.4.2: "**Letters of Approval**"), for ensuring the payments from the lease holders to the State according to any law, and as a condition for the provision of a lease deed, the lease holder will provide an autonomous, unconditional and irrevocable bank guarantee in favor of the State of Israel in the amount of $50 million for each of the Leviathan leases (total of $100 million, the Partnership's share is $45.34 million) in accordance with the timetables stated in Section 2 below (in this Section: the "**Guarantee**").

2. The Guarantee will be provided in three stages, as follows:

    a. By April 10, 2014 a guarantee in the amount of $20 million will be provided for the Leviathan South lease and in the amount of $30 million for the Leviathan North lease. As of the report release date, each of the lease holders in Leviathan provided their share in the foregoing Guarantee.

    b. Upon the provision of approval to operate the production system, the Guarantee will increase to $37.5 million in respect of each of the leases.

    c. Upon the commencement of the production for export in the framework of the expansion of the development plan, and no later than December 31, 2020, the Guarantee will increase to $50 million in respect of each of the leases.

3. The Guarantee will be valid throughout the complete 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.

4. 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

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

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.

5. 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 Dismantling Plan.

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

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

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

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

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

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

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

6. 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.

7. Notwithstanding the provisions in Subsection (6) above, if the prima facie grounds for forfeiture is an act or omission that may be remedied, the Petroleum Commissioner may notify the lease holder that his request to the bank will be made if within a determined

period the lease holder does not remedy the act or omission, and the stated period will pass without the lease holder remedying the act or omission to the satisfaction of the Petroleum Commissioner.

8. 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.

9. 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.

7.4.3. <u>Compliance with the conditions of the work plan in the Leviathan project</u>

Over and above the terms and conditions of Leviathan's lease deeds as specified in Section 7.4.2 above, no binding work plan in the Leviathan project was determined (for details regarding development of the Leviathan reservoir in the Gas Framework, see Section 7.25.1(c)7 below).

7.4.4. <u>Actual and planned work plan for the Leviathan project</u>

Below is a concise description of the main activities actually performed in the Leviathan project, from January 1, 2016 and until the report release date, and a concise description of planned activities in the aforesaid project:

| **Period** | **Concise Description of Activities Actually Performed for the Period or of the Planned Work Plan** | **Total Estimated Budget for Activity at the Petroleum Asset Level (Dollars in thousands)[119]** | **Amount of Actual Participation in the Budget by the Holders of the Equity Interests of the Partnership (Dollars in thousands)[120]** |
|---|---|---|---|
| 2016[121] | • Submission of an updated development plan for the Leviathan reservoir to the Petroleum Commissioner, as specified in Section 7.4.5 below, which was approved by him.<br>• Adoption of the Leviathan Partners' decision regarding the drilling of the Leviathan-5 appraisal and production well in the area of the I/15 Leviathan North lease. | Approx. 5,000 | Approx. 2,267 |
| | • Granting of approval to the Operator to enter into agreements at an aggregate scope of approx. $120 million for receipt of engineering services, including FEED, in connection with the processing and production rig, as approved in the development plan.<br>• Submission of environmental surveys for the Leviathan project.<br>• In July 2016, the Leviathan Partners approved a budget for 2016 until January 2017 for the performance of the required actions which will allow timely completion of the development plan, as was approved.<br>• Adoption of a resolution at the General Partner's board for approval of the development plan, the work plan and the budget proposed for development of Phase 1A of the development plan, and authorization of the Partnership's management to approve a final investment decision (FID) for development of the reservoir. For further details, see Section 7.4.5 below.<br>• Promotion of regulatory activity for receipt of building permits for the purpose of adoption of a final investment decision (FID) for the development plan for the Leviathan reservoir. | Approx. 83,433 | Approx. 37,828 |
| | • Continued monitoring in the environment of the Leviathan-2 well, in coordination with the Ministry of Energy and the Ministry of Environmental Protection.<br>• Continued work on mapping and analysis of additional prospects in the area of the leases, and particularly of deep-water targets and environmental tests. | Approx. 319 | Approx. 150 |
| 2017[122] | • Adoption of a final investment decision (FID) by the Leviathan Partners for the development of Phase 1A for the development of the Leviathan reservoir (for | Approx. 765,931[126] | Approx. 347,273 |

[119] The amounts for 2016-2018 are amounts actually expended and audited in the framework of the financial statements.

[120] The costs in the table reflect the Partnership's holding in the Leviathan Leases following the Merger, namely 45.34%.

[121] The costs specified in 2016 do not include a budget update (decrease) in the sum of approx. $6,318 thousand (in 100% terms) (the Partnership's share was approx. $2,972 thousand).

[122] The costs specified in 2017 do not include a budget update (decrease) in the sum of approx. $2,597 thousand (in 100% terms) (the Partnership's share – approx. $1,222 thousand).

[126] The said cost is partly from the Leviathan reservoir development budget as was approved in the sum of approx. $3.75 billion (100%). For details see Section 7.4.5 below.

| Period | Concise Description of Activities Actually Performed for the Period or of the Planned Work Plan | Total Estimated Budget for Activity at the Petroleum Asset Level (Dollars in thousands)[119] | Amount of Actual Participation in the Budget by the Holders of the Equity Interests of the Partnership (Dollars in thousands)[120] |
|---|---|---|---|
| | further details, see Section 7.4.5 below) and signing of engagements for the purchase of equipment and/or services in connection with the development plan, as was approved[123]. | | |
| | • Construction of the Israeli transmission system up to the border between Israel and Jordan, as specified in Section 7.14.2(b)2.a below. | Approx. 62,075 | Approx. 28,145 |
| | • Completion of the Leviathan-5 appraisal and production well in the area of the Leviathan North lease and verification of the presence of natural gas in three layers in the Leviathan reservoir (sands A, B and C). [124] | Approx. 94,385 | Approx. 42,794 |
| | • Adoption of a resolution by the Leviathan Partners regarding the drilling of the Leviathan-7 development and production well in the area of the I/14 Leviathan South lease and the drilling of its upper part.[125] | Approx. 16,551 | Approx. 7,504 |
| | • Continued monitoring in the area of the Leviathan-2 well, in coordination with the Ministry of Energy and the Ministry of Environmental Protection. As of the report release date, it appears that the 2012 plugging of the well is effective, that there is no evidence of flow therefrom, and that the environment is recovering gradually and continuously. | Approx. 192 | Approx. 90 |
| | • Continued work on mapping and analysis of additional prospects in the area of the leases, and particularly of deep-water targets and environmental tests. | Approx. 1,228 | Approx. 578 |
| | • Initialization of a project for the reprocessing and re-interpretation of seismic surveys.. | | |
| | • Continued update of the geological model and flow model, *inter alia*, according to the data of the wells and planning and preparations for performance of additional drillings. | | |
| 2018[127] | • Completion of drilling of Leviathan 3 and Leviathan 7 wells and completion of Leviathan 3, 4, 5 and 7 wells.[128] Continued development of Phase 1A for the development of the Leviathan reservoir. For further details, see Section 7.4.5(b)3 below. | Approx. 1,521,955 | Approx. 690,054 |

[123] The said cost excludes the cost for the drilling of the Leviathan-5 appraisal and production well and the Leviathan-7 development and production well, which shall be integrated as part of the system of production wells in the Leviathan reservoir, in the framework of the development plan for the Leviathan reservoir and completion of the Leviathan-3 and Leviathan-4 production wells.

[124] The cost of the said well was included in the development budget of the Leviathan reservoir, as approved, in the sum of approx. 3.75 billion (100%).

[125] See footnote 124 above

[127] The costs specified in 2018 do not include a budget update (decrease) in the sum of approx. $211 thousand (in 100% terms) (the Partnership's share – approx. $96 thousand), costs of abandonment of the reservoir including expenses in respect thereof, and costs in respect of the construction of the Israeli transmission system to the Israel-Jordan border, as specified in Section 7.14.2(b)2.a below..

[128] The said budget is included in the total budget of the Phase 1A development as described above and does not include insurance costs and G&A.

| **Period** | **Concise Description of Activities Actually Performed for the Period or of the Planned Work Plan** | **Total Estimated Budget for Activity at the Petroleum Asset Level (Dollars in thousands)[119]** | **Amount of Actual Participation in the Budget by the Holders of the Equity Interests of the Partnership (Dollars in thousands)[120]** |
|---|---|---|---|
| | • Performance of monitoring activities, in the area of the Leviathan-2 well, in coordination with the Ministry of Energy and the Ministry of Environmental Protection, with the aim of ensuring the continued rehabilitation of the environment. | Approx. 25 | Approx. 11 |
| | • Continuation of the project for the reprocessing of seismic surveys and, *inter alia*, in relation to an exploration drilling to the deep-water targets in the Leviathan leases. | Approx. 2,603 | Approx. 1,180 |
| | • Continued update of the geological model and flow model, *inter alia*, according to the data of the wells. | | |
| 2019 forth[129] | • Completion of the development of Phase 1A for the development of the Leviathan reservoir[130] and the commencement of gas piping therefrom. | Approx. 1,395,864 | Approx. 632,884 |
| | • Completion of the project for the reprocessing of seismic surveys, *inter alia*, in relation to exploration drilling to the deep-water targets in the Leviathan leases. | Approx. 1,406 | Approx. 637 |
| | • Formulation of a prospect and plan for exploration drilling to the deep-water targets in the Leviathan leases for the purpose of submission thereof to the Petroleum Commissioner. It is clarified that a decision with respect to the question of execution and budget of such deep-water drilling is expected to be presented for approval by the partners in 2019. | | |
| | • Additional drilling and completion activities over the course of the project's life that are required during the production in the context of Phase 1A of the development of the Leviathan reservoir, as specified in the discounted cash flow figures presented below[131]. | Approx. 3,181,500 | Approx. 1,442,492 |
| | • Development of Phase 1B for the development of the Leviathan reservoir or alternatives thereto, and additional phases, as required, including authorization of the Operator to engage in agreements in the initial amount of approx. $25 million for the receipt of engineering services, including the preparation of FEED and detailed engineering planning in relation to the said alternatives, as specified in Section 7.4.5(b) below. | Will be determined according to the performed alternative. For details, see Sections 7.4.5(b) and 7.4.5(c) below[132] | |
| | • Performance of monitoring activities, insofar as required, in the area of the Leviathan-2 well, with the aim of ensuring the continued rehabilitation of the environment. | Approx. 92 | Approx. 42 |
| | • Continued update of the geological model and the | | |

[129] The costs specified in 2019 do not include costs of abandonment of the reservoir including expenses in respect thereof, and costs in respect of the construction of the Israeli transmission system to the Israel-Jordan border, as specified in Section 7.14.2(b)2.a below

[130] The remaining Phase 1A development budget as described above. Such budget does not include insurance costs and G&A.

[131] Probable reserves and best estimate contingent resources. It is noted that the said budget does not include abandonment costs.

[132] The aforesaid budget has not yet been approved by the Leviathan Partners.

| **Period** | **Concise Description of Activities Actually Performed for the Period or of the Planned Work Plan** | **Total Estimated Budget for Activity at the Petroleum Asset Level (Dollars in thousands)[119]** | **Amount of Actual Participation in the Budget by the Holders of the Equity Interests of the Partnership (Dollars in thousands)[120]** |
|---|---|---|---|
| | flow model, *inter alia* according to the data of the wells.<br>• Drilling and completion of wells, as required, according to the actual production data. | | |

7.4.5. Plan for development of the Leviathan reservoir

a) On June 2, 2016, the Development Plan was approved by the Petroleum Commissioner, as submitted by the Operator. In the approval letter, the Petroleum Commissioner stated that according to the opinion of an international company provided to his office, the total estimated recoverable quantity of natural gas, based on the production plan submitted for the Leviathan reservoir, is 17.6 TCF. The Petroleum Commissioner further noted that upon receipt of additional data regarding the reservoir, particularly from the Leviathan-5 well, and upon receipt of data that shall be received during the production from the field, the recoverable quantity will be revised, *inter alia*, for the purpose of export permit calculations, insofar as required. Concurrently with the Operator's performance of mapping and assessment activities, the data of the Leviathan 3, 4, 5 and 7 wells and completions were provided to the Petroleum Commissioner, in order for him to have all of the relevant information for the purpose of the resource estimate, as stated above. It is noted that the appraisal of the resources in the said opinion differs from the appraisal of the resources of the Leviathan Partners as stated in the resource and reserve report provided to the Partnership by NSAI as specified in Section 7.4.10 of the report.

However, it is emphasized that in the estimation of the Partnership, given the Government's policy with respect to natural gas export, the recoverable quantity, according to the Petroleum Commissioner, is sufficient for implementation of the Development Plan at a production scope of approx. 21 BCM per year, as approved, in full, and is sufficient for the implementation of all of the export agreements relevant to the Development Plan at this scope.

On February 23, 2017, the Leviathan Partners adopted a final investment decision (FID) for the development of Phase 1A of the Development Plan for the Leviathan reservoir, at a capacity of approx. 12 BCM per year, with a budget of approx. $3.75

billion (for 100% of the rights in the Leviathan reservoir)[133], with the aim of enabling commencement of the piping of natural gas from the Leviathan reservoir during Q4/2019.

b) The plan for full development of Leviathan reservoir includes the supply of natural gas to the domestic market and for export and the supply of condensate to the domestic market (in this section: the “**Development Plan**” or the “**Plan**”), the main provisions of which are as follows:

1. Eight production wells (four of which have been drilled and completed for production in Phase 1A) will be connected by a submarine pipeline to a permanent platform (in this section: the "**Platform**"), which shall be constructed offshore (in the territorial waters of Israel) in accordance with the provisions of National Outline Plan 37/H and on which all gas and condensate treatment systems will be installed. The gas will flow from the Platform to the northern onshore entry point of the national transmission system of INGL as defined in National Outline Plan 37/H (the "**INGL Connection Point**"). The condensate will also be piped to the shore through a separate pipeline adjacent to the gas pipeline and will proceed until the connection to existing fuel pipeline of EAPC that leads to the PEI complex and therefrom to Oil Refineries Ltd. (“**ORL**”). Furthermore, pipeline to the Hagit site will be placed and condensate storage and offloading facilities will be set up thereat, for the purpose of providing backup in the event that the piping of condensate to ORL will not be possible. For further details regarding approval of the NOP and the provisions thereof as aforesaid, see Section 7.25.5(l) below.

2. The capacity of production, treatment and transmission of the wells, the Platform, the flowlines leading thereto from the field and the related facilities, including the pipeline from the Platform to the INGL Connection Point, the condensate pipeline and the related onshore facilities (in this section jointly: the "**Production System**") will amount to approx. 21 BCM per year (Phase 1A and Phase 1B). The gas to be supplied at the INGL Connection Point will be designated for the domestic market and for supply through the national transmission system to neighboring countries. Furthermore, the Platform will include an additional exit point, which is designated for connection to a submarine pipeline with a

[133] It is noted that the aforesaid budget does not include insurance costs and G&A and also excludes approx. $111 million for the completion of the Israeli transmission system to the Israel-Jordan border. As of the date of release of the report, such budget is updated to approx. $119 million. It is noted that the drilling cost included in the Phase 1A budget for the development of the Leviathan reservoir totalled an amount approx. $50 million (100%) lower than the drilling budget, as was estimated at the time of approval of the Phase 1A budget as aforesaid.

capacity of up to approx. 12 BCM per year, which will be chiefly designated for export.

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

   a. Phase 1A – includes four production wells, related subsea systems, subsea flowlines to the Platform and a Platform with processing facilities having a capacity of approx. 12 BCM per year, pipeline to the shore and all of the required onshore facilities and pipeline, with a budget of approx. $3.75 billion (for 100% of the rights in the Leviathan project).

   b. Phase 1B – will include four additional wells, related subsea systems, subsea flowlines to the Platform, and expansion of the Platform's processing facilities in a manner that will increase the Platform's total processing capacity by approx. 9 additional BCM per year (approx. 21 BCM per year in total), with an estimated budget of approx. $1.5-2 billion[134] (for 100% of the rights in the Leviathan project).

4. Moreover, in order to enable production in the required amount, additional production wells will be required during the life of the project.

c) As of the Report Release Date, the Leviathan Partners are examining various alternatives to increase the production scope from the Leviathan reservoir (beyond Phase 1A and concurrently with the examination of Phase 1B), based on the existing facilities, and acting and are acting to update the development plan accordingly, so as to allow increase of the capacity up to 24 BCM per year, and all according to the current and projected demands in the local market and regional and global target markets, and *inter alia*:

1. Increase of the production capacity from 12 BCM per year to 16 BCM per year by means of adding wells and related infrastructures, including the addition of a third, 20-inch pipe from the Leviathan field to the Leviathan platform. It is noted that this alternative is not expected to require significant investments in the Platform, beyond those made in the framework of Phase 1A.

2. Increase of the production capacity from 16 BCM per year to 24 BCM per year (subject to implementation of the first alternative as described above), *inter alia*, by means of adding wells, subsea pipeline and related infrastructure

[134] As of the date of release of the report, the Leviathan Partners have not yet made a final investment decision for the development of Phase 1B.

(beyond those specified above). This alternative will enable the supply of additional quantities of gas for export, insofar as required, including to the liquefaction facilities situated in Egypt and/or for the purpose of supply of gas to a floating liquefaction facility (FLNG), as specified in Section 7.14.2(c) below.

In order to examine various expansion alternatives, the Leviathan's partners approved a budget for a detailed engineering plan in 2019, as specified in Section 7.4.4 above.

d) As of the report date, the Ensco DS-7 rig has performed the completion of the Leviathan-4, Leviathan-3, Leviathan-5 and Leviathan-7 production wells, and the rig was released.

e) As of the report release date, approx. 80% of the development of phase 1A of the Leviathan project development plan have been completed, including completion of all production wells in the field, placement of subsea pipeline for the transmission of the gas and condensate, and setup of the platform tower ("Jacket"), with the aim of allowing commencement of piping of natural gas from the Leviathan reservoir during Q4/2019[135].

f) The total cost that was invested in the development of Phase 1A of the Leviathan project development plan, as described above, as of December 31, 2018, is approx. $2.48 billion (100%).

**Caution concerning forward-looking information – the above estimates in relation to the expected production capacity of the Leviathan reservoir, the scope of the budget and the timetables for development of the Leviathan reservoir, as aforesaid, constitute forward-looking information within the meaning thereof in Section 32A of the Securities Law. The said information is based on estimates by the Partnership and the Operator in the Leviathan reservoir, based on a range of factors, including the Development Plan and the timetables for implementation thereof, receipt of regulatory approvals, estimated data of availability of equipment, services and costs as well as past experience. The estimates in this report may not materialize or may materialize in a materially different manner if changes and/or delays occur in the range of factors as specified above, and if the estimates received change, the market conditions change and/or due to a gamut of regulatory and/or geopolitical changes and/or due to operating and technical**

[135] It is noted that in the framework of implementation of Phase 1A of the development plan, the Operator continues to act for the receipt of all regulatory approvals in relation to the implementation of Phase 1A of the development plan, including the receipt of regulatory approvals in relation to the performance of the onshore segment of the project (the site for condensate storage at Hagit and the condensate transmission system to the Hagit site), the approvals pertaining to the operation of the processing and production platform, including environmental, technical and administrative approvals, as well as approvals in relation to the operation of the Hagit site.

**conditions in the Leviathan reservoir and/or due to unexpected factors relating to the exploration, production and marketing of oil and natural gas and/or as a result of the progress of development of the Leviathan reservoir until completion thereof.**

7.4.6. 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 7.4.1 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 7.4.7 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%-17.15% | 45.79%-17.15% | 101%-104% | 101%-104% | See calculation in Section 7.4.8 below. |

7.4.7. 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 due to the transmission systems and gas processing and up to the onshore gas delivery location.<br>For further details, see Section 7.25.12(c) below. |
| Adjusted revenues at the petroleum asset level | 87.5% | 87.5% | |
| Share in the adjusted revenues | 45.34% | 45.34% | |

| **Item** | **Percentage Pre Investment-Recovery** | **Percentage Post Investment-Recovery** | **Concise Explanation as to How Royalties or Payments are Calculated** |
|---|---|---|---|
| deriving from the petroleum asset attributable to the holders of the equity interests of the Partnership (indirect holdings) | | | |
| Total share of the holders of the equity interests of the Partnership in the actual amount of revenues, at the petroleum asset level (and before other payments at the Partnership level) | 39.67% | 39.67% | |
| **Specification of royalties or payments (deriving from revenues post-finding) in connection with the petroleum asset at the Partnership level (the following percentage will be calculated according to the rate of the holders of the equity interests of the Partnership in the petroleum asset)** | | | |
| The rate of the holders of the equity interests of the Partnership in payment to related and third parties | (2.04%) | (4.30%) | Overriding royalty in respect of the Partnership's share at a 4.5% rate Pre Investment-Recovery and at a 9.5% rate Post Investment-Recovery calculated according to market value at the wellhead[136].<br>The said rate was calculated according to the principles under which the State's royalties are calculated, and therefore such rate may change, insofar as the manner of calculation of the State's royalties changes.<br>For further details with respect to the manner of calculation of the royalty rate, see Section 7.27.12 below. |
| Actual rate in revenues from the petroleum asset attributable to the holders of the equity interests of the Partnership | 37.63% | 35.37% | |

[136] The parties entitled to royalties are Delek Energy, Delek Group, Cohen Development and others which are not related parties.

7.4.8. 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% | 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.<br>A rate of 1%-4% for exploration expenses, with the rate of payment to the Operator decreasing upon an increase in the exploration expenses. Such sums are for payment of the Operator's indirect expenses and are in addition to the reimbursement of direct expenses paid thereto. |
| Total actual expense rate on the petroleum asset level | 101% | |
| The share of the holders of equity interests of the Partnership in the petroleum asset expenses (indirect holdings) | 45.34% | |
| Total actual share of the holders of the equity interests of the Partnership, in the expenses, on the petroleum asset level (and prior to other payments on the Partnership level) | 45.79%-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% | The Partnership pays management fees to the General Partner, that are comprised of a fixed amount and a variable amount that is calculated from the exploration expenses (for details see Section (b)7 of Regulation 21 in Chapter D of this report). Such amounts were not taken into account in this table. |

7.4.9. Fees and payments paid during exploration activity at the petroleum asset (in Dollars in thousands)[137]

| 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 2016 | Approx. 37,256 | Approx. (102) | Approx. 460 |
| Budget actually invested in 2017 | Approx. 425,163 | Approx. (20) | Approx. 4,007 |
| Budget actually invested in 2018 | Approx. 703,224 | - | Approx. 6,865 |

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

According to a report received by the Partnership from NSAI, part of the resources at the Leviathan reservoir are classified as reserves and part are classified as contingent resources. Therefore, the NSAI report includes two parts, as specified below.
It is noted that there has been no material change in the appraisal of the gas and condensate quantities in the Leviathan reservoir in the current resource and reserve report compared with the previous resource report.

- A report on reserves which are "Approved for Development". Discounted cash flow figures in respect of such reserves are presented in Section 7.4.10(a)3 below.

- A report on contingent resources, in which the contingent resources were divided into two categories, referring to each one of the reservoir development phases, as follows:

  1. Phase IA (Phase I – First Stage): Contingent resources which are classified under the "Development Pending" stage. Such resources are conditioned upon decisions to drill additional wells (see Section 7.4.5(b)4 above) and execution of additional natural gas sale agreements. In respect of contingent resources at this phase, discounted cash flow figures are presented in Section 7.4.10(b)4 below.

[137] The costs presented in the table reflect the Partnership's post-Merger holding in the Leviathan Leases, i.e. 45.34%.

For a summary of discounted cash flow figures from reserves and contingent resources in Phase 1A, see Section 7.4.10(b)5 below.

2. Future Developments: Resources that are contingent upon the adoption of additional investment decisions, according to additional stages of development of the Leviathan reservoir (beyond Phase 1A of the development plan of the Leviathan reservoir) and upon the signing of additional natural gas sale agreements.

(a) Resources in the Leviathan reservoir[138]

1. Quantity data

According a report received by the Partnership from NSAI which was prepared according to the SPE-PRMS, as of December 31, 2018 (the "**Reserves Report**"), the reserves of natural gas and condensate in the Leviathan reservoir which are classified as "Approved for Development", are as follows:

[138] For details regarding an estimate of the resources in the Leviathan reservoir performed by the Ministry of Energy, via external advisors, see Section 7.25.5(a) below.

| Reserves Category | Total (100%) at the petroleum asset (Gross) | | Total Rate Attributable to the Holders of the Equity Interests of the Partnership (Net)[139] | |
|---|---|---|---|---|
| | **Natural Gas BCF** | **Condensate Million Barrels** | **Natural Gas BCF** | **Condensate Million Barrels** |
| Proved Reserves 1P | 9,425.8 | 16.9 | 3,365.5 | 6.0 |
| Probable Reserves | 3,959.4 | 7.1 | 1,400.2 | 2.5 |
| Total 2P Type Reserves (Proved + Probable Reserves) | 13,385.1 | 24.0 | 4,765.7 | 8.5 |
| Possible Reserves | 819.1 | 1.5 | 289.7 | 0.5 |
| Total 3P Type Reserves (Proved + Probable + Possible Reserves) | 14,204.3 | 25.6 | 5,055.4 | 9.0 |

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

2. In the report, NSAI noted, among other things, several assumptions and reservations, including that: (a) as is common practice in reserve evaluation under the rules of SPE-PRMS, the estimations are not adjusted to reflect risks, such as technical and commercial risks and development risks; (b) NSAI did not visit the oil field and did not examine the mechanical operation of the facilities and wells or their condition; (c) NSAI did not examine possible exposure stemming from environmental protection issues. However, NSAI noted that, as of the date of the Reserves Report, it is not aware of a possible liability pertaining to environmental protection issues, which might materially affect the estimated quantity of reserves in the Reserves Report or the commerciality thereof; (d) NSAI assumed that the reservoirs are

[139] The Reserves Report does not state the Partnership's net share, but rather the Partnership's gross share. The Partnership's net share in the above table is after payment of royalties and assuming investment recovery after the sale of a total amount (in respect of 100% of the rights in the petroleum asset) of approx. 1,416 BCF and approx. 2.5 million barrels of condensate from Phase 1A (the "**Investment Recovery Date**"). Since the Investment Recovery Date is affected by gas and/or condensate prices, the production rate, production and development costs and the royalties rate, and since additional natural gas sale agreements are expected to be signed, it is possible that the total amount of natural gas and/or condensate to be sold by the Investment Recovery Date will materially differ from the aforesaid. The calculation of the rate attributed to the holders of the Partnership's equity interests before and after the Investment Recovery Date was performed in accordance with the rates set forth in Section 7.4.7 above.

developed according to the development plan, will be reasonably operated and that its forecasts with respect to future production will be similar to the actual functioning of the reservoirs; (e) the reserves are located in a site that has not yet been developed and thus the evaluations are based on an estimate of reservoir volume and recovery efficiencies, in analogy to reservoirs of similar geological and engineering features.

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

3. <u>Discounted cash flow data</u>

With respect to the discounted cash flow calculation specified below, it is noted as follows: (a) The discounted cash flow was calculated based on a weighted average of the gas prices according to the price formulas in existing agreements for the sale of natural gas from the Leviathan reservoir, according to the Partnership's assumptions as to sales in future natural gas sale agreements, and according to the price formulas pursuant to the provisions of the Gas Framework, which include, *inter alia,* full or partial linkage to the Electricity Production Tariff, as may change over the years, to the ILS/U.S. dollar exchange rate or to the Brent oil barrel price, and according to a market breakdown according to demand forecasts that were received from independent consulting companies. The price under the Leviathan-Dolphinus Export Agreement (as defined below) (for details, see Section 7.13.5(b)2 below) was adjusted to the point of delivery as determined in the agreement. The information with respect to such gas prices was provided to NSAI by the Partnership; (b) The demand forecast in the local market in Israel, which was used in order to assess the scope of the forecasted future natural gas sales in the domestic market in Israel, was performed by an external consultant, BDO Consulting Group; (c) The discounted cash flow was calculated based on the condensate price which is based on Brent Crude prices; (d) For the purpose of calculation of the Brent price, use was made of the average of the oil price forecasts by third parties that provide long-term price forecasts, including the World Bank and others, for the NYMEX ICE Brent Crude price and adjusted to quality differences, transport costs and the price for which condensate is sold in the region[140]; (e) The operating costs taken into account are costs provided to NSAI by the Partnership. Such costs include direct costs at the project level, insurance costs, production well maintenance costs and estimated G&A and overhead expenses of the operator, which may be directly attributed to the project and together represent the project's operating costs. These costs are divided into expenses at the field level and expenses per output unit. The operation costs that were provided to NSAI by the Partnership are deemed reasonable thereby, based, *inter alia*, on the development plan for the project and NSAI's prior knowledge from similar projects. Such costs are not adjusted to inflation changes; (f) The capital expenditures taken into account for the purpose of preparing the discounted cash flow from reserves are the expenditures approved by the Partnership in the context of the investment decision (FID) as specified in Section 7.4.5 above, plus engineering work expenses, insurance expenses, administrative costs and indirect costs paid to the Operator. The amount of capital expenditures taken into account for the purpose of preparing the discounted cash flow from the contingent resources exceeds the costs approved by the Partnership and it also includes an estimate of future capital expenditures that may be required for the drilling of new wells, additional production equipment and various engineering activities, and are over and above the expenditures as included in

[140] For the purpose of calculating the price forecast, the following data were assumed: (1) a Brent barrel price of $68.3 per barrel in 2020, rising to approx. $81.8 per barrel in 2025, and a 2% rise per annum in the years after the end of the forecasts; (3) a forecast of the Electricity Production Tariff based, *inter alia*, on an average exchange rate for the discounted cash flow period of approx. ILS 4.0 to the dollar.

the budget for the development of Phase 1A of the Leviathan project development plan, plus insurance expenses, administrative costs and indirect costs paid to the Operator. In addition, a capital payment by the Leviathan Partners in respect of the piping of natural gas through the EMG Pipeline was assumed (for details see Section 7.27.7(f)). The capital expenditures provided to NSAI by the Partnership are deemed reasonable thereby, based, *inter alia*, on the development plan for the project and on NSAI's prior knowledge from similar projects. These costs are not adjusted to inflation changes; (g) The abandonment costs taken into account are costs provided to NSAI by the Partnership, in accordance with its estimations of the cost of abandonment of the wells, platforms and production facilities insofar as the project will end in 2064, and that in such year the wells will be sealed and the project will be shut down, but this may not necessarily be the case (the current expiration date of the leases is February 13, 2044). These costs do not take into account the salvage value of the facilities in the Leviathan Lease and are not adjusted to inflation changes; (h) The tax calculations take into account corporate tax rates in accordance with the law. Tax payments and their rate, which are included within the discounted cash flow, were calculated from the perspective of the holder of the Partnership's Participation Units, which is a company holding the Partnership's Participation Units since the project's launch date. It is noted that tax payments to be actually paid by the Partnership in the future on account of the tax payable by the holders of the Partnership's Participation Units in each of the relevant tax years, under the provisions of the Taxation of Profits from Natural Resources Law (in this Section: the "**Law**"), may materially differ; (i) The actual production rate for each of the above specified resource categories, may be higher or lower than the production rate employed for the purpose of estimating the discounted cash flow. Moreover, NSAI did not conduct a sensitivity analysis with respect to the wells' production rate; (j) The discounted cash flow assumes projected quantities for sale in each of the project's years based on the production capacity from the Leviathan reservoir in Phase 1A, estimations with respect to the scope of the demand in the domestic market in each of the project's years, while referring to the projected supply of natural gas from additional reservoirs (including the Tamar, Karish and Tanin reservoirs[141]) and the scope of demands in the

[141] According to the valuation regarding the profit from the sale of the Partnership's rights in the Tanin and Karish Leases, which the Partnership received in March, 2018, the working premise is that natural gas sales to the local

domestic markets, according to the Partnership's estimates which are based on demand forecasts of independent consulting companies. It is noted that Phase 1A does not include future sales in the context of additional development stages of the Leviathan project for the sale of natural gas from contingent resources that were classified above under the "Future Development" category, including sales to ELNG's liquefaction plant which is operated by Shell in Egypt, as specified in Section 7.13.5(b)3 hereof, future sales to the Turkish market, and designated sales via LNG plants, if and to the extent constructed, to additional target markets; (k) The calculation of the discounted cash flow takes into account revenues from the export of gas to the Jordanian market and to the Egyptian domestic market, as of the commencement of production at the Leviathan reservoir, *inter alia*, based on the agreement for the export of natural gas from the Leviathan project to the Jordanian National Electric Power Company Limited (NEPCO), as detailed in Section 7.13.5(b)1 below and an agreement for the export of natural gas from the Leviathan project to Dolphinus, as specified in Section 7.13.5(b)2 below; (l) The calculation of the discounted cash flow takes into account the Partnership's estimate with respect to the actual rate of royalties to the State, at a rate of 11.5%, and of actual royalties to related parties and third parties at a rate of 4.14% prior to the Investment Recovery Date and 8.74% after such date. The actual rate of such royalties is not final and may change. For details with respect to a dispute with the State regarding the State's royalties from the Tamar project, see Section 7.28.2 below; (m) The discounted cash flow calculation also takes into account the petroleum profit levy, which applies to the Partnership under the provisions of the Law. It should be stressed that calculations of the levy were made according to the definitions, formulas and mechanisms defined in the Law, as understood and interpreted by the Partnership, which were reflected in the reports of the Leviathan venture to the Tax Authority. 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. It is noted that, as of the date of release of this report, several interpretive disagreements are being clarified with respect to the implementation of the Law in the reports

market in Israel and commercial production from the Karish reservoir shall commence in 2022, and from the Tanin Reservoir – in 2033, and that the annual scope of the sales from these reservoirs shall be approx. 4 BCM per year.

of the Leviathan venture to the Tax Authority, in the framework of the objection and appeal proceedings prescribed by the Law. The issues to which the disagreements pertain have not yet been discussed in the rulings of the Israeli courts. The levy calculations were made in accordance with the decision of the Tax Authority of October 10, 2018 with respect to the consolidation of the ventures which operate in the Leviathan South and Leviathan North leases for the purpose of the Law. Furthermore, the calculation was made in Dollars, according to the venture's election under Section 13(b) of the Law, and it took into account, *inter alia*, the following assumptions: all payments of the venture (production costs, investments, royalties, etc.) will be recognized by the Tax Authorities for the purpose of calculating the levy; for the purpose of calculating the venture’s revenues the actual gas sale prices will be taken into account.

<u>It is noted that the discounted cash flow changed relative to the discounted cash flow published in the periodic report for 2017 for the following main reasons:</u>

a. Updates were performed to both the investments that were made until the date of release of this report and to the schedule of the expected cost of development of Phase 1A of the Development Plan (including an update to the date of performance of future drillings relative to the data of the discounted cash flow from contingent resources), in accordance with updated estimates received from the operator. It is clarified that there was no material change in the budget for development of phase 1A of the Development Plan as the same was approved.

b. Due to the update in the Electricity Production Tariff, the forecasts of the Electricity Production Tariff, ILS/USD exchange rate, Brent barrel price and other forecasts, the forecasts of the relevant sale prices that are linked thereto were updated.

c. The volume of sales of natural gas from the Leviathan project were updated, *inter alia*, due to an update of the Partnership’s estimations of the volume of sales from Leviathan. This, combined with developments in the domestic and regional markets, have led to growth in the projected annual sale quantities from the Leviathan reservoir in some of the scenarios.

d. A capital payment by the Leviathan Partners in respect of the piping of natural gas through the EMG Pipeline was assumed (for details, see Section 7.27.7(f)).

In accordance with various assumptions, the main ones of which are specified above, set forth below is an estimate of the discounted cash flow as of December 31, 2018 in dollars in thousands (exclusive of levy and income tax), attributed to the Partnership's share from the reserves in the Leviathan reservoir for each of the reserve categories specified above:

| Until | Condensate Sales Volume (Barrels in Thousands) (100% of the Petroleum Asset) | Sales Volume (BCM) (100% of the Petroleum Asset) | Revenues | Royalties to be Paid | Royalties to be Received | Operating Costs | Develop-ment Costs | Abandon-ment and Restor-ation 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 10% | Discounted at 15% | Discounted at 20% |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Total discounted cash flow from 1P proved reserves as of December 31, 2018 (in Dollars in thousands in respect of the Partnership's share)** | | | | | | | | | | | | | | | | |
| **Cash flow components** | | | | | | | | | | | | | | | | |
| **31.12.2019** | - | - | - | - | - | - | 707,614 | - | (707,614) | - | - | (707,614) | (690,561) | (674,684) | (659,854) | (645,960) |
| **31.12.2020** | 320 | 5.05 | 481,758 | 75,347 | - | 70,655 | 37,458 | - | 298,298 | - | - | 298,298 | 277,246 | 258,560 | 241,882 | 226,923 |
| **31.12.2021** | 339 | 5.35 | 523,722 | 81,910 | - | 70,987 | - | - | 370,824 | - | 20,265 | 350,560 | 310,305 | 276,236 | 247,182 | 222,233 |
| **31.12.2022** | 411 | 6.47 | 621,128 | 97,144 | - | 71,888 | - | - | 452,095 | - | 59,288 | 392,808 | 331,144 | 281,388 | 240,845 | 207,513 |
| **31.12.2023** | 411 | 6.47 | 628,911 | 98,362 | - | 66,788 | - | - | 463,761 | - | 61,971 | 401,790 | 322,587 | 261,657 | 214,219 | 176,882 |
| **31.12.2024** | 412 | 6.49 | 634,905 | 99,299 | - | 66,828 | - | - | 468,778 | - | 63,125 | 405,653 | 310,180 | 240,157 | 188,069 | 148,819 |
| **31.12.2025** | 411 | 6.47 | 638,086 | 99,797 | - | 66,841 | - | - | 471,448 | - | 63,739 | 407,709 | 296,907 | 219,431 | 164,367 | 124,644 |
| **31.12.2026** | 411 | 6.47 | 645,481 | 100,953 | - | 66,884 | - | - | 477,644 | - | 65,164 | 412,480 | 286,077 | 201,817 | 144,600 | 105,086 |
| **31.12.2027** | 411 | 6.47 | 657,319 | 129,369 | - | 66,952 | - | - | 460,999 | - | 61,336 | 399,663 | 263,989 | 177,769 | 121,832 | 84,850 |
| **31.12.2028** | 412 | 6.49 | 672,344 | 136,082 | - | 67,044 | - | - | 469,218 | - | 63,226 | 405,992 | 255,399 | 164,167 | 107,619 | 71,828 |
| **31.12.2029** | 411 | 6.47 | 680,950 | 137,824 | - | 87,695 | - | - | 455,431 | 67,091 | 44,624 | 343,715 | 205,926 | 126,350 | 79,227 | 50,675 |
| **31.12.2030** | 411 | 6.48 | 691,198 | 139,899 | - | 67,149 | - | - | 484,151 | 129,206 | 81,207 | 273,739 | 156,192 | 91,479 | 54,867 | 33,632 |
| **31.12.2031** | 411 | 6.47 | 703,193 | 142,326 | - | 67,216 | - | - | 493,651 | 155,734 | 77,721 | 260,196 | 141,395 | 79,048 | 45,350 | 26,640 |
| **31.12.2032** | 412 | 6.49 | 718,822 | 145,490 | - | 67,311 | - | - | 506,021 | 181,704 | 74,593 | 249,724 | 129,243 | 68,970 | 37,848 | 21,307 |

| Total discounted cash flow from 1P proved reserves as of December 31, 2018 (in Dollars in thousands in respect of the Partnership's share) | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cash flow components | | | | | | | | | | | | | | | | | |
| Until | Condensate Sales Volume (Barrels in Thousands) (100% of the Petroleum Asset) | Sales Volume (BCM) (100% of the Petroleum Asset) | Revenues | Royalties to be Paid | Royalties to be Received | Operating Costs | Develop-ment Costs | Abandon-ment and Restor-ation 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 10% | Discounted at 15% | Discounted at 20% |
| **31.12.2033** | 411 | 6.47 | 731,428 | 148,041 | - | 67,379 | - | - | 516,008 | 206,369 | 71,217 | 238,422 | 117,517 | 59,862 | 31,422 | 16,952 |
| **31.12.2034** | 411 | 6.47 | 742,689 | 150,320 | - | 88,051 | - | - | 504,319 | 220,323 | 65,319 | 218,676 | 102,652 | 49,913 | 25,060 | 12,957 |
| **31.12.2035** | 411 | 6.47 | 755,328 | 152,878 | - | 67,516 | - | - | 534,933 | 248,938 | 65,779 | 220,216 | 98,452 | 45,695 | 21,945 | 10,873 |
| **31.12.2036** | 412 | 6.49 | 768,495 | 155,543 | - | 67,597 | - | - | 545,354 | 255,226 | 66,730 | 223,399 | 95,119 | 42,141 | 19,358 | 9,192 |
| **31.12.2037** | 411 | 6.47 | 777,604 | 157,387 | - | 67,645 | - | - | 552,572 | 258,604 | 67,613 | 226,356 | 91,789 | 38,817 | 17,056 | 7,761 |
| **31.12.2038** | 411 | 6.47 | 790,139 | 159,924 | - | 67,717 | - | - | 562,498 | 263,249 | 68,827 | 230,422 | 88,988 | 35,922 | 15,098 | 6,584 |
| **31.12.2039** | 411 | 6.47 | 800,881 | 162,098 | - | 88,386 | - | - | 550,397 | 257,586 | 67,347 | 225,465 | 82,927 | 31,954 | 12,846 | 5,369 |
| **31.12.2040** | 412 | 6.49 | 813,962 | 164,746 | - | 67,859 | - | - | 581,357 | 272,075 | 71,135 | 238,147 | 83,421 | 30,683 | 11,799 | 4,726 |
| **31.12.2041** | 411 | 6.47 | 825,466 | 167,074 | - | 67,920 | - | - | 590,471 | 276,340 | 72,250 | 241,881 | 80,694 | 28,331 | 10,421 | 4,000 |
| **31.12.2042** | 411 | 6.47 | 838,506 | 169,714 | - | 67,995 | - | - | 600,797 | 281,173 | 73,514 | 246,110 | 78,195 | 26,206 | 9,220 | 3,391 |
| **31.12.2043** | 411 | 6.47 | 851,718 | 172,388 | - | 68,071 | - | - | 611,259 | 286,069 | 74,794 | 250,396 | 75,769 | 24,239 | 8,157 | 2,875 |
| **31.12.2044** | 412 | 6.49 | 867,155 | 175,512 | - | 88,773 | - | - | 602,870 | 282,143 | 73,767 | 246,960 | 71,170 | 21,733 | 6,996 | 2,363 |
| **31.12.2045** | 411 | 6.47 | 878,721 | 177,853 | - | 68,227 | - | - | 632,641 | 296,076 | 77,410 | 259,155 | 71,128 | 20,733 | 6,384 | 2,067 |
| **31.12.2046** | 411 | 6.47 | 892,563 | 180,655 | - | 68,307 | - | - | 643,601 | 301,205 | 78,751 | 263,645 | 68,915 | 19,174 | 5,647 | 1,752 |

| **Total discounted cash flow from 1P proved reserves as of December 31, 2018 (in Dollars in thousands in respect of the Partnership's share)** | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Cash flow components** | | | | | | | | | | | | | | | | |
| **Until** | **Condensate Sales Volume (Barrels in Thousands) (100% of the Petroleum Asset)** | **Sales Volume (BCM) (100% of the Petroleum Asset)** | **Revenues** | **Royalties to be Paid** | **Royalties to be Received** | **Operating Costs** | **Develop-ment Costs** | **Abandon-ment and Restor-ation 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 10%** | **Discounted at 15%** | **Discounted at 20%** |
| **31.12.2047** | 411 | 6.47 | 906,324 | 183,440 | - | 68,386 | - | - | 654,498 | 306,305 | 80,084 | 268,109 | 66,745 | 17,726 | 4,994 | 1,485 |
| **31.12.2048** | 412 | 6.49 | 922,271 | 186,668 | - | 68,483 | - | - | 667,120 | 312,212 | 81,629 | 273,279 | 64,792 | 16,426 | 4,426 | 1,261 |
| **31.12.2049** | 411 | 6.47 | 934,149 | 189,072 | - | 89,153 | - | - | 655,924 | 306,972 | 80,259 | 268,693 | 60,671 | 14,682 | 3,784 | 1,033 |
| **31.12.2050** | 411 | 6.47 | 948,343 | 191,945 | - | 68,628 | - | - | 687,770 | 321,877 | 84,156 | 281,738 | 60,587 | 13,995 | 3,450 | 903 |
| **31.12.2051** | 396 | 6.24 | 932,007 | 188,638 | - | 68,463 | - | - | 674,906 | 315,856 | 82,581 | 276,468 | 56,623 | 12,485 | 2,944 | 738 |
| **31.12.2052** | 367 | 5.79 | 881,250 | 178,365 | - | 68,034 | - | - | 634,851 | 297,110 | 77,680 | 260,060 | 50,726 | 10,676 | 2,408 | 579 |
| **31.12.2053** | 343 | 5.41 | 837,853 | 169,581 | - | 67,670 | - | - | 600,601 | 281,081 | 73,490 | 246,030 | 45,704 | 9,182 | 1,981 | 456 |
| **31.12.2054** | 337 | 5.31 | 831,257 | 168,246 | - | 88,210 | - | - | 574,800 | 269,006 | 70,333 | 235,461 | 41,658 | 7,989 | 1,649 | 364 |
| **31.12.2055** | 334 | 5.26 | 830,081 | 168,008 | - | 67,581 | - | - | 594,492 | 278,222 | 72,742 | 243,528 | 41,034 | 7,511 | 1,483 | 314 |
| **31.12.2056** | 331 | 5.22 | 830,833 | 168,161 | - | 67,573 | - | - | 595,099 | 278,506 | 72,816 | 243,776 | 39,119 | 6,835 | 1,291 | 262 |
| **31.12.2057** | 327 | 5.15 | 827,456 | 167,477 | - | 67,533 | - | - | 592,445 | 277,264 | 72,492 | 242,689 | 37,091 | 6,186 | 1,117 | 217 |
| **31.12.2058** | 323 | 5.10 | 825,553 | 167,092 | - | 67,506 | - | - | 590,955 | 276,567 | 72,309 | 242,079 | 35,235 | 5,610 | 969 | 180 |
| **31.12.2059** | 320 | 5.04 | 823,453 | 166,667 | - | 88,084 | - | - | 568,702 | 266,153 | 69,586 | 232,963 | 32,294 | 4,908 | 811 | 145 |
| **31.12.2060** | 317 | 5.00 | 823,172 | 166,610 | - | 67,462 | - | - | 589,100 | 275,699 | 72,082 | 241,319 | 31,859 | 4,622 | 731 | 125 |

| Total discounted cash flow from 1P proved reserves as of December 31, 2018 (in Dollars in thousands in respect of the Partnership's share) | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cash flow components | | | | | | | | | | | | | | | | | |
| Until | Condensate Sales Volume (Barrels in Thousands) (100% of the Petroleum Asset) | Sales Volume (BCM) (100% of the Petroleum Asset) | Revenues | Royalties to be Paid | Royalties to be Received | Operating Costs | Develop-ment Costs | Abandon-ment and Restor-ation 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 10% | Discounted at 15% | Discounted at 20% |
| **31.12.2061** | 313 | 4.93 | 818,474 | 165,659 | - | 67,414 | - | - | 585,401 | 273,968 | 71,630 | 239,804 | 30,152 | 4,175 | 631 | 103 |
| **31.12.2062** | 309 | 4.87 | 815,317 | 165,020 | - | 67,378 | - | - | 582,919 | 272,806 | 66,681 | 243,432 | 29,150 | 3,853 | 557 | 87 |
| **31.12.2063** | 304 | 4.80 | 810,461 | 164,037 | - | 67,329 | - | - | 579,094 | 271,016 | 66,213 | 241,865 | 27,584 | 3,480 | 481 | 72 |
| **31.12.2064** | 35 | 0.56 | 94,903 | 19,208 | - | 61,929 | - | 60,592 | (46,827) | - | - | (46,827) | (5,086) | (613) | (81) | (12) |
| **Total** | **16,929** | **266.9** | **34,325,628** | **6,751,831** | - | **3,192,497** | **745,072** | **60,592** | **23,575,635** | **9,119,734** | **2,997,470** | **11,458,431** | **4,548,707** | **2,397,479** | **1,463,089** | **954,247** |

**Total discounted cash flow from probable reserves as of December 31, 2018 (in Dollars in thousands in respect of the Partnership's share)**

**Cash flow components**

| Until | Condensate Sales Volume (Barrels in Thousands) (100% of the Petroleum Asset) | Sales Volume (BCM) (100% of the Petroleum Asset) | Revenues | Royalties to be Paid | Royalties to be Received | Operating Costs | Develop-ment Costs | Abandon-ment and Restor-ation 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 10% | Discounted at 15% | Discounted at 20% |
| **31.12.2019** | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **31.12.2020** | 314 | 4.95 | 421,419 | 65,910 | - | 3,920 | - | - | 351,589 | - | 60,535 | 291,055 | 270,515 | 252,282 | 236,009 | 221,413 |
| **31.12.2021** | 325 | 5.12 | 466,777 | 73,004 | - | 4,233 | - | - | 389,540 | - | 109,925 | 279,615 | 247,506 | 220,332 | 197,158 | 177,258 |
| **31.12.2022** | 188 | 2.97 | 306,310 | 47,907 | - | 2,660 | - | - | 255,743 | - | 58,821 | 196,922 | 166,009 | 141,065 | 120,740 | 104,030 |
| **31.12.2023** | 256 | 4.04 | 407,837 | 65,291 | - | 3,568 | - | - | 338,978 | - | 77,965 | 261,013 | 209,561 | 169,979 | 139,163 | 114,907 |
| **31.12.2024** | 330 | 5.20 | 524,005 | 135,264 | - | 4,585 | - | - | 384,155 | - | 88,356 | 295,800 | 226,181 | 175,121 | 137,138 | 108,518 |
| **31.12.2025** | 284 | 4.49 | 456,243 | 121,695 | - | 3,981 | - | - | 330,567 | 165,561 | 37,951 | 127,054 | 92,525 | 68,381 | 51,222 | 38,843 |
| **31.12.2026** | 250 | 3.94 | 417,007 | 114,094 | - | 3,591 | - | - | 299,322 | 260,134 | 9,013 | 30,175 | 20,928 | 14,764 | 10,578 | 7,688 |
| **31.12.2027** | 229 | 3.60 | 395,403 | 83,702 | - | 3,364 | - | - | 308,337 | 315,131 | (1,563) | (5,231) | (3,455) | (2,327) | (1,595) | (1,111) |
| **31.12.2028** | 220 | 3.47 | 390,095 | 78,955 | - | 3,292 | - | - | 307,847 | 359,656 | (11,916) | (39,892) | (25,095) | (16,131) | (10,575) | (7,058) |
| **31.12.2029** | 212 | 3.34 | 380,771 | 77,068 | - | 3,201 | - | - | 300,502 | 286,685 | 3,178 | 10,639 | 6,374 | 3,911 | 2,452 | 1,569 |
| **31.12.2030** | 204 | 3.21 | 372,243 | 75,342 | - | 3,112 | - | - | 293,789 | 234,871 | 13,551 | 45,367 | 25,886 | 15,161 | 9,093 | 5,574 |
| **31.12.2031** | 194 | 3.06 | 362,896 | 73,450 | - | 3,014 | - | - | 286,432 | 209,345 | 17,730 | 59,357 | 32,256 | 18,033 | 10,345 | 6,077 |

| Total discounted cash flow from probable reserves as of December 31, 2018 (in Dollars in thousands in respect of the Partnership's share) | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cash flow components | | | | | | | | | | | | | | | | |
| Until | Condensate Sales Volume (Barrels in Thousands) (100% of the Petroleum Asset) | Sales Volume (BCM) (100% of the Petroleum Asset) | Revenues | Royalties to be Paid | Royalties to be Received | Operating Costs | Develop-ment Costs | Abandon-ment and Restor-ation 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 10% | Discounted at 15% | Discounted at 20% |
| **31.12.2032** | 182 | 2.87 | 348,622 | 70,561 | - | 2,875 | - | - | 275,186 | 183,901 | 20,996 | 70,289 | 36,378 | 19,413 | 10,653 | 5,997 |
| **31.12.2033** | 167 | 2.64 | 329,165 | 66,623 | - | 2,692 | - | - | 259,850 | 156,733 | 23,717 | 79,401 | 39,136 | 19,936 | 10,464 | 5,645 |
| **31.12.2034** | 154 | 2.43 | 315,073 | 63,771 | - | 2,546 | - | - | 248,756 | 132,116 | 26,827 | 89,813 | 42,160 | 20,500 | 10,293 | 5,321 |
| **31.12.2035** | 142 | 2.24 | 315,237 | 63,804 | - | 2,492 | - | - | 248,941 | 117,915 | 30,136 | 100,890 | 45,105 | 20,935 | 10,054 | 4,981 |
| **31.12.2036** | 132 | 2.07 | 299,326 | 60,584 | - | 2,350 | - | - | 236,393 | 110,632 | 28,925 | 96,836 | 41,231 | 18,267 | 8,391 | 3,984 |
| **31.12.2037** | 119 | 1.88 | 272,792 | 55,213 | - | 2,139 | - | - | 215,440 | 100,826 | 26,361 | 88,253 | 35,787 | 15,134 | 6,650 | 3,026 |
| **31.12.2038** | 114 | 1.80 | 183,840 | 37,209 | - | 1,600 | - | - | 145,031 | 67,874 | 17,746 | 59,410 | 22,944 | 9,262 | 3,893 | 1,698 |
| **31.12.2039** | 114 | 1.80 | 186,886 | 37,826 | - | 1,618 | - | - | 147,442 | 69,003 | 18,041 | 60,398 | 22,215 | 8,560 | 3,441 | 1,438 |
| **31.12.2040** | 114 | 1.80 | 189,967 | 38,449 | - | 1,637 | - | - | 149,881 | 70,144 | 18,339 | 61,397 | 21,507 | 7,911 | 3,042 | 1,218 |
| **31.12.2041** | 114 | 1.80 | 192,891 | 39,041 | - | 1,652 | - | - | 152,197 | 71,228 | 18,623 | 62,346 | 20,799 | 7,303 | 2,686 | 1,031 |
| **31.12.2042** | 114 | 1.80 | 196,531 | 39,778 | - | 1,673 | - | - | 155,080 | 72,577 | 18,976 | 63,527 | 20,184 | 6,764 | 2,380 | 875 |
| **31.12.2043** | 114 | 1.80 | 200,210 | 40,522 | - | 1,695 | - | - | 157,993 | 73,941 | 19,332 | 64,720 | 19,584 | 6,265 | 2,108 | 743 |
| **31.12.2044** | 114 | 1.80 | 204,527 | 41,396 | - | 1,721 | - | - | 161,410 | 75,540 | 19,750 | 66,120 | 19,055 | 5,819 | 1,873 | 633 |

| Total discounted cash flow from probable reserves as of December 31, 2018 (in Dollars in thousands in respect of the Partnership's share) | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cash flow components | | | | | | | | | | | | | | | | |
| Until | Condensate Sales Volume (Barrels in Thousands) (100% of the Petroleum Asset) | Sales Volume (BCM) (100% of the Petroleum Asset) | Revenues | Royalties to be Paid | Royalties to be Received | Operating Costs | Develop-ment Costs | Abandon-ment and Restor-ation 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 10% | Discounted at 15% | Discounted at 20% |
| 31.12.2045 | 113 | 1.77 | 205,416 | 41,576 | - | 1,718 | - | - | 162,121 | 75,873 | 19,837 | 66,411 | 18,227 | 5,313 | 1,636 | 530 |
| 31.12.2046 | 110 | 1.73 | 204,294 | 41,349 | - | 1,699 | - | - | 161,245 | 75,463 | 19,730 | 66,053 | 17,266 | 4,804 | 1,415 | 439 |
| 31.12.2047 | 106 | 1.68 | 201,231 | 40,729 | - | 1,665 | - | - | 158,837 | 74,336 | 19,435 | 65,066 | 16,198 | 4,302 | 1,212 | 360 |
| 31.12.2048 | 102 | 1.60 | 195,758 | 39,621 | - | 1,611 | - | - | 154,525 | 72,318 | 18,908 | 63,300 | 15,008 | 3,805 | 1,025 | 292 |
| 31.12.2049 | 97 | 1.52 | 189,463 | 38,347 | - | 1,551 | - | - | 149,565 | 69,996 | 18,301 | 61,268 | 13,834 | 3,348 | 863 | 236 |
| 31.12.2050 | 92 | 1.45 | 183,598 | 37,160 | - | 1,495 | - | - | 144,942 | 67,833 | 17,735 | 59,374 | 12,768 | 2,949 | 727 | 190 |
| 31.12.2051 | 103 | 1.62 | 208,067 | 42,113 | - | 1,686 | - | - | 164,269 | 76,878 | 20,100 | 67,291 | 13,782 | 3,039 | 717 | 180 |
| 31.12.2052 | 128 | 2.02 | 264,448 | 53,524 | - | 2,132 | - | - | 208,792 | 97,715 | 25,548 | 85,529 | 16,683 | 3,511 | 792 | 190 |
| 31.12.2053 | 146 | 2.31 | 307,526 | 62,243 | - | 2,467 | - | - | 242,815 | 113,638 | 29,711 | 99,467 | 18,478 | 3,712 | 801 | 184 |
| 31.12.2054 | 148 | 2.33 | 316,517 | 64,063 | - | 2,527 | - | - | 249,927 | 116,966 | 30,581 | 102,380 | 18,113 | 3,474 | 717 | 158 |
| 31.12.2055 | 147 | 2.32 | 319,970 | 64,762 | - | 2,543 | - | - | 252,666 | 118,248 | 30,916 | 103,502 | 17,440 | 3,192 | 630 | 133 |
| 31.12.2056 | 146 | 2.31 | 324,175 | 65,613 | - | 2,564 | - | - | 255,999 | 119,807 | 31,324 | 104,867 | 16,828 | 2,940 | 555 | 113 |
| 31.12.2057 | 145 | 2.28 | 325,825 | 65,947 | - | 2,565 | - | - | 257,313 | 120,422 | 31,485 | 105,406 | 16,109 | 2,687 | 485 | 94 |

| Total discounted cash flow from probable reserves as of December 31, 2018 (in Dollars in thousands in respect of the Partnership's share) | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cash flow components | | | | | | | | | | | | | | | | |
| Until | Condensate Sales Volume (Barrels in Thousands) (100% of the Petroleum Asset) | Sales Volume (BCM) (100% of the Petroleum Asset) | Revenues | Royalties to be Paid | Royalties to be Received | Operating Costs | Develop-ment Costs | Abandon-ment and Restor-ation 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 10% | Discounted at 15% | Discounted at 20% |
| **31.12.2058** | 143 | 2.25 | 327,248 | 66,235 | - | 2,564 | - | - | 258,449 | 120,954 | 31,624 | 105,871 | 15,410 | 2,453 | 424 | 79 |
| **31.12.2059** | 139 | 2.20 | 324,724 | 65,724 | - | 2,532 | - | - | 256,468 | 120,027 | 31,381 | 105,059 | 14,564 | 2,213 | 366 | 65 |
| **31.12.2060** | 136 | 2.15 | 323,359 | 65,448 | - | 2,510 | - | - | 255,400 | 119,527 | 31,251 | 104,622 | 13,812 | 2,004 | 317 | 54 |
| **31.12.2061** | 134 | 2.11 | 323,539 | 65,484 | - | 2,500 | - | - | 255,555 | 119,600 | 31,270 | 104,685 | 13,163 | 1,823 | 276 | 45 |
| **31.12.2062** | 132 | 2.08 | 324,820 | 65,744 | - | 2,499 | - | - | 256,577 | 120,078 | 31,395 | 105,104 | 12,586 | 1,664 | 241 | 38 |
| **31.12.2063** | 129 | 2.03 | 322,293 | 65,232 | - | 2,469 | - | - | 254,592 | 119,149 | 31,152 | 104,291 | 11,894 | 1,501 | 208 | 31 |
| **31.12.2064** | 15 | 0.24 | 39,995 | 8,095 | - | 301 | - | - | 31,598 | - | - | 31,598 | 3,432 | 413 | 55 | 8 |
| **Total** | **7,111** | **112.12** | **13,368,341** | **2,725,472** | **-** | **110,811** | **-** | **-** | **10,532,058** | **5,052,639** | **1,252,999** | **4,226,420** | **1,950,871** | **1,285,785** | **991,118** | **817,721** |

| Total discounted cash flow from 2P proved and probable reserves as of December 31, 2018 (in Dollars in thousands in respect of the Partnership's share) | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cash flow components | | | | | | | | | | | | | | | | |
| Until | Condensate Sales Volume (Barrels in Thousands) (100% of the Petroleum Asset) | Sales Volume (BCM) (100% of the Petroleum Asset) | Revenues | Royalties to be Paid | Royalties to be Received | Operating Costs | Develop-ment Costs | Abandon-ment and Restor-ation 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 10% | Discounted at 15% | Discounted at 20% |
| **31.12.2019** | - | - | - | - | - | - | 707,614 | - | (707,614) | - | - | (707,614) | (690,561) | (674,684) | (659,854) | (645,960) |
| **31.12.2020** | 634 | 10.00 | 903,177 | 141,257 | - | 74,575 | 37,458 | - | 649,887 | - | 60,535 | 589,353 | 547,761 | 510,841 | 477,891 | 448,336 |
| **31.12.2021** | 664 | 10.47 | 990,499 | 154,914 | - | 75,221 | - | - | 760,364 | - | 130,190 | 630,174 | 557,812 | 496,568 | 444,341 | 399,492 |
| **31.12.2022** | 599 | 9.44 | 927,438 | 145,051 | - | 74,548 | - | - | 707,839 | - | 118,109 | 589,730 | 497,154 | 422,453 | 361,585 | 311,544 |
| **31.12.2023** | 667 | 10.51 | 1,036,747 | 163,652 | - | 70,356 | - | - | 802,739 | - | 139,936 | 662,803 | 532,149 | 431,636 | 353,382 | 291,789 |
| **31.12.2024** | 741 | 11.69 | 1,158,909 | 234,563 | - | 71,413 | - | - | 852,933 | - | 151,480 | 701,452 | 536,361 | 415,277 | 325,207 | 257,336 |
| **31.12.2025** | 695 | 10.96 | 1,094,329 | 221,492 | - | 70,822 | - | - | 802,015 | 165,561 | 101,690 | 534,763 | 389,432 | 287,812 | 215,589 | 163,487 |
| **31.12.2026** | 661 | 10.42 | 1,062,489 | 215,048 | - | 70,475 | - | - | 776,966 | 260,134 | 74,177 | 442,655 | 307,005 | 216,581 | 155,179 | 112,773 |
| **31.12.2027** | 639 | 10.08 | 1,052,723 | 213,071 | - | 70,316 | - | - | 769,336 | 315,131 | 59,773 | 394,432 | 260,533 | 175,442 | 120,238 | 83,740 |
| **31.12.2028** | 632 | 9.96 | 1,062,440 | 215,038 | - | 70,336 | - | - | 777,066 | 359,656 | 51,310 | 366,100 | 230,304 | 148,037 | 97,044 | 64,771 |
| **31.12.2029** | 622 | 9.81 | 1,061,721 | 214,892 | - | 90,896 | - | - | 755,933 | 353,777 | 47,802 | 354,354 | 212,300 | 130,261 | 81,679 | 52,244 |
| **31.12.2030** | 614 | 9.69 | 1,063,442 | 215,241 | - | 70,260 | - | - | 777,941 | 364,076 | 94,758 | 319,106 | 182,078 | 106,640 | 63,960 | 39,206 |
| **31.12.2031** | 605 | 9.54 | 1,066,089 | 215,776 | - | 70,230 | - | - | 780,083 | 365,079 | 95,451 | 319,553 | 173,651 | 97,081 | 55,696 | 32,717 |

**Total discounted cash flow from 2P proved and probable reserves as of December 31, 2018 (in Dollars in thousands in respect of the Partnership's share)**

**Cash flow components**

| Until | Condensate Sales Volume (Barrels in Thousands) (100% of the Petroleum Asset) | Sales Volume (BCM) (100% of the Petroleum Asset) | Revenues | Royalties to be Paid | Royalties to be Received | Operating Costs | Develop-ment Costs | Abandon-ment and Restor-ation 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 10% | Discounted at 15% | Discounted at 20% |
| **31.12.2032** | 594 | 9.37 | 1,067,445 | 216,051 | - | 70,186 | - | - | 781,207 | 365,605 | 95,589 | 320,014 | 165,620 | 88,383 | 48,501 | 27,304 |
| **31.12.2033** | 578 | 9.11 | 1,060,593 | 214,664 | - | 70,070 | - | - | 775,858 | 363,102 | 94,934 | 317,823 | 156,653 | 79,798 | 41,886 | 22,597 |
| **31.12.2034** | 564 | 8.90 | 1,057,762 | 214,091 | - | 90,597 | - | - | 753,074 | 352,439 | 92,146 | 308,489 | 144,813 | 70,413 | 35,353 | 18,278 |
| **31.12.2035** | 553 | 8.72 | 1,070,565 | 216,682 | - | 70,008 | - | - | 783,874 | 366,853 | 95,915 | 321,106 | 143,557 | 66,630 | 31,999 | 15,855 |
| **31.12.2036** | 543 | 8.57 | 1,067,821 | 216,127 | - | 69,947 | - | - | 781,747 | 365,857 | 95,655 | 320,235 | 136,350 | 60,408 | 27,750 | 13,176 |
| **31.12.2037** | 530 | 8.35 | 1,050,396 | 212,600 | - | 69,783 | - | - | 768,013 | 359,430 | 93,974 | 314,609 | 127,576 | 53,952 | 23,706 | 10,787 |
| **31.12.2038** | 524 | 8.27 | 973,979 | 197,133 | - | 69,317 | - | - | 707,529 | 331,124 | 86,573 | 289,832 | 111,932 | 45,184 | 18,991 | 8,282 |
| **31.12.2039** | 524 | 8.27 | 987,766 | 199,924 | - | 90,004 | - | - | 697,839 | 326,589 | 85,388 | 285,863 | 105,142 | 40,514 | 16,287 | 6,807 |
| **31.12.2040** | 526 | 8.29 | 1,003,929 | 203,195 | - | 69,497 | - | - | 731,238 | 342,219 | 89,474 | 299,544 | 104,928 | 38,594 | 14,841 | 5,944 |
| **31.12.2041** | 524 | 8.27 | 1,018,357 | 206,115 | - | 69,573 | - | - | 742,668 | 347,569 | 90,873 | 304,227 | 101,493 | 35,634 | 13,107 | 5,031 |
| **31.12.2042** | 524 | 8.27 | 1,035,037 | 209,491 | - | 69,669 | - | - | 755,877 | 353,750 | 92,489 | 309,637 | 98,380 | 32,970 | 11,600 | 4,267 |
| **31.12.2043** | 524 | 8.27 | 1,051,928 | 212,910 | - | 69,766 | - | - | 769,252 | 360,010 | 94,126 | 315,116 | 95,353 | 30,504 | 10,265 | 3,619 |
| **31.12.2044** | 526 | 8.29 | 1,071,683 | 216,909 | - | 90,494 | - | - | 764,281 | 357,683 | 93,517 | 313,080 | 90,225 | 27,551 | 8,869 | 2,996 |

| Total discounted cash flow from 2P proved and probable reserves as of December 31, 2018 (in Dollars in thousands in respect of the Partnership's share) | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cash flow components | | | | | | | | | | | | | | | | |
| | | | | | | | | | | Taxes | | Total Discounted Cash Flow After Tax | | | | |
| Until | Condensate Sales Volume (Barrels in Thousands) (100% of the Petroleum Asset) | Sales Volume (BCM) (100% of the Petroleum Asset) | Revenues | Royalties to be Paid | Royalties to be Received | Operating Costs | Develop-ment Costs | Abandon-ment and Restor-ation Costs | Total Cash Flow Before Levy and Income Tax (discounted at 0%) | Levy | Income Tax | Discounted at 0% | Discounted at 5% | Discounted at 10% | Discounted at 15% | Discounted at 20% |
| **31.12.2045** | 523 | 8.25 | 1,084,137 | 219,429 | - | 69,945 | - | - | 794,762 | 371,949 | 97,247 | 325,566 | 89,356 | 26,046 | 8,019 | 2,596 |
| **31.12.2046** | 520 | 8.21 | 1,096,856 | 222,004 | - | 70,006 | - | - | 804,847 | 376,668 | 98,481 | 329,697 | 86,181 | 23,978 | 7,062 | 2,191 |
| **31.12.2047** | 517 | 8.15 | 1,107,555 | 224,169 | - | 70,051 | - | - | 813,335 | 380,641 | 99,520 | 333,175 | 82,942 | 22,028 | 6,206 | 1,845 |
| **31.12.2048** | 513 | 8.09 | 1,118,029 | 226,289 | - | 70,094 | - | - | 821,646 | 384,530 | 100,537 | 336,579 | 79,800 | 20,230 | 5,451 | 1,553 |
| **31.12.2049** | 507 | 8.00 | 1,123,612 | 227,419 | - | 90,704 | - | - | 805,489 | 376,969 | 98,560 | 329,960 | 74,505 | 18,030 | 4,647 | 1,269 |
| **31.12.2050** | 503 | 7.92 | 1,131,941 | 229,105 | - | 70,123 | - | - | 832,713 | 389,710 | 101,891 | 341,112 | 73,356 | 16,944 | 4,177 | 1,093 |
| **31.12.2051** | 498 | 7.85 | 1,140,074 | 230,751 | - | 70,149 | - | - | 839,175 | 392,734 | 102,681 | 343,759 | 70,405 | 15,524 | 3,661 | 918 |
| **31.12.2052** | 495 | 7.81 | 1,145,698 | 231,889 | - | 70,167 | - | - | 843,642 | 394,825 | 103,228 | 345,590 | 67,409 | 14,187 | 3,200 | 769 |
| **31.12.2053** | 489 | 7.72 | 1,145,379 | 231,825 | - | 70,138 | - | - | 843,417 | 394,719 | 103,200 | 345,497 | 64,182 | 12,894 | 2,782 | 641 |
| **31.12.2054** | 485 | 7.65 | 1,147,774 | 232,309 | - | 90,738 | - | - | 824,727 | 385,972 | 100,914 | 337,841 | 59,771 | 11,462 | 2,366 | 522 |
| **31.12.2055** | 481 | 7.58 | 1,150,051 | 232,770 | - | 70,123 | - | - | 847,158 | 396,470 | 103,658 | 347,030 | 58,473 | 10,704 | 2,113 | 447 |
| **31.12.2056** | 478 | 7.53 | 1,155,008 | 233,774 | - | 70,137 | - | - | 851,098 | 398,314 | 104,140 | 348,644 | 55,948 | 9,776 | 1,846 | 374 |
| **31.12.2057** | 471 | 7.43 | 1,153,280 | 233,424 | - | 70,098 | - | - | 849,758 | 397,687 | 103,976 | 348,095 | 53,200 | 8,873 | 1,603 | 311 |

| Total discounted cash flow from 2P proved and probable reserves as of December 31, 2018 (in Dollars in thousands in respect of the Partnership's share) | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cash flow components | | | | | | | | | | | | | | | | |
| Until | Condensate Sales Volume (Barrels in Thousands) (100% of the Petroleum Asset) | Sales Volume (BCM) (100% of the Petroleum Asset) | Revenues | Royalties to be Paid | Royalties to be Received | Operating Costs | Develop-ment Costs | Abandon-ment and Restor-ation 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 10% | Discounted at 15% | Discounted at 20% |
| **31.12.2058** | 466 | 7.35 | 1,152,801 | 233,327 | - | 70,070 | - | - | 849,405 | 397,521 | 103,933 | 347,950 | 50,645 | 8,063 | 1,393 | 259 |
| **31.12.2059** | 459 | 7.24 | 1,148,177 | 232,391 | - | 90,616 | - | - | 825,170 | 386,179 | 100,968 | 338,023 | 46,857 | 7,121 | 1,177 | 210 |
| **31.12.2060** | 453 | 7.15 | 1,146,531 | 232,058 | - | 69,973 | - | - | 844,501 | 395,226 | 103,333 | 345,941 | 45,672 | 6,625 | 1,047 | 179 |
| **31.12.2061** | 446 | 7.04 | 1,142,013 | 231,143 | - | 69,914 | - | - | 840,955 | 393,567 | 102,899 | 344,489 | 43,314 | 5,998 | 907 | 149 |
| **31.12.2062** | 441 | 6.95 | 1,140,137 | 230,764 | - | 69,877 | - | - | 839,496 | 392,884 | 98,075 | 348,537 | 41,736 | 5,517 | 798 | 125 |
| **31.12.2063** | 433 | 6.83 | 1,132,754 | 229,269 | - | 69,798 | - | - | 833,686 | 390,165 | 97,364 | 346,156 | 39,477 | 4,981 | 689 | 104 |
| **31.12.2064** | 50 | 0.80 | 134,898 | 27,303 | - | 62,230 | - | 60,592 | (15,229) | - | - | (15,229) | (1,654) | (199) | (26) | (4) |
| **Total** | **24,040** | **379.0** | **47,693,969** | **9,477,303** | **-** | **3,303,308** | **745,072** | **60,592** | **34,107,693** | **14,172,373** | **4,250,469** | **15,684,851** | **6,499,578** | **3,683,265** | **2,454,207** | **1,771,967** |

| Total discounted cash flow from possible reserves as of _December 31, 2018 (in Dollars in thousands in respect of the Partnership's share) | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cash flow components | | | | | | | | | | | | | | | | |
| Until | Condensate Sales Volume (Barrels in Thousands) (100% of the Petroleum Asset) | Sales Volume (BCM) (100% of the Petroleum Asset) | Revenues | Royalties to be Paid | Royalties to be Received | Operating Costs | Develop-ment Costs | Abandon-ment and Resto-ration 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 10% | Discounted at 15% | Discounted at 20% |
| **31.12.2019** | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **31.12.2020** | 87 | 1.37 | 109,211 | 17,081 | - | 1,043 | - | - | 91,087 | - | 20,950 | 70,137 | 65,187 | 60,794 | 56,872 | 53,355 |
| **31.12.2021** | 99 | 1.56 | 132,076 | 20,657 | - | 1,230 | - | - | 110,190 | - | 25,344 | 84,846 | 75,103 | 66,857 | 59,826 | 53,787 |
| **31.12.2022** | 55 | 0.87 | 70,924 | 11,092 | - | 670 | - | - | 59,162 | - | 13,607 | 45,554 | 38,403 | 32,633 | 27,931 | 24,066 |
| **31.12.2023** | 93 | 1.46 | 140,996 | 46,740 | - | 1,254 | - | - | 93,002 | - | 21,390 | 71,612 | 57,495 | 46,635 | 38,181 | 31,526 |
| **31.12.2024** | 16 | 0.25 | 26,829 | 5,430 | - | 231 | - | - | 21,168 | 63,580 | (9,755) | (32,657) | (24,971) | (19,334) | (15,140) | (11,981) |
| **31.12.2025** | 56 | 0.89 | 91,611 | 18,542 | - | 795 | - | - | 72,273 | 92,298 | (4,606) | (15,419) | (11,229) | (8,299) | (6,216) | (4,714) |
| **31.12.2026** | 72 | 1.14 | 104,993 | 21,251 | - | 949 | - | - | 82,794 | 75,967 | 1,570 | 5,257 | 3,646 | 2,572 | 1,843 | 1,339 |
| **31.12.2027** | 75 | 1.19 | 103,600 | 20,969 | - | 956 | - | - | 81,676 | 74,728 | 1,598 | 5,350 | 3,534 | 2,379 | 1,631 | 1,136 |
| **31.12.2028** | 67 | 1.06 | 92,375 | 18,697 | - | 853 | - | - | 72,826 | 38,093 | 7,988 | 26,744 | 16,824 | 10,814 | 7,089 | 4,732 |
| **31.12.2029** | 56 | 0.88 | 81,622 | 16,520 | - | 736 | - | - | 64,365 | 30,123 | 7,876 | 26,367 | 15,797 | 9,692 | 6,078 | 3,887 |
| **31.12.2030** | 55 | 0.86 | 83,958 | 16,993 | - | 743 | - | - | 66,222 | 30,992 | 8,103 | 27,127 | 15,478 | 9,065 | 5,437 | 3,333 |
| **31.12.2031** | 54 | 0.85 | 88,240 | 17,860 | - | 765 | - | - | 69,615 | 32,580 | 8,518 | 28,517 | 15,497 | 8,664 | 4,970 | 2,920 |
| **31.12.2032** | 61 | 0.96 | 104,127 | 21,075 | - | 889 | - | - | 82,163 | 38,452 | 10,053 | 33,657 | 17,419 | 9,296 | 5,101 | 2,872 |

| Total discounted cash flow from possible reserves as of _December 31, 2018 (in Dollars in thousands in respect of the Partnership's share) | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cash flow components | | | | | | | | | | | | | | | | |
| Until | Condensate Sales Volume (Barrels in Thousands) (100% of the Petroleum Asset) | Sales Volume (BCM) (100% of the Petroleum Asset) | Revenues | Royalties to be Paid | Royalties to be Received | Operating Costs | Develop-ment Costs | Abandon-ment and Resto-ration 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 10% | Discounted at 15% | Discounted at 20% |
| **31.12.2033** | 67 | 1.05 | 119,976 | 24,283 | - | 1,008 | - | - | 94,685 | 44,313 | 11,586 | 38,787 | 19,118 | 9,738 | 5,112 | 2,758 |
| **31.12.2034** | 70 | 1.10 | 127,026 | 25,710 | - | 1,064 | - | - | 100,252 | 46,918 | 12,267 | 41,067 | 19,278 | 9,374 | 4,706 | 2,433 |
| **31.12.2035** | 70 | 1.10 | 118,427 | 23,970 | - | 1,013 | - | - | 93,444 | 43,732 | 11,434 | 38,278 | 17,113 | 7,943 | 3,815 | 1,890 |
| **31.12.2036** | 72 | 1.13 | 127,251 | 25,756 | - | 1,073 | - | - | 100,422 | 46,997 | 12,288 | 41,137 | 17,515 | 7,760 | 3,565 | 1,693 |
| **31.12.2037** | 77 | 1.21 | 136,611 | 27,650 | - | 1,153 | - | - | 107,808 | 50,454 | 13,191 | 44,163 | 17,908 | 7,573 | 3,328 | 1,514 |
| **31.12.2038** | 76 | 1.20 | 122,684 | 24,831 | - | 1,068 | - | - | 96,785 | 45,295 | 11,843 | 39,647 | 15,312 | 6,181 | 2,598 | 1,133 |
| **31.12.2039** | 68 | 1.07 | 110,984 | 22,463 | - | 961 | - | - | 87,560 | 40,978 | 10,714 | 35,868 | 13,193 | 5,083 | 2,044 | 854 |
| **31.12.2040** | 66 | 1.04 | 109,452 | 22,153 | - | 943 | - | - | 86,356 | 40,414 | 10,566 | 35,375 | 12,391 | 4,558 | 1,753 | 702 |
| **31.12.2041** | 63 | 1.00 | 107,113 | 21,680 | - | 918 | - | - | 84,516 | 39,553 | 10,341 | 34,621 | 11,550 | 4,055 | 1,492 | 572 |
| **31.12.2042** | 58 | 0.92 | 100,654 | 20,372 | - | 857 | - | - | 79,425 | 37,171 | 9,718 | 32,536 | 10,337 | 3,464 | 1,219 | 448 |
| **31.12.2043** | 52 | 0.82 | 91,258 | 18,471 | - | 772 | - | - | 72,015 | 33,703 | 8,812 | 29,500 | 8,927 | 2,856 | 961 | 339 |
| **31.12.2044** | 46 | 0.73 | 82,463 | 16,691 | - | 694 | - | - | 65,079 | 30,457 | 7,963 | 26,659 | 7,683 | 2,346 | 755 | 255 |
| **31.12.2045** | 40 | 0.64 | 73,649 | 14,907 | - | 616 | - | - | 58,127 | 27,203 | 7,112 | 23,811 | 6,535 | 1,905 | 587 | 190 |
| **31.12.2046** | 26 | 0.40 | 47,657 | 9,646 | - | 396 | - | - | 37,614 | 17,604 | 4,603 | 15,408 | 4,028 | 1,121 | 330 | 102 |

| Total discounted cash flow from possible reserves as of _December 31, 2018 (in Dollars in thousands in respect of the Partnership's share) | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cash flow components | | | | | | | | | | | | | | | | |
| Until | Condensate Sales Volume (Barrels in Thousands) (100% of the Petroleum Asset) | Sales Volume (BCM) (100% of the Petroleum Asset) | Revenues | Royalties to be Paid | Royalties to be Received | Operating Costs | Develop-ment Costs | Abandon-ment and Resto-ration 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 10% | Discounted at 15% | Discounted at 20% |
| 31.12.2047 | 27 | 0.43 | 51,285 | 10,380 | - | 424 | - | - | 40,480 | 18,945 | 4,953 | 16,582 | 4,128 | 1,096 | 309 | 92 |
| 31.12.2048 | 30 | 0.47 | 57,790 | 11,697 | - | 476 | - | - | 45,618 | 21,349 | 5,582 | 18,687 | 4,430 | 1,123 | 303 | 86 |
| 31.12.2049 | 32 | 0.51 | 63,673 | 12,887 | - | 521 | - | - | 50,264 | 23,524 | 6,150 | 20,590 | 4,649 | 1,125 | 290 | 79 |
| 31.12.2050 | 35 | 0.55 | 69,486 | 14,064 | - | 566 | - | - | 54,856 | 25,673 | 6,712 | 22,471 | 4,832 | 1,116 | 275 | 72 |
| 31.12.2051 | 37 | 0.58 | 75,056 | 15,191 | - | 608 | - | - | 59,256 | 27,732 | 7,251 | 24,274 | 4,971 | 1,096 | 258 | 65 |
| 31.12.2052 | 39 | 0.62 | 80,551 | 16,303 | - | 649 | - | - | 63,598 | 29,764 | 7,782 | 26,052 | 5,082 | 1,070 | 241 | 58 |
| 31.12.2053 | 41 | 0.64 | 85,177 | 17,240 | - | 683 | - | - | 67,254 | 31,475 | 8,229 | 27,550 | 5,118 | 1,028 | 222 | 51 |
| 31.12.2054 | 40 | 0.63 | 85,081 | 17,220 | - | 679 | - | - | 67,181 | 31,441 | 8,220 | 27,520 | 4,869 | 934 | 193 | 43 |
| 31.12.2055 | 11 | 0.18 | 24,534 | 4,966 | - | 195 | - | - | 19,374 | 9,067 | 2,371 | 7,936 | 1,337 | 245 | 48 | 10 |
| 31.12.2056 | (43) | (0.67) | (94,575) | (19,142) | - | (748) | - | - | (74,685) | (34,953) | (9,138) | (30,594) | (4,910) | (858) | (162) | (33) |
| 31.12.2057 | (66) | (1.04) | (148,854) | (30,128) | - | (1,172) | - | - | (117,554) | (55,015) | (14,384) | (48,155) | (7,360) | (1,227) | (222) | (43) |
| 31.12.2058 | (79) | (1.24) | (180,068) | (36,446) | - | (1,411) | - | - | (142,212) | (66,555) | (17,401) | (58,256) | (8,479) | (1,350) | (233) | (43) |
| 31.12.2059 | (77) | (1.22) | (180,607) | (36,555) | - | (1,409) | - | - | (142,644) | (66,757) | (17,454) | (58,433) | (8,100) | (1,231) | (203) | (36) |
| 31.12.2060 | (71) | (1.11) | (167,783) | (33,959) | - | (1,303) | - | - | (132,521) | (62,020) | (16,215) | (54,286) | (7,167) | (1,040) | (164) | (28) |

| Total discounted cash flow from possible reserves as of _December 31, 2018 (in Dollars in thousands in respect of the Partnership's share) | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cash flow components | | | | | | | | | | | | | | | | |
| Until | Condensate Sales Volume (Barrels in Thousands) (100% of the Petroleum Asset) | Sales Volume (BCM) (100% of the Petroleum Asset) | Revenues | Royalties to be Paid | Royalties to be Received | Operating Costs | Develop-ment Costs | Abandon-ment and Resto-ration 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 10% | Discounted at 15% | Discounted at 20% |
| **31.12.2061** | (65) | (1.02) | (156,893) | (31,755) | - | (1,213) | - | - | (123,925) | (57,997) | (15,163) | (50,765) | (6,383) | (884) | (134) | (22) |
| **31.12.2062** | (59) | (0.94) | (145,948) | (29,540) | - | (1,123) | - | - | (115,286) | (53,954) | (14,106) | (47,226) | (5,655) | (747) | (108) | (17) |
| **31.12.2063** | (52) | (0.82) | (129,552) | (26,221) | - | (993) | - | - | (102,338) | (47,894) | (12,522) | (41,922) | (4,781) | (603) | (83) | (13) |
| **31.12.2064** | (6) | (0.09) | (14,726) | (2,981) | - | (111) | - | - | (11,635) | - | - | (11,635) | (1,264) | (152) | (20) | (3) |
| **Total** | **1,471** | **23.20** | **2,079,393** | **424,710** | **-** | **18,972** | **-** | **-** | **1,635,711** | **795,429** | **195,941** | **644,341** | **454,390** | **306,467** | **226,673** | **181,459** |

| Total discounted cash flow from 3P proved and probable and possible reserves as of December 31, 2018 (in Dollars in thousands in respect of the Partnership's share) | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cash flow components | | | | | | | | | | | | | | | | |
| Until | Condensate Sales Volume (Barrels in Thousands) (100% of the Petroleum Asset) | Sales Volume (BCM) (100% of the Petroleum Asset) | Revenues | Royalties to be Paid | Royalties to be Received | Operating Costs | Develop-ment Costs | Abandon-ment and Restor-ation 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 10% | Discounted at 15% | Discounted at 20% |
| **31.12.2019** | - | - | - | - | - | - | 707,614 | - | (707,614) | - | - | (707,614) | (690,561) | (674,684) | (659,854) | (645,960) |
| **31.12.2020** | 721 | 11.37 | 1,012,388 | 158,338 | - | 75,618 | 37,458 | - | 740,974 | - | 81,485 | 659,490 | 612,949 | 571,635 | 534,763 | 501,691 |
| **31.12.2021** | 763 | 12.02 | 1,122,575 | 175,571 | - | 76,451 | - | - | 870,554 | - | 155,533 | 715,020 | 632,915 | 563,426 | 504,166 | 453,279 |
| **31.12.2022** | 654 | 10.31 | 998,362 | 156,144 | - | 75,218 | - | - | 767,000 | - | 131,716 | 635,284 | 535,557 | 455,086 | 389,516 | 335,609 |
| **31.12.2023** | 760 | 11.98 | 1,177,743 | 210,392 | - | 71,610 | - | - | 895,741 | - | 161,326 | 734,415 | 589,644 | 478,271 | 391,563 | 323,315 |
| **31.12.2024** | 757 | 11.94 | 1,185,739 | 239,993 | - | 71,644 | - | - | 874,101 | 63,580 | 141,726 | 668,796 | 511,390 | 395,944 | 310,067 | 245,356 |
| **31.12.2025** | 751 | 11.85 | 1,185,939 | 240,034 | - | 71,617 | - | - | 874,288 | 257,860 | 97,084 | 519,344 | 378,203 | 279,513 | 209,372 | 158,773 |
| **31.12.2026** | 733 | 11.56 | 1,167,481 | 236,298 | - | 71,423 | - | - | 859,760 | 336,100 | 75,748 | 447,912 | 310,651 | 219,153 | 157,021 | 114,112 |
| **31.12.2027** | 715 | 11.27 | 1,156,323 | 234,040 | - | 71,271 | - | - | 851,012 | 389,859 | 61,371 | 399,781 | 264,067 | 177,822 | 121,868 | 84,875 |
| **31.12.2028** | 699 | 11.02 | 1,154,815 | 233,735 | - | 71,189 | - | - | 849,891 | 397,749 | 59,299 | 392,844 | 247,128 | 158,851 | 104,133 | 69,502 |
| **31.12.2029** | 678 | 10.70 | 1,143,342 | 231,412 | - | 91,632 | - | - | 820,298 | 383,900 | 55,678 | 380,721 | 228,097 | 139,953 | 87,757 | 56,131 |
| **31.12.2030** | 669 | 10.55 | 1,147,400 | 232,234 | - | 71,004 | - | - | 844,162 | 395,068 | 102,861 | 346,233 | 197,557 | 115,705 | 69,398 | 42,539 |
| **31.12.2031** | 659 | 10.39 | 1,154,329 | 233,636 | - | 70,995 | - | - | 849,698 | 397,659 | 103,969 | 348,070 | 189,148 | 105,745 | 60,666 | 35,637 |

| Total discounted cash flow from 3P proved and probable and possible reserves as of December 31, 2018 (in Dollars in thousands in respect of the Partnership's share) | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cash flow components | | | | | | | | | | | | | | | | |
| Until | Condensate Sales Volume (Barrels in Thousands) (100% of the Petroleum Asset) | Sales Volume (BCM) (100% of the Petroleum Asset) | Revenues | Royalties to be Paid | Royalties to be Received | Operating Costs | Develop-ment Costs | Abandon-ment and Restor-ation 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 10% | Discounted at 15% | Discounted at 20% |
| 31.12.2032 | 655 | 10.32 | 1,171,571 | 237,126 | - | 71,075 | - | - | 863,371 | 404,057 | 105,642 | 353,671 | 183,039 | 97,678 | 53,602 | 30,175 |
| 31.12.2033 | 645 | 10.16 | 1,180,569 | 238,947 | - | 71,078 | - | - | 870,544 | 407,414 | 106,520 | 356,609 | 175,771 | 89,536 | 46,997 | 25,355 |
| 31.12.2034 | 634 | 10.00 | 1,184,788 | 239,801 | - | 91,661 | - | - | 853,326 | 399,357 | 104,413 | 349,557 | 164,090 | 79,787 | 40,059 | 20,711 |
| 31.12.2035 | 622 | 9.81 | 1,188,992 | 240,652 | - | 71,022 | - | - | 877,319 | 410,585 | 107,349 | 359,385 | 160,671 | 74,573 | 35,813 | 17,745 |
| 31.12.2036 | 615 | 9.69 | 1,195,071 | 241,882 | - | 71,020 | - | - | 882,168 | 412,855 | 107,942 | 361,371 | 153,865 | 68,168 | 31,314 | 14,869 |
| 31.12.2037 | 607 | 9.57 | 1,187,007 | 240,250 | - | 70,936 | - | - | 875,821 | 409,884 | 107,165 | 358,771 | 145,484 | 61,525 | 27,034 | 12,302 |
| 31.12.2038 | 600 | 9.47 | 1,096,663 | 221,965 | - | 70,385 | - | - | 804,314 | 376,419 | 98,416 | 329,479 | 127,244 | 51,365 | 21,588 | 9,414 |
| 31.12.2039 | 592 | 9.33 | 1,098,750 | 222,387 | - | 90,964 | - | - | 785,399 | 367,567 | 96,101 | 321,731 | 118,335 | 45,598 | 18,331 | 7,661 |
| 31.12.2040 | 592 | 9.33 | 1,113,382 | 225,348 | - | 70,440 | - | - | 817,593 | 382,634 | 100,041 | 334,919 | 117,319 | 43,152 | 16,593 | 6,646 |
| 31.12.2041 | 588 | 9.27 | 1,125,469 | 227,795 | - | 70,490 | - | - | 827,184 | 387,122 | 101,214 | 338,848 | 113,043 | 39,689 | 14,598 | 5,603 |
| 31.12.2042 | 583 | 9.19 | 1,135,691 | 229,864 | - | 70,526 | - | - | 835,301 | 390,921 | 102,207 | 342,173 | 108,717 | 36,435 | 12,819 | 4,715 |
| 31.12.2043 | 576 | 9.09 | 1,143,186 | 231,381 | - | 70,538 | - | - | 841,267 | 393,713 | 102,937 | 344,617 | 104,279 | 33,359 | 11,226 | 3,957 |
| 31.12.2044 | 572 | 9.02 | 1,154,146 | 233,599 | - | 91,188 | - | - | 829,359 | 388,140 | 101,480 | 339,739 | 97,908 | 29,897 | 9,624 | 3,251 |

**Total discounted cash flow from 3P proved and probable and possible reserves as of December 31, 2018 (in Dollars in thousands in respect of the Partnership's share)**

| Until | Condensate Sales Volume (Barrels in Thousands) (100% of the Petroleum Asset) | Sales Volume (BCM) (100% of the Petroleum Asset) | Revenues | Royalties to be Paid | Royalties to be Received | Operating Costs | Develop-ment Costs | Abandon-ment and Restor-ation 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 10% | Discounted at 15% | Discounted at 20% |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **31.12.2045** | 564 | 8.88 | 1,157,786 | 234,336 | - | 70,562 | - | - | 852,889 | 399,152 | 104,359 | 349,377 | 95,891 | 27,950 | 8,606 | 2,786 |
| **31.12.2046** | 546 | 8.61 | 1,144,513 | 231,649 | - | 70,402 | - | - | 842,461 | 394,272 | 103,084 | 345,106 | 90,208 | 25,099 | 7,392 | 2,293 |
| **31.12.2047** | 544 | 8.58 | 1,158,840 | 234,549 | - | 70,475 | - | - | 853,816 | 399,586 | 104,473 | 349,757 | 87,071 | 23,125 | 6,514 | 1,937 |
| **31.12.2048** | 543 | 8.57 | 1,175,819 | 237,986 | - | 70,570 | - | - | 867,263 | 405,879 | 106,118 | 355,266 | 84,230 | 21,354 | 5,754 | 1,639 |
| **31.12.2049** | 540 | 8.51 | 1,187,285 | 240,307 | - | 91,226 | - | - | 855,753 | 400,492 | 104,710 | 350,551 | 79,155 | 19,155 | 4,937 | 1,348 |
| **31.12.2050** | 537 | 8.47 | 1,201,427 | 243,169 | - | 70,689 | - | - | 887,569 | 415,382 | 108,603 | 363,584 | 78,188 | 18,061 | 4,453 | 1,165 |
| **31.12.2051** | 535 | 8.44 | 1,215,130 | 245,942 | - | 70,757 | - | - | 898,431 | 420,466 | 109,932 | 368,033 | 75,376 | 16,620 | 3,919 | 983 |
| **31.12.2052** | 534 | 8.42 | 1,226,249 | 248,193 | - | 70,816 | - | - | 907,240 | 424,588 | 111,010 | 371,642 | 72,491 | 15,257 | 3,441 | 827 |
| **31.12.2053** | 530 | 8.35 | 1,230,556 | 249,065 | - | 70,821 | - | - | 910,671 | 426,194 | 111,430 | 373,047 | 69,300 | 13,922 | 3,004 | 692 |
| **31.12.2054** | 525 | 8.27 | 1,232,854 | 249,530 | - | 91,417 | - | - | 891,908 | 417,413 | 109,134 | 365,361 | 64,640 | 12,396 | 2,558 | 565 |
| **31.12.2055** | 492 | 7.76 | 1,174,585 | 237,736 | - | 70,318 | - | - | 866,531 | 405,537 | 106,029 | 354,966 | 59,810 | 10,948 | 2,161 | 457 |
| **31.12.2056** | 435 | 6.86 | 1,060,433 | 214,632 | - | 69,389 | - | - | 776,413 | 363,361 | 95,002 | 318,050 | 51,038 | 8,918 | 1,684 | 341 |
| **31.12.2057** | 405 | 6.39 | 1,004,427 | 203,296 | - | 68,926 | - | - | 732,204 | 342,672 | 89,593 | 299,940 | 45,840 | 7,646 | 1,381 | 268 |

| Total discounted cash flow from 3P proved and probable and possible reserves as of December 31, 2018 (in Dollars in thousands in respect of the Partnership's share) | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cash flow components | | | | | | | | | | | | | | | |
| Until | Condensate Sales Volume (Barrels in Thousands) (100% of the Petroleum Asset) | Sales Volume (BCM) (100% of the Petroleum Asset) | Revenues | Royalties to be Paid | Royalties to be Received | Operating Costs | Develop-ment Costs | Abandon-ment and Restor-ation 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 10% | Discounted at 15% | Discounted at 20% |
| **31.12.2058** | 387 | 6.11 | 972,733 | 196,881 | - | 68,659 | - | - | 707,193 | 330,966 | 86,532 | 289,694 | 42,166 | 6,713 | 1,160 | 216 |
| **31.12.2059** | 382 | 6.02 | 967,570 | 195,836 | - | 89,208 | - | - | 682,526 | 319,422 | 83,514 | 279,590 | 38,757 | 5,890 | 973 | 174 |
| **31.12.2060** | 383 | 6.03 | 978,748 | 198,099 | - | 68,670 | - | - | 711,979 | 333,206 | 87,118 | 291,655 | 38,505 | 5,586 | 883 | 151 |
| **31.12.2061** | 382 | 6.02 | 985,121 | 199,388 | - | 68,702 | - | - | 717,030 | 335,570 | 87,736 | 293,724 | 36,931 | 5,114 | 773 | 127 |
| **31.12.2062** | 382 | 6.02 | 994,188 | 201,224 | - | 68,754 | - | - | 724,211 | 338,931 | 83,969 | 301,311 | 36,081 | 4,769 | 690 | 108 |
| **31.12.2063** | 382 | 6.02 | 1,003,202 | 203,048 | - | 68,806 | - | - | 731,348 | 342,271 | 84,842 | 304,235 | 34,696 | 4,378 | 606 | 91 |
| **31.12.2064** | 45 | 0.71 | 120,171 | 24,323 | - | 62,119 | - | 60,592 | (26,863) | - | - | (26,863) | (2,918) | (351) | (46) | (7) |
| **Total** | **25,511** | **402.2** | **49,773,362** | **9,902,013** | **-** | **3,322,281** | **745,072** | **60,592** | **35,743,404** | **14,967,802** | **4,446,410** | **16,329,192** | **6,953,968** | **3,989,732** | **2,680,880** | **1,953,426** |

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

**Caution concerning forward-looking information – The aforesaid discounted cash flow figures 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 sales of natural gas from the project, operating costs, capital expenditure, abandonment expenses, royalty rates and sale prices, and there is no certainty that such assumptions will materialize. It is noted that the quantities of natural gas and/or condensate that shall actually be produced, such expenses and such revenues may materially**

**differ from the above estimates and conjectures, *inter alia* as a result of operating and technical conditions and/or regulatory changes and/or supply and demand conditions on 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. Below is a sensitivity analysis in respect of the principal parameters comprising the discounted cash flow (the price of gas and the amount of gas sales) as of December 31, 2018 (Dollars in thousands), which was performed by the Partnership[142]:

| Sensitivity/Category | Current Value Discounted at 0% | Current Value Discounted at 10% | Current Value Discounted at 15% | Current Value Discounted at 20% | Sensitivity/Category | Current Value Discounted at 0% | Current Value Discounted at 10% | Current Value Discounted at 15% | Current Value Discounted at 20% |
|---|---|---|---|---|---|---|---|---|---|
| **10% Increase in Gas Price** | | | | | **10% Decrease in Gas Price** | | | | |
| Proved Reserves P1 | 12,549,643 | 2,636,858 | 1,632,537 | 1,087,270 | Proved Reserves P1 | 10,367,892 | 2,148,806 | 1,285,567 | 814,804 |
| Probable Reserves | 4,668,113 | 1,379,918 | 1,053,414 | 864,835 | Probable Reserves | 3,781,708 | 1,191,712 | 927,357 | 767,932 |
| Total P2 Type Reserves (Proved + Probable Reserves) | 17,217,757 | 4,016,777 | 2,685,951 | 1,952,104 | Total P2 Type Reserves (Proved + Probable Reserves) | 14,149,600 | 3,340,517 | 2,212,924 | 1,582,736 |
| Possible Reserves | 718,243 | 337,760 | 248,374 | 197,857 | Possible Reserves | 581,755 | 283,920 | 212,393 | 171,313 |
| Total P3 Type Reserves (Proved + Probable + Possible Reserves) | 17,935,999 | 4,354,537 | 2,934,324 | 2,149,961 | Total P3 Type Reserves (Proved + Probable + Possible Reserves) | 14,731,355 | 3,624,437 | 2,425,316 | 1,754,049 |
| **15% Increase in Gas Price** | | | | | | | | | |
| Proved Reserves P1 | 13,101,399 | 2,756,974 | 1,717,097 | 1,153,440 | Proved Reserves P1 | 9,828,286 | 2,021,620 | 1,193,758 | 742,296 |
| Probable Reserves | 4,888,537 | 1,428,364 | 1,085,603 | 889,067 | Probable Reserves | 3,559,860 | 1,147,932 | 898,028 | 744,942 |
| Total P2 Type Reserves (Proved + Probable Reserves) | 17,989,936 | 4,185,338 | 2,802,701 | 2,042,507 | Total P2 Type Reserves (Proved + Probable Reserves) | 13,388,146 | 3,169,552 | 2,091,786 | 1,487,238 |

[142] With respect to an analysis of the discounted cash flow's sensitivity to the gas sales volume variable, it is noted that costs in respect of additional wells that may be required in order to adjust to an increase in the amount of gas sales, were not included.

| Sensitivity/Category | Current Value Discounted at 0% | Current Value Discounted at 10% | Current Value Discounted at 15% | Current Value Discounted at 20% | Sensitivity/Category | Current Value Discounted at 0% | Current Value Discounted at 10% | Current Value Discounted at 15% | Current Value Discounted at 20% |
|---|---|---|---|---|---|---|---|---|---|
| Possible Reserves | 750,679 | 351,279 | 257,778 | 205,060 | Possible Reserves | 544,509 | 268,843 | 202,039 | 163,476 |
| Total P3 Type Reserves (Proved + Probable + Possible Reserves) | 18,740,615 | 4,536,617 | 3,060,479 | 2,247,567 | Total P3 Type Reserves (Proved + Probable + Possible Reserves) | 13,932,655 | 3,438,395 | 2,293,825 | 1,650,714 |
| **20% Increase in Gas Price** | | | | | | | | | |
| Proved Reserves P1 | 13,648,207 | 2,872,225 | 1,797,641 | 1,216,407 | Proved Reserves P1 | 9,286,818 | 1,890,507 | 1,098,993 | 667,679 |
| Probable Reserves | 5,110,150 | 1,479,842 | 1,120,147 | 915,025 | Probable Reserves | 3,336,637 | 1,103,332 | 867,310 | 720,281 |
| Total P2 Type Reserves (Proved + Probable Reserves) | 18,758,357 | 4,352,067 | 2,917,788 | 2,131,432 | Total P2 Type Reserves (Proved + Probable Reserves) | 12,623,455 | 2,993,839 | 1,966,303 | 1,387,959 |
| Possible Reserves | 786,286 | 364,411 | 266,410 | 211,273 | Possible Reserves | 507,471 | 254,864 | 192,752 | 156,594 |
| Total P3 Type Reserves (Proved + Probable + Possible Reserves) | 19,544,643 | 4,716,478 | 3,184,198 | 2,342,705 | Total P3 Type Reserves (Proved + Probable + Possible Reserves) | 13,130,926 | 3,248,704 | 2,159,055 | 1,544,554 |

| **Sensitivity/Category** | **Current Value Discounted at 0%** | **Current Value Discounted at 10%** | **Current Value Discounted at 15%** | **Current Value Discounted at 20%** | **Sensitivity/Category** | **Current Value Discounted at 0%** | **Current Value Discounted at 10%** | **Current Value Discounted at 15%** | **Current Value Discounted at 20%** |
|---|---|---|---|---|---|---|---|---|---|
| **10% Increase in Gas Sales** | | | | | **10% Decrease in Gas Sales** | | | | |
| Proved Reserves P1 | 11,218,008 | 2,614,849 | 1,629,781 | 1,087,151 | Proved Reserves P1 | 10,371,313 | 2,149,775 | 1,286,272 | 815,356 |
| Probable Reserves | 4,083,946 | 1,367,524 | 1,050,205 | 863,382 | Probable Reserves | 3,783,124 | 1,192,090 | 927,640 | 768,167 |
| Total P2 Type Reserves (Proved + Probable Reserves) | 15,301,954 | 3,982,373 | 2,679,986 | 1,950,533 | Total P2 Type Reserves (Proved + Probable Reserves) | 14,154,437 | 3,341,865 | 2,213,912 | 1,583,523 |
| Possible Reserves | 619,204 | 333,845 | 247,537 | 197,633 | Possible Reserves | 582,047 | 284,033 | 212,473 | 171,375 |
| Total P3 Type Reserves (Proved + Probable + Possible Reserves) | 15,921,158 | 4,316,218 | 2,927,522 | 2,148,166 | Total P3 Type Reserves (Proved + Probable + Possible Reserves) | 14,736,484 | 3,625,898 | 2,426,385 | 1,754,899 |
| **15% Increase in Gas Sales** | | | | | | | | | |
| Proved Reserves P1 | 11,120,199 | 2,717,308 | 1,709,947 | 1,151,586 | Proved Reserves P1 | 9,829,744 | 2,021,846 | 1,194,094 | 742,695 |
| Probable Reserves | 4,044,981 | 1,411,838 | 1,082,647 | 888,295 | Probable Reserves | 3,565,665 | 1,149,753 | 899,198 | 745,744 |
| Total P2 Type Reserves (Proved + Probable Reserves) | 15,165,180 | 4,129,146 | 2,792,595 | 2,039,881 | Total P2 Type Reserves (Proved + Probable Reserves) | 13,395,409 | 3,171,599 | 2,093,292 | 1,488,439 |
| Possible Reserves | 624,653 | 343,711 | 255,998 | 204,579 | Possible Reserves | 544,952 | 269,018 | 202,165 | 163,577 |
| Total P3 Type Reserves (Proved + Probable + Possible Reserves) | 15,789,833 | 4,472,857 | 3,048,593 | 2,244,460 | Total P3 Type Reserves (Proved + Probable + Possible Reserves) | 13,940,361 | 3,440,617 | 2,295,457 | 1,652,016 |
| **20% Increase in Gas Sales[143]** | | | | | | | | | |
| Proved Reserves P1 | 11,024,367 | 2,814,384 | 1,786,831 | 1,213,633 | Proved Reserves P1 | 9,293,659 | 1,892,526 | 1,100,468 | 668,834 |
| Probable Reserves | 4,012,217 | 1,456,249 | 1,115,757 | 913,875 | Probable Reserves | 3,339,506 | 1,104,090 | 867,886 | 720,764 |
| Total P2 Type Reserves (Proved + Probable Reserves) | 15,036,583 | 4,270,633 | 2,902,588 | 2,127,508 | Total P2 Type Reserves (Proved + Probable Reserves) | 12,633,165 | 2,996,615 | 1,968,354 | 1,389,599 |
| Possible Reserves | 626,565 | 352,483 | 263,445 | 210,464 | Possible Reserves | 508,015 | 255,071 | 192,901 | 156,714 |
| Total P3 Type Reserves (Proved + Probable + Possible Reserves) | 15,663,148 | 4,623,116 | 3,166,034 | 2,337,972 | Total P3 Type Reserves (Proved + Probable + Possible Reserves) | 13,141,180 | 3,251,687 | 2,161,255 | 1,546,312 |

[143] It is noted that due to infrastructure limitations, it is impossible to increase the amount of gas by this rate.

(b) Contingent resources in the Leviathan reservoir

1. Quantity data
According to the NSAI report, the contingent resources and the condensate in the Leviathan reservoir, which are classified under the "Development Pending" stage, are as follows:

| **Natural Gas BCF** | | | | | | |
|---|---|---|---|---|---|---|
| **Category** | **Total (100%) in the Petroleum Asset (Gross)** | | | **Total Rate Attributable to the Holders of the Equity Interests of the Partnership (Net)**[144] | | |
| | **Phase 1A** | **Future Developments** | **Total** | **Phase 1A** | **Future Developments** | **Total** |
| 1C – Low Estimate | 7,370.7 | 186.6 | 7,557.3 | 2,606.7 | 66.0 | 2,672.7 |
| 2C – Best Estimate | 4,700.0 | 3,410.1 | 8,110.1 | 1,662.2 | 1,206.0 | 2,868.2 |
| 3C – High Estimate | 4,465.5 | 7,174.1 | 11,639.6 | 1,579.2 | 2,537.1 | 4,116.4 |

| **Condensate Million Barrels** | | | | | | |
|---|---|---|---|---|---|---|
| **Category** | **Total (100%) in the Petroleum Asset (Gross)** | | | **Total Rate Attributable to the Holders of the Equity Interests of the Partnership (Net)** | | |
| | **Phase 1A** | **Future Developments** | **Total** | **Phase 1A** | **Future Developments** | **Total** |
| 1C – Low Estimate | 13.2 | 0.3 | 13.6 | 4.7 | 0.1 | 4.8 |
| 2C – Best Estimate | 8.4 | 6.1 | 14.6 | 3.0 | 2.2 | 5.1 |
| 3C – High Estimate | 8.0 | 12.9 | 21.0 | 2.8 | 4.6 | 7.4 |

[144] The Resources Report does not state the Partnership's net share, but rather the Partnership's gross share. The Partnership's share in the table above is after payment of royalties, and assuming that investment-recovery is made after the sale of a total amount (in respect of 100% of the rights in the petroleum asset) of approx. 1,416 BCF and approx. 2.5 million barrels of condensate from Phase 1A (in this footnote: the "**Investment Recovery Date**"). Since the Investment Recovery Date is affected by gas and/or condensate prices, the production rate, production and development costs and the royalty rate, and since additional natural gas sale agreements are expected to be signed, it is possible that the total amount of natural gas and/or condensate to be sold by the Investment Recovery Date will materially differ from the aforesaid. The calculation of the rate attributed to the holders of the Partnership's equity interests before and after the Investment Recovery Date was performed according to the rates set forth in Section 7.4.7 above.

2. In view of the significant amount of resources estimated in the Leviathan project, the potential markets for such resources are the domestic market and/or the international market. For a description of the potential market for such resources, see Sections 6 and 7.14 hereof. For details regarding an examination of the possibility to export the gas, see Section 7.14.2 hereof. For details regarding the engagement of the Leviathan Partners in an agreement for the export of natural gas from the Leviathan project to the Jordanian National Electric Power Company Limited (NEPCO), see Section 7.13.5(b)1 of the report and for details regarding the agreement for export of natural gas from the Leviathan project to Dolphinus, see Section 7.13.5(b)2.

3. The Resource Report states that the classification of the contingent resources in the Leviathan project under the Phase 1A category as reserves, is conditioned upon the adoption of decisions to drill additional wells and the execution of additional natural gas sale agreements, and that the classification of the contingent resources in the Leviathan project under the "Future Development" category as reserves, is conditioned upon the adoption of additional investment decisions and the execution of additional natural gas sale agreements. Insofar as such conditions are met, some or all of the contingent resources may be classified as reserves.

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

**Caution concerning forward-looking information – NSAI's evaluations pertaining to the quantities of contingent resources and reserves of natural gas and condensate at the Leviathan reservoir are forward-looking information as defined in the Securities Law, 5728-1968. The aforesaid evaluations are based, *inter alia,* on geologic, geophysical, engineering and other information received from the Operator, from the wells at the reservoir and from wells at adjacent reservoirs and constitute merely professional evaluations and estimates of NSAI, in respect of which there is no certainty. The amounts of the natural gas and/or the condensate, which will be actually produced, might be different from the aforesaid evaluations and estimates, *inter alia*, as a result of operational 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 the actual performance of the reservoir. The aforesaid evaluations and estimates might be updated insofar as further information will accumulate and/or as a result of a gamut of factors related to projects of exploration and production of oil and natural gas.**

4. Discounted cash flow figures

In accordance with the above, set forth below is the estimated discounted cash flow as of December 31, 2018 in Dollars in thousands (after levy and income tax), which is attributed to the Partnership's share, from the contingent resources in the Leviathan reservoir, for each one of the categories of contingent resources specified above:

| **Total discounted cash flow from low estimate contingent resources as of December 31, 2018 (in $ in thousands in relation to the Partnership's share)** | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Cash flow components** | | | | | | | | | | | | | | | | |
| **Until** | **Condensate Sales Volume (Barrels in Thousands) (100% of the Petroleum Asset)** | **Sales Volume (BCM) (100% of the Petroleum Asset)** | **Revenues** | **Royalties to be Paid** | **Royalties to be Received** | **Operating Costs** | **Develop-ment Costs** | **Abandon-ment and Restor-ation 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 10%** | **Discounted at 15%** | **Discounted at 20%** |
| **31.12.2019** | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **31.12.2020** | 401 | 6.32 | 530,630 | 82,991 | - | 4,963 | - | - | 442,677 | - | 81,485 | 361,192 | 335,702 | 313,075 | 292,881 | 274,768 |
| **31.12.2021** | 423 | 6.67 | 597,780 | 93,493 | - | 5,454 | - | - | 498,833 | - | 135,063 | 363,770 | 321,999 | 286,646 | 256,497 | 230,608 |
| **31.12.2022** | 243 | 3.84 | 377,234 | 58,999 | - | 3,329 | - | - | 314,905 | - | 72,428 | 242,477 | 204,413 | 173,698 | 148,671 | 128,096 |
| **31.12.2023** | 342 | 5.39 | 537,012 | 108,853 | - | 4,719 | - | - | 423,440 | - | 97,391 | 326,049 | 261,776 | 212,332 | 173,837 | 143,538 |
| **31.12.2024** | 353 | 5.57 | 563,901 | 143,339 | - | 4,929 | 174,015 | - | 241,618 | 24,542 | 87,950 | 129,126 | 98,735 | 76,446 | 59,865 | 47,372 |
| **31.12.2025** | 352 | 5.56 | 567,549 | 144,224 | - | 4,945 | - | - | 418,380 | 246,401 | 35,553 | 136,426 | 99,350 | 73,425 | 55,000 | 41,708 |
| **31.12.2026** | 352 | 5.56 | 573,097 | 145,687 | - | 4,976 | - | - | 422,434 | 342,229 | 14,445 | 65,760 | 45,608 | 32,175 | 23,053 | 16,753 |
| **31.12.2027** | 352 | 5.56 | 583,342 | 121,741 | - | 5,036 | - | - | 456,565 | 417,799 | 4,914 | 33,852 | 22,360 | 15,057 | 10,319 | 7,187 |
| **31.12.2028** | 353 | 5.57 | 594,750 | 120,377 | - | 5,106 | - | - | 469,266 | 439,211 | 2,910 | 27,145 | 17,076 | 10,976 | 7,196 | 4,803 |

| Total discounted cash flow from low estimate contingent resources as of December 31, 2018 (in $ in thousands in relation to the Partnership's share) | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cash flow components | | | | | | | | | | | | | | | | |
| Until | Condensate Sales Volume (Barrels in Thousands) (100% of the Petroleum Asset) | Sales Volume (BCM) (100% of the Petroleum Asset) | Revenues | Royalties to be Paid | Royalties to be Received | Operating Costs | Develop-ment Costs | Abandon-ment and Restor-ation 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 10% | Discounted at 15% | Discounted at 20% |
| **31.12.2029** | 352 | 5.56 | 601,267 | 121,696 | - | 5,139 | - | - | 474,431 | 368,084 | 20,458 | 85,890 | 51,458 | 31,573 | 19,798 | 12,663 |
| **31.12.2030** | 352 | 5.55 | 608,919 | 123,245 | - | 5,182 | - | - | 480,492 | 322,248 | 32,394 | 125,851 | 71,809 | 42,057 | 25,225 | 15,462 |
| **31.12.2031** | 352 | 5.56 | 621,425 | 125,776 | - | 5,255 | - | - | 490,393 | 304,799 | 38,684 | 146,910 | 79,834 | 44,632 | 25,605 | 15,041 |
| **31.12.2032** | 353 | 5.57 | 636,331 | 128,793 | - | 5,346 | - | - | 502,192 | 290,140 | 44,770 | 167,282 | 86,575 | 46,201 | 25,353 | 14,273 |
| **31.12.2033** | 352 | 5.56 | 647,689 | 131,092 | - | 5,407 | - | - | 511,190 | 274,360 | 50,469 | 186,362 | 91,857 | 46,791 | 24,561 | 13,250 |
| **31.12.2034** | 352 | 5.56 | 659,590 | 133,501 | - | 5,475 | - | - | 520,614 | 259,345 | 58,091 | 203,178 | 95,377 | 46,376 | 23,284 | 12,038 |
| **31.12.2035** | 352 | 5.56 | 673,111 | 136,238 | - | 5,553 | 174,015 | - | 357,305 | 168,629 | 81,418 | 107,258 | 47,952 | 22,256 | 10,688 | 5,296 |
| **31.12.2036** | 353 | 5.57 | 685,865 | 138,819 | - | 5,631 | - | - | 541,415 | 253,382 | 62,245 | 225,788 | 96,136 | 42,592 | 19,565 | 9,290 |
| **31.12.2037** | 352 | 5.56 | 680,736 | 137,781 | - | 5,597 | 22,897 | - | 514,462 | 240,768 | 63,950 | 209,744 | 85,052 | 35,969 | 15,804 | 7,192 |
| **31.12.2038** | 352 | 5.56 | 604,452 | 122,341 | - | 5,158 | - | - | 476,954 | 223,214 | 53,831 | 199,908 | 77,204 | 31,165 | 13,099 | 5,712 |
| **31.12.2039** | 352 | 5.56 | 613,140 | 124,100 | - | 5,208 | - | - | 483,833 | 226,434 | 54,673 | 202,726 | 74,564 | 28,732 | 11,551 | 4,827 |
| **31.12.2040** | 353 | 5.57 | 623,036 | 126,102 | - | 5,269 | 174,015 | - | 317,649 | 148,660 | 72,361 | 96,629 | 33,848 | 12,450 | 4,787 | 1,917 |
| **31.12.2041** | 352 | 5.56 | 630,134 | 127,539 | - | 5,305 | - | - | 497,290 | 232,732 | 52,317 | 212,241 | 70,806 | 24,860 | 9,144 | 3,510 |
| **31.12.2042** | 352 | 5.56 | 640,196 | 129,576 | - | 5,363 | - | - | 505,257 | 236,460 | 53,292 | 215,505 | 68,471 | 22,947 | 8,073 | 2,970 |
| **31.12.2043** | 352 | 5.56 | 650,382 | 131,637 | - | 5,422 | - | - | 513,323 | 240,235 | 54,279 | 218,809 | 66,211 | 21,181 | 7,128 | 2,513 |

**Total discounted cash flow from low estimate contingent resources as of December 31, 2018 (in $ in thousands in relation to the Partnership's share)**

**Cash flow components**

| Until | Condensate Sales Volume (Barrels in Thousands) (100% of the Petroleum Asset) | Sales Volume (BCM) (100% of the Petroleum Asset) | Revenues | Royalties to be Paid | Royalties to be Received | Operating Costs | Develop-ment Costs | Abandon-ment and Restor-ation 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 10% | Discounted at 15% | Discounted at 20% |
| **31.12.2044** | 353 | 5.57 | 663,305 | 134,253 | - | 5,501 | - | - | 523,551 | 245,022 | 55,530 | 222,999 | 64,265 | 19,624 | 6,317 | 2,134 |
| **31.12.2045** | 352 | 5.56 | 671,275 | 135,866 | - | 5,542 | - | - | 529,866 | 247,978 | 58,304 | 223,585 | 61,366 | 17,887 | 5,507 | 1,783 |
| **31.12.2046** | 352 | 5.56 | 682,074 | 138,052 | - | 5,605 | - | - | 538,418 | 251,979 | 61,352 | 225,086 | 58,836 | 16,370 | 4,821 | 1,496 |
| **31.12.2047** | 352 | 5.56 | 692,649 | 140,192 | - | 5,666 | - | - | 546,792 | 255,898 | 62,640 | 228,253 | 56,823 | 15,091 | 4,251 | 1,264 |
| **31.12.2048** | 353 | 5.57 | 705,665 | 142,827 | - | 5,745 | 185,463 | - | 371,630 | 173,923 | 81,994 | 115,713 | 27,435 | 6,955 | 1,874 | 534 |
| **31.12.2049** | 352 | 5.56 | 714,466 | 144,608 | - | 5,791 | - | - | 564,067 | 263,983 | 60,751 | 239,332 | 54,042 | 13,077 | 3,371 | 920 |
| **31.12.2050** | 352 | 5.56 | 725,902 | 146,923 | - | 5,857 | - | - | 573,122 | 268,221 | 63,860 | 241,041 | 51,836 | 11,973 | 2,952 | 772 |
| **31.12.2051** | 367 | 5.79 | 767,836 | 155,410 | - | 6,170 | 318,264 | - | 287,992 | 134,780 | 100,514 | 52,698 | 10,793 | 2,380 | 561 | 141 |
| **31.12.2052** | 398 | 6.27 | 842,022 | 170,425 | - | 6,741 | - | - | 664,856 | 311,152 | 69,766 | 283,937 | 55,384 | 11,656 | 2,629 | 632 |
| **31.12.2053** | 362 | 5.71 | 764,911 | 154,818 | - | 6,127 | 196,912 | - | 407,054 | 190,501 | 81,247 | 135,306 | 25,135 | 5,050 | 1,090 | 251 |
| **31.12.2054** | 291 | 4.58 | 621,375 | 125,766 | - | 4,961 | 196,912 | - | 293,736 | 137,468 | 62,852 | 93,415 | 16,527 | 3,169 | 654 | 144 |
| **31.12.2055** | 236 | 3.72 | 513,169 | 103,865 | - | 4,078 | - | - | 405,226 | 189,646 | 28,940 | 186,640 | 31,448 | 5,757 | 1,136 | 240 |
| **31.12.2056** | 190 | 3.00 | 420,977 | 85,206 | - | 3,329 | - | - | 332,442 | 155,583 | 20,034 | 156,825 | 25,166 | 4,397 | 830 | 168 |
| **31.12.2057** | 119 | 1.87 | 266,878 | 54,016 | - | 2,101 | - | - | 210,761 | 98,636 | 5,145 | 106,980 | 16,350 | 2,727 | 493 | 96 |
| **31.12.2058** | 81 | 1.28 | 186,767 | 37,802 | - | 1,463 | - | - | 147,502 | 69,031 | (462) | 78,934 | 11,489 | 1,829 | 316 | 59 |

| Total discounted cash flow from low estimate contingent resources as of December 31, 2018 (in $ in thousands in relation to the Partnership's share) | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cash flow components | | | | | | | | | | | | | | | | |
| Until | Condensate Sales Volume (Barrels in Thousands) (100% of the Petroleum Asset) | Sales Volume (BCM) (100% of the Petroleum Asset) | Revenues | Royalties to be Paid | Royalties to be Received | Operating Costs | Develop-ment Costs | Abandon-ment and Restor-ation 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 10% | Discounted at 15% | Discounted at 20% |
| **31.12.2059** | 74 | 1.16 | 171,757 | 34,764 | - | 1,340 | - | - | 135,654 | 63,486 | 221 | 71,947 | 9,974 | 1,516 | 250 | 45 |
| **31.12.2060** | 64 | 1.02 | 152,957 | 30,958 | - | 1,187 | - | - | 120,811 | 56,539 | (1,596) | 65,867 | 8,696 | 1,261 | 199 | 34 |
| **31.12.2061** | 52 | 0.82 | 126,048 | 25,512 | - | 974 | - | - | 99,562 | 46,595 | (536) | 53,502 | 6,727 | 932 | 141 | 23 |
| **31.12.2062** | 40 | 0.63 | 97,866 | 19,808 | - | 753 | - | - | 77,305 | 36,179 | (7,243) | 48,369 | 5,792 | 766 | 111 | 17 |
| **31.12.2063** | 28 | 0.44 | 69,867 | 14,141 | - | 535 | - | - | 55,191 | 25,829 | (7,684) | 37,046 | 4,225 | 533 | 74 | 11 |
| **31.12.2064** | 3 | 0.05 | 8,108 | 1,641 | - | 61 | - | 99,703 | (93,297) | - | - | (93,297) | (10,133) | (1,220) | (161) | (23) |
| **Total** | **13,238** | **208.7** | **24,367,444** | **4,954,795** | - | **203,296** | **1,442,492** | **99,703** | **17,667,158** | **8,482,104** | **2,120,998** | **7,064,057** | **3,096,348** | **1,835,343** | **1,308,402** | **1,031,528** |

| Total discounted cash flow from best estimate contingent resources as of December 31, 2018 (in $ in thousands in relation to the Partnership’s share) | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cash flow components | | | | | | | | | | | | | | | | |
| | | | | | | | | | | Taxes | | Total Discounted Cash Flow After Tax | | | | |
| Until | Condensate Sales Volume (Barrels in Thousands) (100% of the Petroleum Asset) | Sales Volume (BCM) (100% of the Petroleum Asset) | Revenues | Royalties to be Paid | Royalties to be Received | Operating Costs | Develop-ment Costs | Abandon-ment and Restor-ation Costs | Total Cash Flow Before Levy and Income Tax (discounted at 0%) | Levy | Income Tax | Discounted at 0% | Discounted at 5% | Discounted at 10% | Discounted at 15% | Discounted at 20% |
| **31.12.2019** | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **31.12.2020** | 87 | 1.37 | 109,211 | 17,081 | - | 1,043 | - | - | 91,087 | - | 20,950 | 70,137 | 65,187 | 60,794 | 56,872 | 53,355 |
| **31.12.2021** | 98 | 1.54 | 130,769 | 20,452 | - | 1,218 | - | - | 109,098 | - | 25,093 | 84,006 | 74,359 | 66,195 | 59,233 | 53,254 |
| **31.12.2022** | 55 | 0.87 | 70,924 | 11,092 | - | 670 | - | - | 59,161 | - | 13,607 | 45,554 | 38,403 | 32,633 | 27,931 | 24,066 |
| **31.12.2023** | 85 | 1.34 | 127,569 | 43,217 | - | 1,138 | - | - | 83,215 | - | 19,139 | 64,075 | 51,444 | 41,728 | 34,163 | 28,208 |
| **31.12.2024** | 24 | 0.38 | 39,976 | 8,091 | - | 344 | 174,015 | - | (142,474) | 24,521 | (387) | (166,608) | (127,396) | (98,636) | (77,243) | (61,122) |
| **31.12.2025** | 68 | 1.07 | 111,405 | 22,548 | - | 965 | - | - | 87,892 | 80,689 | (2,346) | 9,549 | 6,954 | 5,139 | 3,849 | 2,919 |
| **31.12.2026** | 102 | 1.61 | 156,269 | 31,629 | - | 1,387 | - | - | 123,253 | 82,001 | 5,486 | 35,767 | 24,806 | 17,500 | 12,539 | 9,112 |
| **31.12.2027** | 124 | 1.95 | 187,966 | 38,044 | - | 1,672 | - | - | 148,250 | 102,602 | 6,497 | 39,151 | 25,860 | 17,414 | 11,935 | 8,312 |
| **31.12.2028** | 134 | 2.11 | 204,680 | 41,427 | - | 1,814 | - | - | 161,439 | 79,564 | 14,829 | 67,046 | 42,177 | 27,111 | 17,772 | 11,862 |
| **31.12.2029** | 141 | 2.22 | 220,516 | 44,632 | - | 1,939 | - | - | 173,945 | 81,406 | 17,282 | 75,257 | 45,088 | 27,665 | 17,347 | 11,095 |
| **31.12.2030** | 149 | 2.34 | 236,684 | 47,905 | - | 2,070 | - | - | 186,709 | 87,380 | 18,843 | 80,486 | 45,924 | 26,897 | 16,132 | 9,889 |
| **31.12.2031** | 158 | 2.49 | 258,528 | 52,326 | - | 2,241 | - | - | 203,960 | 95,453 | 20,954 | 87,553 | 47,578 | 26,599 | 15,260 | 8,964 |

**Total discounted cash flow from best estimate contingent resources as of December 31, 2018 (in $ in thousands in relation to the Partnership’s share)**

**Cash flow components**

| Until | Condensate Sales Volume (Barrels in Thousands) (100% of the Petroleum Asset) | Sales Volume (BCM) (100% of the Petroleum Asset) | Revenues | Royalties to be Paid | Royalties to be Received | Operating Costs | Develop-ment Costs | Abandon-ment and Restor-ation 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 10% | Discounted at 15% | Discounted at 20% |
| **31.12.2032** | 171 | 2.70 | 287,712 | 58,233 | - | 2,471 | - | - | 227,008 | 106,240 | 23,774 | 96,994 | 50,198 | 26,788 | 14,700 | 8,276 |
| **31.12.2033** | 185 | 2.92 | 318,530 | 64,470 | - | 2,715 | - | - | 251,344 | 117,629 | 26,752 | 106,963 | 52,722 | 26,856 | 14,097 | 7,605 |
| **31.12.2034** | 199 | 3.13 | 344,536 | 69,734 | - | 2,929 | - | - | 271,873 | 127,236 | 31,265 | 113,371 | 53,219 | 25,877 | 12,992 | 6,717 |
| **31.12.2035** | 210 | 3.32 | 357,870 | 72,433 | - | 3,061 | - | - | 282,376 | 132,152 | 34,552 | 115,672 | 51,714 | 24,002 | 11,527 | 5,711 |
| **31.12.2036** | 222 | 3.50 | 386,560 | 78,240 | - | 3,282 | 174,015 | - | 131,024 | 61,319 | 54,054 | 15,650 | 6,664 | 2,952 | 1,356 | 644 |
| **31.12.2037** | 233 | 3.68 | 407,945 | 82,568 | - | 3,458 | - | - | 321,918 | 150,658 | 35,388 | 135,873 | 55,097 | 23,301 | 10,238 | 4,659 |
| **31.12.2038** | 239 | 3.76 | 420,610 | 85,131 | - | 3,557 | 22,897 | - | 309,025 | 144,624 | 38,813 | 125,588 | 48,502 | 19,579 | 8,229 | 3,589 |
| **31.12.2039** | 239 | 3.76 | 426,239 | 86,271 | - | 3,590 | - | - | 336,379 | 157,425 | 36,630 | 142,323 | 52,347 | 20,171 | 8,109 | 3,389 |
| **31.12.2040** | 239 | 3.77 | 433,067 | 87,653 | - | 3,632 | - | - | 341,782 | 159,954 | 37,292 | 144,537 | 50,630 | 18,622 | 7,161 | 2,868 |
| **31.12.2041** | 239 | 3.76 | 437,243 | 88,498 | - | 3,653 | - | - | 345,092 | 161,503 | 37,697 | 145,893 | 48,671 | 17,088 | 6,285 | 2,412 |
| **31.12.2042** | 239 | 3.76 | 443,669 | 89,799 | - | 3,690 | - | - | 350,180 | 163,884 | 38,319 | 147,977 | 47,016 | 15,757 | 5,544 | 2,039 |
| **31.12.2043** | 239 | 3.76 | 450,169 | 91,114 | - | 3,727 | - | - | 355,327 | 166,293 | 38,949 | 150,085 | 45,415 | 14,528 | 4,889 | 1,723 |
| **31.12.2044** | 239 | 3.77 | 458,777 | 92,856 | - | 3,780 | 174,015 | - | 188,125 | 88,043 | 56,512 | 43,570 | 12,556 | 3,834 | 1,234 | 417 |

| Total discounted cash flow from best estimate contingent resources as of December 31, 2018 (in $ in thousands in relation to the Partnership's share) | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cash flow components | | | | | | | | | | | | | | | | |
| Until | Condensate Sales Volume (Barrels in Thousands) (100% of the Petroleum Asset) | Sales Volume (BCM) (100% of the Petroleum Asset) | Revenues | Royalties to be Paid | Royalties to be Received | Operating Costs | Develop-ment Costs | Abandon-ment and Restor-ation 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 10% | Discounted at 15% | Discounted at 20% |
| **31.12.2045** | 240 | 3.78 | 465,863 | 94,291 | - | 3,824 | - | - | 367,749 | 172,106 | 36,466 | 159,176 | 43,688 | 12,734 | 3,921 | 1,269 |
| **31.12.2046** | 243 | 3.82 | 477,780 | 96,703 | - | 3,905 | - | - | 377,172 | 176,517 | 39,621 | 161,035 | 42,093 | 11,712 | 3,449 | 1,070 |
| **31.12.2047** | 246 | 3.88 | 491,414 | 99,462 | - | 4,001 | 185,463 | - | 202,488 | 94,764 | 60,771 | 46,952 | 11,689 | 3,104 | 875 | 260 |
| **31.12.2048** | 252 | 3.97 | 509,908 | 103,205 | - | 4,134 | - | - | 402,568 | 188,402 | 40,727 | 173,439 | 41,121 | 10,425 | 2,809 | 800 |
| **31.12.2049** | 256 | 4.03 | 525,006 | 106,261 | - | 4,240 | 185,463 | - | 229,042 | 107,191 | 60,281 | 61,569 | 13,902 | 3,364 | 867 | 237 |
| **31.12.2050** | 260 | 4.11 | 542,304 | 109,762 | - | 4,362 | - | - | 428,180 | 200,388 | 39,858 | 187,933 | 40,415 | 9,335 | 2,302 | 602 |
| **31.12.2051** | 265 | 4.18 | 559,765 | 113,296 | - | 4,484 | 219,808 | - | 222,176 | 103,979 | 62,680 | 55,518 | 11,371 | 2,507 | 591 | 148 |
| **31.12.2052** | 270 | 4.26 | 578,720 | 117,133 | - | 4,617 | 306,816 | - | 150,154 | 70,272 | 67,823 | 12,059 | 2,352 | 495 | 112 | 27 |
| **31.12.2053** | 244 | 3.85 | 525,037 | 106,267 | - | 4,186 | - | - | 414,583 | 194,025 | 26,082 | 194,476 | 36,127 | 7,258 | 1,566 | 361 |
| **31.12.2054** | 236 | 3.72 | 512,264 | 103,682 | - | 4,073 | - | - | 404,509 | 189,310 | 26,851 | 188,348 | 33,323 | 6,390 | 1,319 | 291 |
| **31.12.2055** | 240 | 3.79 | 529,749 | 107,221 | - | 4,195 | - | - | 418,333 | 195,780 | 30,544 | 192,010 | 32,353 | 5,922 | 1,169 | 247 |
| **31.12.2056** | 246 | 3.87 | 549,657 | 111,251 | - | 4,333 | - | - | 434,073 | 203,146 | 32,470 | 198,457 | 31,847 | 5,565 | 1,051 | 213 |
| **31.12.2057** | 201 | 3.18 | 453,659 | 91,821 | - | 3,571 | - | - | 358,268 | 167,669 | 25,327 | 165,272 | 25,259 | 4,213 | 761 | 148 |

| Total discounted cash flow from best estimate contingent resources as of December 31, 2018 (in $ in thousands in relation to the Partnership's share) | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cash flow components | | | | | | | | | | | | | | | | |
| | | | | | | | | | | Taxes | | Total Discounted Cash Flow After Tax | | | | |
| Until | Condensate Sales Volume (Barrels in Thousands) (100% of the Petroleum Asset) | Sales Volume (BCM) (100% of the Petroleum Asset) | Revenues | Royalties to be Paid | Royalties to be Received | Operating Costs | Develop-ment Costs | Abandon-ment and Restor-ation Costs | Total Cash Flow Before Levy and Income Tax (discounted at 0%) | Levy | Income Tax | Discounted at 0% | Discounted at 5% | Discounted at 10% | Discounted at 15% | Discounted at 20% |
| **31.12.2058** | 189 | 2.99 | 434,229 | 87,888 | - | 3,402 | - | - | 342,939 | 160,495 | 25,584 | 156,860 | 22,831 | 3,635 | 628 | 117 |
| **31.12.2059** | 197 | 3.10 | 458,373 | 92,775 | - | 3,575 | - | - | 362,023 | 169,427 | 30,052 | 162,544 | 22,532 | 3,424 | 566 | 101 |
| **31.12.2060** | 204 | 3.22 | 484,294 | 98,021 | - | 3,760 | - | - | 382,513 | 179,016 | 34,692 | 168,805 | 22,286 | 3,233 | 511 | 87 |
| **31.12.2061** | 204 | 3.22 | 493,762 | 99,937 | - | 3,816 | - | - | 390,009 | 182,524 | 38,137 | 169,348 | 21,293 | 2,948 | 446 | 73 |
| **31.12.2062** | 156 | 2.45 | 382,294 | 77,376 | - | 2,941 | - | - | 301,976 | 141,325 | 25,778 | 134,874 | 16,151 | 2,135 | 309 | 48 |
| **31.12.2063** | 157 | 2.47 | 391,769 | 79,294 | - | 3,001 | - | - | 309,474 | 144,834 | 30,223 | 134,417 | 15,330 | 1,934 | 268 | 40 |
| **31.12.2064** | 19 | 0.30 | 50,925 | 10,307 | - | 384 | - | 99,703 | (59,469) | - | - | (59,469) | (6,459) | (778) | (103) | (15) |
| **Total** | **8,441** | **133.1** | **16,444,195** | **3,331,400** | **-** | **134,852** | **1,442,492** | **99,703** | **11,435,748** | **5,411,747** | **1,383,910** | **4,640,091** | **1,394,640** | **589,950** | **325,567** | **216,089** |

| Total discounted cash flow from high estimate contingent resources as of December 31, 2018 (in $ in thousands in relation to the Partnership's share) | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cash flow components | | | | | | | | | | | | | | | | |
| | | | | | | | | | | Taxes | | Total Discounted Cash Flow After Tax | | | | |
| Until | Condensate Sales Volume (Barrels in Thousands) (100% of the Petroleum Asset) | Sales Volume (BCM) (100% of the Petroleum Asset) | Revenues | Royalties to be Paid | Royalties to be Received | Operating Costs | Develop-ment Costs | Abandon-ment and Restor-ation Costs | Total Cash Flow Before Levy and Income Tax (discounted at 0%) | Levy | Income Tax | Discounted at 0% | Discounted at 5% | Discounted at 10% | Discounted at 15% | Discounted at 20% |
| **31.12.2019** | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **31.12.2020** | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **31.12.2021** | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **31.12.2022** | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **31.12.2023** | - | - | - | (672) | - | - | - | - | 672 | - | 155 | 518 | 416 | 337 | 276 | 228 |
| **31.12.2024** | 8 | 0.12 | 13,067 | 2,645 | - | 112 | 174,015 | - | (163,705) | (38,863) | 9,309 | (134,151) | (102,577) | (79,421) | (62,195) | (49,215) |
| **31.12.2025** | 12 | 0.18 | 19,695 | 3,986 | - | 169 | - | - | 15,540 | (10,162) | 1,909 | 23,793 | 17,327 | 12,805 | 9,592 | 7,274 |
| **31.12.2026** | 30 | 0.47 | 51,385 | 10,400 | - | 439 | - | - | 40,546 | 7,444 | 3,611 | 29,490 | 20,453 | 14,429 | 10,338 | 7,513 |
| **31.12.2027** | 49 | 0.77 | 84,442 | 17,091 | - | 717 | - | - | 66,634 | 28,641 | 4,736 | 33,257 | 21,967 | 14,793 | 10,138 | 7,061 |
| **31.12.2028** | 66 | 1.04 | 112,269 | 22,723 | - | 961 | - | - | 88,585 | 41,458 | 6,837 | 40,290 | 25,346 | 16,292 | 10,680 | 7,128 |
| **31.12.2029** | 85 | 1.34 | 138,912 | 28,116 | - | 1,203 | - | - | 109,594 | 51,290 | 9,408 | 48,896 | 29,295 | 17,974 | 11,271 | 7,209 |
| **31.12.2030** | 94 | 1.48 | 152,723 | 30,911 | - | 1,326 | - | - | 120,486 | 56,387 | 10,740 | 53,358 | 30,446 | 17,831 | 10,695 | 6,556 |
| **31.12.2031** | 104 | 1.64 | 170,446 | 34,498 | - | 1,478 | - | - | 134,470 | 62,932 | 12,451 | 59,087 | 32,109 | 17,951 | 10,298 | 6,050 |
| **31.12.2032** | 110 | 1.74 | 183,781 | 37,197 | - | 1,584 | - | - | 145,000 | 67,860 | 13,740 | 63,400 | 32,812 | 17,510 | 9,609 | 5,409 |

| Total discounted cash flow from high estimate contingent resources as of December 31, 2018 (in $ in thousands in relation to the Partnership's share) | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cash flow components | | | | | | | | | | | | | | | | |
| | | | | | | | | | | Taxes | | Total Discounted Cash Flow After Tax | | | | |
| Until | Condensate Sales Volume (Barrels in Thousands) (100% of the Petroleum Asset) | Sales Volume (BCM) (100% of the Petroleum Asset) | Revenues | Royalties to be Paid | Royalties to be Received | Operating Costs | Develop-ment Costs | Abandon-ment and Restor-ation Costs | Total Cash Flow Before Levy and Income Tax (discounted at 0%) | Levy | Income Tax | Discounted at 0% | Discounted at 5% | Discounted at 10% | Discounted at 15% | Discounted at 20% |
| **31.12.2033** | 119 | 1.87 | 199,098 | 40,297 | - | 1,712 | - | - | 157,089 | 73,518 | 15,219 | 68,352 | 33,691 | 17,162 | 9,008 | 4,860 |
| **31.12.2034** | 129 | 2.03 | 218,002 | 44,124 | - | 1,869 | - | - | 172,010 | 80,500 | 19,046 | 72,463 | 34,016 | 16,540 | 8,304 | 4,293 |
| **31.12.2035** | 141 | 2.22 | 239,398 | 48,454 | - | 2,047 | - | - | 188,897 | 88,404 | 23,113 | 77,380 | 34,594 | 16,056 | 7,711 | 3,821 |
| **31.12.2036** | 150 | 2.37 | 259,332 | 52,489 | - | 2,208 | - | - | 204,635 | 95,769 | 25,039 | 83,826 | 35,692 | 15,813 | 7,264 | 3,449 |
| **31.12.2037** | 156 | 2.46 | 271,373 | 54,926 | - | 2,306 | - | - | 214,141 | 100,218 | 26,202 | 87,721 | 35,571 | 15,043 | 6,610 | 3,008 |
| **31.12.2038** | 163 | 2.56 | 297,928 | 60,301 | - | 2,489 | - | - | 235,138 | 110,045 | 28,771 | 96,322 | 37,199 | 15,016 | 6,311 | 2,752 |
| **31.12.2039** | 171 | 2.70 | 315,255 | 63,808 | - | 2,629 | - | - | 248,818 | 116,447 | 30,445 | 101,926 | 37,489 | 14,446 | 5,807 | 2,427 |
| **31.12.2040** | 173 | 2.73 | 323,613 | 65,499 | - | 2,689 | - | - | 255,425 | 119,539 | 31,254 | 104,632 | 36,652 | 13,481 | 5,184 | 2,076 |
| **31.12.2041** | 175 | 2.77 | 330,135 | 66,819 | - | 2,735 | - | - | 260,580 | 121,951 | 31,885 | 106,744 | 35,611 | 12,503 | 4,599 | 1,765 |
| **31.12.2042** | 180 | 2.84 | 343,011 | 69,425 | - | 2,833 | - | - | 270,752 | 126,712 | 33,129 | 110,911 | 35,239 | 11,810 | 4,155 | 1,528 |
| **31.12.2043** | 187 | 2.94 | 358,910 | 72,643 | - | 2,955 | 174,015 | - | 109,297 | 51,151 | 51,396 | 6,750 | 2,043 | 653 | 220 | 78 |
| **31.12.2044** | 193 | 3.05 | 376,318 | 76,167 | - | 3,086 | - | - | 297,065 | 139,026 | 32,347 | 125,692 | 36,223 | 11,061 | 3,561 | 1,203 |
| **31.12.2045** | 200 | 3.15 | 392,210 | 79,383 | - | 3,208 | - | - | 309,619 | 144,902 | 33,883 | 130,835 | 35,909 | 10,467 | 3,223 | 1,043 |
| **31.12.2046** | 217 | 3.42 | 430,124 | 87,057 | - | 3,509 | 22,897 | - | 316,661 | 148,197 | 39,747 | 128,716 | 33,646 | 9,361 | 2,757 | 855 |

| Total discounted cash flow from high estimate contingent resources as of December 31, 2018 (in $ in thousands in relation to the Partnership's share) | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cash flow components | | | | | | | | | | | | | | | | |
| Until | Condensate Sales Volume (Barrels in Thousands) (100% of the Petroleum Asset) | Sales Volume (BCM) (100% of the Petroleum Asset) | Revenues | Royalties to be Paid | Royalties to be Received | Operating Costs | Develop-ment Costs | Abandon-ment and Restor-ation 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 10% | Discounted at 15% | Discounted at 20% |
| **31.12.2047** | 219 | 3.45 | 440,134 | 89,083 | - | 3,577 | - | - | 347,474 | 162,618 | 37,988 | 146,868 | 36,562 | 9,710 | 2,736 | 813 |
| **31.12.2048** | 222 | 3.50 | 452,118 | 91,509 | - | 3,659 | - | - | 356,950 | 167,053 | 39,147 | 150,750 | 35,742 | 9,061 | 2,442 | 696 |
| **31.12.2049** | 223 | 3.52 | 461,329 | 93,373 | - | 3,719 | - | - | 364,237 | 170,463 | 40,039 | 153,735 | 34,714 | 8,400 | 2,165 | 591 |
| **31.12.2050** | 226 | 3.56 | 472,818 | 95,698 | - | 3,796 | - | - | 373,324 | 174,716 | 41,151 | 157,457 | 33,861 | 7,822 | 1,928 | 505 |
| **31.12.2051** | 228 | 3.59 | 484,713 | 98,106 | - | 3,876 | 174,015 | - | 208,717 | 97,679 | 59,032 | 52,005 | 10,651 | 2,348 | 554 | 139 |
| **31.12.2052** | 231 | 3.64 | 498,169 | 100,829 | - | 3,968 | - | - | 393,372 | 184,098 | 39,602 | 169,672 | 33,096 | 6,966 | 1,571 | 378 |
| **31.12.2053** | 233 | 3.68 | 508,582 | 102,937 | - | 4,038 | - | - | 401,607 | 187,952 | 42,611 | 171,044 | 31,774 | 6,384 | 1,377 | 317 |
| **31.12.2054** | 238 | 3.76 | 526,259 | 106,515 | - | 4,164 | - | - | 415,580 | 194,491 | 46,321 | 174,767 | 30,920 | 5,930 | 1,224 | 270 |
| **31.12.2055** | 271 | 4.27 | 604,862 | 122,424 | - | 4,773 | 185,463 | - | 292,202 | 136,750 | 71,512 | 83,940 | 14,144 | 2,589 | 511 | 108 |
| **31.12.2056** | 330 | 5.21 | 744,722 | 150,732 | - | 5,860 | - | - | 588,130 | 275,245 | 62,958 | 249,927 | 40,106 | 7,008 | 1,323 | 268 |
| **31.12.2057** | 358 | 5.64 | 816,841 | 165,329 | - | 6,406 | - | - | 645,107 | 301,910 | 70,193 | 273,003 | 41,723 | 6,959 | 1,257 | 244 |
| **31.12.2058** | 376 | 5.92 | 870,182 | 176,125 | - | 6,798 | - | - | 687,259 | 321,637 | 75,351 | 290,271 | 42,250 | 6,727 | 1,162 | 216 |
| **31.12.2059** | 382 | 6.02 | 897,243 | 181,602 | - | 6,982 | 185,463 | - | 523,195 | 244,855 | 93,667 | 184,673 | 25,600 | 3,890 | 643 | 115 |
| **31.12.2060** | 383 | 6.03 | 913,614 | 184,915 | - | 7,081 | - | - | 721,617 | 337,717 | 71,024 | 312,877 | 41,306 | 5,992 | 947 | 162 |

| Total discounted cash flow from high estimate contingent resources as of December 31, 2018 (in $ in thousands in relation to the Partnership's share) | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cash flow components | | | | | | | | | | | | | | | | |
| | | | | | | | | | | Taxes | | Total Discounted Cash Flow After Tax | | | | |
| Until | Condensate Sales Volume (Barrels in Thousands) (100% of the Petroleum Asset) | Sales Volume (BCM) (100% of the Petroleum Asset) | Revenues | Royalties to be Paid | Royalties to be Received | Operating Costs | Develop-ment Costs | Abandon-ment and Restor-ation Costs | Total Cash Flow Before Levy and Income Tax (discounted at 0%) | Levy | Income Tax | Discounted at 0% | Discounted at 5% | Discounted at 10% | Discounted at 15% | Discounted at 20% |
| **31.12.2061** | 382 | 6.02 | 924,977 | 187,215 | - | 7,142 | - | - | 730,620 | 341,930 | 74,127 | 314,563 | 39,551 | 5,477 | 828 | 136 |
| **31.12.2062** | 382 | 6.02 | 939,321 | 190,119 | - | 7,224 | 219,808 | - | 522,169 | 244,375 | 80,895 | 196,899 | 23,578 | 3,116 | 451 | 71 |
| **31.12.2063** | 382 | 6.02 | 953,486 | 192,986 | - | 7,306 | 306,816 | - | 446,379 | 208,905 | 43,710 | 193,763 | 22,098 | 2,788 | 386 | 58 |
| **31.12.2064** | 45 | 0.71 | 120,171 | 24,323 | - | 906 | - | 99,703 | (4,760) | - | - | (4,760) | (517) | (62) | (8) | (1) |
| **Total** | **8,020** | **126.4** | **16,910,969** | **3,422,108** | **-** | **135,539** | **1,442,492** | **99,703** | **11,811,128** | **5,535,762** | **1,483,699** | **4,791,666** | **1,108,326** | **331,018** | **116,912** | **43,457** |

5. Summary of the discounted cash flow figures from the contingent resources and reserves classified in Phase 1 – First Stage

Set forth below are tables summarizing the discounted cash flow figures from the contingent resources and reserves which are presented in addition to the discounted cash flow figures from the contingent resources and reserves as provided in Sections 7.4.10(a)3 and 7.4.10(b)4 above:

| Total discounted cash flow from proved reserves and low estimate contingent resources as of _December 31, 2018 (in $ in thousands in relation to the Partnership's share) | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cash flow components | | | | | | | | | | | | | | | | |
| Until | Condensate Sales Volume (Barrels in Thousands) (100% of the Petroleum Asset) | Sales Volume (BCM) (100% of the Petroleum Asset) | Revenues | Royalties to be Paid | Royalties to be Received | Operating Costs | Develop-ment Costs | Abandon-ment and Restor-ation 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 10% | Discounted at 15% | Discounted at 20% |
| **31.12.2019** | - | - | - | - | - | - | 707,614 | - | (707,614) | - | - | (707,614) | (690,561) | (674,684) | (659,854) | (645,960) |
| **31.12.2020** | 721 | 11.37 | 1,012,388 | 158,338 | - | 75,618 | 37,458 | - | 740,974 | - | 81,485 | 659,490 | 612,949 | 571,635 | 534,763 | 501,691 |
| **31.12.2021** | 762 | 12.01 | 1,121,501 | 175,403 | - | 76,441 | - | - | 869,657 | - | 155,327 | 714,330 | 632,304 | 562,882 | 503,680 | 452,841 |
| **31.12.2022** | 654 | 10.31 | 998,362 | 156,144 | - | 75,218 | - | - | 767,000 | - | 131,716 | 635,284 | 535,557 | 455,086 | 389,516 | 335,609 |
| **31.12.2023** | 753 | 11.87 | 1,165,923 | 207,214 | - | 71,508 | - | - | 887,201 | - | 159,362 | 727,839 | 584,364 | 473,989 | 388,056 | 320,420 |
| **31.12.2024** | 765 | 12.06 | 1,198,806 | 242,638 | - | 71,757 | 174,015 | - | 710,396 | 24,542 | 151,074 | 534,779 | 408,915 | 316,603 | 247,934 | 196,190 |
| **31.12.2025** | 763 | 12.03 | 1,205,635 | 244,021 | - | 71,786 | - | - | 889,828 | 246,401 | 99,292 | 544,136 | 396,257 | 292,856 | 219,367 | 166,352 |
| **31.12.2026** | 763 | 12.03 | 1,218,578 | 246,640 | - | 71,860 | - | - | 900,078 | 342,229 | 79,609 | 478,240 | 331,685 | 233,992 | 167,653 | 121,839 |
| **31.12.2027** | 763 | 12.03 | 1,240,661 | 251,110 | - | 71,988 | - | - | 917,564 | 417,799 | 66,249 | 433,515 | 286,349 | 192,826 | 132,152 | 92,037 |
| **31.12.2028** | 765 | 12.06 | 1,267,094 | 256,460 | - | 72,150 | - | - | 938,484 | 439,211 | 66,136 | 433,137 | 272,475 | 175,144 | 114,814 | 76,631 |

| Total discounted cash flow from proved reserves and low estimate contingent resources as of _December 31, 2018 (in $ in thousands in relation to the Partnership’s share) | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cash flow components | | | | | | | | | | | | | | | | |
| Until | Condensate Sales Volume (Barrels in Thousands) (100% of the Petroleum Asset) | Sales Volume (BCM) (100% of the Petroleum Asset) | Revenues | Royalties to be Paid | Royalties to be Received | Operating Costs | Develop-ment Costs | Abandon-ment and Restor-ation 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 10% | Discounted at 15% | Discounted at 20% |
| **31.12.2029** | 763 | 12.03 | 1,282,217 | 259,521 | - | 92,834 | - | - | 929,862 | 435,175 | 65,081 | 429,605 | 257,384 | 157,923 | 99,024 | 63,338 |
| **31.12.2030** | 763 | 12.03 | 1,300,118 | 263,144 | - | 72,330 | - | - | 964,644 | 451,453 | 113,601 | 399,590 | 228,001 | 133,536 | 80,092 | 49,094 |
| **31.12.2031** | 763 | 12.03 | 1,324,619 | 268,103 | - | 72,471 | - | - | 984,044 | 460,533 | 116,405 | 407,106 | 221,229 | 123,680 | 70,955 | 41,681 |
| **31.12.2032** | 765 | 12.06 | 1,355,153 | 274,283 | - | 72,657 | - | - | 1,008,213 | 471,844 | 119,363 | 417,007 | 215,818 | 115,171 | 63,201 | 35,579 |
| **31.12.2033** | 763 | 12.03 | 1,379,117 | 279,133 | - | 72,785 | - | - | 1,027,199 | 480,729 | 121,686 | 424,784 | 209,374 | 106,653 | 55,982 | 30,202 |
| **31.12.2034** | 763 | 12.03 | 1,402,280 | 283,821 | - | 93,526 | - | - | 1,024,933 | 479,668 | 123,410 | 421,855 | 198,029 | 96,289 | 48,344 | 24,995 |
| **31.12.2035** | 763 | 12.03 | 1,428,438 | 289,116 | - | 73,069 | 174,015 | - | 892,238 | 417,567 | 147,197 | 327,474 | 146,404 | 67,951 | 32,633 | 16,169 |
| **31.12.2036** | 765 | 12.06 | 1,454,360 | 294,363 | - | 73,229 | - | - | 1,086,769 | 508,608 | 128,975 | 449,186 | 191,256 | 84,733 | 38,924 | 18,482 |
| **31.12.2037** | 763 | 12.03 | 1,458,341 | 295,168 | - | 73,242 | 22,897 | - | 1,067,034 | 499,372 | 131,563 | 436,099 | 176,841 | 74,786 | 32,861 | 14,953 |
| **31.12.2038** | 763 | 12.03 | 1,394,591 | 282,265 | - | 72,874 | - | - | 1,039,452 | 486,463 | 122,658 | 430,330 | 166,192 | 67,088 | 28,196 | 12,296 |
| **31.12.2039** | 763 | 12.03 | 1,414,021 | 286,198 | - | 93,593 | - | - | 1,034,230 | 484,019 | 122,019 | 428,191 | 157,491 | 60,686 | 24,397 | 10,196 |
| **31.12.2040** | 765 | 12.06 | 1,436,998 | 290,848 | - | 73,129 | 174,015 | - | 899,006 | 420,735 | 143,496 | 334,776 | 117,269 | 43,133 | 16,586 | 6,643 |
| **31.12.2041** | 763 | 12.03 | 1,455,600 | 294,613 | - | 73,226 | - | - | 1,087,761 | 509,072 | 124,567 | 454,122 | 151,500 | 53,191 | 19,565 | 7,509 |
| **31.12.2042** | 763 | 12.03 | 1,478,702 | 299,289 | - | 73,359 | - | - | 1,106,054 | 517,633 | 126,805 | 461,615 | 146,667 | 49,153 | 17,293 | 6,361 |

| Total discounted cash flow from proved reserves and low estimate contingent resources as of _December 31, 2018 (in $ in thousands in relation to the Partnership's share) | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cash flow components | | | | | | | | | | | | | | | | |
| Until | Condensate Sales Volume (Barrels in Thousands) (100% of the Petroleum Asset) | Sales Volume (BCM) (100% of the Petroleum Asset) | Revenues | Royalties to be Paid | Royalties to be Received | Operating Costs | Develop-ment Costs | Abandon-ment and Restor-ation 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 10% | Discounted at 15% | Discounted at 20% |
| **31.12.2043** | 763 | 12.03 | 1,502,100 | 304,025 | - | 73,494 | - | - | 1,124,582 | 526,304 | 129,073 | 469,205 | 141,979 | 45,419 | 15,285 | 5,388 |
| **31.12.2044** | 765 | 12.06 | 1,530,460 | 309,765 | - | 94,274 | - | - | 1,126,421 | 527,165 | 129,298 | 469,958 | 135,435 | 41,357 | 13,313 | 4,497 |
| **31.12.2045** | 763 | 12.03 | 1,549,996 | 313,719 | - | 73,769 | - | - | 1,162,508 | 544,054 | 135,714 | 482,740 | 132,494 | 38,620 | 11,891 | 3,850 |
| **31.12.2046** | 763 | 12.03 | 1,574,637 | 318,706 | - | 73,911 | - | - | 1,182,019 | 553,185 | 140,103 | 488,731 | 127,751 | 35,544 | 10,468 | 3,248 |
| **31.12.2047** | 763 | 12.03 | 1,598,974 | 323,632 | - | 74,052 | - | - | 1,201,290 | 562,204 | 142,724 | 496,362 | 123,567 | 32,818 | 9,245 | 2,749 |
| **31.12.2048** | 765 | 12.06 | 1,627,936 | 329,494 | - | 74,228 | 185,463 | - | 1,038,751 | 486,135 | 163,623 | 388,992 | 92,227 | 23,381 | 6,300 | 1,795 |
| **31.12.2049** | 763 | 12.03 | 1,648,615 | 333,680 | - | 94,945 | - | - | 1,219,990 | 570,956 | 141,010 | 508,025 | 114,713 | 27,759 | 7,155 | 1,954 |
| **31.12.2050** | 763 | 12.03 | 1,674,245 | 338,867 | - | 74,485 | - | - | 1,260,893 | 590,098 | 148,016 | 522,779 | 112,423 | 25,969 | 6,402 | 1,675 |
| **31.12.2051** | 763 | 12.03 | 1,699,844 | 344,048 | - | 74,633 | 318,264 | - | 962,898 | 450,636 | 183,095 | 329,167 | 67,416 | 14,865 | 3,505 | 879 |
| **31.12.2052** | 765 | 12.06 | 1,723,272 | 348,790 | - | 74,775 | - | - | 1,299,706 | 608,263 | 147,446 | 543,997 | 106,110 | 22,333 | 5,038 | 1,211 |
| **31.12.2053** | 705 | 11.12 | 1,602,764 | 324,399 | - | 73,797 | 196,912 | - | 1,007,656 | 471,583 | 154,736 | 381,337 | 70,840 | 14,232 | 3,071 | 707 |
| **31.12.2054** | 628 | 9.90 | 1,452,632 | 294,013 | - | 93,172 | 196,912 | - | 868,536 | 406,475 | 133,185 | 328,876 | 58,185 | 11,158 | 2,303 | 508 |
| **31.12.2055** | 569 | 8.98 | 1,343,250 | 271,874 | - | 71,658 | - | - | 999,718 | 467,868 | 101,682 | 430,168 | 72,482 | 13,268 | 2,619 | 554 |
| **31.12.2056** | 521 | 8.22 | 1,251,810 | 253,366 | - | 70,902 | - | - | 927,541 | 434,089 | 92,850 | 400,602 | 64,286 | 11,233 | 2,121 | 430 |

| Total discounted cash flow from proved reserves and low estimate contingent resources as of _December 31, 2018 (in $ in thousands in relation to the Partnership's share) | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cash flow components | | | | | | | | | | | | | | | | | |
| | | | | | | | | | | Taxes | | Total Discounted Cash Flow After Tax | | | | | |
| Until | Condensate Sales Volume (Barrels in Thousands) (100% of the Petroleum Asset) | Sales Volume (BCM) (100% of the Petroleum Asset) | Revenues | Royalties to be Paid | Royalties to be Received | Operating Costs | Develop-ment Costs | Abandon-ment and Restor-ation Costs | Total Cash Flow Before Levy and Income Tax (discounted at 0%) | Levy | Income Tax | Discounted at 0% | Discounted at 5% | Discounted at 10% | Discounted at 15% | Discounted at 20% |
| **31.12.2057** | 445 | 7.02 | 1,094,334 | 221,493 | - | 69,634 | - | - | 803,206 | 375,901 | 77,637 | 349,669 | 53,440 | 8,913 | 1,610 | 313 |
| **31.12.2058** | 405 | 6.38 | 1,012,320 | 204,894 | - | 68,969 | - | - | 738,458 | 345,598 | 71,847 | 321,013 | 46,725 | 7,439 | 1,285 | 239 |
| **31.12.2059** | 393 | 6.20 | 995,210 | 201,431 | - | 89,423 | - | - | 704,356 | 329,639 | 69,807 | 304,911 | 42,267 | 6,423 | 1,061 | 189 |
| **31.12.2060** | 381 | 6.01 | 976,129 | 197,569 | - | 68,650 | - | - | 709,911 | 332,238 | 70,487 | 307,186 | 40,555 | 5,883 | 930 | 159 |
| **31.12.2061** | 365 | 5.75 | 944,522 | 191,171 | - | 68,388 | - | - | 684,962 | 320,562 | 71,094 | 293,306 | 36,879 | 5,107 | 772 | 127 |
| **31.12.2062** | 349 | 5.50 | 913,182 | 184,828 | - | 68,131 | - | - | 660,223 | 308,985 | 59,438 | 291,801 | 34,942 | 4,619 | 668 | 105 |
| **31.12.2063** | 332 | 5.24 | 880,328 | 178,178 | - | 67,865 | - | - | 634,285 | 296,845 | 58,528 | 278,911 | 31,808 | 4,013 | 555 | 84 |
| **31.12.2064** | 39 | 0.61 | 103,011 | 20,849 | - | 61,990 | - | 160,295 | (140,124) | - | - | (140,124) | (15,219) | (1,833) | (243) | (35) |
| **Total** | **30,167** | **475.6** | **58,693,072** | **11,706,626** | **-** | **3,395,793** | **2,187,564** | **160,295** | **41,242,793** | **17,601,838** | **5,118,468** | **18,522,488** | **7,645,054** | **4,232,822** | **2,771,491** | **1,985,775** |

| Total discounted cash flow from probable reserves and best estimate contingent resources as of December 31, 2018 (in $ in thousands in relation to the Partnership's share) | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cash flow components | | | | | | | | | | | | | | | | |
| | | | | | | | | | | Taxes | | Total Discounted Cash Flow After Tax | | | | |
| Until | Condensate Sales Volume (Barrels in Thousands) (100% of the Petroleum Asset) | Sales Volume (BCM) (100% of the Petroleum Asset) | Revenues | Royalties to be Paid | Royalties to be Received | Operating Costs | Develop-ment Costs | Abandon-ment and Restor-ation Costs | Total Cash Flow Before Levy and Income Tax (discounted at 0%) | Levy | Income Tax | Discounted at 0% | Discounted at 5% | Discounted at 10% | Discounted at 15% | Discounted at 20% |
| **31.12.2019** | - | - | - | - | - | - | 707,614 | - | (707,614) | - | - | (707,614) | (690,561) | (674,684) | (659,854) | (645,960) |
| **31.12.2020** | 721 | 11.37 | 1,012,388 | 158,338 | - | 75,618 | 37,458 | - | 740,974 | - | 81,485 | 659,490 | 612,949 | 571,635 | 534,763 | 501,691 |
| **31.12.2021** | 762 | 12.01 | 1,121,268 | 175,366 | - | 76,439 | - | - | 869,462 | - | 155,282 | 714,180 | 632,171 | 562,764 | 503,574 | 452,746 |
| **31.12.2022** | 654 | 10.31 | 998,362 | 156,144 | - | 75,218 | - | - | 767,000 | - | 131,716 | 635,284 | 535,557 | 455,086 | 389,516 | 335,609 |
| **31.12.2023** | 752 | 11.85 | 1,164,317 | 206,869 | - | 71,494 | - | - | 885,954 | - | 159,075 | 726,879 | 583,593 | 473,364 | 387,545 | 319,997 |
| **31.12.2024** | 765 | 12.06 | 1,198,885 | 242,654 | - | 71,757 | 174,015 | - | 710,458 | 24,521 | 151,094 | 534,844 | 408,965 | 316,641 | 247,964 | 196,214 |
| **31.12.2025** | 763 | 12.03 | 1,205,734 | 244,041 | - | 71,787 | - | - | 889,907 | 246,250 | 99,345 | 544,312 | 396,385 | 292,951 | 219,438 | 166,406 |
| **31.12.2026** | 763 | 12.03 | 1,218,757 | 246,676 | - | 71,862 | - | - | 900,219 | 342,134 | 79,663 | 478,422 | 331,811 | 234,081 | 167,717 | 121,885 |
| **31.12.2027** | 763 | 12.03 | 1,240,689 | 251,115 | - | 71,988 | - | - | 917,586 | 417,733 | 66,270 | 433,583 | 286,393 | 192,856 | 132,172 | 92,052 |
| **31.12.2028** | 765 | 12.06 | 1,267,119 | 256,465 | - | 72,150 | - | - | 938,504 | 439,220 | 66,139 | 433,145 | 272,480 | 175,147 | 114,816 | 76,632 |
| **31.12.2029** | 763 | 12.03 | 1,282,236 | 259,525 | - | 92,834 | - | - | 929,877 | 435,183 | 65,083 | 429,611 | 257,388 | 157,926 | 99,026 | 63,339 |
| **31.12.2030** | 763 | 12.03 | 1,300,126 | 263,145 | - | 72,330 | - | - | 964,650 | 451,456 | 113,601 | 399,592 | 228,003 | 133,537 | 80,093 | 49,095 |
| **31.12.2031** | 763 | 12.03 | 1,324,617 | 268,102 | - | 72,471 | - | - | 984,043 | 460,532 | 116,405 | 407,106 | 221,228 | 123,680 | 70,955 | 41,681 |
| **31.12.2032** | 765 | 12.06 | 1,355,156 | 274,284 | - | 72,657 | - | - | 1,008,216 | 471,845 | 119,363 | 417,008 | 215,818 | 115,171 | 63,201 | 35,579 |

| Total discounted cash flow from probable reserves and best estimate contingent resources as of December 31, 2018 (in $ in thousands in relation to the Partnership's share) | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cash flow components | | | | | | | | | | | | | | | | |
| Until | Condensate Sales Volume (Barrels in Thousands) (100% of the Petroleum Asset) | Sales Volume (BCM) (100% of the Petroleum Asset) | Revenues | Royalties to be Paid | Royalties to be Received | Operating Costs | Develop-ment Costs | Abandon-ment and Restor-ation 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 10% | Discounted at 15% | Discounted at 20% |
| **31.12.2033** | 763 | 12.03 | 1,379,122 | 279,134 | - | 72,785 | - | - | 1,027,203 | 480,731 | 121,686 | 424,786 | 209,375 | 106,654 | 55,982 | 30,202 |
| **31.12.2034** | 763 | 12.03 | 1,402,298 | 283,825 | - | 93,526 | - | - | 1,024,947 | 479,675 | 123,411 | 421,860 | 198,032 | 96,290 | 48,345 | 24,995 |
| **31.12.2035** | 763 | 12.03 | 1,428,435 | 289,115 | - | 73,069 | - | - | 1,066,250 | 499,005 | 130,466 | 436,779 | 195,271 | 90,632 | 43,526 | 21,566 |
| **31.12.2036** | 765 | 12.06 | 1,454,381 | 294,367 | - | 73,229 | 174,015 | - | 912,770 | 427,177 | 149,709 | 335,885 | 143,014 | 63,361 | 29,106 | 13,820 |
| **31.12.2037** | 763 | 12.03 | 1,458,341 | 295,168 | - | 73,242 | - | - | 1,089,931 | 510,088 | 129,362 | 450,482 | 182,673 | 77,252 | 33,944 | 15,446 |
| **31.12.2038** | 763 | 12.03 | 1,394,589 | 282,265 | - | 72,874 | 22,897 | - | 1,016,553 | 475,747 | 125,386 | 415,420 | 160,434 | 64,764 | 27,219 | 11,870 |
| **31.12.2039** | 763 | 12.03 | 1,414,005 | 286,195 | - | 93,593 | - | - | 1,034,217 | 484,014 | 122,018 | 428,186 | 157,490 | 60,685 | 24,396 | 10,196 |
| **31.12.2040** | 765 | 12.06 | 1,436,996 | 290,848 | - | 73,129 | - | - | 1,073,020 | 502,173 | 126,766 | 444,081 | 155,558 | 57,216 | 22,002 | 8,812 |
| **31.12.2041** | 763 | 12.03 | 1,455,600 | 294,613 | - | 73,226 | - | - | 1,087,761 | 509,072 | 128,569 | 450,119 | 150,165 | 52,722 | 19,392 | 7,443 |
| **31.12.2042** | 763 | 12.03 | 1,478,706 | 299,290 | - | 73,359 | - | - | 1,106,057 | 517,635 | 130,808 | 457,614 | 145,395 | 48,727 | 17,144 | 6,306 |
| **31.12.2043** | 763 | 12.03 | 1,502,096 | 304,024 | - | 73,494 | - | - | 1,124,579 | 526,303 | 133,074 | 465,201 | 140,768 | 45,032 | 15,155 | 5,342 |
| **31.12.2044** | 765 | 12.06 | 1,530,460 | 309,765 | - | 94,274 | 174,015 | - | 952,406 | 445,726 | 150,030 | 356,650 | 102,782 | 31,386 | 10,103 | 3,413 |
| **31.12.2045** | 763 | 12.03 | 1,550,000 | 313,720 | - | 73,769 | - | - | 1,162,511 | 544,055 | 133,714 | 484,742 | 133,044 | 38,780 | 11,940 | 3,866 |
| **31.12.2046** | 763 | 12.03 | 1,574,637 | 318,706 | - | 73,911 | - | - | 1,182,019 | 553,185 | 138,102 | 490,732 | 128,274 | 35,690 | 10,511 | 3,261 |

| Total discounted cash flow from probable reserves and best estimate contingent resources as of December 31, 2018 (in $ in thousands in relation to the Partnership's share) | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cash flow components | | | | | | | | | | | | | | | | |
| | | | | | | | | | | Taxes | | Total Discounted Cash Flow After Tax | | | | |
| Until | Condensate Sales Volume (Barrels in Thousands) (100% of the Petroleum Asset) | Sales Volume (BCM) (100% of the Petroleum Asset) | Revenues | Royalties to be Paid | Royalties to be Received | Operating Costs | Develop-ment Costs | Abandon-ment and Restor-ation Costs | Total Cash Flow Before Levy and Income Tax (discounted at 0%) | Levy | Income Tax | Discounted at 0% | Discounted at 5% | Discounted at 10% | Discounted at 15% | Discounted at 20% |
| **31.12.2047** | 763 | 12.03 | 1,598,970 | 323,631 | - | 74,052 | 185,463 | - | 1,015,823 | 475,405 | 160,291 | 380,127 | 94,631 | 25,133 | 7,080 | 2,105 |
| **31.12.2048** | 765 | 12.06 | 1,627,936 | 329,494 | - | 74,228 | - | - | 1,224,214 | 572,932 | 141,263 | 510,018 | 120,921 | 30,655 | 8,260 | 2,354 |
| **31.12.2049** | 763 | 12.03 | 1,648,619 | 333,680 | - | 94,945 | 185,463 | - | 1,034,530 | 484,160 | 158,841 | 391,529 | 88,408 | 21,394 | 5,514 | 1,506 |
| **31.12.2050** | 763 | 12.03 | 1,674,245 | 338,867 | - | 74,485 | - | - | 1,260,893 | 590,098 | 141,749 | 529,046 | 113,771 | 26,280 | 6,479 | 1,695 |
| **31.12.2051** | 763 | 12.03 | 1,699,839 | 344,047 | - | 74,633 | 219,808 | - | 1,061,351 | 496,712 | 165,361 | 399,277 | 81,775 | 18,031 | 4,252 | 1,066 |
| **31.12.2052** | 765 | 12.06 | 1,724,418 | 349,022 | - | 74,784 | 306,816 | - | 993,796 | 465,097 | 171,051 | 357,649 | 69,761 | 14,683 | 3,312 | 796 |
| **31.12.2053** | 734 | 11.57 | 1,670,416 | 338,092 | - | 74,324 | - | - | 1,258,000 | 588,744 | 129,283 | 539,973 | 100,309 | 20,152 | 4,348 | 1,001 |
| **31.12.2054** | 721 | 11.37 | 1,660,038 | 335,992 | - | 94,811 | - | - | 1,229,235 | 575,282 | 127,764 | 526,189 | 93,094 | 17,853 | 3,684 | 813 |
| **31.12.2055** | 721 | 11.37 | 1,679,800 | 339,992 | - | 74,318 | - | - | 1,265,491 | 592,250 | 134,202 | 539,039 | 90,826 | 16,626 | 3,282 | 694 |
| **31.12.2056** | 723 | 11.40 | 1,704,666 | 345,024 | - | 74,470 | - | - | 1,285,171 | 601,460 | 136,610 | 547,101 | 87,795 | 15,341 | 2,897 | 587 |
| **31.12.2057** | 673 | 10.61 | 1,606,940 | 325,245 | - | 73,669 | - | - | 1,208,026 | 565,356 | 129,303 | 513,367 | 78,458 | 13,086 | 2,364 | 459 |
| **31.12.2058** | 656 | 10.34 | 1,587,030 | 321,215 | - | 73,472 | - | - | 1,192,344 | 558,017 | 129,517 | 504,810 | 73,477 | 11,698 | 2,021 | 376 |
| **31.12.2059** | 656 | 10.34 | 1,606,550 | 325,166 | - | 94,191 | - | - | 1,187,193 | 555,606 | 131,020 | 500,567 | 69,390 | 10,545 | 1,743 | 311 |
| **31.12.2060** | 657 | 10.36 | 1,630,825 | 330,079 | - | 73,732 | - | - | 1,227,013 | 574,242 | 138,025 | 514,746 | 67,957 | 9,858 | 1,558 | 266 |

| Total discounted cash flow from probable reserves and best estimate contingent resources as of December 31, 2018 (in $ in thousands in relation to the Partnership's share) | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cash flow components | | | | | | | | | | | | | | | | |
| | | | | | | | | | | Taxes | | Total Discounted Cash Flow After Tax | | | | |
| Until | Condensate Sales Volume (Barrels in Thousands) (100% of the Petroleum Asset) | Sales Volume (BCM) (100% of the Petroleum Asset) | Revenues | Royalties to be Paid | Royalties to be Received | Operating Costs | Develop-ment Costs | Abandon-ment and Restor-ation Costs | Total Cash Flow Before Levy and Income Tax (discounted at 0%) | Levy | Income Tax | Discounted at 0% | Discounted at 5% | Discounted at 10% | Discounted at 15% | Discounted at 20% |
| **31.12.2061** | 651 | 10.26 | 1,635,775 | 331,081 | - | 73,730 | - | - | 1,230,964 | 576,091 | 141,036 | 513,837 | 64,607 | 8,946 | 1,353 | 222 |
| **31.12.2062** | 596 | 9.40 | 1,522,430 | 308,140 | - | 72,818 | - | - | 1,141,472 | 534,209 | 123,853 | 483,410 | 57,887 | 7,651 | 1,107 | 174 |
| **31.12.2063** | 590 | 9.30 | 1,524,523 | 308,563 | - | 72,800 | - | - | 1,143,160 | 534,999 | 127,588 | 480,573 | 54,807 | 6,915 | 957 | 144 |
| **31.12.2064** | 70 | 1.10 | 185,823 | 37,611 | - | 62,614 | - | 160,295 | (74,697) | - | - | (74,697) | (8,113) | (977) | (129) | (19) |
| **Total** | **32,481** | **512.1** | **64,138,164** | **12,808,703** | **-** | **3,438,161** | **2,187,564** | **160,295** | **45,543,441** | **19,584,120** | **5,634,380** | **20,324,942** | **7,894,218** | **4,273,215** | **2,779,773** | **1,988,057** |

| Total discounted cash flow from possible reserves and high estimate contingent resources as of December 31, 2018 (in $ in thousands in relation to the Partnership's share) | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cash flow components | | | | | | | | | | | | | | | | |
| Until | Condensate Sales Volume (Barrels in Thousands) (100% of the Petroleum Asset) | Sales Volume (BCM) (100% of the Petroleum Asset) | Revenues | Royalties to be Paid | Royalties to be Received | Operating Costs | Develop-ment Costs | Abandon-ment and Restor-ation 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 10% | Discounted at 15% | Discounted at 20% |
| **31.12.2019** | - | - | - | - | - | - | 707,614 | - | (707,614) | - | - | (707,614) | (690,561) | (674,684) | (659,854) | (645,960) |
| **31.12.2020** | 721 | 11.37 | 1,012,388 | 158,338 | - | 75,618 | 37,458 | - | 740,974 | - | 81,485 | 659,490 | 612,949 | 571,635 | 534,763 | 501,691 |
| **31.12.2021** | 763 | 12.02 | 1,122,575 | 175,571 | - | 76,451 | - | - | 870,554 | - | 155,533 | 715,020 | 632,915 | 563,426 | 504,166 | 453,279 |
| **31.12.2022** | 654 | 10.31 | 998,362 | 156,144 | - | 75,218 | - | - | 767,000 | - | 131,716 | 635,284 | 535,557 | 455,086 | 389,516 | 335,609 |
| **31.12.2023** | 760 | 11.98 | 1,177,743 | 209,720 | - | 71,610 | - | - | 896,414 | - | 161,481 | 734,933 | 590,059 | 478,609 | 391,839 | 323,543 |
| **31.12.2024** | 765 | 12.06 | 1,198,806 | 242,638 | - | 71,757 | 174,015 | - | 710,396 | 24,717 | 151,034 | 534,645 | 408,813 | 316,523 | 247,872 | 196,141 |
| **31.12.2025** | 763 | 12.03 | 1,205,635 | 244,020 | - | 71,786 | - | - | 889,828 | 247,698 | 98,993 | 543,137 | 395,529 | 292,319 | 218,964 | 166,047 |
| **31.12.2026** | 763 | 12.03 | 1,218,866 | 246,699 | - | 71,862 | - | - | 900,305 | 343,545 | 79,359 | 477,402 | 331,104 | 233,582 | 167,360 | 121,626 |
| **31.12.2027** | 763 | 12.03 | 1,240,765 | 251,131 | - | 71,989 | - | - | 917,646 | 418,500 | 66,107 | 433,039 | 286,034 | 192,614 | 132,006 | 91,936 |
| **31.12.2028** | 765 | 12.06 | 1,267,084 | 256,458 | - | 72,150 | - | - | 938,476 | 439,207 | 66,135 | 433,134 | 272,473 | 175,143 | 114,813 | 76,630 |
| **31.12.2029** | 763 | 12.03 | 1,282,254 | 259,528 | - | 92,834 | - | - | 929,892 | 435,189 | 65,085 | 429,617 | 257,391 | 157,928 | 99,027 | 63,340 |
| **31.12.2030** | 763 | 12.03 | 1,300,123 | 263,145 | - | 72,330 | - | - | 964,648 | 451,455 | 113,601 | 399,592 | 228,002 | 133,537 | 80,092 | 49,094 |
| **31.12.2031** | 763 | 12.03 | 1,324,775 | 268,135 | - | 72,473 | - | - | 984,168 | 460,591 | 116,420 | 407,157 | 221,256 | 123,695 | 70,964 | 41,687 |

**Total discounted cash flow from possible reserves and high estimate contingent resources as of December 31, 2018 (in $ in thousands in relation to the Partnership's share)**

**Cash flow components**

| Until | Condensate Sales Volume (Barrels in Thousands) (100% of the Petroleum Asset) | Sales Volume (BCM) (100% of the Petroleum Asset) | Revenues | Royalties to be Paid | Royalties to be Received | Operating Costs | Develop-ment Costs | Abandon-ment and Restor-ation 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 10% | Discounted at 15% | Discounted at 20% |
| **31.12.2032** | 765 | 12.07 | 1,355,353 | 274,323 | - | 72,659 | - | - | 1,008,370 | 471,917 | 119,382 | 417,071 | 215,851 | 115,188 | 63,211 | 35,585 |
| **31.12.2033** | 763 | 12.04 | 1,379,667 | 279,245 | - | 72,790 | - | - | 1,027,633 | 480,932 | 121,739 | 424,962 | 209,462 | 106,698 | 56,006 | 30,215 |
| **31.12.2034** | 763 | 12.03 | 1,402,791 | 283,925 | - | 93,530 | - | - | 1,025,336 | 479,857 | 123,459 | 422,020 | 198,106 | 96,327 | 48,363 | 25,005 |
| **31.12.2035** | 763 | 12.03 | 1,428,391 | 289,106 | - | 73,069 | - | - | 1,066,215 | 498,989 | 130,462 | 436,765 | 195,265 | 90,629 | 43,524 | 21,565 |
| **31.12.2036** | 765 | 12.06 | 1,454,403 | 294,371 | - | 73,229 | - | - | 1,086,803 | 508,624 | 132,981 | 445,198 | 189,557 | 83,981 | 38,578 | 18,318 |
| **31.12.2037** | 763 | 12.03 | 1,458,380 | 295,176 | - | 73,242 | - | - | 1,089,962 | 510,102 | 133,368 | 446,492 | 181,056 | 76,568 | 33,644 | 15,309 |
| **31.12.2038** | 763 | 12.03 | 1,394,591 | 282,265 | - | 72,874 | - | - | 1,039,452 | 486,463 | 127,187 | 425,801 | 164,443 | 66,382 | 27,900 | 12,167 |
| **31.12.2039** | 763 | 12.03 | 1,414,005 | 286,195 | - | 93,593 | - | - | 1,034,217 | 484,014 | 126,547 | 423,657 | 155,824 | 60,043 | 24,138 | 10,088 |
| **31.12.2040** | 765 | 12.06 | 1,436,995 | 290,848 | - | 73,129 | - | - | 1,073,018 | 502,173 | 131,295 | 439,551 | 153,971 | 56,633 | 21,777 | 8,722 |
| **31.12.2041** | 763 | 12.03 | 1,455,604 | 294,614 | - | 73,226 | - | - | 1,087,764 | 509,073 | 133,099 | 445,592 | 148,654 | 52,192 | 19,197 | 7,368 |
| **31.12.2042** | 763 | 12.03 | 1,478,702 | 299,289 | - | 73,359 | - | - | 1,106,054 | 517,633 | 135,337 | 453,084 | 143,956 | 48,245 | 16,974 | 6,243 |
| **31.12.2043** | 763 | 12.03 | 1,502,096 | 304,024 | - | 73,494 | 174,015 | - | 950,564 | 444,864 | 154,333 | 351,367 | 106,322 | 34,013 | 11,446 | 4,035 |
| **31.12.2044** | 765 | 12.06 | 1,530,464 | 309,766 | - | 94,274 | - | - | 1,126,424 | 527,167 | 133,827 | 465,431 | 134,131 | 40,958 | 13,184 | 4,454 |

| Total discounted cash flow from possible reserves and high estimate contingent resources as of December 31, 2018 (in $ in thousands in relation to the Partnership's share) | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cash flow components | | | | | | | | | | | | | | | | |
| Until | Condensate Sales Volume (Barrels in Thousands) (100% of the Petroleum Asset) | Sales Volume (BCM) (100% of the Petroleum Asset) | Revenues | Royalties to be Paid | Royalties to be Received | Operating Costs | Develop-ment Costs | Abandon-ment and Restor-ation 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 10% | Discounted at 15% | Discounted at 20% |
| **31.12.2045** | 763 | 12.03 | 1,549,996 | 313,719 | - | 73,769 | - | - | 1,162,508 | 544,054 | 138,242 | 480,212 | 131,800 | 38,417 | 11,829 | 3,829 |
| **31.12.2046** | 763 | 12.03 | 1,574,637 | 318,706 | - | 73,911 | 22,897 | - | 1,159,122 | 542,469 | 142,831 | 473,822 | 123,854 | 34,460 | 10,149 | 3,149 |
| **31.12.2047** | 763 | 12.03 | 1,598,974 | 323,632 | - | 74,052 | - | - | 1,201,290 | 562,204 | 142,461 | 496,625 | 123,633 | 32,835 | 9,250 | 2,750 |
| **31.12.2048** | 765 | 12.06 | 1,627,936 | 329,494 | - | 74,228 | - | - | 1,224,214 | 572,932 | 145,266 | 506,016 | 119,972 | 30,414 | 8,196 | 2,335 |
| **31.12.2049** | 763 | 12.03 | 1,648,615 | 333,680 | - | 94,945 | - | - | 1,219,990 | 570,956 | 144,749 | 504,286 | 113,868 | 27,555 | 7,102 | 1,939 |
| **31.12.2050** | 763 | 12.03 | 1,674,245 | 338,867 | - | 74,485 | - | - | 1,260,893 | 590,098 | 149,754 | 521,041 | 112,049 | 25,882 | 6,381 | 1,670 |
| **31.12.2051** | 763 | 12.03 | 1,699,844 | 344,048 | - | 74,633 | 174,015 | - | 1,107,148 | 518,145 | 168,964 | 420,039 | 86,027 | 18,968 | 4,473 | 1,122 |
| **31.12.2052** | 765 | 12.06 | 1,724,418 | 349,022 | - | 74,784 | - | - | 1,300,612 | 608,686 | 150,612 | 541,314 | 105,586 | 22,223 | 5,013 | 1,205 |
| **31.12.2053** | 763 | 12.03 | 1,739,138 | 352,002 | - | 74,859 | - | - | 1,312,278 | 614,146 | 154,040 | 544,092 | 101,074 | 20,306 | 4,381 | 1,009 |
| **31.12.2054** | 763 | 12.03 | 1,759,113 | 356,045 | - | 95,581 | - | - | 1,307,488 | 611,904 | 155,455 | 540,128 | 95,560 | 18,326 | 3,782 | 835 |
| **31.12.2055** | 763 | 12.03 | 1,779,448 | 360,160 | - | 75,091 | 185,463 | - | 1,158,733 | 542,287 | 177,540 | 438,906 | 73,954 | 13,537 | 2,672 | 565 |
| **31.12.2056** | 765 | 12.06 | 1,805,155 | 365,363 | - | 75,249 | - | - | 1,364,543 | 638,606 | 157,960 | 567,977 | 91,145 | 15,926 | 3,007 | 610 |
| **31.12.2057** | 763 | 12.03 | 1,821,267 | 368,625 | - | 75,332 | - | - | 1,377,311 | 644,582 | 159,786 | 572,944 | 87,564 | 14,605 | 2,638 | 512 |

**Total discounted cash flow from possible reserves and high estimate contingent resources as of December 31, 2018 (in $ in thousands in relation to the Partnership's share)**

**Cash flow components**

| Until | Condensate Sales Volume (Barrels in Thousands) (100% of the Petroleum Asset) | Sales Volume (BCM) (100% of the Petroleum Asset) | Revenues | Royalties to be Paid | Royalties to be Received | Operating Costs | Develop-ment Costs | Abandon-ment and Restor-ation 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 10% | Discounted at 15% | Discounted at 20% |
| **31.12.2058** | 763 | 12.03 | 1,842,915 | 373,006 | - | 75,457 | - | - | 1,394,452 | 652,604 | 161,883 | 579,965 | 84,416 | 13,440 | 2,322 | 432 |
| **31.12.2059** | 763 | 12.03 | 1,864,813 | 377,438 | - | 96,190 | 185,463 | - | 1,205,722 | 564,278 | 177,181 | 464,263 | 64,357 | 9,780 | 1,616 | 288 |
| **31.12.2060** | 765 | 12.06 | 1,892,362 | 383,014 | - | 75,751 | - | - | 1,433,596 | 670,923 | 158,142 | 604,532 | 79,811 | 11,578 | 1,830 | 313 |
| **31.12.2061** | 763 | 12.03 | 1,910,098 | 386,604 | - | 75,844 | - | - | 1,447,651 | 677,500 | 161,862 | 608,288 | 76,483 | 10,591 | 1,601 | 262 |
| **31.12.2062** | 763 | 12.03 | 1,933,509 | 391,342 | - | 75,978 | 219,808 | - | 1,246,380 | 583,306 | 164,864 | 498,210 | 59,659 | 7,886 | 1,140 | 179 |
| **31.12.2063** | 763 | 12.03 | 1,956,688 | 396,034 | - | 76,112 | 306,816 | - | 1,177,726 | 551,176 | 128,552 | 497,998 | 56,794 | 7,166 | 991 | 149 |
| **31.12.2064** | 90 | 1.42 | 240,342 | 48,645 | - | 63,025 | - | 160,295 | (31,623) | - | - | (31,623) | (3,435) | (414) | (55) | (8) |
| **Total** | **33,531** | **528.7** | **66,684,331** | **13,324,120** | - | **3,457,819** | **2,187,564** | **160,295** | **47,554,532** | **20,503,565** | **5,930,109** | **21,120,858** | **8,062,294** | **4,320,750** | **2,797,792** | **1,996,883** |

6. Below is a sensitivity analysis in respect of the principal parameters comprising the discounted cash flow of resources and reserves (the price of gas and the amount of gas sales) as of December 31, 2018 (Dollars in thousands), which was performed by the Partnership[145]

| Sensitivity/Category | Current Value Discounted at 0% | Current Value Discounted at 10% | Current Value Discounted at 15% | Current Value Discounted at 20% | Sensitivity/Category | Current Value Discounted at 0% | Current Value Discounted at 10% | Current Value Discounted at 15% | Current Value Discounted at 20% |
|---|---|---|---|---|---|---|---|---|---|
| **10% Increase in Gas Price** | | | | | **10% Decrease in Gas Price** | | | | |
| Proved Reserves and Low Estimate Contingent Resources | 20,422,523 | 4,636,286 | 3,043,601 | 2,192,737 | Proved Reserves and Low Estimate Contingent Resources | 16,632,023 | 3,827,918 | 2,496,093 | 1,774,744 |
| Probable Reserves and Best Estimate Contingent Resources | 22,405,425 | 4,680,454 | 3,052,490 | 2,195,104 | Probable Reserves and Best Estimate Contingent Resources | 18,254,015 | 3,864,529 | 2,503,764 | 1,776,939 |
| Possible Reserves and High Estimate Contingent Resources | 23,286,837 | 4,730,190 | 3,071,173 | 2,204,285 | Possible Reserves and High Estimate Contingent Resources | 8,964,587 | 3,909,929 | 2,521,159 | 1,785,434 |

[145] With respect to an analysis of the discounted cash flow's sensitivity to the gas sales volume variable, it is noted that no changes were made in the forecast of the wells for adjustment to the number of wells required.

| **15% Increase in Gas Price** | | | | | **15% Decrease in Gas Price** | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Proved Reserves and Low Estimate Contingent Resources | 21,367,640 | 4,833,916 | 3,176,080 | 2,293,144 | Proved Reserves and Low Estimate Contingent Resources | 15,690,382 | 3,624,761 | 2,357,027 | 1,667,608 |
| Probable Reserves and Best Estimate Contingent Resources | 23,440,788 | 4,879,983 | 3,185,281 | 2,295,560 | Probable Reserves and Best Estimate Contingent Resources | 17,222,165 | 3,659,489 | 2,364,397 | 1,669,761 |
| Possible Reserves and High Estimate Contingent Resources | 24,364,798 | 4,930,748 | 3,204,246 | 2,304,881 | (Possible Reserves and High Estimate Contingent Resources) | 17,889,882 | 3,703,752 | 2,381,439 | 1,678,068 |
| **20% Increase in Gas Price** | | | | | | | | | |
| Proved Reserves and Low Estimate Contingent Resources | 22,318,934 | 5,033,507 | 3,309,461 | 2,393,772 | Proved Reserves and Low Estimate Contingent Resources | 14,754,710 | 3,422,268 | 2,217,735 | 1,559,836 |
| Probable Reserves and Best Estimate Contingent Resources | 24,482,322 | 5,081,475 | 3,318,976 | 2,396,239 | Probable Reserves and Best Estimate Contingent Resources | 16,196,260 | 3,455,103 | 2,224,799 | 1,561,945 |
| Possible Reserves and High Estimate Contingent Resources | 25,445,896 | 5,133,185 | 3,338,169 | 2,405,652 | Possible Reserves and High Estimate Contingent Resources | 16,821,323 | 3,498,314 | 2,241,539 | 1,570,093 |

| Sensitivity/Category | Current Value Discounted at 0% | Current Value Discounted at 10% | Current Value Discounted at 15% | Current Value Discounted at 20% | Sensitivity/Category | Current Value Discounted at 0% | Current Value Discounted at 10% | Current Value Discounted at 15% | Current Value Discounted at 20% |
|---|---|---|---|---|---|---|---|---|---|
| **10% Increase in Gas Sales Volume** | | | | | **10% Decrease in Gas Sales Volume** | | | | |
| Proved Reserves and Low Estimate Contingent Resources | 18,095,025 | 4,590,348 | 3,035,460 | 2,190,678 | Proved Reserves and Low Estimate Contingent Resources | 16,638,074 | 3,829,507 | 2,497,224 | 1,775,628 |
| Probable Reserves and Best Estimate Contingent Resources | 19,787,137 | 4,635,244 | 3,044,956 | 2,193,234 | Probable Reserves and Best Estimate Contingent Resources | 18,260,525 | 3,866,127 | 2,504,896 | 1,777,823 |
| Possible Reserves and High Estimate Contingent Resources | 20,228,873 | 4,679,552 | 3,062,929 | 2,202,307 | Possible Reserves and High Estimate Contingent Resources | 18,971,307 | 3,911,534 | 2,522,293 | 1,786,319 |
| **15% Increase in Gas Sales Volume** [146] | | | | | | | | | |
| Proved Reserves and Low Estimate Contingent Resources | 17,896,809 | 4,754,764 | 3,161,221 | 2,289,410 | Proved Reserves and Low Estimate Contingent Resources | 15,699,422 | 3,627,147 | 2,358,731 | 1,668,944 |
| Probable Reserves and Best Estimate Contingent Resources | 19,597,975 | 4,806,892 | 3,172,654 | 2,292,461 | Probable Reserves and Best Estimate Contingent Resources | 17,231,894 | 3,661,889 | 2,366,104 | 1,671,098 |
| Possible Reserves and High Estimate Contingent Resources | 19,921,555 | 4,849,877 | 3,190,561 | 2,301,609 | Possible Reserves and High Estimate Contingent Resources | 17,899,926 | 3,706,160 | 2,383,148 | 1,679,407 |
| | | | | | | | | | |

[146] See Footnote 143 above.

| Sensitivity/Category | Current Value Discounted at 0% | Current Value Discounted at 10% | Current Value Discounted at 15% | Current Value Discounted at 20% | Sensitivity/Category | Current Value Discounted at 0% | Current Value Discounted at 10% | Current Value Discounted at 15% | Current Value Discounted at 20% |
|---|---|---|---|---|---|---|---|---|---|
| **20% Increase in Gas Sales Volume [147]** | | | | | **20% Decrease in Gas Sales Volume** | | | | |
| Proved Reserves and Low Estimate Contingent Resources | 17,606,225 | 4,911,756 | 3,285,396 | 2,387,707 | Proved Reserves and Low Estimate Contingent Resources | 14,766,767 | 3,425,478 | 2,220,036 | 1,561,643 |
| Probable Reserves and Best Estimate Contingent Resources | 19,432,456 | 4,976,275 | 3,300,102 | 2,391,621 | Probable Reserves and Best Estimate Contingent Resources | 16,209,236 | 3,458,333 | 2,227,103 | 1,563,753 |
| Possible Reserves and High Estimate Contingent Resources | 19,743,349 | 5,021,212 | 3,318,599 | 2,400,964 | Possible Reserves and High Estimate Contingent Resources | 16,834,719 | 3,501,555 | 2,243,847 | 1,571,903 |

[147] See Footnote 143 above.

(c) <u>Conformity between the report data and data of previous reports pertaining to the petroleum asset</u>

The updated Reserves and Resources Report reflects no material change in the overall quantities of natural gas and condensate in the reservoir relative to the previous Resources Report released in the Periodic Report for 2017. However, in view of new data received about the reservoir, including data from the Leviathan-7 well, laboratory tests and flow tests carried out in the context of the process of completion of the Leviathan production wells, the total resources in the low category (1P+1C) were updated by approx. 1.5% (from approx. 16,729 BCF to approx. 16,983 BCF), in the best category (2P+2C) by approx. 0.6% (from approx. 21,363 BCF to approx. 21,495 BCF), and in the high category (3P+3C) by approx. 0.3% (from approx. 25,777 BCF to approx. 25,844 BCF). In addition, in view of the update of the Partnership's assessments of the quantities of sale from Leviathan, the signing of new agreements for the supply of natural gas from the Leviathan reservoir and progress in negotiations for the supply of natural gas from the reservoir, combined with developments in the local and regional markets, part of the resources was reclassified as follows: Increase of the 1P reserves in the current report by approx. 16 BCF, and increase of the 1C contingent resources in the Phase 1A category by approx. 2,260 BCF, on account of the contingent resources in the 1C future developments category (which was reduced by approx. 2,023 BCF due to a reclassification of the recourses and increase of the quantity of resources in the reservoir). The increase of the 2P reserves in the current report by approx. 734 BCF, and the increase of the 2C contingent resources in the Phase 1A category by approx. 344 BCF, at the expense of the contingent resources in the 2C future developments category (which was reduced by approx. 946 BCF due to a reclassification of the resources and increase in the quantity of resources in the reservoir). The increase of the 3P reserves in the current report by approx. 405 BCF and the increase of the 3C contingent resources in the Phase 1A category by approx. 549 BCF, at the expense of the contingent resources in the 3C future developments category (which was reduced accordingly by approx. 886 BCF due to a reclassification of the resources and increase of the quantities of resources in the reservoir).

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

Opinion of the evaluator

A report on reserves and a report on contingent resources in the Leviathan reservoir, which were prepared by NSAI, as of December 31, 2018, are attached hereto as **Annex D**, and the consent of NSAI to the inclusion thereof in this report is attached as **Annex A** to this chapter.

(d) Management declaration

(1) Date of the declaration: March 21, 2019;
(2) Name of the corporation: Delek Drilling, Limited Partnership;
(3) Name and position of the resource evaluation officer at the Partnership: Assi Bartfeld, Chairman of the Board of the General Partner;
(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 herein were prepared according to the professional terms listed in Chapter G of the Third Schedule to the Securities Regulations (Details of the Prospectus and Draft Prospectus – Structure and Form), 5729-1969, and within the meaning afforded thereto in Petroleum Resources Management System (2007), as published by the SPE, the AAPG, the WPC and the SPEE, as being at the time of release of the report;
(8) We confirm that no change has been made to the identity of the evaluator who performed the last contingent resource or reserve disclosure released by the Partnership;
(9) We agree to the inclusion of the foregoing declaration herein.

______________________________
Assi Bartfeld

(e) Prospective resources in the Leviathan leases

For details regarding prospective resources of natural gas and oil in the Leviathan leases as of December 31, 2017, see Section 7.4.10(e) of the Periodic Report for 2017, the information in which is hereby presented by way of reference. As of December 31, 2018, there has been no change in the said details. Attached hereto as **Annex A** is NSAI's consent to the inclusion of the said report herein.

7.5. Roy License

The Partnership was granted an option to acquire from Edison International S.P.A ("**Edison**"), an option granted to Edison by Ratio, for the purchase of working interests at an overall rate of 20% (out of 100%) in the 399/Roy Licenses (in this section: the "**Option**" and below: the "**Roy License**"). On March 19, 2019, the Partnership notified Ratio and Edison, which acts as operator of the Roy License, of the exercise of the Option (in this section: the "**Exercise Notice**").

According to the Exercise Notice, and in accordance with certain changes in the terms and conditions of the Option that were agreed upon between Ratio and the Partnership, the Partnership shall purchase from Ratio interests at the rate of 24.99% in the Roy License (in this section: the "**Transaction**"). The closing of the Transaction and the transfer of the interests in the Roy License to the Partnership are subject to the fulfillment of conditions precedent and receipt of the necessary approvals, all as elaborated in Section 7.27.14 below.

Below is a specification of the holding rates of the partners in the Roy License as of the report release date:

| | |
|---|---|
| Edison | 20% |
| Ratio | 70% |
| Israel Opportunity – Energy Resources, Limited Partnership ("**Israel Opportunity**") | 10% |

Assuming that the Transaction is closed, the rates of the participation rights in the said license shall be as follows:

| | |
|---|---|
| Edison | 20% |
| Ratio | 45.01% |
| Israel Opportunity | 10% |
| The Partnership | 24.99% |

Set forth below are details regarding the Roy License which are based, *inter alia*, on information received by the Partnership from Ratio, in the context of the due diligence investigations that were carried out by the Partnership, and on public information released by Ratio. If the Transaction is closed, the Roy License shall be classified as a negligible petroleum asset relative to the Partnership's entire activity and assets (so long as the partners do not make a drilling decision), and therefore a brief description is presented below of the said petroleum asset, assuming that the Transaction will be closed:

### 7.5.1. General

| General Details about the Petroleum Asset | |
|---|---|
| **Name of Petroleum Asset:** | Roy |
| **Location[148]:** | The Mediterranean Sea |
| **Area** | Approx. 400,000,000 sqm[149] |
| **Type of petroleum asset:** | License |
| **Original grant date of the petroleum asset:** | April 15, 2013 |
| **Original expiration date of the petroleum asset:** | April 14, 2016 |
| **Dates on which an extension of the petroleum asset period was decided:** | August 18, 2015, December 3, 2016, April 12, 2018, July 1, 2018, September 2, 2018 and September 23, 2018 |
| **Current date for expiration of the petroleum asset:** | April 14, 2020 |
| **Statement whether there is another option for the extension of the petroleum asset period; if such an option exists – please state the possible extension period:** | Subject to the Petroleum Law, it is possible to extend up to seven years from the date of grant, with a possibility, in case of a discovery, to extend by two more years. The current expiration date is seven years from the grant date. |
| **Statement of Operator's Name[150]:** | Edison |
| **Statement of the names of the direct partners in the petroleum asset, and their direct share in the petroleum asset, and, to the best of the Partnership's knowledge, the names of the controlling shareholders in the said partners (subject to the closing of the Transaction):** | ▪ The Partnership (24.99%).<br>▪ Ratio (45.01%)[151].<br>▪ Edison (20%). To the best of the Partnership's knowledge, Edison is part of the Edison Group controlled by the Electricité de France Group (EDF).<br>▪ Israel Opportunity (10%). To the best of the Partnership's knowledge, the control holder of Israel Opportunity is Israel Opportunity – Oil & Gas Exploration Ltd. ("**Opportunity Ltd.**"), which serves as Israel Opportunity's general partner. To the best of the Partnership's knowledge, the shares of Opportunity Ltd. are held by Capernaum Finance SA (33.9%), Halman-Aldubi Energy Ltd. (28.9%), Rony Halman (chairman of Opportunity Ltd.) (1.3%), Uri Aldubi (director of Opportunity Ltd.) (1.3%), Halman-Aldubi Holdings Ltd. (2.5%) (Halman-Aldubi Energy Ltd. and Halman-Aldubi Holdings Ltd. are companies that are jointly owned, directly and through companies, in equal shares, by Messrs. Rony Halman and Uri Aldubi) |

[148] The license letter notes that the area of the license is included in the EEZ of the State of Israel, the borders of which are yet to be conclusively determined. If, during the term of the license or during the term of any petroleum right to be granted in consequence thereof (a license or a lease), an area or areas are removed from the area of the license, the area of the license or such other right will be accordingly reduced without any compensation to the right holder.

[149] On May 23, 2017, the Minister of Energy (further to the Petroleum Council's recommendation of January 25, 2017) approved the Partners' application of September 2016 for a change of the borders of the license. The area of the Roy license within such new borders remains 400 sq. km.

[150] On September 23, 2018 the Petroleum Commissioner approved, in principle, Ratio's request to be recognized as operator in the Roy license in the event that Edison, the current license operator, is not the operator in the license.

[151] For a specification of the names of the control holders of Ratio, to the best of the Partnership's knowledge, see Section 7.4.1 above.

| General Details about the Petroleum Asset | |
|---|---|
| | (Halman-Aldubi Energy Ltd., Rony Halman and Uri Aldubi shall be referred to collectively as: the "**Halman Aldubi Group**") and by several other shareholders. To the best of the Partnership's knowledge, a shareholders' agreement was signed between Capernaum Finance SA and the Halman Aldubi Group, which also relates to companies controlled by the Halman Aldubi Group, which regulates the relations between them as shareholders of Opportunity Ltd. |

| General details regarding the Partnership's share in the petroleum asset | |
|---|---|
| **In respect of holding a petroleum asset purchased – statement of the purchase date:** | March 19, 2019. |
| **Description of the nature and manner of holding of the petroleum asset by the Partnership:** | The Partnership directly holds 24.99% of the interests in the license (subject to receipt of all of the necessary approvals). |
| **Statement of the actual share attributed to the holders of the equity interests of the Partnership in the revenues from the petroleum asset, assuming that it will hold licenses:** | Pre Investment-Recovery – 20.44%.<br>Post Investment-Recovery – 19.19%. |
| **The total share of the holders of the Partnership's equity interests in the aggregate investment in the petroleum asset in the five years preceding the last day of the reporting year (whether recognized as an expense or as an asset in the financial statements):** | Payment of the Past Costs in the sum of approx. $4 million, in accordance with the terms and conditions of the Transaction described in Section 7.27.14 above. |

7.5.2. Actual and planned work plan at the Roy License

Below is a concise description of the main actions that have actually been performed in the Roy License from January 1, 2016 until the report release date, as well as a concise description of the planned actions in the Roy License, in accordance with the binding work plan in the license. It is emphasized that the estimated timetables and costs are based on general assessments only, and may change considerably. It is further noted that the work plans may change following discoveries that are made, and which may cause changes in the work plans, and the estimated costs and timetables:

| **Period** | **Concise description of actions actually performed for the period or of the planned work plan** | **Total estimated budget for activity at the petroleum asset level (dollars in thousands)** | **Amount of actual participation in the budget by the holders of the Partnership's equity interests (dollars in thousands)** |
| --- | --- | --- | --- |
| 2016 | • A combined analysis was performed of all of the geological and geophysical data in the area of the license in view of the work that was performed, and a report was submitted which includes a current geological and geophysical description of the drilling target in the license.<br>• A summary report was submitted regarding a specific analysis of the pore pressure and the fracture gradient of the rock at the depths of the site designated for drilling with the assistance of the 3D seismic material and other materials.<br>• An updated geological and engineering prospect was submitted for the well in view of the results of all of the work performed.<br>• An environmental document was submitted. | Approx. 2,195 | - |
| 2017 | • An evaluation of prospective resources report was submitted following modification of the boundaries of the Roy License (which was approved on May 23, 2017).<br>• Continued geological work and seismic interpretation.<br>• Continued preparation work towards a possible drilling. | Approx. 1,596 | - |
| 2018 | • Continued geological work and preparation for drilling. | Approx. 382 | - |
| 2019 forth [152] | In accordance with the binding work plan in the license, the following actions are required to be taken:<br>• By June 15, 2019 – signing of a contract with a drilling contractor and delivery thereof to the Commissioner.<br>• By September 30, 2019 – commencement of drilling in the area of the Roy License.<br>• Three months from completion of the drilling – submission of a summary report of the results of the drilling. | TBD | TBD |

**Caution concerning forward-looking information – the information regarding the actions planned at the Roy License, including with respect of the costs, timetables and the actual performance thereof is forward-looking information as defined in the Securities Law, which is based, *inter alia*, on information and estimates received by the Partnership from Ratio and on public releases of Ratio, in respect of which the Partnership has not yet carried out a full inspection. The actual performance of the work plan, including the**

[152] In the framework of the Commissioner's approvals for the update of the work plan in the Roy License, the Commissioner stated that in the event that drilling in the license does not begin by September 30, 2019, the guaranty in the sum of $2.5 million, which was provided by the holders of the interests in the license, will be forfeited, and the validity of the license will not be extended beyond the seventh anniversary on April 14, 2020. After this date, no activity will be carried out in the license unless a discovery is recognized therein.

**timetables and the costs, might be materially different to the above information, and it is contingent upon, *inter alia,* on market conditions, regulation, many external circumstances, technical needs, technical ability and economic merit. The closing of the Transaction is subject to the fulfillment of the conditions precedent specified in Section 7.25.14 below.**

7.6. New Ofek License

On March 19, 2019, the Partnership entered into an agreement with S.O.A Energy Israel Ltd. ("**SOA**") for the purchase of interests at the rate of 25% (out of 100%) in the 405/New Ofek license (the "**New Ofek License**"), which is an onshore license, in the center of the State of Israel, (in this section: the "**Purchase Agreement**" and the "**Transaction**").

As of the report release date, Globe Oil Exploration Ltd., Globe's general partner ("**Globe Exploration**"), acts as operator in the New Ofek License. If the Transaction is closed, SOA shall act as operator in the Petroleum Assets.

It is clarified that the closing of the Transaction is subject to the fulfillment of several conditions precedent. For further details regarding the Purchase Agreement, see Section 7.27.15 below.

The holding rates in the New Ofek license, as of the report release date:

| | |
|---|---|
| SOA | 70.00% |
| Globe Exploration (Y.C.D.), Limited Partnership ("**Globe**") | 20.00% |
| Capital Point Ltd. ("**Capital**") | 10.00% |

The holding rates in the New Ofek license, assuming that the Transaction is closed:

| | |
|---|---|
| The Partnership | 25.00% |
| SOA | 45.00% |
| Globe | 20.00% |
| Capital | 10.00% |

Set forth below are details regarding the New Ofek License, to the best of the Partnership's knowledge, based on information that it received from SOA, in the context of the due diligence investigations that were carried out by the Partnership. It is noted that if the Transaction is closed, the New Ofek license shall constitute a negligible petroleum asset relative to the Partnership's entire activity and assets, and therefore a brief description is presented below of the said petroleum asset, assuming that the Transaction will be closed.

In the area of the New Ofek License (preceded by the 381/Ofek license), in the 1990s, several exploration wells were drilled, upon completion of which no discovery was declared. In 2012-2013, another exploration well was drilled (Ofek-2), upon completion of which, after logs were carried out, Globe reported that the operator had reached the conclusion that there were significant indications of petroleum in the Permian layer (at a depth of approx. 5,950 meters). However, in production tests that were carried out by Globe in the said drill hole in 2013, no significant flow of petroleum was recorded, and no discovery was declared. Below are additional details regarding the New Ofek License.

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7.6.1 General details

| General Details about the Petroleum Asset | |
|---|---|
| **Name of the petroleum asset:** | 405/New Ofek |
| **Location:** | Onshore license in the Shfela region in central Israel |
| **Area:** | 344.1 $km^2$ |
| **Type of petroleum asset:** | Oil exploration license |
| **Original grant date of the petroleum asset:** | June 21, 2017 |
| **Original expiration date of the petroleum asset:** | June 20, 2020 |
| **Dates on which an extension of the petroleum asset period was decided:** | - |
| **Current expiration date of the petroleum asset:** | June 20, 2020 |
| **State whether there is another option to extend the petroleum asset period; if such an option exists – state the possible extension period:** | Subject to the Petroleum Law it may be extended for another 4 years, with an option, in the case of a discovery, to extend by an additional two years. |
| **The operator's name:** | As of the Effective Date (as defined in the |

| General Details about the Petroleum Asset | |
|---|---|
| | Purchase Agreement) – SOA. |
| **The names of the direct partners in the petroleum asset, and their direct share in the petroleum asset and, to the best of the Partnership's knowledge, the names of the control holders of the said partners (subject to the closing of the Transaction):** | ▪ The Partnership - 25%;<br>▪ SOA - 45%, to the best of the Partnership’s knowledge, the control holder of SOA is Mr. Saed Sarsur (a businessman, Israeli citizen and resident of England);<br>▪ Globe – 20%, to the best of the Partnership’s knowledge, the control holder of Globe is Globe Exploration, which serves as Globe’s general partner;[153]<br>▪ Capital - 10%, to the best of the Partnership's knowledge, Capital has no controlling shareholder. |

### 7.6.2 The Partnership’s share in the petroleum asset

| General details regarding the Partnership's share in the Petroleum Asset | |
|---|---|
| **For a holding in a petroleum asset that is purchased – state the purchase date:** | March 19, 2019. |
| **Description of the nature and manner of the Partnership’s holding in the petroleum asset:** | The Partnership shall directly hold 25% of the interests in the license. |
| **State the actual share attributed to the holders of the equity interests of the Partnership in the revenues from the petroleum asset:** | Pre Investment-Recovery – 20.50%.<br>Post Investment-Recovery – 19.25%. |
| **The total share of the holders of the Partnership’s equity interests in the aggregate investment in the petroleum asset in the five years preceding the last day of the reporting year (whether recognized as an expense or as an asset in the financial statements):** | According to the Purchase Agreement, the Partnership shall pay $1 million for the Purchased Interests (as defined in Section 7.27.15 below). |

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

7.6.3 Actual and planned work plan

Below is a concise description of the main actions that have actually been performed in the New Ofek License from June 21, 2017 (the date of the granting of the New Ofek License) until the report release date, as well as a concise description of the planned actions in the license, in accordance with the updated work plan that was approved by the Petroleum Commissioner in January 2019.

| **Period** | **Concise description of actions actually performed for the period or of the planned work plan** | **Total estimated budget for activity at the petroleum asset level (dollars in thousands)** | **Amount of actual participation in the budget by the holders of the Partnership's equity interests (dollars in thousands)** |
|---|---|---|---|
| 2017 | • Compilation, processing, analysis and summary of all of the existing geological, geophysical and engineering data.<br>• Digitization of sections and wells, and compilation and digitization of existing maps.<br>• A signed contract with a data processing center was delivered to the Petroleum Commissioner. | 11 | - |
| 2018 | • An agreement was signed with a drilling contractor + a production test plan was submitted for the Petroleum Commissioner's approval. | - | - |
| 2019 forth [154] | • The following were delivered to the Petroleum Commissioner:<br>a. Digitization of scans of the seismic sections that was performed.<br>b. Interpretation of logs that were performed – direction, characterization and density of the fracturing in the Permian layers.<br>c. Stochastic analysis to assess petrophysical characteristics and identify intervals with production potential. | 30<br><br>60<br><br>30 | 7.5<br><br>15<br><br>7.5 |

[154] The work plan for 2019 that is specified above was approved by the Petroleum Commissioner, per Globe's request, in January 2019. The Petroleum Commissioner's approval stated that in the event that the license holders comply with the said work plan, a date shall be scheduled for commencement of production tests as requested.

| | | | |
|---|---|---|---|
| | • By May 15, 2019 – submission of a production test plan for the Petroleum Commissioner's approval.<br>• By May 15, 2019 – receipt of all of the necessary permits and approvals for breaking ground and performing the production tests, including approval from the land owner and approval of the District Committee. | 10 (estimate)<br><br>10 (estimate) | 2.5 (estimate)<br><br>2.5 (estimate) |

**Caution concerning forward-looking information – the information regarding the actions planned in the New Ofek License, including with respect to the costs, timetables and the actual performance thereof, constitutes forward-looking information, within the meaning thereof in the Securities Law, which is based, *inter alia*, on information and estimates received by the Partnership from SOA and on public releases of Globe, in respect of which the Partnership has not yet carried out a full inspection. Actual performance of the work plan, including the timetables and the costs, may be materially different to the above information, and is contingent, *inter alia*, on market conditions, regulation, many external circumstances, technical needs, technical ability and economic merit. The closing of the Transaction and the transfer of the Purchased Interests to the Partnership is subject to the fulfillment of the conditions precedent in the Purchase Agreement, as specified in Section 7.27.15. below**.

7.7 New Yahel License

On March 19, 2019 the Partnership entered into an agreement with SOA for the purchase of a 25% interest (out of 100%) in the 406/"New Yahel" license (the "**New Yahel License**"), located onshore in the north of the State of Israel (in this section, the "**Purchase Agreement**" and the "**Transaction**").

As of the Report Release Date, Globe Exploration is the operator in the New Yahel License. Insofar as the Transaction is closed, SOA will act as operator in the petroleum asset.

It is clarified that the closing of the Transaction is subject to the fulfillment of several closing conditions. For further details about the Purchase Agreement, see Section 7.27.15 below.

The holding rates in the New Yahel License, as of the Report Release Date:
SOA – 70.00%
Globe – 20.00%
Capital – 10.00%

The holding rates in the New Yahel License, assuming that the Transaction is closed:

The Partnership - 25.00%
SOA - 45.00%
Globe - 20.00%
Capital - 10.00%

Following are details about the New Yahel License, to the best of the Partnership’s knowledge, based on information received thereby from SOA in the context of the due diligence investigation carried out by the Partnership. It is noted that if and insofar as the Transaction is closed, the New Yahel License will be a negligible petroleum asset relative to the Partnership’s total business and assets, and therefore a brief description of the said petroleum asset is presented below, assuming the Transaction is closed.

In the area of the New Yahel License (preceded by the 386/Yahel license), several wells were drilled in the previous century in shallow layers, and not to the relevant deep targets. Below are additional details regarding the New Yahel License.

7.7.1 General details

| **General Details about the Petroleum Asset** | |
|---|---|
| **Name of the petroleum asset:** | 406/New Yahel |
| **Location:** | Onshore license in the Haifa Bay area, south of the Akko-Safed highway and north of Yokneam |
| **Area:** | 397.5 $km^2$ |
| **Type of petroleum asset:** | Oil exploration license |
| **Original grant date of the petroleum asset:** | June 21, 2017 |
| **Original expiration date of the petroleum asset:** | June 20, 2020 |
| **Dates on which an extension of the petroleum asset period was decided:** | - |
| **Current expiration date of the petroleum asset:** | June 20, 2020 |
| **State whether there is another option to extend the petroleum asset period; if such an option exists – state the possible extension period:** | Subject to the Petroleum Law, it may be extended for another 4 years, with an option, in the case of a discovery, to extend by an additional two years. |
| **The operator's name:** | As of the Effective Date (as defined in the Purchase Agreement) – SOA. |
| **The names of the direct partners in the petroleum asset, and their direct share in the petroleum asset and, to the best of the Partnership's knowledge, the names of the control holders of the said partners (subject to the closing of the Transaction):**[155] | ▪ The Partnership - 25%;<br>▪ SOA - 45%;<br>▪ Globe – 20%;<br>▪ Capital - 10%. |

[155] For a specification of the control holders of the Partners, see Section 7.6.1 above.

### 7.7.2 The Partnership's share in the petroleum asset

| General details regarding the Partnership's share in the Petroleum Asset | |
|---|---|
| **For a holding in a petroleum asset that is purchased – state the purchase date:** | March 19, 2019. |
| **Description of the nature and manner of the Partnership's holding in the petroleum asset:** | The Partnership shall directly hold 25% of the interests in the license. |
| **State the actual share attributed to the holders of the equity interests of the Partnership in the revenues from the petroleum asset:** | Pre Investment-Recovery – 20.50%.<br>Post Investment-Recovery – 19.25%. |
| **The total share of the holders of the Partnership's equity interests in the aggregate investment in the petroleum asset in the five years preceding the last day of the reporting year (whether recognized as an expense or as an asset in the financial statements):** | According to the Purchase Agreement, the Partnership shall pay $1 million for the Purchased Interests (as defined in Section 7.27.15 below). |

### 7.7.3 Actual and planned work plan

In January 2019, the Petroleum Commissioner approved, per Globe's request, an update to the work plan in the license as specified in the table below. The Petroleum Commissioner's approval stated that in the event that the license holders comply with the said work plan, dates will be scheduled for continuation of the work plan.

| Period | Concise description of actions actually performed for the period or of the planned work plan | Total estimated budget for activity at the petroleum asset level (dollars in thousands) | Amount of actual participation in the budget by the holders of the Partnership's equity interests (dollars in thousands) |
|---|---|---|---|
| 2019 forth | • By May 30, 2019 – completion of an environmental document according to the Petroleum Regulations (Authorization to Deviate from the Provisions of the Planning and Building Law), 5772-2012. | 27 | 6.75 |

| | | | |
|---|---|---|---|
| | • By May 30, 2019 – submission of an application according to the Uniform Building Plan Procedure which shall be approved by the Northern District Planning and Building Committee. It is noted that a plan that is submitted and not confirmed to have been received according to the procedure will be excluded from this section. | - | - |

**<u>Caution concerning forward-looking information</u> – the information regarding the actions planned in the New Yahel License, including with respect to the costs, timetables and the actual performance thereof, constitutes forward-looking information, within the meaning thereof in the Securities Law, which is based, *inter alia*, on information and estimates received by the Partnership from SOA and on public releases of Globe, in respect of which the Partnership has not yet carried out a full inspection. Actual performance of the work plan, including the timetables and the costs, may be materially different to the above information, and is contingent, *inter alia*, on market conditions, regulation, many external circumstances, technical needs, technical ability and economic merit. The closing of the Transaction and the transfer of the Purchased Interests to the Partnership is subject to the fulfillment of the conditions precedent in the Purchase Agreement, as specified in Section 7.27.15 below**.

7.7.

7.8. <u>Rights in Cyprus</u>

7.8.1. <u>Background</u>

On January 22, 2009 an agreement was executed (as amended on March 2, 2010) between the General Partner of the Partnership and the general partner of Avner and Noble Cyprus, according to which Noble Cyprus undertook to transfer to the general partner of each of the partnerships as aforesaid 15% of a production sharing contract dated October 24, 2008 (the "**Production Sharing Contract**" or the "**PSC**") conferring gas and/or oil exploration, evaluation, development and production rights in the EEZ of the Republic of Cyprus in an area known as Block 12 ("**Block 12**") and in an exploration license granted to Noble Cyprus according to the PSC (the "**License**" or the "**Block 12 License**" and the "**Transfer Agreement**" or the "**Transfer**", respectively).

Following the aforesaid, an agreement was executed on August 21, 2011 between Noble Cyprus and the General Partner of the Partnership, in his name and in the name of the Partnership and the general partner of Avner, in his name and in the name of Avner, which amends the Transfer Agreement, according to which it was determined that subject to the receipt of an approval from the authorities of Cyprus, each of the general partners in the Partnership and in Avner will transfer all of their rights, liabilities and undertakings according to the Transfer Agreement to the Partnership and to Avner.

On February 11, 2013, the approval of the authorities in Cyprus was granted for the Transfer of the rights in the PSC and in the said license, and therefore, commencing from that date, the Partnership is a party to the PSC and directly holds 15% of the License. As of the closing of the Merger between the Partnership and Avner on May 17, 2017, the Partnership directly holds 30% of the License.

On January 18, 2016 the approval of the authorities in Cyprus was granted for the sale of 35% of Noble's rights in the PSC and in the said license to BG Cyprus Limited (hereinafter: "**BG Cyprus**"), and therefore, commencing from that date, BG Cyprus is a party to the PSC and directly holds 35% of the License.

7.8.2. General details regarding Block 12

| **General details about the petroleum asset** | |
|---|---|
| **Name of Petroleum Asset:** | Block 12 |
| **Location:** | An offshore area at the EEZ of Cyprus, located approx. 35 km north-west of the Leviathan reservoir[156]. |
| **Area** | Approx. 386 square km |
| **Type of petroleum asset and description of actions permitted according to this type:** | Exploration license granted subject to the PSC |
| **Original grant date of the petroleum asset:** | October 24, 2008 |
| **Original expiration date of the petroleum asset:** | October 24, 2011 |
| **Dates on which an extension of the petroleum asset period was decided:** | October 23, 2011, August 20, 2013 and May 19, 2014 |
| **Current date for expiration of the petroleum asset:** | May 23, 2016.<br>On April 20, 2016, the partners submitted an application for a production license. For details, see Section 7.8.3(d) below. |
| **Statement whether there is another option for the extension of the petroleum asset period; if such an option exists – please state the possible extension period:** | See Section 7.8.3(d) below. |
| **Statement of Operator's Name:** | Noble Cyprus |
| **Statement of the names of the direct partners in the petroleum asset, and their direct share in the petroleum asset, and, to the best of the Partnership's knowledge, the names of the controlling shareholders in the said partners:** | ▪ Noble Cyprus (35%)<br>▪ BG Cyprus (35%). To the best of the Partnership's knowledge, BG Cyprus is a subsidiary (indirect holdings) of Royal Dutch Shell Plc. ("**Shell**"), an energy company engaged in all fields of activity of the gas and oil industry, which is active in more than 70 countries worldwide.<br>▪ The Partnership (30%). |

[156] It is noted that the vast majority of the Aphrodite reservoir is in the area of the EEZ of Cyprus, and the minority thereof is in the area of the Yishai/370 license, which is in the area of the EEZ of Israel. As of the report release date, the Israeli and Cypriot governments are in negotiations for regulation of the parties' rights in the Aphrodite reservoir.

| General details regarding the Partnership's share in the petroleum asset | |
|---|---|
| **In respect of holding a petroleum asset purchased – statement of the purchase date:** | January 22, 2009[157] |
| **Description of the nature and manner of holding of the petroleum asset by the Partnership:** | The Partnership holds directly 30% of the license. |
| **Statement of the actual share attributed to the holders of the equity interests of the Partnership in the revenues from the petroleum asset:** | For details see Section 7.8.8 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. $23,443 thousand. |

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

(a) The license confers upon the holders of rights in Block 12 the right to perform exploration and/or evaluation activity at the License area for a period of 3 years with an option for extension by two additional periods, each of which shall not exceed two years, subject to the conditions stipulated in the PSC (the "**License Periods**" and the "**License Period**", respectively). Upon each such extension, the holders of rights in the project are obligated to waive 25% of the original license area. It is noted that the second license period commenced on May 24, 2014, (and ended on May 23, 2016).

(b) The aforesaid exploration and/or evaluation activities will be performed according to the work plan which was stipulated in the PSC during each of the license periods.

(c) The PSC included provisions pertaining to the manner of performance and management of the exploration, development and production activities at Block 12 while granting preference to Cypriot or European Union entities regarding the purchase of equipment and/or employment

[157] As stated above, on February 11, 2013, the approval of the Cypriot authorities was granted for the transfer of the rights in the franchise agreement and in the license to the Partnership.

and/or training of manpower for the performance of the activities as aforesaid.

(d) In case that the holders of the rights in the project will reach a commercial discovery of oil and/or natural gas, then they are entitled to receive the right to produce Petroleum and/or Gas, as applicable, in a specific area out of the license area, for a period of 25 years with an option for extension by another period of 10 years, subject to a development and production plan which will be approved by the Republic of Cyprus (the "**Production License**"). It is noted that on June 5, 2015 and June 10, 2015, the partners in the Aphrodite reservoir submitted notice to the Cypriot Government regarding the declaration of commerciality and a proposed outline for development of the Aphrodite reservoir, respectively. It is further noted that on April 20, 2016, the partners in the license submitted an updated plan for development of the reservoir, concurrently with the submission of an application for a production license and that on September 21, 2017, the partners in the License submitted updated chapters on technical engineering issues out of the plan for development of the reservoir. Upon the date of expiration of the exploration license, the exploration areas which are not included in the area of the Aphrodite reservoir were returned to the Cypriot Government. To the best of the Partnership's understanding, based on a legal opinion of its legal advisors, in the interim period after the date of expiration of the exploration license and before receipt of a production license, as aforesaid, the partners in the license have the right to receive a production license in the area of the Aphrodite reservoir, upon approval of the development plan (if and insofar as approved). As of the date of this report, the Cypriot Government has not yet approved the updated development plan submitted by the partners in the Aphrodite reservoir. Although, ostensibly, according to the Production Sharing Contract, the Cypriot Government has the option, in the absence of an approved development plan, to claim for termination of the Production Sharing Contract, the partners in the Aphrodite reservoir are continuing to act, in cooperation with the Cypriot Government, for the update and approval of the development plan and the update of the Production Sharing Contract. In this context, the Cypriot Government decided to invite the partners to a series of discussions on the issue of the update of the Production Sharing Contract, including updating the mechanism of the fiscal conditions. As of the date of this report, and following such invitation, the parties are holding continuous discussions on the said issue.

(e) The holders of the rights are obligated to begin development actions within 6 months after receipt of the approval of the Republic of Cyprus for the said development plan.

(f) Payments to the Republic of Cyprus

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

2. The holders of the rights in Block 12 will share the natural gas and/or oil produced (after setting off expenses as specified below) with the Republic of Cyprus according to the daily average production rate of natural gas and/or oil, to the extent it shall be produced[158], as follows:

In respect of oil produced:

| **Average daily production (in barrels)[159]** | **Price per barrel (in Dollar)** | | |
|---|---|---|---|
| | Up to 50 | From 50.1 to 100 | Above 100 |
| | **The share of the Republic of Cyprus (including corporate tax in Cyprus)** | | |
| For the share in the average daily production lower than 50,000 (inclusive) | 60% | 63% | 65% |
| For the share in the average daily production between 50,001 and 100,000 (inclusive) | 63% | 67% | 72% |
| For the share in the average daily production between 100,001 and 150,000 (inclusive) | 70% | 75% | 80% |
| For the share in the average daily production between 150,001 and 200,000 (inclusive) | 77% | 80% | 83% |
| For the share in the average daily production higher than 200,000 | 83% | 85% | 85% |

In respect of gas produced:

| **Daily average production (in thousand square feet)[160]** | **The share of the Republic of Cyprus (including corporate tax in Cyprus)** |
|---|---|
| For the share in the average daily production lower than 150,000 (inclusive) | 55% |

[158] The Republic of Cyprus is entitled to receive its share in the natural gas and/or oil produced, in whole or in part, in kind.
[159] The calculation is carried out progressively according to the brackets presented in the table.
[160] The calculation is carried out progressively according to the brackets presented in the table.

| **Daily average production (in thousand square feet)**[160] | **The share of the Republic of Cyprus (including corporate tax in Cyprus)** |
|---|---|
| For the share in the average daily production between 150,001 and 300,000 (inclusive) | 60% |
| For the share in the average daily production between 300,001 and 600,000 (inclusive) | 65% |
| For the share in the average daily production between 600,001 and 900,000 (inclusive) | 70% |
| For the share in the average daily production between 900,001 and 1,200,000 (inclusive) | 75% |
| For the share in the average daily production higher than 1,200,000 | 80% |

(g) 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**")[161] 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 ("**Production Designated for Expense Reimbursement Coverage**"). In case that the expenses will be higher than the Production 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.

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

[161] The recognition of the Block 12 Expenses is done every year within a budget submitted for approval to the Republic of Cyprus as part of the annual work plan approval proceeding by virtue of the Production Sharing Contract.

(i) The bonuses as specified in Section 7.8.3(f)1 above are not included in the expenses which may be offset as aforesaid.

(j) 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.

(k) 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.

(l) <u>Termination of the Production Sharing Contract</u>

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

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

(m) <u>Grant of a performance guarantee to the Republic of Cyprus</u>

As a condition for performance of the transfer of rights to the Partnership as aforesaid, the Republic of Cyprus required, according to the conditions of the PSC, that a performance guarantee at an unlimited amount, will be issued by Delek Energy to the benefit of the Republic of Cyprus for securing the fulfillment of all of the undertakings of the Partnership under the PSC (the "**Guarantee**"). The Guarantee was required, according to the PSC, from each of the holders of rights in the License. Accordingly, Noble Cyprus also issued a guarantee from its parent company (the "**Noble Parent Company**").

Following the transfer of rights, a requirement was received from the Republic of Cyprus, to replace the Delek Energy guarantee with a guarantee from Delek Group. On April 18, 2013, Delek Group executed the Guarantee replacing Delek Energy's guarantee under the same conditions (the "**Guarantee Agreement**"), all as specified below:

1. The Partnership pays for the provision of the Guarantee by Delek Group, a fee on an annual basis commencing from the date of provision of the Guarantee and for as long as the Guarantee is in effect. The annual fee paid by the Partnership was in the amount of $490 thousand in the first five years as of the date of provision of the Guarantee, and from the sixth year until 25 years from the date of provision of the Guarantee, it is in the amount of $368 thousand. In case that the holding rate of the Partnership in Block 12 will decrease, then the amount of the fee will decrease *pro rata* to the decrease in the holding in the asset. In addition, in case that Delek Group will be absolutely released from the Guarantee, whether due to the finding of an alternative guarantor or due to the sale of the rights in Block 12 by the Partnership, the Partnership and Delek Group agree that the payment of the fee will be ceased immediately. On this matter, also see Regulation 22 in Chapter D of this report.

2. Commencing from the date of provision of the Guarantee and for as long as the Guarantee is in effect, the Partnership will not approve a new work plan/s in Block 12 and/or in relation to any other activity in Block 12 by virtue of the joint operating agreement with Noble Cyprus ("**Block 12 Work Plan**")[162], in the absence of: (1) insurance covering expenses of taking control of a well which went out of control, including coverage for bodily injuries and property damage and cleaning expenses deriving from the risks of accidental contamination in respect of the Partnership's activity in Block 12 to the satisfaction of Delek Group (Insurances

[162] The Partnership will provide Delek Group with an advance notice in respect of any intention to approve Block 12 Work Plan.

for loss of control over well and third party liability[163]); (2) Due approval of the competent organs in the Partnership of the engagement conditions with Delek Group as specified above and below and of the arrangements regarding the payment of a guarantee fee by the Partnership to the Delek Group. (It is noted that as of the report release date, a Block 12 Work Plan for 2019 has been approved at a scope of approx. $9 million (for 100% of the rights)).

3. In addition, the Partnership undertook that commencing from the date of providing the Guarantee and for as long as the Guarantee is in effect, the following provisions will apply:

   a. In case that the Partnership will sell its rights in Block 12, the Partnership will act for releasing Delek Group from the Guarantee, or from its *pro rata* share (in case of a partial sale of the rights) within such sale, all subject to the provisions of the PSC and the decisions of the authorities in Cyprus on the matter. It shall be stated that the sale of some of the rights in Block 12 will be possible only subject to reaching arrangements for liability distribution and mutual indemnification with the potential buyer of some of the rights as aforesaid, in respect of their *pro rata* share.

   b. Delek Group will have the right to require the Partnership, in a written notice, at any time and according to the discretion thereof that it shall release it from the Guarantee. In case of such requirement, the Partnership undertakes to perform the actions required for the release of Delek Group from the Guarantee, including, if and to the extent required for the release of Delek Group from the Guarantee as aforesaid, the sale of its rights, in whole or in part, in Block 12 and/or waiver thereof, without requiring the receipt of additional approvals at the Partnership. In case of such requirement, the Partnership undertakes that within 12 months from the date of provision of a written requirement, it will cause the release of Delek Group from the Guarantee or alternatively execute an agreement for the sale of the rights in Block 12. In case of such sale, the Partnership undertakes to consummate the sale within 6 months from the date of execution of the sale agreement.

[163] The Partnership engaged in insurance policies covering it in respect of accidental and unexpected damage related to expenses due to loss of control of a well and in third party liability insurance related to the activity in Block 12.

c. The Partnership will indemnify Delek Group for damage of any type whatsoever and/or any type of expenses and/or payments borne by the Delek Group (including expenses and/or legal fees and/or expert fees) in respect of the enforcement of the Guarantee and/or a claim and/or demand, whose cause is related to the Guarantee and/or the enforcement thereof, with no limitation on amount. Without derogating from the aforesaid, Delek Group will deliver to the Partnership, without delay, a notice regarding the filing of such claim and/or demand upon its receipt thereby and will allow the Partnership and/or anyone on its behalf conduct proper and necessary legal defense as deemed by the Partnership in the circumstances of the matter, against any demand and/or claim as aforesaid and/or negotiations for settlement as aforesaid and/or reduce the damage to the extent it shall be able to.

4. Whereas the undertakings of the Partnership and Noble Cyprus according to the PSC are joint and several, an agreement was executed between Delek and the Noble Parent Company, and the parent company of BG Cyprus, regarding liability distribution and mutual indemnification between them, regarding the activity in Block 12, according to the holding percentage of the Partnership, Noble Cyprus and BG Cyprus in the rights in Block 12 (in this section: the "**Agreement**"). The Agreement determines, *inter alia*, that:

   a. Each party to the Agreement will be liable for damage or liability related to the activity in Block 12 according to the participation rate of the corporation in respect of which it had issued a guarantee to the benefit of the Republic of Cyprus as aforesaid, in Block 12 (i.e.: Delek Group at a rate of 30%, the Noble Parent Company at a rate of 35%, and the parent company of BG Cyprus at a rate of 35%).

   b. Therefore, each party to the Agreement undertook to indemnify or release the other party from liability, in respect of damage and/or liability related to the activity in Block 12 which are beyond the participation rate of the corporation in respect of which it had issued a guarantee to the benefit of the Republic of Cyprus, as aforesaid, in Block 12 (the "**Indemnification Undertaking**").

   c. The parties' undertaking as aforesaid is not limited by amount or scope for the insurance coverage of the

Partnership, Noble Cyprus and BG Cyprus within their activity in Block 12.

d. Each party to the Agreement undertook to receive from its insurer a waiver of subrogation right against the other party to the Agreement in respect of damage or liability related to the activity thereof in Block 12.

e. The Agreement sets forth a binding arbitration mechanism for the resolution of disputes between the parties.

f. The Agreement will be in effect until the termination of the joint operating agreement applicable to Block 12, subject to a final accounting between the parties in respect to the Agreement.

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

| **Performing Entity** | **Period in which the action was performed** | **Summary description of the action** | **Summary description of the action results** |
|---|---|---|---|
| Noble Cyprus | 2011-2012 | Preparation for drilling of the test well "Aphrodite A-1", drilling of the said well and an analysis of the well results and preparation for drilling of an appraisal well[164]. | - |

7.8.5. Compliance with the binding Block 12 Work Plan

The binding Block 12 Work Plan has been fully complied with until the report release date[165].

7.8.6. Actual and planned work plan at Block 12

Following is a summary description of the main activities actually carried out in the petroleum asset from January 1, 2016 until the report release date as well as a summary description of planned activities:

[164] On October 2, 2013, the Aphrodite A-2 appraisal well, which began on June 7, 2013, was completed.
[165] It is noted that on January 28, 2016, the Cypriot government announced that it had waived the requirement to drill an additional well outside of the boundaries of the Aphrodite finding, according to the binding work plan in Block 12, against payment of a sum of $6 million, which was borne by the Operator as part of the completion of the transfer of the rights from Noble Cyprus to BG Cyprus.

| **Period** | **Summary description of actions actually carried out for the period or of the planned work plan** | **Estimated overall budget per action on the petroleum asset level (in Dollars in thousands)[166]** | **Scope of actual participation of the holders of the equity interests of the Partnership in the budget (in Dollars in thousands)[167]** |
|---|---|---|---|
| 2016 | • On April 20, 2016, the partners submitted an updated plan for the development of the Aphrodite reservoir in the format specified in Section 7.8.11 below, concurrently with an application for a production license.<br>• Continued examination of various alternatives for the development of the Aphrodite reservoir.<br>• Continued geological, geophysical and engineering analysis of the database existing at the license, *inter alia*, while integrating data from adjacent fields, and updating the geological model and the flow model. | Approx. 4,728 | Approx. 1,418 |
| | • Examination of a possible location for an appraisal well and the scope of appraisal actions therein and preparation for drilling additional wells in the area of the license. | - | - |
| | • Continued analysis of the prospectivity in the area of the license, *inter alia*, in view of findings from adjacent fields, and in particular, a technical and financial analysis of a deep prospect. | Approx. 821 | Approx. 246 |

[166] The amounts for 2016-2018 are amounts actually expended and audited in the financial statements.
[167] The costs in the table reflect the Partnership's holdings in Block 12 following the Merger, namely 30%.

| **Period** | **Summary description of actions actually carried out for the period or of the planned work plan** | **Estimated overall budget per action on the petroleum asset level (in Dollars in thousands)[166]** | **Scope of actual participation of the holders of the equity interests of the Partnership in the budget (in Dollars in thousands)[167]** |
|---|---|---|---|
| 2017 | • Submission of an update to the development plan.<br>• On September 21, 2017, the partners submitted updated chapters on engineering and technical issues for the plan for development of the Aphrodite reservoir. As of the report release date, the approval of the Cypriot Government for the development plan and for the application for a production license as aforesaid has not yet been received.<br>• Continued geological, geophysical and engineering analysis of the database existing at the license, *inter alia*, while integrating data from adjacent fields, and updating the geological model and the flow model. | Approx. 1,471 | Approx. 441 |
| | • Examination of a possible location for an appraisal well and the scope of appraisal actions therein and preparation for drilling additional wells in the area of the license.<br>• Continued analysis of the prospectivity in the area of the license, *inter alia*, in view of findings from adjacent fields, and in particular, a technical and financial analysis of a deep prospect. | Approx. 772 | Approx. 232 |
| 2018 | • Continued examination of various alternatives for the development of Aphrodite reservoir.<br>• Continued geological, geophysical and engineering analysis of database existing at the license, *inter alia*, while integrating data from adjacent fields, and updating the geological model and the flow model. | Approx. 1,898 | Approx. 569 |
| | • Examination of a possible location for an appraisal well and the scope of appraisal actions therein.<br>• Continued analysis of the prospectivity in the area of the license, *inter alia*, in view of findings from adjacent fields, and in particular, a technical and financial analysis of a deep prospect.<br>• Preparation for the drilling of additional wells in the area of the license. | Approx. 368 | Approx. 116 |

| **Period** | **Summary description of actions actually carried out for the period or of the planned work plan** | **Estimated overall budget per action on the petroleum asset level (in Dollars in thousands)[166]** | **Scope of actual participation of the holders of the equity interests of the Partnership in the budget (in Dollars in thousands)[167]** |
|---|---|---|---|
| 2019 forth | • Submission of an updated plan for development of the Aphrodite reservoir to the Cypriot Government.<br>• Continued examination of various alternatives for the development of Aphrodite reservoir.<br>• Continued geological, geophysical and engineering analysis of database existing at the license, *inter alia*, while integrating data from adjacent fields, and updating the geological model and the flow model.<br>• Examination of a possible location for an appraisal well and the scope of appraisal actions therein.<br>• Continued analysis of the prospectivity in the area of the license, *inter alia*, in view of findings from adjacent fields, and in particular, a technical and financial analysis of a deep prospect.<br>• Preparation for the drilling of additional wells in the area of the license. | Approx. 9,091[168] | Approx. 2,727 |
| | • Adoption of a final investment decision (FID) and development of the Aphrodite reservoir in the format specified in Section 7.8.11 below. | Approx. 2,500,000 to approx. 3,200,000[169] | Approx. 750,000 to approx. 960,000 |

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

[168] As of the report release date, the said budget has been approved by the Block 12 partners.
[169] As of the report release date, such development plan has not yet been approved by the Cypriot Government.

7.8.7. 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 7.8.2 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 7.8.8 below. | | | | |
| The actual participation rate of the holders of the equity interests of the Partnership in the **expenses** involved in the exploration activity at the petroleum asset | 30.3%-31.2% | 30.3%-31.2% | 101%-104% | 101%-104% | For details see Section 7.8.9 below. |

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

According to the PSC, the Republic of Cyprus is entitled to a share of the gas produced, according to the average daily production rate of the natural gas, after setting off development and production expenses incurred by the holders of the rights in Block 12 at a rate of up to 55% of the total gas produced, if any (in this section: the "**Partnership's Expenses**" and the "**Production Rate**", respectively)[170]. In view of the fact that the share of the Republic of Cyprus in the gas which will be produced from Block 12 depends on the production rate, which is unknown and not evaluable as of the report release date, since the reservoir evaluation actions have not been completed yet and a development plan has not been formulated yet, then it is not possible to determine, as of the report release date, the rate actually attributed to the holders of the equity interests of the Partnership in the revenues from Block 12. In view of the aforesaid, the Partnership respectfully presents six merely theoretic examples for the manner of calculation of the rate actually attributed to the holders of the equity interests of the

[170] It shall be stated that the expenses shall be offset as aforesaid on an annual basis.

Partnership in the revenues from Block 12 while the average daily production rate of natural gas is at 150,000 MCF, 300,000 MCF, 600,000 MCF, 900,000 MCF, 1,200,000 MCF and 1,400,000 MCF.

For the avoidance of doubt it shall be clarified, that the data presented below constitutes only theoretic examples, and therefore, the actual production rate of natural gas from Block 12 might be lower or higher than the production rate in the examples, and accordingly also the share of the Republic of Cyprus in the gas which will be produced.

In addition, within the examples below, calculation of royalty to affiliated and third parties (Delek Energy and Delek Group) was done under the assumption that the royalty is paid out of the Partnership's share (net) in the petroleum asset, after distribution of the gas, which will be produced, between the Republic of Cyprus and the Partnership according to the provisions of the PSC. It shall be stated that this matter has not been examined yet by the Partnership and the parties entitled to royalty, and therefore, there is no certainty that this will be the manner of calculation of the royalty. In case that the aforesaid calculation method will be different, the share actually attributed to the holders of the equity interests of the Partnership in the revenues from the petroleum asset will be reduced, as specified in the examples presented below at a rate between 0.334% and 1.763%. In addition, it shall be stated that the calculation of the royalty to affiliated and third parties was done before the deduction of the "Production Designated for Expense Coverage" as provided in Section 7.8.3(g) above, similarly to the method of calculation of the share of the Republic of Cyprus in the gas produced. In case that the method of calculation of the royalty to affiliated and third parties, net of expenses as aforesaid will be different, the rate actually attributed to the holders of the equity interests of the Partnership in the revenues from the petroleum asset, might grow.

| Average daily production rate of natural gas at a rate of 150,000 MCF | | | | |
|---|---|---|---|---|
| **Item** | **Before investment recovery for purposes of calculation of the royalties to affiliated and third parties and before full investment recovery for purposes of calculation of the share of the Republic of Cyprus[171]** | **After investment recovery for purposes of calculation of the royalties to affiliated and third parties and before full investment recovery for purposes of calculation of the share of the Republic of Cyprus[172]** | **After investment recovery for purposes of calculation of the royalties to affiliated and third parties and for purposes of calculation of the share of the Republic of Cyprus[173]** | **Summary explanation of how the royalties or the payments are calculated** |
| Annual projected revenues of a petroleum asset | 100% | 100% | 100% | |
| **Specification of the royalties or the payment (derived from the revenues post-discovery) on the petroleum asset level:** | | | | |
| The Republic of Cyprus | 24.75% | 24.75% | 49.5% | The share of the Republic of Cyprus in the gas to be produced from Block 12 engrosses therein also the corporate tax payments which the holders of rights in Block 12 must pay to the Republic of Cyprus. For further details regarding the rate of the Republic of Cyprus see Section 7.8.3 (f) above. |
| Adjusted revenues on the petroleum asset level | 75.25% | 75.25% | 50.50% | |
| Share attributed to the holders of the equity interests of the Partnership in the revenues deriving from the petroleum asset which are adjusted (indirect holdings) | 30% | 30% | 30% | |

[171] After deduction of expenses as specified in Section 7.8.3 above at a rate of 55% of the total revenues.
[172] After deduction of expenses as specified in Section 7.8.3 above at a rate of 55% of the total revenues.
[173] It is noted that the calculation was carried out based on an assumption of production expenses at a rate of 10% of the total gas which will be produced. There is no certainty that the production costs will be a fixed rate of the revenues.

| Average daily production rate of natural gas at a rate of 150,000 MCF | | | | |
|---|---|---|---|---|
| **Item** | **Before investment recovery for purposes of calculation of the royalties to affiliated and third parties and before full investment recovery for purposes of calculation of the share of the Republic of Cyprus[171]** | **After investment recovery for purposes of calculation of the royalties to affiliated and third parties and before full investment recovery for purposes of calculation of the share of the Republic of Cyprus[172]** | **After investment recovery for purposes of calculation of the royalties to affiliated and third parties and for purposes of calculation of the share of the Republic of Cyprus[173]** | **Summary explanation of how the royalties or the payments are calculated** |
| Total, the share of the holders of the equity interests of the Partnership, in the actual revenues rate, on the petroleum asset level (and before other payments on the Partnership level) | 22.58% | 22.58% | 15.15% | |
| **Specification of royalties or payments (derived from revenues post-discovery) related to the petroleum asset on the Partnership level (the percentages below will be calculated according to the share of the holders of the equity interests of the Partnership in the petroleum asset):** | | | | |
| The share of the holders of the equity interests of the Partnership in the payment to affiliated and third parties | (1.02%) | (2.14%) | (1.44%) | Overriding royalty in respect of the Partnership's share at a rate of 4.5% Pre Investment-Recovery and at a rate of 9.5% Post Investment-Recovery[174]. |
| The share actually attributed to the holders of the equity interests of the Partnership in the revenues from the petroleum asset. | 21.56% | 20.44% | 13.71% | |

[174] The parties entitled to a royalty are Delek Energy, the Delek Group, Cohen Developments and others which are not related parties.

| **Average daily production rate of natural gas at a rate of 300,000 MCF** | | | | |
|---|---|---|---|---|
| **Item** | **Pre Investment-Recovery for purposes of calculation of the royalties to affiliated and third parties and pre full investment-recovery for purposes of calculation of the share of the Republic of Cyprus[175]** | **Post Investment-Recovery for purposes of calculation of the royalties to affiliated and third parties and pre full investment-recovery for purposes of calculation of the share of the Republic of Cyprus[176]** | **Post Investment-Recovery for purposes of calculation of the royalties to affiliated and third parties and for purposes of calculation of the share of the Republic of Cyprus[177]** | **Summary explanation of how the royalties or the payments are calculated** |
| Annual projected revenues of a petroleum asset | 100% | 100% | 100% | |
| **Specification of the royalties or the payment (derived from the revenues post-discovery) on the petroleum asset level:** | | | | |
| The Republic of Cyprus | 25.88% | 25.88% | 51.75% | The rate of the Republic of Cyprus in the gas to be produced from Block 12 engrosses therein also the corporate tax payments which the holders of rights in Block 12 must pay to the Republic of Cyprus. For further details regarding the rate of the Republic of Cyprus see Section 7.8.3(f) above. |
| Adjusted revenues on the petroleum asset level | 74.13% | 74.13% | 48.25% | |
| Share attributed to the holders of the equity interests of the Partnership in the revenues deriving from the petroleum asset which are adjusted (indirect holdings) | 30% | 30% | 30% | |

[175] After deduction of expenses as specified in Section 7.8.3 above at a rate of 55% of the total revenues.
[176] After deduction of expenses as specified in Section 7.8.3 above at a rate of 55% of the total revenues.
[177] It is noted that the calculation was carried out based on an assumption of production expenses at a rate of 10% of the total gas which will be produced. There is no certainty that the production costs will be a fixed rate of the revenues.

| Average daily production rate of natural gas at a rate of 300,000 MCF | | | | |
|---|---|---|---|---|
| **Item** | **Pre Investment-Recovery for purposes of calculation of the royalties to affiliated and third parties and pre full investment-recovery for purposes of calculation of the share of the Republic of Cyprus[175]** | **Post Investment-Recovery for purposes of calculation of the royalties to affiliated and third parties and pre full investment-recovery for purposes of calculation of the share of the Republic of Cyprus[176]** | **Post Investment-Recovery for purposes of calculation of the royalties to affiliated and third parties and for purposes of calculation of the share of the Republic of Cyprus[177]** | **Summary explanation of how the royalties or the payments are calculated** |
| Total, the share of the holders of the equity interests of the Partnership, in the actual revenues rate, on the petroleum asset level (and before other payments on the Partnership level) | 22.24% | 22.24% | 14.48% | |
| **Specification of royalties or payments (derived from revenues post-discovery) related to the petroleum asset on the Partnership level (the percentages below will be calculated according to the share of the holders of the equity interests of the Partnership in the petroleum asset):** | | | | |
| The share of the holders of the equity interests of the Partnership in the payment to affiliated and third parties | (1.00%) | (2.11%) | (1.38%) | Overriding royalty of the Partnership's share at a rate of 4.5% Pre Investment-Recovery and at a rate of 9.5% Post Investment-Recovery[178].. |
| The share actually attributed to the holders of the equity interests of the Partnership in the revenues from the petroleum asset. | 21.24% | 20.13% | 13.10% | |

[178] The parties entitled to a royalty are Delek Energy, the Delek Group, Cohen Developments and others which are not related parties.

| **Average daily production rate of natural gas at a rate of 600,000 MCF** | | | | |
|---|---|---|---|---|
| **Item** | **Pre Investment-Recovery for purposes of calculation of the royalties to affiliated and third parties and pre full investment-recovery for purposes of calculation of the share of the Republic of Cyprus[179]** | **Post Investment-Recovery for purposes of calculation of the royalties to affiliated and third parties and pre full investment-recovery for purposes of calculation of the share of the Republic of Cyprus[180]** | **Post Investment Recovery for purposes of calculation of the royalties to affiliated and third parties and for purposes of calculation of the share of the Republic of Cyprus[181]** | **Summary explanation of how the royalties or the payments are calculated** |
| Annual projected revenues of the petroleum asset | 100% | 100% | 100% | |
| **Specification of the royalties or the payment (derived from the revenues post-discovery) on the petroleum asset level:** | | | | |
| The Republic of Cyprus | 27.56% | 27.56% | 55.13% | The rate of the Republic of Cyprus in the gas to be produced from Block 12 engrosses therein also the corporate tax payments which the holders of rights in Block 12 must pay to the Republic of Cyprus. For further details regarding the rate of the Republic of Cyprus see Section 7.8.3(f) above. |
| Adjusted revenues on the petroleum asset level | 72.44% | 72.44% | 44.88% | |
| Share attributed to the holders of the equity interests of the Partnership in the revenues deriving from the petroleum asset which are adjusted (indirect holdings) | 30% | 30% | 30% | |

[179] After deduction of expenses as specified in Section 7.8.3 above at a rate of 55% of the total revenues.
[180] After deduction of expenses as specified in Section 7.8.3 above at a rate of 55% of the total revenues.
[181] It is noted that the calculation was carried out based on an assumption of production expenses at a rate of 10% of the total gas which will be produced. There is no certainty that the production costs will be a fixed rate of the revenues.

| Average daily production rate of natural gas at a rate of 600,000 MCF | | | | |
|---|---|---|---|---|
| **Item** | **Pre Investment-Recovery for purposes of calculation of the royalties to affiliated and third parties and pre full investment-recovery for purposes of calculation of the share of the Republic of Cyprus[179]** | **Post Investment-Recovery for purposes of calculation of the royalties to affiliated and third parties and pre full investment-recovery for purposes of calculation of the share of the Republic of Cyprus[180]** | **Post Investment Recovery for purposes of calculation of the royalties to affiliated and third parties and for purposes of calculation of the share of the Republic of Cyprus[181]** | **Summary explanation of how the royalties or the payments are calculated** |
| Total, the share of the holders of the equity interests of the Partnership, in the actual revenues rate, on the petroleum asset level (and before other payments on the Partnership level) | 21.73% | 21.73% | 13.46% | |
| **Specification of royalties or payments (derived from revenues post-discovery) related to the petroleum asset on the Partnership level (the percentages below will be calculated according to the share of the holders of the equity interests of the Partnership in the petroleum asset):** | | | | |
| The share of the holders of the equity interests of the Partnership in the payment to affiliated and third parties | (0.98%) | (2.06%) | (1.28%) | Overriding royalty of the Partnership's share at a rate of 4.5% Pre Investment-Recovery and at a rate of 9.5% Post Investment-Recovery[182].. |
| The share actually attributed to the holders of the equity interests of the Partnership in the revenues from the petroleum asset. | 20.75% | 19.67% | 12.18% | |

[182] The parties entitled to a royalty are Delek Energy, the Delek Group, Cohen Developments and others which are not related parties.

| **Average daily production rate of natural gas at a rate of 900,000 MCF** | | | | |
|---|---|---|---|---|
| **Item** | **Pre Investment-Recovery for purposes of calculation of the royalties to affiliated and third parties and pre full investment-recovery for purposes of calculation of the share of the Republic of Cyprus[183]** | **Post Investment-Recovery for purposes of calculation of the royalties to affiliated and third parties and pre full investment-recovery for purposes of calculation of the share of the Republic of Cyprus[184]** | **Post Investment-Recovery for purposes of calculation of the royalties to affiliated and third parties and for purposes of calculation of the share of the Republic of Cyprus[185]** | **Summary explanation of how the royalties or the payments are calculated** |
| Theoretical annual revenues of the petroleum asset | 100% | 100% | 100% | |
| **Specification of the royalties or the payment (derived from the revenues post-discovery) on the petroleum asset level:** | | | | |
| The Republic of Cyprus | 28.88% | 28.88% | 57.75% | The rate of the Republic of Cyprus in the gas to be produced from Block 12 engrosses therein also the corporate tax payments which the holders of rights in Block 12 must pay to the Republic of Cyprus. For further details regarding the rate of the Republic of Cyprus, see Section 7.8.3(f) above. |
| Adjusted revenues on the petroleum asset level | 71.13% | 71.13% | 42.25% | |
| Share attributed to the holders of the equity interests of the Partnership in the revenues deriving from the petroleum asset which are adjusted (indirect holdings) | 30% | 30% | 30% | |

[183] After deduction of expenses as specified in Section 7.8.3 above at a rate of 55% of the total revenues.
[184] After deduction of expenses as specified in Section 7.8.3 above at a rate of 55% of the total revenues.
[185] It is noted that the calculation was carried out based on an assumption of production expenses at a rate of 10% of the total gas which will be produced. There is no certainty that the production costs will be a fixed rate of the revenues.

| **Average daily production rate of natural gas at a rate of 900,000 MCF** | | | | |
|---|---|---|---|---|
| **Item** | **Pre Investment-Recovery for purposes of calculation of the royalties to affiliated and third parties and pre full investment-recovery for purposes of calculation of the share of the Republic of Cyprus[183]** | **Post Investment-Recovery for purposes of calculation of the royalties to affiliated and third parties and pre full investment-recovery for purposes of calculation of the share of the Republic of Cyprus[184]** | **Post Investment-Recovery for purposes of calculation of the royalties to affiliated and third parties and for purposes of calculation of the share of the Republic of Cyprus[185]** | **Summary explanation of how the royalties or the payments are calculated** |
| Total, the share of the holders of the equity interests of the Partnership, in the actual revenues rate, on the petroleum asset level (and before other payments on the Partnership level) | 21.34% | 21.34% | 12.68% | |
| **Specification of royalties or payments (derived from revenues post-discovery) related to the petroleum asset on the Partnership level (the percentages below will be calculated according to the share of the holders of the equity interests of the Partnership in the petroleum asset):** | | | | |
| The share of the holders of the equity interests of the Partnership in the payment to affiliated and third parties | (0.96%) | (2.03%) | (1.20%) | Overriding royalty of the Partnership's share at a rate of 4.5% Pre Investment-Recovery and at a rate of 9.5% Post Investment-Recovery[186]. |
| The share actually attributed to the holders of the equity interests of the Partnership in the revenues from the petroleum asset. | 20.38% | 19.31% | 11.47% | |

[186] The parties entitled to a royalty are Delek Energy, the Delek Group, Cohen Developments and others which are not related parties.

| **Average daily production rate of natural gas at a rate of 1,200,000 MCF** | | | | |
|---|---|---|---|---|
| **Item** | **Pre Investment-Recovery for purposes of calculation of the royalties to affiliated and third parties and pre full investment-recovery for purposes of calculation of the share of the Republic of Cyprus[187]** | **Post Investment-Recovery for purposes of calculation of the royalties to affiliated and third parties and pre full investment-recovery for purposes of calculation of the share of the Republic of Cyprus[188]** | **Post Investment-Recovery for purposes of calculation of the royalties to affiliated and third parties and for purposes of calculation of the share of the Republic of Cyprus[189]** | **Summary explanation of how the royalties or the payments are calculated** |
| Annual projected revenues of the petroleum asset | 100% | 100% | 100% | |
| **Specification of the royalties or the payment (derived from the revenues post-discovery) on the petroleum asset level:** | | | | |
| The Republic of Cyprus | 30.09% | 30.09% | 60.19% | The rate of the Republic of Cyprus in the gas to be produced from Block 12 engrosses therein also the corporate tax payments which the holders of rights in Block 12 must pay to the Republic of Cyprus. For further details regarding the rate of the Republic of Cyprus, see Section 7.8.3(f) above. |
| Adjusted revenues on the petroleum asset level | 69.91% | 69.91% | 39.81% | |
| Share attributed to the holders of the equity interests of the Partnership in the revenues deriving from the petroleum asset which are adjusted (indirect holdings) | 30% | 30% | 30% | |

[187] After deduction of expenses as specified in Section 7.8.3 above at a rate of 55% of the total revenues.
[188] After deduction of expenses as specified in Section 7.8.3 above at a rate of 55% of the total revenues.
[189] It is noted that the calculation was carried out based on an assumption of production expenses at a rate of 10% of the total gas which will be produced. There is no certainty that the production costs will be a fixed rate of the revenues.

| **Average daily production rate of natural gas at a rate of 1,200,000 MCF** | | | | |
|---|---|---|---|---|
| **Item** | **Pre Investment-Recovery for purposes of calculation of the royalties to affiliated and third parties and pre full investment-recovery for purposes of calculation of the share of the Republic of Cyprus[187]** | **Post Investment-Recovery for purposes of calculation of the royalties to affiliated and third parties and pre full investment-recovery for purposes of calculation of the share of the Republic of Cyprus[188]** | **Post Investment-Recovery for purposes of calculation of the royalties to affiliated and third parties and for purposes of calculation of the share of the Republic of Cyprus[189]** | **Summary explanation of how the royalties or the payments are calculated** |
| Total, the share of the holders of the equity interests of the Partnership, in the actual revenues rate, on the petroleum asset level (and before other payments on the Partnership level) | 20.97% | 20.97% | 11.94% | |
| **Specification of royalties or payments (derived from revenues post-discovery) related to the petroleum asset on the Partnership level (the percentages below will be calculated according to the share of the holders of the equity interests of the Partnership in the petroleum asset):** | | | | |
| The share of the holders of the equity interests of the Partnership in the payment to affiliated and third parties | (0.94%) | (1.99%) | (1.13%) | Overriding royalty in respect of the Partnership's share at a rate of 4.5% Pre Investment-Recovery and at a rate of 9.5% Post Investment-Recovery[190].. |
| The share actually attributed to the holders of the equity interests of the Partnership in the revenues from the petroleum asset. | 20.03% | 18.98% | 10.81% | |

[190] The parties entitled to a royalty are Delek Energy, the Delek Group, Cohen Developments and others which are not related parties.

| **Average daily production rate of natural gas at a rate of 1,400,000 MCF** | | | | |
|---|---|---|---|---|
| **Item** | **Pre Investment-Recovery for purposes of calculation of the royalties to affiliated and third parties and pre full investment-recovery for purposes of calculation of the share of the Republic of Cyprus[191]** | **Post Investment-Recovery for purposes of calculation of the royalties to affiliated and third parties and pre full investment-recovery for purposes of calculation of the share of the Republic of Cyprus[192]** | **Post Investment-Recovery for purposes of calculation of the royalties to affiliated and third parties and for purposes of calculation of the share of the Republic of Cyprus[193]** | **Summary explanation of how the royalties or the payments are calculated** |
| Annual projected revenues of the petroleum asset | 100% | 100% | 100% | |
| **Specification of the royalties or the payment (derived from the revenues post-discovery) on the petroleum asset level:** | | | | |
| The Republic of Cyprus | 30.94% | 30.94% | 61.88% | The rate of the Republic of Cyprus in the gas to be produced from Block 12 engrosses therein also the corporate tax payments which the holders of rights in Block 12 must pay to the Republic of Cyprus. For further details regarding the rate of the Republic of Cyprus, see Section 7.8.3(f) above. |
| Adjusted revenues on the petroleum asset level | 69.06% | 69.06% | 38.13% | |
| Share attributed to the holders of the equity interests of the Partnership in the revenues deriving from the petroleum asset which are adjusted (indirect holdings) | 30% | 30% | 30% | |

191 After deduction of expenses as specified in Section 7.8.3 above at a rate of 55% of the total revenues.
192 After deduction of expenses as specified in Section 7.8.3 above at a rate of 55% of the total revenues.
193 It is noted that the calculation was carried out based on an assumption of production expenses at a rate of 10% of the total gas which will be produced. There is no certainty that the production costs will be a fixed rate of the revenues.

| **Average daily production rate of natural gas at a rate of 1,400,000 MCF** | | | | |
|---|---|---|---|---|
| **Item** | **Pre Investment-Recovery for purposes of calculation of the royalties to affiliated and third parties and pre full investment-recovery for purposes of calculation of the share of the Republic of Cyprus**[191] | **Post Investment-Recovery for purposes of calculation of the royalties to affiliated and third parties and pre full investment-recovery for purposes of calculation of the share of the Republic of Cyprus**[192] | **Post Investment-Recovery for purposes of calculation of the royalties to affiliated and third parties and for purposes of calculation of the share of the Republic of Cyprus**[193] | **Summary explanation of how the royalties or the payments are calculated** |
| Total, the share of the holders of the equity interests of the Partnership, in the actual revenues rate, on the petroleum asset level (and before other payments on the Partnership level) | 20.72% | 20.72% | 11.44% | |
| **Specification of royalties or payments (derived from revenues post-discovery) related to the petroleum asset on the Partnership level (the percentages below will be calculated according to the share of the holders of the equity interests of the Partnership in the petroleum asset):** | | | | |
| The share of the holders of the equity interests of the Partnership in the payment to affiliated and third parties | (0.93%) | (1.97%) | (1.09%) | Overriding royalty in respect of the Partnership's share at a rate of 4.5% Pre Investment-Recovery and at a rate of 9.5% Post Investment-Recovery[194]. |
| The share actually attributed to the holders of the equity interests of the Partnership in the revenues from the petroleum asset. | 19.79% | 18.75% | 10.35% | |

[194] The parties entitled to a royalty are Delek Energy, the Delek Group, Cohen Developments and others which are not related parties.

7.8.9. Participation rate of the holders of the equity interests of the Partnership in the exploration and development expenses at Block 12

| **Item** | **Percentage** | **Summary explanation of how the royalties or payments are calculated** |
|---|---|---|
| Theoretical expenses within the framework of a petroleum asset (without the said royalties) | 100% | |
| **Specification of the payments (derived from the expenses) on the petroleum asset level:** | | |
| The Operator | 1%-4% | The rate in the table 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 upon the increase in the exploration expenses. The rate of payment in respect of development and production expenses has not yet been determined. |
| Total actual expense rate on the petroleum asset level | 101%-104% | |
| The share of the holders of equity interests of the Partnership in the petroleum asset expenses (indirect holdings) | 30% | |
| Total actual share of the holders of the equity interests of the Partnership, in the expenses, on the petroleum asset level (and prior to other payments on the Partnership level) | 30.3%-31.2% | |
| **Specification of payments (derived from the expenses) in respect of the petroleum asset and on the Partnership level (the following percentage will be calculated according to the share of the holders of the equity interests of the Partnership in the petroleum asset**): | | |
| The rate actually attributed to the holders of the equity interests of the Partnership in expenses involved in the exploration, development or | 30.3%-31.2% | The Partnership pays management fees to the General Partner, that are comprised of a fixed amount and a variable |

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

7.8.10. Fees and payments paid during exploration and development activity at Block 12 (in Dollars in thousands)[195]

| Item | Total share of the holders of the equity interests of the Partnership in the investment in the petroleum asset in this period[196] | 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 2016 | Approx. 3,132 | - | Approx. 82 |
| Budget actually invested in 2017 | Approx. 1,890 | - | Approx. 72 |
| Budget actually invested in 2018 | Approx. 2,176 | - | Approx. 70 |

7.8.11. Plan for the development of the Aphrodite reservoir

(a) As of the report release date, the plan for the development of the Aphrodite reservoir that was submitted for the approval of the Cypriot Government[197], includes examination of the supply of natural gas to the local market in Cyprus, whether via a pipeline to a terminal on the shores of Cyprus or alternatively via the supply of LNG to Cyprus, and the export of natural gas in a pipeline to other markets including the Egyptian market through the establishment of an independent floating production facility in the area of the Aphrodite reservoir, with an estimated maximum production capacity of around 800 MMCF a day (the "**Floating Facility**"), and the "**Development Plan**", respectively).

[195] The costs in the table reflect the Partnership's post-merger holding in Block 12, i.e. 30%.
[196] Including costs in respect of which no payments are made to the Operator.
[197] As of the Report Release Date, the approval of the Cypriot Government for the development plan has not yet been received.

(b) According to the Operator's current estimate, which was delivered to the Partnership and the Cypriot Government, and before finishing the techno-economic feasibility tests, including the performance of a Front End Engineering Design (FEED), the estimated cost of the Development Plan, without the cost of building the pipelines to the Target Markets, is estimated at an amount of approx. $2.5 - $3.2 billion (in 100% terms).

(c) Formulation of the development plan and reaching the stage of making a FID for the production of the Aphrodite reservoir, is subject, inter alia, to the approval of the aforesaid plan by the Cypriot Government and the partners in Block 12, the receipt of a production license under the concession agreement, performance of a FEED, commercial arrangements for the development of the pipelines, execution of agreements for the supply of natural gas and the fulfillment of the conditions precedent in those agreements, regulatory approvals and the execution of finance arrangements. Note that the supply agreements to the Target Markets may be contingent, inter alia, on the execution of inter-governmental framework agreements between Cyprus and Egypt.

(d) The updated Development Plan is subject, *inter alia* to approval by the Cypriot Government. Insofar as such approval is received during 2019, and insofar as the aforesaid conditions precedent are fulfilled, the scheduled date for commencement of the supply of natural gas from the Aphrodite reservoir is during 2025 at the earliest.

(e) It is emphasized that the development plan mentioned above, including the estimated budget and the timetable are only preliminary, since inter alia, the techno-economic tests, the FEED, and the crystallization of the project's commercial and finance arrangements have not yet been completed.

(f) In addition, the partners in Block 12 are concurrently looking into additional possibilities for development of the Aphrodite reservoir, including the option to integrate the development thereof with development plans of adjacent reservoirs located in the Israeli EEZ, including the Leviathan reservoir, and/or the co-use of gas transmission infrastructures, and are looking into the possibility of using existing infrastructures in the area.

**Caution concerning forward-looking information – the Partnership's estimations, as aforesaid, regarding the format of the development plan, timetables, costs, and production rates in the Aphrodite reservoir, are forward-looking information as defined in the Securities Law, based on evaluations of the General Partner of the Partnership regarding the format of the development plan, timetables, costs and production rates in the Aphrodite reservoir,**

**which are all based on the evaluations which the General Partner of the Partnership received from the Operator. The actual development format, timetables, costs, and production rates in the Aphrodite reservoir may materially differ from the aforesaid evaluations and are contingent upon, *inter alia*, the fulfillment of the conditions precedent specified above, the completion of the detailed planning of the project's components, the actual performance of this project, and a gamut of additional factors related to the performance of the development plan.**

7.8.12. Contingent and prospective resources in Block 12

For details regarding contingent and prospective resources in Block 12 as of December 31, 2017, see Section 7.6.12 of the Periodic Report for 2017, the information in which is hereby presented by way of reference.

As of December 31, 2018, there has been no change in the details presented in the said report. Attached hereto as **Annex A** is NSAI's consent to the inclusion of the said report herein.

7.9. Alon D License

7.9.1. General

| **General Details about the Petroleum Asset** | |
|---|---|
| **Name of Petroleum Asset:** | Alon D |
| **Location:** | Offshore asset located approx. 50 km north-west of the shores of the city of Nahariya |
| **Area:** | Approx. 400 square km |
| **Type of petroleum asset and description of actions permitted according to this type:** | License;<br>Actions permitted under the Petroleum Law – exploration and production |
| **Original grant date of the petroleum asset:** | March 1, 2009 |
| **Original expiration date of the petroleum asset:** | February 29, 2012 |
| **Dates on which an extension of the petroleum asset period was decided:** | January 18, 2015, March 31, 2015 and August 24, 2015 and August 21, 2017. |
| **Current date for expiration of the petroleum asset:** | April 21, 2010, see Section 7.9.3 below. |
| **State whether there is another option for the extension of the petroleum asset period; if such an option exists – please state the possible extension period:** | - |
| **The Operator's Name:** | Noble |
| **State the names of the direct partners in the petroleum asset, and their direct share in the petroleum asset, and, to the best of the Partnership's knowledge, the names of the controlling shareholders in the said partners:** | ▪ Noble (47.059%) (in this respect, see Section 7.9.2 below).<br>▪ The Partnership (52.941%). |

| General details regarding the Partnership's share in the petroleum asset | |
|---|---|
| **In respect of holding a petroleum asset purchased – state the purchase date:** | -[198] |
| **Description of the nature and manner of holding of the petroleum asset by the Partnership:** | The Partnership directly holds 52.941% in the Alon D License. |
| **State the actual share attributed to the holders of the equity interests of the Partnership in the revenues from the petroleum asset:** | Pre Investment-Recovery – 43.94%<br>Post Investment-Recovery – 41.29% |
| **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. $313 thousand[199] |

7.9.2. As aforesaid, and as of the Report Release Date, Noble is holding approx. 47.06% of the rights in Alon D License, and it is also the operator in the license. Noble has recently notified the Partnership that it wishes to withdraw from the exploration activity in the petroleum asset and waive its rights therein. In view of the aforesaid, the Partnership reached an agreement with Noble whereby Noble shall transfer rights at the rate of 25% (out of 100%) in the Petroleum Asset to another operator that shall step into its shoes, as the Partnership shall decide, for no consideration (in this section: the "**Operator's Rights**")[200], and Noble shall transfer its remaining rights at the rate of 22.059% (out of 100%), to the Partnership, also for no consideration.

On March 5, 2019 and March 17, 2019 and after several potential operators, which the Partnership contacted, expressed no interest in the proposal to act as operator in the Alon D License, the audit committee and the board of the General Partner, respectively, approved the engagement of the Partnership with Ithaca Energy Inc. ("**Ithaca**")[201], a company wholly-owned by Delek Group, in a transaction whereby Ithaca shall be appointed as the operator of the petroleum asset pursuant to the Joint Operation Agreement (JOA) which presently applies, and shall receive from the Noble, by transfer, the

[198] The Alon D license is part of the licenses that were granted on March 1, 2009, in lieu of Alon/198 preliminary permit.
[199] The costs in the table reflect the Partnership's post-merger holding in the Alon D License , i.e. 52.941%.
[200] It is noted that according to the Petroleum Regulations (Principles of Action for Offshore Petroleum Exploration and Production), 5777-2016 and the Directives released by the Petroleum Commissioner, one of the conditions to the holding of an offshore petroleum asset is that one of the partners in the petroleum asset, who holds at least 25% of the interests therein, is an "operator" as defined in the said Regulations, which was approved by the Petroleum Commissioner. Therefore, if at the time of Noble's retirement from the Alon D license no operator is found to step into its shoes and hold at least 25% of the interests in the Alon D license, grounds may be established for termination of the license.
[201] Ithaca is a company incorporated in Canada in 2004, which engages in the exploration, production and sale of oil and gas in several petroleum assets located in the Northern Sea area, in the territorial waters of the U.K., and serves as operator in some of the said assets. In June 2017 Delek Group, the Partnership's control holder, closed the acquisition of the entire share capital of Ithaca. It is noted that Ithaca intends to apply to the Petroleum Commissioner for approval that it meets the conditions for recognition as an operator in an offshore petroleum asset.

Operator's Rights, and all subject to the receipt of any and all required approvals, including the approval of the Petroleum Commissioner, approval of the Competition Authority (if required) and approval of the General Meeting of the Partnership unit holders (in this section: the ("**Meeting**"), in accordance with the provisions of Section 65(51) of the Partnerships Ordinance, as an irregular transaction of the Partnership with its control holder (in this Section: the ("**Transaction**").

Further details regarding the Transaction, including the reasons of the audit committee and the board for the approval thereof, shall be specified in the report on the convening of the Meeting which the Partnership intends to release, according to the law.

Assuming that the Transaction is closed – the Partnership's holding rate in the Alon D License will be 75%, and Ithaca will hold 25%.

7.9.3. <u>Fulfillment of the terms and conditions of the work plan in the Alon D License</u>

On February 16, 2016, the Petroleum Commissioner notified the partners in the license that the Alon D License would expire on March 1, 2016 and that non-receipt of the approvals required for the drilling pursuant to law on behalf of other authorities does not constitute grounds for extension of the Alon D license beyond the period set forth in the Petroleum Law. On February 25, 2016, the partners in the license filed an appeal with the Minister of Energy from the Petroleum Commissioner's decision as aforesaid. On August 21, 2017, the Minister of Energy notified the partners in the License of his decision whereby the License will continue to be in effect for 32 months from the date of the Minister of Energy's decision as aforesaid, subject to conditions, as follows, which the partners in the License are required to meet within a reasonable period of time: (a) the partners in the License shall clarify to the Commissioner, in writing and without delay, that they recognize that drilling-preventing circumstances currently still exist in the area, effective pending further notice, and that in the future there is no intention to recognize an additional impediment in the area as grounds that will mandate a further freezing of the License; (b) the partners shall undertake to carry out an environmental survey within 18 months, in order to adapt the terms and conditions of the continuing license to the standards generally accepted in 2017[202]; (c) the partners shall reconfirm their commitment to drill, within a reasonable period of time under the circumstances, from the moment that the green light is given for

[202] On April 29, 2018, the Operator sent the Petroleum Commissioner an application for the issuance of instructions for the conduct of the aforesaid environmental survey. On January 29, 2019, the Petroleum Commissioner requested the partners in the Alon D license to provide additional details with respect to the location at which the well is intended to be drilled in the area of the Alon D license, in order to issue detailed instructions with respect to the conduct of the environmental survey. On February 21, 2019, the Partnership provided the Petroleum Commissioner with the information he requested to receive as aforesaid, and, as of the date of the report, his response to the information so provided has not yet been received.

the drilling of the well. On September 18, 2017, the partners in the License sent a letter to the Minister of Energy which includes clarifications, undertakings and confirmations as aforesaid. On January 16, 2018 the Operator transferred an updated work plan in the Alon D License to the Petroleum Commissioner.

7.9.4. Actual and planned work plan in the Alon D License

Below is a concise description of the main activities actually carried out in the Alon D License from January 1, 2016 until the report release date, as well as a concise description of planned activities:

| **Period** | **Concise description of actions actually carried out for the period or of the planned work plan** | **Estimated overall budget per action on the petroleum asset level (in Dollars in thousands)**[203] | **Scope of actual participation of the holders of the equity interests of the Partnership in the budget (in Dollars in thousands)**[204] |
|---|---|---|---|
| 2016 | • In the area of the license, a geological structure has been identified, in similar layers to those drilled in adjacent licenses, which may contain significant quantities of natural gas. However, in view of the proximity of the reservoir to the border of the EEZ of Israel and Lebanon, it has been clarified to the Partnership and to the Operator in the license that at this stage, a plan to drill an exploration well in the license will not be approved. Therefore, the Operator in the license requested that the Petroleum Commissioner declare the existence of "*force majeure*", which is preventing the partners in the license from planning and consummating a work plan, which includes, *inter alia*, drilling a well. | - | - |
| 2017 | • Continued geological, geophysical and engineering analysis of the database existing at the lease, *inter alia*, while integrating data from adjacent fields.<br>• Acquisition of a new seismic survey. | Approx. 35<br><br>Approx. 500 | Approx. 19<br><br>Approx. 250 |
| 2018 | • Continued geological, geophysical and engineering analysis of the database existing at the lease, including the new seismic material, *inter alia*, while integrating data from adjacent fields. | Approx. 142 | Approx. 75 |

[203] The amounts for the years 2016-2018 are amounts actually spent and audited within the financial statements.
[204] The costs in the table reflect the Partnership's holdings in the Alon D License following the Merger, i.e. 52.941%.

| **Period** | **Concise description of actions actually carried out for the period or of the planned work plan** | **Estimated overall budget per action on the petroleum asset level (in Dollars in thousands)**[203] | **Scope of actual participation of the holders of the equity interests of the Partnership in the budget (in Dollars in thousands)**[204] |
|---|---|---|---|
| | • Presenting the geological analysis to the Petroleum Commissioner.<br>• Discussion with the Ministry of Energy in relation to conducting an environmental survey. | | |
| 2019 forth | • Performance of an environmental survey before an exploration drilling and submission thereof to the Ministry of Energy.<br>• Engagement with a drilling rig.<br>• Drilling of an exploration well in the area of the license insofar as a decision is adopted to drill the same, and insofar as the appropriate approvals to drill the same are received. | Approx. 100,000[205] | Approx. 55,000[206] |

7.9.5. The actual participation rate in the expenses and revenues in the Alon D License

| **Participation Rate** | **Percentage before investment recovery** | **Percentage after investment recovery** | **Rate grossed-up to 100% before investment recovery** | **Rate grossed-up to 100% after investment recovery** | **Explanations** |
|---|---|---|---|---|---|
| The rate actually attributed to the holders of the equity interests of the Partnership in the petroleum asset | 52.941% | 52.941% | 100% | 100% | See description of the holdings in Section 7.9.1 above. |
| The rate actually attributed to the holders of the equity interests of the Partnership in the **revenues** from the petroleum asset | 43.94% | 41.29% | 83% | 78% | See calculation in Section 7.9.6 below. |
| The actual participation rate of the holders of the equity interests of the Partnership in the **expenses** involved in the exploration activity in the petroleum asset | 53.47%-55.06% | 53.47%-55.06% | 101%-104% | 101%-104% | See calculation in Section 7.9.7 below. |

[205] The aforesaid budget has not yet been approved by the partners in the Alon D license.
[206] For details regarding the transfer of Noble's interests in the license to the Partnership at the rate of 22.059%, see Section 7.9 above.

7.9.6. Participation rate of the holders of the equity interests of the Partnership in the revenues from the Alon D License

| **Item** | **Percentage Pre Investment-Recovery** | **Percentage Post Investment-Recovery** | **Concise explanation of how the royalties or payments are calculated** |
|---|---|---|---|
| Projected annual revenues of a petroleum asset | 100% | 100% | |
| **Specification of the royalties or the payment (derived from the revenues post-discovery) on the petroleum asset level:** | | | |
| The State | (12.50%) | (12.50%) | As determined in the Petroleum Law, the royalties are calculated according to market value at wellhead.<br>The actual royalty rate might be lower as a result of deduction of expenses in respect of the gas transmission and processing systems until the onshore gas delivery point. For further details see Section 7.27.12(c) below. |
| Adjusted revenues on the petroleum asset level | 87.50% | 87.50% | |
| Rate attributed to the holders of the equity interests of the Partnership in the revenues deriving from the petroleum asset which are adjusted (indirect holdings) | 52.941% | 52.941% | |
| Total rate of the holders of the equity interests of the Partnership, at the actual revenues rate, at the petroleum asset level (and before other payments at the Partnership level) | 46.32% | 46.32% | |
| **Specification of royalties or payments (derived from revenues post-discovery) in connection with the petroleum asset at the Partnership level (the percentages below will be calculated according to the rate of the holders of the equity interests of the Partnership in the petroleum asset):** | | | |
| Rate of the holders of the equity interests of the Partnership in the payment to affiliated and third parties | (2.38%) | (5.03%) | Overriding royalty for the share of the Partnership at a rate of 4.5% before investment recovery and at a rate of 9.5% after investment recovery, calculated according to market |

| **Item** | **Percentage Pre Investment-Recovery** | **Percentage Post Investment-Recovery** | **Concise explanation of how the royalties or payments are calculated** |
|---|---|---|---|
| | | | value at wellhead[207]. The manner of calculation of the said rate is done according to the principles according to which the State's royalties are calculated, and therefore the said rate might change insofar as the manner of calculation of the State's royalties changes. For further details regarding the manner of calculation of the royalty rate, see Section 7.27.12 below. |
| The rate actually attributed to the holders of the equity interests of the Partnership in the revenues from the petroleum asset. | 43.94% | 41.29% | |

7.9.7. Participation rate of the holders of the equity interests of the Partnership in the exploration expenses in the Alon D License

| **Item** | **Percentage** | **Concise explanation of how the royalties or payments are calculated** |
|---|---|---|
| Theoretical expenses in 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% | The rate in the table 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 upon the increase in the exploration expenses. The rate of payment in respect of development and production expenses has not yet been determined. |
| Total actual expense rate at the | 101%-104% | |

[207] The parties entitled to royalties are Delek Energy, Delek Group, Cohen Developments and others which are not related parties..

| **Item** | **Percentage** | **Concise explanation of how the royalties or payments are calculated** |
|---|---|---|
| petroleum asset level | | |
| Rate of the holders of equity interests of the Partnership in the petroleum asset expenses (indirect holdings) | 53.47%-55.06% | |
| Total actual rate 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) | 53.47%-55.06% | |
| **Specification of payments (derived from the expenses) in connection with the petroleum asset and on the Partnership level (the following percentages will be calculated according to the rate 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 activity in the petroleum asset | 52.941% | The Partnership pays management fees to the General Partner, that are comprised of a fixed amount and a variable amount that is calculated from the exploration expenses (for details see Section (b)7 of Regulation 21 in Chapter D of this report). Such amounts were not taken into account in this table. |

7.9.8. Fees and payments paid during exploration activity in the petroleum asset (in Dollars in thousands)[208]

| **Item** | **Total share of the holders of the equity interests of the Partnership in the investment in the petroleum asset in this period[209]** | **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 2016 | Approx. 2 | - | - |
| Budget actually invested in 2017 | Approx. 35 | - | - |
| Budget actually invested in 2018 | Approx. 75 | - | Approx. 1 |

[208] The costs presented in the table reflect the Partnership's post-Merger holding in the Alon D License, i.e. 52.941%.
[209] Including costs in respect of which no payments are made to the Operator.

## Set forth below are details regarding petroleum assets from which the Partnership has a benefit

### 7.10. The Tanin and Karish Leases

It is noted that the description presented below is mainly based on public releases by Energean Israel Ltd. ("**Energean**") and Energean Oil & Gas Plc. (which is, to the best of the Partnership's knowledge, the control holder of Energean), the veracity of the details presented in which the Partnership is unable to verify independently.

#### 7.10.1. General

In view of the Government's decision to ratify the Gas Framework, on August 16, 2016, an agreement was signed between the Partnership and Avner and Energean Israel Limited ("**Energean**"), for the sale of all of the rights of the Partnership, Avner and Noble in the I/16 Tanin and I/17 Karish leases (collectively: the "**Tanin and Karish Leases**"), in consideration for a payment, which constitutes reimbursement of past expenses invested in the leases by the Partnership, Avner and Noble plus royalties in connection with natural gas and condensate to be produced from the leases.[210] Following the fulfillment of all of the conditions precedent on December 26, 2016 the transaction was closed and all of the rights in the leases were transferred to Energean. For further details regarding the agreement, see Section 7.27.16 below.

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

[210] As published by the Ministry of Energy, on April 25, 2017, the Ministry of Energy granted Energean a lease deed for exploration and production of petroleum in the area of the leases.

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

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

| **General details regarding the Partnership's share in the petroleum asset** | |
|---|---|
| **In respect of holding a petroleum asset purchased – statement of the purchase date:** | - |
| **Description of the nature and manner of holding of the petroleum asset by the Partnership:** | The Partnership is entitled to royalties in connection with natural gas and condensate that shall be produced from the leases. |
| **Statement of the actual share attributed to the holders of the equity interests of the Partnership in the revenues from the petroleum asset:** | 5.12% before payment of a petroleum profit levy under the Taxation of Profits from Natural Resources Law, 5771-2011 (the "**Levy**") and before the Investment Recovery Date;<br>2.47% before payment of the Levy and after the Investment Recovery Date; and<br>3.22% upon commencement of payment of the Levy and after the Investment Recovery Date. |

| | |
|---|---|
| **The total share of the holders of the equity interests of the Partnership in the aggregate investment in the petroleum asset during the five years preceding the last day of the report year (whether recognized as an expense or as an asset in the financial statements):** | Approx. $(6,094) thousand[211] |

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

To the best of the Partnership's knowledge, the development plan for the "Karish" and "Tanin" natural gas discoveries that was submitted by Energean to the Petroleum Commissioner, was approved by the Ministry of Energy in August 2017 (below in this section: the "**Development Plan**") with the Karish field developed first and the Tanin field developed down the line.[212]

According to Energean's releases, on March 22, 2018, a final investment decision (FID) was adopted in the project for the development of Karish and Tanin.

Furthermore, on June 25, 2018 Energean released a notice whereby the Energean Board had approved the drilling of a first exploration well in the "Karish North" prospect, in the area of the Karish lease off the coast of Israel. On March 4, 2019 Energean announced the commencement of performance of the drilling plan in the Karish reservoir. The drilling series will consist of three wells which, to the Partnership's understanding, will serve as production wells in the Karish project, in addition to an exploration well in the "Karish North" prospect. After the said drilling series, Energean has another six drilling options under its engagement agreement with the company which owns the drilling rig (Stena Drilling Ltd.). According to another notice released by Energean on August 16, 2018, the total prospective resources in the "Karish North" prospect is approx. 1.3 TCF of natural gas and approx. 16 million barrels of hydrocarbon liquids (condensate and natural gas liquids), with a 69% probability of geological success[213]. It further arises from Energean's notice of August 16, 2018 that out of the total contingent resources of natural gas in the best estimate (2C) in the Karish and Tanin reservoirs, approx. 2.2 TCF were classified as 2P reserves, while approx. 0.2 TCF remained classified as contingent resources by Energean's independent resources evaluator. The total resources in these reservoirs (2P reserves and 2C contingent resources together) remained

[211] Such investment is from the pre-sale period, in which the petroleum asset was held directly by the Partnership; the specified cost presents the Partnership's post-merger cost, i.e. 52.941%. The investment in the aforesaid period includes a budget update (decrease) in the sum of approx. $6,094 thousand.

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

[213] https://www.investegate.co.uk/energean-oil---38--gas--enog-/rns/independent-cpr-of-reserves---resources-in-israel/201808160700049445X

unchanged, but the notice was not accompanied by the independent resources evaluator's report to support the said updates.

The Karish and Tanin reservoirs, according to estimates published by Energean, contain prospective resources at a scope of approx. 2.4 TCF, including approx. 1.3 TCF of natural gas in the 'Karish North' prospect, as specified above)[214] and, according to public data of Energean only as aforesaid, the beginning of gas production from the Karish reservoir is expected at the beginning of 2021.

In addition, according to the prospectus for the offering and listing on the stock exchange in London which was released by Energean Oil & Gas Plc. (the "**Energean Prospectus**"), the estimated total budget of the development plan for the period between Q1/2018 and commencement of commercial production in 2021, is approx. U.S. $2,066 million. It is noted that the Partnership, as the holder of a right to royalties, does not bear the said development plan expenses.

**Caution concerning forward-looking information – the above description regarding the actions planned in the Karish lease, including timetables for the performance thereof and the date of commencement of the flow of the gas from the Karish reservoir, is forward-looking information, within the meaning thereof in the Securities Law, and is based on public releases of Energean only. Actual performance of the work plan, including the timetables, may materially differ from the specification above and is contingent, *inter alia*, on the applicable regulation, technical ability and economic merit**.

Below is a concise description of the main activities actually carried out in the Tanin and Karish Leases from January 1, 2016 until the report release date, and a concise description of planned activities:

| Karish Lease | | | |
|---|---|---|---|
| **Period** | **Concise description of actions actually taken for the period or of the planned work plan** | **Estimated overall budget per action on the petroleum asset level (in Dollars in thousands)** | **Scope of actual participation of the holders of the equity interests of the Partnership in the budget (in Dollars in thousands)** |
| 2016 | • Sale of the Partnership's rights in the Karish Lease, according to the provisions of the Gas Framework, as specified in Section 7.25.1(b)1 below. | - | - |
| 2017 | • Approval of the Development Plan | - | - |

[214] It is noted that the said reservoirs also include quantities of condensate.

| **Karish Lease** | | | |
|---|---|---|---|
| **Period** | **Concise description of actions actually taken for the period or of the planned work plan** | **Estimated overall budget per action on the petroleum asset level (in Dollars in thousands)** | **Scope of actual participation of the holders of the equity interests of the Partnership in the budget (in Dollars in thousands)** |
| | for Karish and Tanin reservoirs<br>• Engagement with suppliers and contractors<br>• Performance of an environmental survey | | |
| 2018 | • Adoption of final investment decision (FID).<br>• Planning and producing of an FPSO (Floating, Production, Storage and Offloading) with a production capacity of approx. 8 BCM per annum and approx. 0.8 million barrels of hydrocarbon liquids, to be connected via the 24-inch pipeline to Dor Beach.<br>• Planning of the subsea transmission system that will connect the production wells of the Karish reservoir to the FPSO. | See the estimated budget for the Development Plan above | - |
| 2019 forth | • Continued planning and producing of an FPSO (Floating, Production, Storage and Offloading) with a production capacity of approx. 8 BCM per annum and approx. 0.8 million barrels of hydrocarbon liquids, to be connected via the 24-inch pipeline to Dor Beach.<br>• Beginning of drilling of a first exploration well in the ‘Karish North’ prospect in March 2019.<br>• Drilling and completion of three production wells, commencing from Q2/2019.<br>• Continued planning, producing and laying of the subsea transmission system that will connect the production wells of the Karish reservoir to the FPSO.<br>• Commencement of commercial piping of gas and hydrocarbon liquids from the Karish reservoir in 2021. | See the estimated budget for the Development Plan above | - |

| **Tanin Lease** | | | |
|---|---|---|---|
| **Period** | **Concise description of actions actually taken for the period or of the planned work plan** | **Estimated overall budget per action on the petroleum asset level (in Dollars in thousands)** | **Scope of actual participation of the holders of the equity interests of the Partnership in the budget (in Dollars in thousands)** |
| 2016 | • Sale of the Partnership's rights in the Tanin Lease, according to the provisions of the Gas Framework, as specified in Section 7.25.1(b)1 below. | - | - |
| 2017 | • Approval of the Development Plan for the Tanin and Karish reservoirs. According to the Energean Prospectus and according to the Development Plan, the Tanin reservoir will be developed at stage two, after development of the Karish reservoir (as specified above), according, *inter alia*, with demand in the market, the functioning of the wells and the system's performance, and in accordance with a timetable that has not yet been determined. | - | - |
| 2018 | • Planning of a subsea transmission system which will connect the production wells to the FPSO. | See the estimated budget for the Development Plan above | - |
| 2019 forth | • Drilling and completion of production wells.<br>• Continued planning, producing and laying of a subsea transmission system which will connect the production wells to the FPSO. | See the estimated budget for the Development Plan above | - |

7.11. Discontinued operations

Following is a table summarizing main petroleum assets which were returned, transferred or expired in recent years:

| Name of Asset | Date of expiration of the right | Reason for expiration |
|---|---|---|
| Eran License | June 14, 2013 | Expired. For details regarding a legal proceeding in connection with non-extension of the license, see Section 7.28.7(a) below. |

7.12 Products

7.12.1 Natural Gas

The natural gas discovered in the reservoirs held by the Partnership is dry, with no corrosive components, and mostly comprises Methane gas. As such, the treatment required for transportation thereof to customers is 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.

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

For details regarding the domestic gas market, including developments and changes therein, see Section 6 above, and for details regarding the possibility of natural gas export and sale on the international market, see Section 7.14.2 below.

7.12.2 Condensate

In the course of production of natural gas, condensate is also produced, which is a natural product of the condensation process of various components of natural gas and is caused as a result of temperature and pressure differences between the reservoir and the surface. Condensate requires minimal treatment, which is mainly stabilization, for transportation thereof to the Partnership's customers and it mainly serves as feedstock in the production of oil refined products. It is noted that the amount of condensate produced is small and directly derives from the amount of natural gas produced and is a few single barrels per million square feet of natural gas (MMCF).

7.13 Customers

7.13.1 Domestic Market: As of the report release date, the Partnership, together with its partners in the Tamar Project, supplies natural gas to the IEC, industrial customers, private electricity producers and natural gas marketing companies, as well as condensate, to PAR, as specified in Sections 7.13.4(a)3, 7.13.4(a)4 and 7.13.6 below. In addition, during 2016-2018, the Partnership, together with its partners in the Leviathan project, signed several agreements for the supply of natural gas from the

Leviathan project to private electricity producers and industrial customers, as specified in Section 7.13.4(b) below. It shall be noted that as of the report release date, the Tamar and Leviathan partners are continuing to conduct negotiations, at various stages, in order to sign binding agreements for the supply of natural gas to the local market from the Tamar and Leviathan projects.

7.13.2 Export: As of the report release date, the Partnership, together with its partners in the Tamar Project, exports natural gas to Jordan in accordance with the agreements specified in Section 7.13.5(a)1 below, and has signed binding agreements for the supply of gas together with its partners in the Tamar and/or Leviathan project, including with the national electric company of Jordan (NEPCO), as specified in Section 7.13.5 below and with Dolphinus as specified in Sections 7.13.5(a)2 and 7.13.5(b)2 below. In addition, negotiations are being conducted for the export of natural gas to other consumers, as specified in Section 7.13.5 below.

7.13.3 The IEC is the largest customer of the Partnership and therefore, termination of the agreement executed between it and the Tamar Partners, or the non-fulfillment thereof, will materially affect the activity of the Partnership and the future revenues thereof. The Partnership's revenues from the IEC in 2016, 2017 and 2018 constituted approx. 55%, approx. 54% and approx. 50% of its total revenues from the Tamar Project, respectively. The Partnership's other revenues in 2018 were from private electricity producers, industrial customers in Israel and Jordan and natural gas marketing companies. In the Partnership's estimation, its revenues from the IEC will on average constitute approx. 37% of its total revenues in the next three years from the Tamar Project. However, the more the customer base of the Partnership expands, in the domestic and the international markets, and upon commencement of production of the gas from Leviathan, increase of the exported quantities, and continued development of the private electricity production sector, so the dependency on the IEC will be reduced. For details regarding the Tamar Partners' agreement with the IEC, see Sections 7.13.4(a) and 7.13.4(a)4 below.

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

**Leviathan reservoirs, the date of commencement of the piping of the natural gas from the Leviathan reservoir, and a decline in the rate of the Partnership's holdings in the Tamar reservoir**.

### 7.13.4 Engagements for the supply of natural gas

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

1. Below is a table presenting a summary of the agreements for the sale of natural gas by the Tamar Partners, as of the report release date. It is noted that other than the IEC and Dalia Power Energies Ltd. ("**Dalia Energies**"), the Tamar Partners do not have any other customer, the revenues from which in 2016-2018 constituted more than 10% of the Partnership's revenues. The remaining customers with whom the Tamar Partners have engaged in gas supply agreements are grouped in the table below according to the price linkage basis determined in such agreements. For further details regarding such agreements, see subsections (2) and (3) below.

| | Supply commence-ment year | Basic gas supply period[215] | Is there an option for extension? | Total maximal amount for supply (100%) (BCM) [216] | Amount supplied until December 31, 2018 (100%) (BCM) | Main linkage basis of the gas price |
|---|---|---|---|---|---|---|
| IEC[217] | 2013 | 15 years | Option for extension by two additional years. | Approx. 87 | Approx. 25.8 | The US Consumer Price Index (U.S. CPI) |
| Dalia Energies[218] | 2015 | 17 years | Option for extension by two additional years. | Approx. 23.3 | Approx. 4.1 | The linkage formula is based mainly on linkage to the Electricity Production Tariff and includes a "floor price". |
| Other private electricity producers[219] | 2013-2020 | 15-18 years except for one agreement for a shorter period. | Some of the agreements include an option for extension thereof by a | Approx. 57.5 | Approx. 12.2 | In most of the agreements linkage is based on the Electricity Production Tariff and the rest are linked to the U.S. |

215 In most of the agreements, the gas supply period, commencing from the date of piping with respect to the relevant agreement, will be according to the table presented above or until the purchaser shall have consumed the maximal contractual amount set forth in the agreement, whichever is earlier.

216 Such amount is the maximum amount which the Tamar Partners have undertaken to supply to the customer throughout the term of the agreements. The amount which the customers undertook to purchase is lower than the said amount (for details see Section 7.15 below).

217 In the estimation of the Partnership, as of December 31, 2018, the balance of the monetary amount of the agreement with the IEC is approx.$6,040 million (100%), based on the minimal gas amounts in respect of which there is an undertaking to take-or-pay, assuming non-exercise of the Carry Forward (as defined below) and based on the estimation of the Partnership of the gas price during the supply period.

218 In the Partnership's estimation, as of December 31, 2018, the balance of the financial scope of the agreement with Dalia Energies will be approx. $1,340 million (100%) based on the minimal gas quantities in respect of which there is an undertaking to take-or-pay therefor, assuming non-exercise of the Carry Forward (as defined below) and based on the Partnership's estimate with respect to the gas price during the supply period.

219 It is clarified that in some of the agreements, the conditions precedent to the agreement have not all been fulfilled.

| | Supply commence-ment year | Basic gas supply period[215] | Is there an option for extension? | Total maximal amount for supply (100%) (BCM) [216] | Amount supplied until December 31, 2018 (100%) (BCM) | Main linkage basis of the gas price |
|---|---|---|---|---|---|---|
| | | | period of between one to three more years[220]. | | | CPI.<br>In a number of agreements, the price is linked mainly to the Electricity Production Tariff and the remainder is linked to the Brent prices.<br>In all of the agreements the gas price is determined according to a formula which includes a base price and linkage and includes a "floor price". |
| Industrial customers | 2013-2017 | 5-7 years | In one of the agreements there is an option to extend by an additional two years. | Approx. 7.6 | Approx. 5.0 | In most of the agreements the linkage is based on the Brent prices and includes a “floor price” (while in one agreement, in addition to the aforesaid, the linkage formula is also based in small part on the Electricity Production Tariff). In one of the agreements, the linkage formula is based on prices of liquid fuels and includes a "floor price" and in another agreement, the price formula is based on the base price determined in the Gas Framework. |
| Natural gas marketing companies | 2013-2018 | 5-7 years | Some of the agreements include an option for extension thereof by an additional year. | Approx. 1.5 | Approx. 0.2 | The linkage formula is based on linkage to the Brent prices and includes a “floor price”. |
| NBL export agreements (as specified at length | 2017 (for further details, see Section | 15 years | There is an option for extension by two additional years. | Approx. 3[221] | Approx. 0.2 | The linkage formula is based mainly on linkage to the Brent prices and includes a “floor price”. |

[220]Except the extension period that was determined in the agreement that was signed between the Tamar Partners and Israel Chemicals Ltd. (“ **ICL**”) on February 21, 2018 (the “**ICL from Tamar Agreement**”). Pursuant to the aforesaid supply agreement, in the event of a delay in the date of commencement of commercial production from the Tanin and Karish reservoirs, the term of the agreement shall be automatically extended by additional periods of six months each, until the date of commencement of commercial production from the Tanin and Karish reservoirs or until December 31, 20125, whichever is earlier. It was further determined that ICL shall be entitled to notify the Tamar Partners of the termination of the supply agreement upon the expiration of each of the aforesaid extension periods. If the Tanin Karish agreement is terminated, the term of the supply agreement shall be automatically extended until December 31, 2025. For details on a natural gas supply agreement between the Tamar Partners and ICL, see immediate report dated February 22, 2018 (Ref.: 2018-01-014514), the information included in which is incorporated herein by reference.

[221] It is noted that the last agreement with NBL, which was signed in October 2018, is on an interruptible basis for the supply of a total quantity of up to approx. 1 BCM, for details see Section 7.13.5(a)1 below.

| | Supply commence-ment year | Basic gas supply period[215] | Is there an option for extension? | Total maximal amount for supply (100%) (BCM) [216] | Amount supplied until December 31, 2018 (100%) (BCM) | Main linkage basis of the gas price |
|---|---|---|---|---|---|---|
| in Section 7.13.5(a)1 below). | 7.13.5(a)1 below | | | | | |
| Dolphinus export agreement (as specified at length in Section 7.13.5(a)2 below. | For details see Section 7.13.5(a)2 below. | Starting from the completion of the relevant transmission to Egypt systems until December 31, 2030. | - | Approx. 32 | - | The linkage formula is based mainly on linkage to the Brent prices and includes a "floor price". |
| **Total** | | | | Approx. 212 | Approx. 47.5 | |

2. <u>The table below presents a breakdown of the Partnership's revenues in 2016, 2017 and 2018 in accordance with the price linkage basis determined therein[222]:</u>

| | **2016** | | **2017** | | **2018** | | **Primary gas price linkage basis** |
|---|---|---|---|---|---|---|---|
| **Name of customer** | **Total revenues ($ in millions)** | **In % of the total revenues** | **Total revenues ($ in millions)** | **In % of the total revenues** | **Total revenues ($ in millions)** | **In % of the total revenues** | |
| IEC (CPI) | Approx. 297.7 | Approx. 55 | Approx. 282.1 | Approx. 54 | Approx. 256.8 | Approx. 50 | U.S CPI |
| Private electricity producers | | | | | | | The linkage formula is based mainly on linkage to the electricity production tariff and includes a "floor price" |
| Dalia Energies | Approx. 55.8 | Approx. 10 | Approx. 60.2 | Approx. 11 | Approx. 52.4 | Approx. 10 | |
| Others | Approx. 120.5 | Approx. 22 | Approx. 123.8 | Approx. 23 | Approx. 157.8 | Approx. 30 | |
| Industrial customers and marketing companies | | | | | | | The linkage formula is based mainly on linkage to the Brent prices and includes a "floor price". |
| | Approx. 67.5 | Approx. 13 | Approx. 64.1 | Approx. 12 | Approx. 49.5 | Approx. 10 | |

222 The revenues in the table reflect the Partnership's holding in the Tamar Project at the rate of 31.25% until June 30, 2017 and at the rate of approx. 25.7%, from July 1, 2017. For details see Footnote 10 above.

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

   a. In each of the agreements for the sale of natural gas, the aforesaid purchasers undertook to take or pay for a minimal annual amount of natural gas at the scope and according to the mechanism determined in the supply agreement (the "**Minimal Quantity**"). In the event that such purchasers do not buy the Minimal Quantity in any year, they will be obligated to pay the sellers for the difference between the Minimal Quantity that was defined and the quantity actually purchased by the purchaser. The supply agreements further determine a mechanism of accumulating a balance in respect of surplus quantities consumed by the purchaser in any year and utilization thereof for reducing the purchaser's duty to purchase the Minimal Quantity as aforesaid, for a few years thereafter (“**Carry Forward**”). In addition, provisions and mechanisms were determined allowing the said purchasers, after consuming the chargeable Minimal Quantity in respect of a certain year, to receive in such year gas for no additional payment up to the balance of the gas quantity that was not consumed in previous years and for which they paid the sellers in the framework of their commitment to a chargeable Minimal Quantity as aforesaid.

   b. Following the decisions of the Competition Commissioner stated in Section 7.25.2(e)3 below regarding the granting of an exemption from a restrictive arrangement in connection with agreements in which the basic supply period is longer than 7 years, except for the agreement with the IEC (the “**Long-Term Agreements**”), in six agreements that were signed with customers each of the purchasers were given an option to reduce the Minimal Quantity, so that it will be approx. 50% of the average annual amount consumed thereby in the three years preceding the notice regarding exercise of the option, subject to adjustments as specified in the supply agreement (in this section: the "**Option**"). Upon the reduction of the Minimal Quantity, the other amounts specified in the supply agreement will be reduced accordingly. As of the report release date, the Tamar Partners are acting for the amendment of the other purchase agreements with the relevant consumers in accordance with the Commissioner’s decision. For details regarding the said decisions of the Competition Commissioner, see Section 7.25.2(e)3 below.

In this context it is noted that at the beginning of 2019, the Tamar Partners signed an amendment to the agreement with Dalia Energies, in which Dalia Energies undertook to purchase from the Tamar project the full quantities of natural gas that it shall consume in its facilities in the period commencing from the date of flow of gas from the Leviathan reservoir until such time as Dalia Energies exercises the Option (in this section: the "**Period**"), if exercised. In the same amendment, the parties further agreed that for the purpose of calculation of the average annual quantity consumed by Dalia Energies under the agreement in the three years preceding the notice of exercise of the Option relative to the Period, the calculation shall be made based on the Minimal Quantity billable (in accordance with the mechanism set forth in the amendment to the agreement therewith), and not based on the quantity actually taken by Dalia Energies. The amendment to the agreement with Dalia Energies is subject, *inter alia*, to the approval of the Competition Authority.

c. Pursuant to the Gas Framework, in the agreements for the supply of natural gas signed commencing from August 16, 2015 for a period exceeding 8 years, the consumer received a one-sided right to shorten the term of the agreement. Such right will also be granted in agreements signed up to December 13, 2020 for a period exceeding 8 years. For details, see Section 7.25.1(b)3.b.

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

In November 2016, the Tamar Partners notified most of the customers with which agreements for the sale of natural gas were signed from October 2012 as aforesaid (according to the order of precedence of signing of the agreements), including private electricity producers, including Dorad Energy Ltd. and OPC Rotem Ltd. ("**OPC**"), natural gas marketing companies and industrial customers, that on September 30, 2020, the Interim Period shall end, and accordingly, the Tamar Partners will be able to supply to such customers natural gas under the agreements on a binding basis from such date.

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

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

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

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

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

c. In the Agreement, the IEC was afforded an option to increase the total contractual amount from approx. 78 BCM to approx. 87 BCM and to increase the maximum hourly quantity (in this section: the "**Option**"). The Option refers to two periods as specified below: (a) until April 15, 2013, the IEC may exercise the option to give notice of the increase of the gas quantities which it will consume from January 1, 2017 until December 31, 2018 (the "**First Option**"); (b) Until April 15, 2015, the IEC may exercise the option to give notice of the continued consumption of the increased gas quantities from January 1, 2019 until the end of the term of the agreement (the "**Second Option**"), according to the terms and conditions stipulated in the agreement.

d. On April 11, 2013, the IEC notified the Tamar Partners about its decision to exercise the First Option until the end of 2018 and on April 16, 2015, the IEC notified the Tamar Partners about its decision to partially exercise the Second Option.

e. In the framework of an amendment to the gas supply agreement between the Tamar Partners and the IEC, it was agreed that the date of the increase of the quantities was scheduled for January 1, 2017 and shall continue until the end of 2018.

f. In accordance with the exercise of the increase options as stated in Section d. above, the annual chargeable Minimal Quantity from the commercial operation date until the date of exercise of the First Option (namely, December 31, 2016) was approx. 3.5 BCM. The chargeable Minimal Quantity from January 1, 2017 until December 31, 2018 was approx. 5 BCM per annum (subject to adjustments according to the scope of gas sales by the Tamar Partners to private electricity producers and the scope of electricity production of the IEC, but no less than approx. 3.6 BCM per year). From January 1, 2019 until the end of the term of the agreement, the Minimal Quantity for charging shall be approx. 3 BCM per annum. The agreement contains provisions regarding the calculation and adjustment of the minimal quantity for charging including under circumstances of *force majeure* or non-supply by the sellers.

g. The gas price is determined according to a formula which includes a base price and linkage which is based on the US CPI, plus 1% a year until 2019 and less 1% a year from 2020 onwards. The gas price in respect of one unit of MMBTU in 2011 was calculated according to a base price of $5.042. In relation to the additional natural gas quantities that shall be consumed by the IEC in the framework of the Options for increasing the quantities stated in the agreement, from 2014, the gas price is linked (for the gas quantities consumed above 24,000 MMBtu per hour) only to 30% of the rate of the change in the US CPI, and the addition or reduction of 1% a year as aforesaid does not apply.

h. The agreement stipulated two dates on which each party may request the adjustment of the price (according to a mechanism stipulated in the agreement), if such party believes that the price stipulated in the agreement is not suitable anymore for a long-term contract with an anchor buyer for consumption of natural gas for use in the Israeli market: upon the lapse of 8 years and 11 years from the commercial operation date (as defined in the agreement commencing on July 1, 2013) of the Tamar Project (i.e.: July 1, 2021 and July 1, 2024), whichever is earlier. On the first adjustment date (July 1, 2021) (the "**First Adjustment Date**"), the adjustment which will be carried out to the price will be at a range of up to 25% (addition or reduction), and on the second adjustment date (July 1, 2024), the adjustment which will be carried out to the price will be at a range of up to 10% (addition or reduction) of the price on such date.[223] If the Tamar Partners and the IEC fail to reach an agreement on the rate of the price adjustment, either party may refer the matter to arbitration.

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

j. The IEC or the Tamar Partners will be entitled to terminate the agreement, in the event that the other party will perform an insolvency act (as defined in the agreement) which is likely to

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

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

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

l. The Tamar Partners are acting jointly in respect to issues such as development of the reservoir, the Tamar Partners' facilities, the gas production, transportation and supply according to each one of the agreements. However, it was determined that no provision in the agreement will be construed as creating mutual liability among the Tamar Partners and each of the Tamar Partners will be responsible towards the IEC only in respect to their share in the petroleum rights in respect to liability which will arise from the agreement. Even though the IEC may order gas quantities through one notice which will be issued to the coordinator on behalf of the Tamar Partners, the amount which will be deemed as ordered from each of the Tamar Partners will be the share of each of the Tamar Partners out of the overall ordered quantity.

m. The gas supply according to the agreement is on an hourly basis with a maximal amount per hour, according to the mechanisms and procedures specified in the agreement.

n. The delivery of the gas is done at the connection point to the INGL national transmission system, adjacent to the Terminal or at any other connection point which will be agreed upon between the parties.

o. The natural gas which is supplied at the delivery point according to the agreement must comply with the specifications stipulated in the agreement. The IEC has the right to refuse to accept non-standard gas until the flaw is corrected. Any dispute between the parties pertaining to the gas quality will be referred (upon the request of any party) to an expert for decision.

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

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

r. Any dispute or claim that pertains to the Agreement will be resolved by a decision of an expert on specific issues that were determined in the Agreement (mainly of a professional technical nature) or in an arbitration proceeding in accordance with the procedures set forth in the Agreement.

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

t. On February 14, 2019, the board of the Partnership's General Partner approved an amendment to the agreement in connection with the gas price which shall apply until the First Adjustment Date, and in connection with the daily gas quantity which the IEC shall be entitled to order under the agreement (in this section: the "**Amendment to the Agreement**"). The Amendment to the Agreement provides that from January 2019 until the First Adjustment Date (in this section: the "**Interim Period**"), the linkage clause set forth in the agreement (and specified in Subsection g. above) shall not be implemented, such that the price to be paid by the IEC shall be the contractual price that was valid during 2018. On the First Adjustment Date, an adjustment shall be made of the contractual price as set forth in the agreement, in reference to the contractual price that would have been paid but for the Amendment to the Agreement, i.e., the contractual price assuming implementation of the linkage set forth in the agreement, as specified in Subsection g. above.

In the estimation of the Partnership, the savings amount that is expected to become due to the IEC from the Amendment to the Agreement as aforesaid in the Interim Period is approx. U.S. $85 million (in 100% terms) (the Partnership's share is approx. U.S. $19 million) (in this section: the "**Savings Amount**"). If and insofar as it shall be determined that a price reduction is required on the First Adjustment Date, the parties shall discuss the manner and scope at which the Savings Amount may be taken into account in such reduction.

The Amendment to the Agreement further provides that from the date of flow of gas from the Leviathan project to the Israeli market, the maximum daily gas quantity which the IEC shall be entitled to order under the agreement shall be reduced from 655,200 MMBTU to 500,000 MMBTU, without reducing the minimal annual quantity which the IEC undertook to ‘take or pay’ under the agreement.

The Amendment to the Agreement shall be subject to the receipt of approval from some of the Tamar Partners’ finance providers, as well as the approval of the Competition Authority, if and insofar as such approval is required by law. The Amendment to the Agreement is expected to be signed upon receipt of the regulatory approvals that are required by the IEC (if and insofar as received). It is noted that to the best of the Partnership’s knowledge, on February 14, 2019, the IEC’s board approved the principles of the Amendment to the Agreement and authorized the IEC’s management to sign the Amendment to the Agreement after receipt of the relevant regulatory approvals, if and insofar as required.

**Cautions regarding forward-looking information–**

**The forecast regarding the signing of the Amendment to the Agreement constitutes forward-looking information, within the meaning thereof in the Securities Law, with respect to which there is no certainty that it will materialize, in whole or in part, in the said manner or in any other manner, and which may materialize in a materially different manner, due to various factors including non-receipt of the regulatory approvals required by the IEC prior to signing the Amendment to the Agreement, approval of some of the Tamar Partners’ finance providers, and the approval of the Competition Authority (if and to the extent required).**

**The Partnership’s estimate of the savings to be derived by the IEC constitutes forward-looking information, within the meaning thereof in the Securities Law, with respect to which there is no certainty that it will materialize, in whole or in part, in the said manner or in any other manner, and which may materialize in a materially different manner, due to various factors including changes in the quantities to**

**be used by the IEC and changes in the U.S. CPI in the Interim Period**.

On December 2, 2018, a request for proposals was delivered to the Tamar Partners and the Leviathan Partners by the IEC for the supply of natural gas at an estimated annual quantity of up to 2 BCM, to be supplied from October 1, 2019 or the date of commencement of production of gas from the Leviathan reservoir, whichever is later, until June 30, 2021 or the date of commencement of production of gas from the Karish reservoir, whichever is earlier (in this section: the "**Supply Period**"). During the Supply Period, the IEC shall approach the winner only for the purchase of gas, according to its needs, over and above the gas supplied thereto under the agreement therewith that is described above. On March 7, 2019, the Tamar and Leviathan partners submitted proposals under the said request.

**Caution regarding forward-looking information – the aforesaid evaluations regarding the overall financial scopes of the supply agreements specified above, the natural gas quantities which will be purchased by the purchasers specified above, and the commencement of the supply dates according to the supply agreement, constitute forward-looking information as defined in the Securities Law, in respect of which there is no certainty it will materialize, in whole or in part, and which might materialize in a materially different manner, due to different factors including due to the non-fulfillment of the conditions precedent in each of the supply agreements (to the extent such have not been fulfilled yet), non-obtainment of regulatory approvals, changes in scope, rate and timing of the natural gas consumption by each of the said purchasers, the gas prices which will be determined according to the formulas stipulated in the supply agreements, the Electricity Production Tariff, the Dollar-Shekel exchange rate (to the extent relevant to the supply agreement), the Brent prices (to the extent relevant to the supply agreement), the US CPI (to the extent relevant to the supply agreement), performance and completion of the expansion of capacity of the Tamar Project (to the extent relevant to the supply agreement), construction and operation of the power stations and/or other facilities of the purchasers (to the extent relevant to the supply agreement), exercise of the options granted in each of the supply agreements and the date of exercise thereof and so forth.**

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

During the years 2016-2018, the Partnership, together with the other Leviathan Partners, signed several agreements for the supply of natural gas from the Leviathan project, the main principles of which are presented below:

| | Supply commence-ment year | Basic gas supply period[224] | Is there an extension option? | Total maximal amount for supply (100%) (BCM)[225] | Main linkage basis of the gas price |
|---|---|---|---|---|---|
| Private electricity producers[226] | Date of piping of the gas in commercial quantities from the Leviathan reservoir, or the date of commencement of the commercial operation of the buyer's power plant (whichever is later). | 18-20 years from the supply commencement date, except one agreement which determined that this period will be counted from the date of commencement of commercial operation of the buyer's power plant or the date of commencement of commercial operation of the Leviathan project (whichever is earlier) (except the agreement between ICL and the Leviathan Partners[227] whereby there is a different supply period). | Option for extension by two additional years (with the exception of the agreement between ICL and the Leviathan Partners)[228]. | Approx. 28.9 | The linkage formula of the agreements (except the agreement between ICL and the Leviathan Partners[229]) is based on linkage to the Electricity Production Tariff and includes a "floor price". |

224 In most of the agreements, the gas supply period, commencing from the date of piping with respect to the relevant agreement, will be according to the table presented above or until the purchaser consumes the maximal contractual amount set forth in the agreement, whichever is earlier.

225 This amount is the maximum amount which the Leviathan Partners have undertaken to supply to the customer throughout the term of the agreements. The quantity which they undertook to purchase is lower than this quantity (for details see Section 7.15 below). It is noted that there are agreements in which a mechanism is determined whereby the purchaser will be entitled to increase / reduce the purchased quantities (including the total maximal quantity) until the date set forth in the agreement, according to its needs and the provisions determined in the agreement.

226 It is noted that as of the Report Date, in most of the agreements described above, all of the conditions precedent to the agreement have been fulfilled.

227 For details, see Footnote 228 below.

228 The supply agreement that was signed between the Leviathan Partners and ICL on February 21, 2018, contains a mechanism similar to the ICL from Tamar Agreement extension mechanism. For details on an agreement to supply natural gas between the Leviathan Partners and ICL, see immediate report dated February 22, 2018 (Ref.: 2018-01-014514), the information included in which is incorporated herein by reference.

229 For details, see Footnote 228 above.

| | | | | | |
|---|---|---|---|---|---|
| Industrial customer | Date of the piping of the gas in commercial quantities from the Leviathan reservoir | 15 years | Option for extension by one additional year | Approx. 3.1 | 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".<br>There is partial linkage also to the refining margin index. |
| Nepco export agreement (as specified at length in Section 7.13.5(b)1 below | Date of the piping of the gas in commercial quantities from the Leviathan reservoir, the date on which the purchaser's facilities are ready or the date on which the relevant transmission systems will be ready (whichever is later) | 15 years | The agreement is for a period of 15 years may be extended for a period of up to two additional years. | Approx. 45 | The linkage formula is based on linkage to the Brent prices plus a marketing commission, transmission fees and participation in payments to INGL. |
| Dolphinus export agreement (as specified at length in Section 7.13.5(b)2 below). | Date of the piping of the gas in commercial quantities from the Leviathan reservoir, the date on which the purchaser's facilities are ready or the date on which the relevant transmission systems will be ready (whichever is later) | 10 years | - | Approx. 32 | The linkage formula is based on linkage to the Brent prices. |
| **Total** | | | | Approx. 109 | |

1. <u>Further details regarding all of the agreements for the sale of natural gas to the domestic market which were signed by the Leviathan Partners</u>

   a. In each of the agreements for the sale of natural gas, the aforesaid purchasers undertook to take or pay for a minimal annual amount of natural gas at the scope and according to the mechanism determined in the supply agreement (the "**Minimal Quantity**"). The supply agreements further determine a mechanism of accumulating a balance in respect of surplus quantities consumed by the purchaser in any year and utilization thereof for reducing the purchaser's duty to purchase the Minimal Quantity as aforesaid, for a few years thereafter – Carry Forward. In addition, provisions and mechanisms were determined allowing each of the said purchasers, after paying for gas it did not consume due to the operation of the Minimal Quantity mechanism for charging as aforesaid, to receive gas for no additional payment up to the quantity that it paid for in respect of gas which it did not consume.

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

   c. The supply agreements include several conditions precedent which include, *inter alia*, receipt of a license for the gas transmission system from the Leviathan reservoir in accordance with the Natural Gas Sector Law, adoption of a final investment decision (FID) by the Leviathan Partners (for details regarding such decision, see Section 7.4.5 above) and receipt of the approvals required on the part of the purchasers in connection with the agreement.

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

7.13.5 <u>Engagements for natural gas export</u>

(a) <u>Tamar Project</u>

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

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

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

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

On October 14, 2018, another agreement was signed for the supply of natural gas between the Tamar Partners and NBL for the export of natural gas to consumers in Jordan and the supply thereof to the Purchasers (the "**Second NBL-Tamar Agreement**"). Concurrently with the signing of the Second NBL-Tamar agreement, NBL signed another agreement with the Purchasers, according to which the Purchasers will buy from NBL an additional quantity of natural gas which will be used thereby as aforesaid at their plants which are located on the eastern bank of the Dead Sea in Jordan (the "**Second Supply Agreement**"), on an interruptible basis, at a scope of approx. 0.1 BCM per annum, while NBL is entitled, in accordance with the dates determined in the agreement, to notify the Purchasers that the supply under the Second NBL-Tamar Agreement shall be carried out on a firm basis. The supply according to the Second NBL-Tamar Agreement began during Q1/2019 and is expected to continue until the date of completion of the supply under the First Supply Agreement. With respect to the NBL agreements, see also Section 7.25.4(c) below.

It is noted that within a tax ruling regarding the First Supply Agreement and the Second Supply Agreement, given to Tamar partners by the Tax Authority, the Tamar partners undertook to offer new potential consumers to engage in agreements for the sale of natural gas, at a price which be calculated according to the optimal formula, based on the Brent price, as specified in the Gas Framework, with an undertaking for such offer to apply for a period of 3 years from the date of the government decision (i.e., until August 16, 2018) and from the date of execution of the Second Supply Agreement (i.e., until October 14, 2021), respectively. The offer will be carried out according to the provisions of the Gas Framework, including with respect to the date of supply which may apply at any time commencing from the commencement of supply under the supply agreements (the first and the second, as the case may be) up to six years from their execution date, as specified above. For details see Sections 7.25.1(c)1 and 7.25.1(c)4 below.

2. On March 17, 2015, the Tamar Partners signed an agreement for the supply of natural gas from the Tamar Project to Dolphinus Holdings Limited[230] ("**Dolphinus**").

[230] To the best of the Partnership's knowledge, the buyer is a company which engages in natural gas trade and intends to supply gas to large industrial and commercial consumers in Egypt.

On February 19, 2018, an agreement was signed between the Partnership and Noble and Dolphinus for the export of natural gas from the Tamar Project to Egypt (in this section: the "**Tamar-Dolphinus Agreement**"), whose scope is significantly larger than the agreement signed between the Tamar Partners and Dolphinus on March 17, 2015 and which was signed with the intention of replacing it.

On September 26, 2018, the Partnership and Noble endorsed the Tamar-Dolphinus Agreement to the other Tamar Partners. In addition, on the same date, partners in the Tamar project signed a non-binding MOU with the Partnership and Noble in connection with the allocation of capacity and other arrangements for the flow of natural gas in transmission infrastructures from Israel to Egypt, including in EMG's existing gas transmission pipeline and in the section of the pipeline between Aqaba and Al-Arish (the "**Arab Gas Pipeline**") via Aqaba (in Section 7.13.5: the "**Transmission Infrastructures**"), as specified in Section 7.27.7(f) below. In addition, EMED, a company jointly owned by subsidiaries of Noble, the Partnership and an Egyptian partner, on September 26, 2018, entered into agreements for the purchase of 39% of EMG's shares, all as specified in Section 7.27.7 below (in Section 7.13.5: the "**EMG Transaction**") for the purpose of realization of the Tamar-Dolphinus Agreement.

Note that as of the report release date, the parties are conducting negotiations regarding amendments to the Tamar-Dolphinus Agreement and the memorandum of understanding with the Tamar partners, as specified in Section 7.27.7(f) below, that have not yet resulted in agreements. It is further noted that at the same time, negotiations are held with Dolphinus for increasing the quantity of gas to be supplied to Dolphinus under the Leviathan-Dolphinus Agreement as specified in Section 7.13.5(b)2, and with the Leviathan partners regarding the memorandum of understanding as specified in Section 7.27.7(f) below.

<u>Below is a summary of the details and terms and conditions of the Tamar-Dolphinus Agreement</u>:

In the Tamar-Dolphinus Agreement it was determined that the supply of gas to Dolphinus would initially be on an interruptible basis. As part of the Tamar-Dolphinus Agreement, the Tamar Partners were given an option to inform Dolphinus that the supply of gas (in whole or in part) will become binding (in this section: the "**Option**"). The Option may be exercised by the Tamar Partners, in part or in whole, during the period commencing from July 2020 and ending at the end of December 2021, or during another period, to be agreed between the Tamar Partners and Dolphinus. From the exercise date of the Option as aforesaid, the Tamar Partners will be obligated to supply Dolphinus with an annual quantity of up to approx. 3.5 BCM (in accordance with the scope of quantities for which the Option is exercised) and Dolphinus will be obligated to take or pay for a minimal annual quantity of natural gas according to the mechanism set forth in the Tamar-Dolphinus Agreement. The total contractual gas quantity stated in the Tamar-Dolphinus Agreement is approx. 32 BCM.

The price of gas to be supplied to Dolphinus under the Tamar-Dolphinus Agreement will be determined according to a formula based on the price of a Brent oil barrel. On the date of signing the agreement, the Partnership estimated that the aggregate scope of income with respect to all of the Tamar Partners from the sale of natural gas to Dolphinus under the Tamar-Dolphinus Agreement may amount to approx. $7.5 billion. The Partnership's estimation as stated, was based on the assumption that Dolphinus would consume the total contractual quantity set forth in the Tamar-Dolphinus Agreement, as well as on the Partnership's estimate regarding the price of natural gas during the term of the agreement. It is clarified that the actual income will be derived from a gamut of factors, including the quantities of gas actually purchased by Dolphinus and the prices of Brent at the time of the sale.
For details regarding the alternatives examined by the Tamar Partners for the gas flow to Egypt, see Section 7.14.2(b)2.b below.
The supply under the Tamar-Dolphinus Agreement is expected to begin during 2019, upon the regulation of the use of infrastructures required for the transmission of natural gas to Egypt. The supply will continue until the supply of the total contractual quantity set forth in the Tamar-Dolphinus Agreement or until the end of December 2030, whichever is earlier.

The Tamar-Dolphinus Agreement includes several conditions precedent, mainly the receipt of regulatory approvals in Israel and in Egypt (including receipt of approvals for the export and import of the gas as aforesaid), entering into agreements that will enable use of the transmission infrastructure, including the signing of transmission agreements with INGL (if required), the receipt of guarantees in favor of the Tamar Partners as required under the Tamar-Dolphinus Agreement, and receipt of approvals from the Israeli Tax Authorities in respect of the transactions that are the subject matter of the Tamar-Dolphinus Agreement.

It is clarified that there is no certainty that the sale of the gas to Dolphinus under the Tamar-Dolphinus Agreement will materialize, due to the non-fulfillment of the conditions precedent in the Tamar-Dolphinus Agreement, in whole or in part, etc.

**Caution regarding forward-looking information – the above estimates regarding the gas transmission options, the expected supply date, the total financial scopes of the Tamar-Dolphinus Agreement and the quantities of natural gas that shall be purchased by Dolphinus, and the binding arrangements, as shall ultimately be determined vis-à-vis the Tamar Partners and the Leviathan Partners, constitute forward-looking information as defined in the Securities Law, regarding which there is no certainty that it will materialize, in whole or in part, and which may materialize in a materially different manner, due to various factors, including due to the non-fulfillment of the conditions precedent in the agreement, non-receipt of regulatory approvals, changes in the scope, rate and timing of the natural gas consumption by Dolphinus, changes in the gas price as a result of changes in the price of a Brent oil barrel, exercise of the Option in the Tamar-Dolphinus Agreement (if and insofar as it is exercised), the exercise date of the Option and the scope of the exercise, and changes which shall occur following negotiations held for the amendment of the Tamar-Dolphinus Agreement as aforesaid.**

3. For details on the examination of a possibility to expand the supply capacity of the Tamar Project, see Section 7.3.4(c) above.

(b) Leviathan project

1. On September 26, 2016, a detailed agreement was signed for the supply of natural gas between NBL Jordan Marketing Limited (the "**Marketing Company**") and the national electric company of Jordan (NEPCO) (the "**Export Agreement**"). The Marketing Company is a wholly owned subsidiary of the partners in the Leviathan project, including the Partnership, which hold it proportionately to the rate of their holdings in the Leviathan project.

   According to the Export Agreement, the Marketing Company undertook to supply to NEPCO natural gas for a period of approx. 15 years after commencement of the commercial supply or until the total supply volume would be approx. 45 BCM. The supply according to the Export Agreement is expected to begin upon commencement of the supply from the Leviathan reservoir and completion of the transmission systems required for transmission of natural gas to NEPCO in Israel and in Jordan.

The gas is expected to be supplied at the exit from the Israeli transmission system at the border between Israel and Jordan. In July 2017, the Leviathan Partners approved the budget for the completion of the Israeli transmission system up to the border between Israel and Jordan in the amount of approx. $111 million (100%). As of the report release date, the said amount has been updated to approx. $119 million.

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

The gas price determined in the agreement is based on a price that is linked to the Brent oil barrel prices, and includes a “floor price” plus a marketing fee, a transmission fee and participation in payments to INGL. On the signing date, the Leviathan Partners estimated that the aggregate scope of the revenues from the sale of natural gas to NEPCO may amount to approx. U.S. $10 billion, assuming that NEPCO consumes the total contractual quantity, and based on the Partnership’s estimate with respect to the natural gas price during the term of the agreement.

As of the report release date, all of the conditions precedent set forth in the agreement have been fulfilled.

The Marketing Company shall purchase the natural gas from the Leviathan Partners for the purpose of sale thereof to NEPCO in the context of the Export Agreement, under the same terms (back-to-back). Note that pursuant to a taxation decision in relation to the agreement, the Leviathan Partners undertook to offer every new Israeli customer a natural gas price alternative to be determined according to a Brent barrel price, as shall be calculated in accordance with the optimal formula for the consumer, which exists on the date of the Government resolution in agreements of the Tamar Partners. For details see Sections 7.25.1(c)1 and 7.25.1(c)4 below.

The undertaking with respect to an offer as aforesaid by virtue of the taxation decision shall apply in the course of a three-year period from the Export Agreement signing date (namely, until September 25, 2019). The date of supply under the offer shall apply in any period whatsoever which begins from the commencement of the supply pursuant to the Export Agreement (which is expected to occur upon commencement of the gas supply from the Leviathan reservoir, i.e. during Q4/2019 according to the Partnership’s estimation) and up to six years from the date of signing of the Export Agreement.

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

2. On February 19, 2018, an agreement was signed between the Partnership and Noble and Dolphinus (in this section: the "**Purchaser**") for the export of natural gas from the Leviathan project to Egypt (in this section: the "**Leviathan-Dolphinus Agreement**").

   On September 26, 2018, the Partnership and Noble endorsed the Leviathan-Dolphinus Agreement to the other Leviathan Partners. In addition, on the same date, the Leviathan Partners signed a non-binding MOU with the Partnership and Noble in connection with the allocation of capacity and other arrangements for the flow of natural gas in transmission infrastructures, as specified in Section 7.27.7(f) below. For details regarding the EMG Transaction, see Section 7.27.7 below.

   Note that as of the report release date, the Partnership and Noble are conducting negotiations with Dolphinus for increasing the gas quantity to be supplied to Dolphinus under the Leviathan-Dolphinus Agreement. It is further noted that at the same time, negotiations are held regarding amendments to the Tamar-Dolphinus Agreement as specified in Section 7.13.5(a)2 above and with respect to the memorandum of understanding with the Tamar partners as specified in Section 7.27.7(f) below.

   <u>Below is a summary of the details and terms and conditions of the Leviathan-Dolphinus Agreement</u>:

   The Leviathan-Dolphinus Agreement determines that the supply of gas to the Purchaser will be on a firm basis. The Leviathan Partners undertook to supply the Purchaser with an annual quantity of approx. 3.5 BCM and the Purchaser undertook to take or pay for a minimal quantity according to the mechanism set forth in the agreement. The total contractual gas quantity stated in the Leviathan-Dolphinus Agreement is approx. 32 BCM.

The price of gas to be supplied to the Purchaser under the Leviathan-Dolphinus Agreement will be determined according to a formula based on the price of a Brent oil barrel. On the date of signing the agreement, the Partnership estimated that the aggregate scope of income with respect to all of the Leviathan Partners from the sale of natural gas to the Purchaser under the Leviathan-Dolphinus Agreement may amount to approx. U.S. $7.5 billion. The Partnership's estimation as stated, was based on the assumption that the Purchaser would consume the total contractual quantity set forth in the Leviathan-Dolphinus Agreement, as well as on the Partnership's estimate regarding the price of natural gas during the term of the agreement. It is clarified that the actual income will be derived from a gamut of factors, including the quantities of gas actually purchased by the Purchaser and the prices of Brent at the time of the sale.

For details regarding the alternatives examined for the gas flow to Egypt, see Section 7.14.2(b)2.b below.

The supply under the Leviathan-Dolphinus Agreement is expected to begin with the commencement of production from the Leviathan reservoir. The supply will continue until the supply of the total contractual quantity set forth in the Leviathan-Dolphinus Agreement or until December 2030, whichever is earlier.

The Leviathan-Dolphinus Agreement includes several conditions precedent, mainly the receipt of regulatory approvals in Israel and in Egypt (including receipt of approvals for the export and import of the gas as aforesaid), entering into agreements that will enable the use of the transmission infrastructure, including the signing of transmission agreements between the Leviathan Partners and INGL (if required), the receipt of guarantees in favor of the Leviathan Partners as required under the Leviathan-Dolphinus Agreement, and receipt of approvals from the Israeli Tax Authorities in respect of the transactions that are the subject matter of the Leviathan-Dolphinus Agreement.

It is clarified that there is no certainty that the sale of the gas to the Purchaser under the Leviathan-Dolphinus Agreement will materialize, due to the non-fulfillment of the conditions precedent in the Leviathan-Dolphinus Agreement, in whole or in part, etc.

**Caution regarding forward-looking information – the above estimates regarding the gas transmission options, the projected supply date, the total financial scopes of the Leviathan-Dolphinus Agreement and the quantities of natural gas that**

**shall be purchased by Dolphinus and the binding arrangements as shall be ultimately determined vis-à-vis the Tamar Partners and the Leviathan Partners, constitute forward-looking information as defined in the Securities Law, regarding which there is no certainty that it will materialize, in whole or in part, and which may materialize in a materially different manner, due to various factors, including due to the non-fulfillment of the conditions precedent in the agreement, non-receipt of regulatory approvals, changes in the scope, rate and timing of the natural gas consumption by Dolphinus , changes in the gas price as a result of changes in the price of a Brent oil barrel, exercise of the option in the Leviathan-Dolphinus Agreement (if and insofar as exercised), exercise date of the option and exercise scope, as well as changes to occur following negotiations held for the amendment of the Leviathan-Dolphinus Agreement as aforesaid.**

3. Pursuant to the non-binding letter of intent dated June 27, 2014 that was signed between the Leviathan Partners and BG International Limited, which was acquired during 2015 by Shell[231], the Partnership is continuing together with the other Leviathan Partners to conduct negotiations with Shell for the supply of natural gas, for the purpose of feeding the existing liquefaction facility operated by Shell and situated in proximity to the city of Idku in Egypt (in this section: the "**Liquefaction Facility**").

   It is clarified that the aforesaid transaction shall be subject to the successful completion of the negotiations between the parties and to the signing of the binding agreement. There is no certainty that the parties will reach an agreement on the terms and conditions of the binding agreement, and there is no certainty that an agreement as aforesaid will be signed.

   It is noted that as of the report release date, the Partnership, together with its other partners in the Aphrodite reservoir, is examining the possibility of supply of natural gas together with the Leviathan project to the Liquefaction Facility, that will be performed, if performed, from the Aphrodite reservoir, in the scope of approx. 6 BCM per year for a period of approx. 10-15 years, subject to the Aphrodite reservoir Development Plan as specified in Section 7.8.11 above, and from the Leviathan reservoir, in the context of additional development stages of the Leviathan reservoir (beyond Phase 1A of the Leviathan reservoir Development Plan), as specified in Section 7.4.5 above. It is noted that, to the best of

[231] The acquisition transaction was completed in Q1/2016.

the Partnership's knowledge, the maximum annual capacity of the liquefaction facilities is approx. 12 BCM per year.

It is further noted that as of the report release date, the Partnership is looking into various arrangements with the owners of liquefaction facilities for the export of LNG in Egypt, both in relation to the ELNG liquefaction facility that is operated by Shell and is situated in proximity to the city of Idku, and in relation to the SEGAS liquefaction facility that is operated by Union Fenosa Gas (UFG) and is situated in proximity to the city of Damietta. The arrangements being examined include, *inter alia*, the purchase of liquefaction capacity, arrangements in relation to receipt of liquefaction services that will enable the Partnership to market natural gas in LNG form while paying for liquefaction services, and additional possibilities in connection with the purchase of rights in these facilities.

7.13.6 Agreement for condensate supply to PAR

On November 28, 2012, an agreement for the supply of condensate (in this section: the "**Agreement**") was executed between PAR and the Tamar Partners (in this section: the "**Sellers**"), according to which the Sellers undertook to supply PAR with condensate for a period of 5 years which commenced on March 30, 2013 at a scope (quantities and price) which is not material. In November 2016, the parties agreed on the extension of the agreement for 5 additional years from March 30, 2018. The condensate price is determined according to the Brent prices less a margin, as set forth in the supply agreement. All of the sales of condensate by the Tamar Partners is in the context of the aforesaid engagement agreement.

7.14 Marketing and Distribution

7.14.1 Supply to the domestic market

As of the report release date, the Partnership, together with its partners in the Tamar Project and in the Leviathan project, is acting for the marketing of natural gas and condensate to potential consumers (see Section 7.12.2 above) and is conducting negotiations at various stages with potential customers in the domestic market including private electricity producers and industrial consumers, aiming to engage in binding agreements for the sale of natural gas and/or condensate from the said projects, all in accordance with the gas prices and the term of the agreements set forth in the Gas Framework, as specified in Sections 7.25.1(b)3 and 7.25.1(c)1 below, and subject to supply capacity of said projects.

Piping the natural gas to some of the additional customers may also be contingent upon the continued development of the natural gas national transmission system by INGL, and the completion of the regional distribution systems.

7.14.2 Export

(a) General

The Partnership, together with its partners in the various projects, is acting to find markets outside of Israel and outside of Cyprus for the marketing of the natural gas that it has discovered. The Partnership estimates that the potential markets include the countries that are close to Israel (including the Palestinian market which currently purchases electricity from Israel, and in which there are plans to build power plants for the production of its own electricity), chiefly Egypt and Jordan, to which gas may be exported via pipelines, and the more distant global markets to which it is possible to export natural gas via LNG (liquefied natural gas) and/or CNG (compressed natural gas). In the context of the Partnership's marketing efforts for export, several agreements were signed with customers in Jordan and in Egypt, and negotiations are also being conducted for the supply of natural gas to additional customers in these and other countries[232]. The Partnership is further examining the economic merit of several projects of export through LNG (including liquefaction of natural gas in a floating facility - FLNG) and CNG, as specified below.

(b) Pipeline

1. The Partnership is acting, in addition to the export agreements in which it has engaged and which are specified in Section 7.13.5 above, for promotion of possibilities to use the (existing and/or new) pipeline, and in this context is promoting contacts and/or negotiations, at various stages, pertaining to the export of natural gas through pipes in significant scopes to Jordan, Egypt, the Palestinian Authority, Turkey and Cyprus.

   Within the aforesaid contacts and/or negotiations, the main parameters in the possible agreements for the sale of natural gas through pipelines are discussed, including, *inter alia*¸ engagement term, amounts, capacity, price per unit, linkage formula, minimal purchase undertaking (take-or-pay), undertaking for building pipelines etc. In addition, to the best of the Partnership's knowledge, discussions are being held and an examination carried out of the technical feasibility of various government agencies and outside business entities with financing thereby for the

[232] For details on the export agreements and letters of intent that have been signed, see Section 7.13.5.

construction of a pipeline for the export of natural gas to Italy via, *inter alia*, Cyprus and Greece.

**Caution regarding forward-looking information – the information specified above regarding contacts and/or negotiations as aforesaid constitutes forward-looking information as defined in the Securities Law, which there is no certainty that it will materialize, in whole or in part, in the manner stated or in any other manner, and it may materialize in a materially different manner than described above, and in particular there is no certainty that the aforesaid contacts and/or negotiations will mature into binding gas sale agreements and that the conditions required according to any law for such agreements to take effect, if signed, shall be fulfilled.**

2. Following is a description of the main potential target markets for the export of natural gas through pipelines from the Tamar Project and from the Leviathan project[233] -

   a. Jordan – To the Partnership's understanding, and based on independent consulting firms, the gas consumption in Jordan for domestic use was approx. 3.9 BCM in 2017, up approx. 6% relative to 2016. Natural gas constituted, in 2017, approx. 38% of Jordan's energy sources, with oil being the main energy source. In the electricity production sector, natural gas is the main production source in Jordan, constituting a source for the production of more than 70% of the electricity in Jordan. Accordingly, more than 90% of the natural gas consumption in Jordan was used for electricity production. In 2018, the domestic demand in the Jordanian market is estimated at approx. 4 BCM. Note that in the estimation of part of the independent consulting firms, the demand for natural gas in the Jordanian market in 2020 is expected to be approx. 4 BCM per year, and to remain within a range of 4.0-4.3 BCM per year in this decade. The relative cooling in the forecast for the consumption of natural gas in Jordan originates from accelerated penetration of renewable energies into the electricity production sector in Jordan, following proactive activity of the government in this sector. The target that was set by the Jordanian government is that renewable energies shall constitute approx. 20% of the scope of the electricity production in the country in 2020, and it is estimated that in

[233] The said information was prepared by the Partnership, *inter alia*, based on the data of reports released by independent consulting firms.

practice, electricity production from renewable energies shall constitute approx. 17% of the total electricity production in this year. The current forecast is that this rate is expected to rise to more than 25% in 2025, and to more than 30% in 2030. Jordan currently leases a floating regasification facility, which is located in Aqaba for the import of LNG. To the best of the Partnership's knowledge, Jordan has an agreement for the purchase of 1.1 million tons of LNG per year until mid-2020, while the remaining purchases are made through LNG tenders or in spot transactions. Jordan currently imports natural gas mainly via LNG cargo, which constitutes the majority of the gas consumed in Jordan, and also imports natural gas from the Tamar project to industrial plants in the area of the Jordanian Dead Sea, imports small quantities of natural gas from Egypt via the Arab Gas Pipeline, and produces negligible quantities of natural gas. The domestic natural gas production in 2018 was at a scope of approx. 0.1 BCM. Since early 2017, the Tamar Partners have exported approx. 0.15 BCM of natural gas per year to two industrial plants that are situated on the Eastern bank of the Dead Sea in Jordan, as specified in Section 7.13.5(a)1 above, through the connection of the Israeli transmission system to the plants located on the eastern bank of the Dead Sea in Jordan (the "**Southern Pipeline**"). In addition, the project of construction of a new natural gas pipeline that connects INGL's transmission system (from the Dovrat area) to the Jordanian border, has been completed, and the construction of a pipeline that shall connect the new pipeline that has been constructed by INGL on the Israel-Jordan border, to the existing transmission pipeline in Jordan (the Arab Gas Pipeline that is operated by FAJR) (the "**Northern Pipeline**"), is expected to be completed during 2019. With respect to the budget for construction of the Northern Pipeline, as approved by the Leviathan Partners, see Section 7.4.4 above. Based on the figures that are known to the Partnership, the Northern Pipeline's capacity shall enable the flow of natural gas in an annual amount of up to approx. 10 BCM to Jordan and via Jordan to Egypt.

For the agreements signed in respect of the supply of natural gas to Jordan, see Sections 7.13.5(a)1 and 7.13.5.(b)1 above.

b. <u>Egypt</u> – To the Partnership's understanding, and based on independent consulting firms, natural gas plays a key role in the Egyptian energy market, while in 2017 it was a source for approx. 55% of Egypt's energy sources, versus oil and coal which accounted for approx. 38% and less than 3%, respectively, of Egypt's energy sources. Natural gas consumption in Egypt is mainly used for electricity production but also for industry and households. To the Partnership's understanding, the local production in Egypt in 2017 was approx. 52 BCM, up approx. 25% relative to 2016, with the growth in production deriving mainly from commencement of production of natural gas from new gas fields. The demand for natural gas for the domestic market in Egypt in 2017 was approx. 58.9 BCM (up 15% compared with 2016), of which approx. 8.3 BCM were imported in the form of liquefied natural gas for consumption in the domestic market. Domestic production in 2018 is estimated at approx. 62.4 BCM (primarily due to the commencement of production from the Zohr reservoir which began production in mid-December 2017), with domestic demand in Egypt in 2018 being estimated at approx. 62.8 BCM. As a result of the increase in the scope of production, the Egyptian government reduced the number of LNG regasification facilities (which are used for the import of liquefied natural gas) from two to one. It is noted that seasonality in the use of natural gas in Egypt contributes to the possibility that Egypt may export certain quantities of natural gas in the winter months and import natural gas in the summer months. In addition, in Egypt there are two natural gas liquefaction facilities for production of LNG for export from Egypt, with a total liquefaction capacity of approx. 12.2 million tons of liquefied gas per year, in respect of which natural gas is required for gas feed at a scope of approx. 18-20 BCM per year, in addition to the domestic demand. As of the report release date, due to a shortage of natural gas in Egypt, such facilities are operating at a low output or are not operating at all. The demand forecasts for the local Egyptian market for 2019, 2020 and 2021 are approx. 67.6 BCM, approx. 70.6 BCM and approx. 72 BCM, respectively, while forecasts for domestic production from producing fields, either at development stages or with a high probability of commencement of production in 2019, 2020 and 2021, are approx. 70 BCM, approx. 74 BCM and approx. 74.3 BCM, respectively, when disregarding the demand for the LNG export facilities. The small oversupply in the domestic market, in 2019 to 2021 is expected to lead to increased export of natural gas mainly as LNG from Egypt in this period, however in order to realize the full LNG export capacity, import of approx. 15 BCM will be required in the relevant years, while it is forecasted that from 2023, a gas shortage is expected to arise for domestic consumption in the local Egyptian market, based on forecasts for domestic production from producing fields, either at development stages or with a high probability of production. The demand forecasts for 2025 to 2030 relate to a scope of consumption in the domestic market of approx. 78-80 BCM per year, without including the natural gas required as feed gas for feeding the said liquefaction facilities, and with the forecast for domestic production from producing fields, either at development stages or with a high probability of production, being approx. 62.5 BCM in 2025 and approx. 47 BCM in 2030, insofar as no other reservoirs are discovered and/or enter production. To the best of the Partnership's knowledge, the Egyptian government is acting to promote projects for the supply of natural gas from discoveries in Israel and Cyprus, with the aim of turning Egypt into a natural gas hub, in order to supply the needs of the domestic market alongside use of the existing export facilities and promotion of investments in new export facilities, all concurrently with the encouragement of activities for the development and exploration of natural gas projects in Egypt, such as the last exploration tender whose results were released in February 2019, and in which 12 offshore and onshore blocks were allocated for natural gas and oil exploration. Natural gas exploration activity, which is promoted by the Egyptian government, may reinforce and spur the natural gas exploration activity in Egypt, and therefore there may be additional natural gas discoveries in Egypt. For details regarding engagements for the export of natural gas to Egypt, see Sections 7.13.5(a)2, 7.13.5(b)2 and 7.13.5(b)3 above.

For details regarding the EMG Transaction, which is expected to allow the flow of natural gas to Egypt, see Section 7.27.7 below.

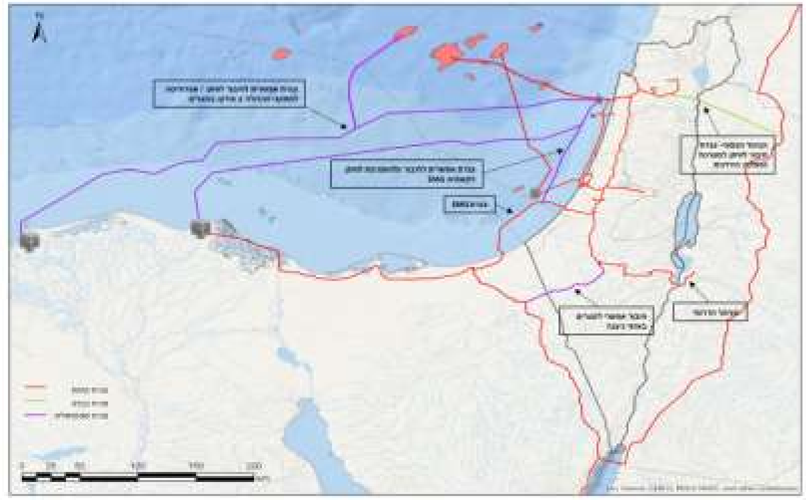
<ins>Transmission to Egypt using existing infrastructures</ins>

According to an estimation that was provided to the Partnership by Noble, in view of the expected demands in the Israeli market, and based on the existing transmission infrastructure in the Israeli market, on the date that commercial gas supply from the Leviathan reservoir is expected to start, it will be possible to transport, in the EMG Pipeline, through INGL's existing transmission system infrastructure, natural gas in the daily amount of approx. 400,000 to 450,000 MMBtu (approx. 4 to 4.5 BCM per year). Noble further estimates that it will be possible to transport natural gas from Israel to Egypt, through Jordan (using the Arab Gas Pipeline), through the Northern Pipeline, in the additional quantity of 2 to 2.5 BCM per year. I.e., the total quantity that will be transportable in the EMG Pipeline and the existing infrastructure (the INGL system and through Jordan), without further investment in new infrastructure, is approx. 6 to 7 BCM annually.

The Partnership is also examining the possibility of making a direct offshore connection of the Tamar and/or Yam Tethys and/or Leviathan platforms, to the EMG Pipeline (Hop Tap), in such manner that will obviate the need to use the transmission system of INGL and the EAPC site and in such manner that will enable to transport natural gas in the quantity of approx. 7 BCM per year (and even more) in the EMG Pipeline. Concurrently, Noble is examining, together with the other Tamar and Leviathan partners, the opening of bottlenecks in the INGL system in order to increase the piping capacity that is possible through the EMG Pipeline.

<u>Transmission through construction of new infrastructures</u>

As of the report release date, the Partnership is promoting, together with Noble, various additional possibilities for piping of natural gas from Israel to Egypt in the context of which, negotiations are conducted for piping natural gas from Israel through Jordan (using the Arab Gas Pipeline) by means of the Northern Pipeline (for additional details, see 7.27.7(e) below) and the alternative is being examined of construction of a new offshore pipeline to Egypt and/or construction, by INGL, of a new onshore connection between the Israeli transmission system and Egypt (in the area of Nitzana or Kerem Shalom).



**<u>Cautions regarding forward-looking information</u> – the information specified above regarding negotiations with EAPC and INGL and regarding the construction and/or use of infrastructures, as specified above, constitutes forward-looking information as defined in the Securities Law, regarding which there is no certainty that it will materialize, in whole or in part, in the said manner or in any other manner, and it may materialize in a materially different manner than as described above, due to various factors over which the Partnership has no control. In addition, Noble's estimations with regard to the capacity of the transmission infrastructures as aforesaid, constitute forward-looking information as defined in the Securities Law, which is based on tests and simulations performed thereby. The aforesaid information may not materialize, in whole or in part, or may materialize in a materially different manner, *inter alia*, due to operating and technical conditions and/or as the result of system constraints and/or supply and demand conditions in the domestic market.**

**In addition, the forecasts and estimates regarding the Jordanian and Egyptian market are forward-looking information within the meaning thereof in the Securities Law. This information is based, inter alia, on information received from independent advisory companies and constitutes estimated assumptions and projections which are naturally subject to uncertainty. Such projections and estimations may not materialize, in whole or in part, or may materialize in a materially different manner, due to various factors beyond the**

**Partnership's control, including changes in the demand for natural gas, changes in the supply of natural gas – including local production, discovery of new reservoirs and commencement of production therefrom, changes in the energy mix – including accelerated penetration of additional energy sources including renewable energy, changes due to macro-economic effects which impact on the economic activity in these markets, including acceleration or deceleration in the economic activity, etc.**

c. The Palestinian Authority – Israel is the main source that provides electricity to the territories of the Palestinian Authority (West Bank and Gaza Strip). In recent years, the Palestinian Authority began a process of creating independent electricity production capabilities, *inter alia*, by promoting the construction of a new power plant for production of electricity in Jenin. As of the report release date, the Partnership, together with its partners in the various projects, is conducting negotiations, that are at various stages, with various entities, pertaining to the possibility of supplying natural gas to an existing power plant in Gaza and/or a future plant in the Jenin area.

The Partnership estimates that the demand for natural gas for the benefit of operating the power plants to be established in the Jenin area will be approx. 0.7 BCM per year, while the demand for natural gas for the operation of the existing power plant in Gaza will be approx. 0.5 BCM per year.

d. Turkey – the natural gas consumption in Turkey in 2017 was approx. 53.3 BCM and the natural gas consumption in 2018 was approx. 49.2 BCM, down approx. 7.7% relative to the gas consumption in 2017. As of the report release date, Turkey is almost completely dependent on the import of natural gas through a pipeline and on LNG to supply its domestic demand for natural gas. In general, Turkey is acting to diversify its supply sources and to become a transition country of gas in pipelines to Europe, including by way of increasing the quantities of natural gas that are piped to and through it from countries which are currently supplying natural gas thereto. In recent years, the Partnership has negotiated with various entities in the Turkish market for the supply of natural gas from the Leviathan reservoir, and negotiated with officials in the Turkish government for a project that shall include the construction of an offshore pipeline from Israel to Turkey for the sale of natural gas to the Turkish market and through the Turkish market, to Europe.

e. Cyprus – As of the report release date, Cyprus is almost completely dependent on import of the various petroleum products, and the production of electricity in Cyprus is based mainly (around 90%) on the use of petroleum-based products such as diesel. In addition, Cyprus encounters difficulties in connecting to the energy infrastructures in Europe due to its geographical location and its being an island. In 2007, the Cypriot government established the public gas company ("**DEFA**"), which is solely responsible for the import, storage, marketing, transportation, supply and trade of natural gas in Cyprus, including management of the natural gas transmission and distribution system in Cyprus. According to regulations promulgated in 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 release date, Cyprus does not consume any natural gas. For further details pertaining to the Cypriot market, see Section 7.16.2(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, in significant scopes, to regional markets, including the Egyptian market, including negotiations for the supply of natural gas for feeding the existing liquefaction facility in Idku, Egypt, at a scope of approx. 6 BCM per year for a period of approx. 10-15 years.

**Caution regarding forward-looking information – the information specified above with respect to the said discussions and/or negotiations, constitutes forward-looking information, within the meaning thereof in the Securities Law, which there is no certainty will materialize, in whole or in part, in the manner stated or in any other manner, and it may materialize in a manner materially different to the description above, and in particular there is no certainty that the said discussions and/or negotiations will result in binding gas sale agreements or that the conditions required pursuant to any law for the taking effect of such agreements, if signed, will be fulfilled**.

(c) Liquefied Natural Gas (LNG)

The Partnership is examining the possibility of liquefying the gas and transporting it in a liquefied state (LNG) in designated tankers to various countries where there is demand for LNG. The construction of a natural gas liquefaction facility is a highly complex project, *inter alia* due to the tremendous scope of investment and due to design, engineering, environmental and commercial challenges that are entailed by such a project.

In this context the Partnership is examining the construction of a floating liquefaction facility (FLNG) to be located offshore on a designated ship. In recent years, three initial FLNG facilities were launched (in Russia, Cameroon and Australia). In addition, there are additional floating liquefaction facilities in planning and construction phases.

As of the report publication date, the Partnership is conducting negotiations, that are at various stages, with suppliers of FLNG services and technology, with the aim of examining the techno-economic feasibility of constructing an FLNG facility for the Leviathan project.

**Caution regarding forward-looking information – the information specified above with respect to such discussions and/or negotiations and construction, constitutes forward-looking information, within the meaning thereof in the Securities Law, which there is no certainty will materialize, in whole or in part, in the manner stated or in any other manner, and in particular there is no certainty that the said discussions and/or negotiations will result in binding agreements or that the conditions required pursuant to any law for such agreements to take effect, if signed, will be fulfilled.**

(d) Compressed Natural Gas (CNG) – as of the report release date, the Partnership is performing an initial examination of the possibility of exporting gas to countries in the Mediterranean Basin, through natural gas compression (CNG) and transportation thereof in designated ships to those countries, including the examination of engineering planning for the project. Export of natural gas in this manner may allow access to new and additional export markets, including Greece, the Mediterranean Islands, Italy and other countries. The Partnership held preliminary discussions with governments interested in Israeli natural gas in such a manner. It is noted that to the Partnership's best knowledge, there are currently no existing projects in the world for the supply of CNG through maritime transportation at large scopes.

7.15. Order backlog

7.15.1. Below please find the Partnership's order backlog calculated on the basis of the minimum gas quantities (according to the take or pay quantity in the agreements) determined in binding agreements (agreements to which all of the conditions precedent were fulfilled) for the supply of natural gas from the Yam Tethys, Tamar and Leviathan projects, which customers have undertaken to consume or pay for, subject to the following main assumptions: (1) all of the options granted to the customers of the Leviathan and Tamar Partners to reduce the contractual quantity, as specified in Sections 7.13.4(a)3 and 7.13.4(b)1 above shall be exercised; (2) from 2019, the minimal consumption of the IEC shall be approx. 3 BCM per year (without assuming the exercise of carry forward); (3) commencement of the supply of gas from the Leviathan project will commence during Q4/2019; (4) the price forecasts are based on the assumptions made in respect of the calculation of the discounted cash flows in the Tamar and Leviathan projects, as detailed in Section 7.3.11(a)3 and in Section 7.4.10(a)3 above, respectively; (5) the revenues from the Tamar Project were calculated according to the Partnership's holdings (directly and indirectly) in the Tamar Project (25.7855%):

| **Year** | **Total Revenues (dollars in millions) As of Dec. 31, 2018**[234] |
|---|---|
| Q1/2019* | Approx. 65 |
| Q2/2019* | Approx. 65 |
| Q3/2019* | Approx. 65 |
| Q4/2019* | Approx. 65 |
| 2020 | Approx. 550 |
| 2021 | Approx. 560 |
| 2022 | Approx. 520 |
| 2023 | Approx. 520 |
| 2024 | Approx. 530 |
| 2025 | Approx. 510 |
| 2026 | Approx. 510 |
| 2027 | Approx. 510 |
| 2028 | Approx. 430 |

* The division between the quarters was made on a linear basis.

**Caution regarding forward-looking information – the Partnership's estimations with regard to the time and scope of anticipated revenue from the order backlog constitute forward-looking information as defined in the Securities Law, based on the minimum gas quantities set forth in the binding agreements for natural gas supply from the Yam Tethys, Tamar and Leviathan projects, and on the assumptions detailed in this section, and there is no certainty of their consummation, and this *inter alia*, due to the effect of the risk factors**

[234] As of March 21, 2019 no change has occurred in the order backlog.

**associated with the Partnership's activity, as detailed in Section 7.31 below.**

7.15.2. As of December 31, 2017, the Partnership's order backlog for 2018 was approx. $370 million. The Partnership's actual revenues in 2018 from such order backlog amounted to approx. $530 million. The difference between the anticipated amount of revenues from the order backlog and the actual revenues in 2018 derives from the fact that actual sales exceeded the minimum gas quantities set forth in the agreements for the supply of natural gas from the aforesaid projects. Despite the fact that the Tamar reservoir shall constitute a sole source for the supply of natural gas in most of 2019, for the purpose of the forecast of the order backlog, only agreements on a firm basis were taken into account, while agreements on an interruptible basis were not taken into account.

7.16. Competition

7.16.1. Natural gas discoveries in Israel

In general, due to the complexity and the high costs in transporting natural gas other than via a transmission pipeline (for instance by setting up an LNG facility which requires natural gas reserves in a significant scope and considerable financial investments), the natural market for the supply of natural gas is the domestic market, and the markets in neighboring countries, to which it is possible to transport the natural gas by a pipeline. Therefore, the main competition of the gas reservoirs of the Partnership in Israel is with holders of natural gas and petroleum assets which operate in Israel and in neighboring countries and with LNG importers. It is noted that insofar as LNG facilities are built, and the export by pipeline options are expanded, such that the target markets potential will expand and the motivation to drill additional wells will increase.

With the commencement of the piping of natural gas from the Tamar reservoir and decline of production from the Yam Tethys reservoirs, the vast majority of the natural gas currently supplied to the Israeli market originates from the Tamar reservoir, which is the only material producing reservoir, as of the date of this report, in the area of the State of Israel. In addition, small quantities of natural gas are supplied to the IEC via an LNG regasification vessel through the offshore buoy set up by INGL (the "**Offshore Buoy for LNG Import**").

In order to fulfill the provisions of the Gas Framework (as specified in Section 7.25.1 below) (a) the rights of the Partnership and Noble, in the Karish and Tanin reservoirs, were sold to Energean; (b) the Partnership sold 9.25% of its interests in the Tamar and Dalit leases to Tamar Petroleum, as specified in Section 1.1.7(g) above; (c) a transaction was closed for the sale of 3.5% of Noble's interests in the Tamar and Dalit leases to Everest; and (d) on March 14, 2018, a transaction was closed for the sale of 7.5% of Noble's interests in the Tamar and Dalit leases to Tamar Petroleum.

To the best of the Partnership’s knowledge, in the coming years, the development of at least two additional reservoirs will be completed, which are expected to constitute additional significant suppliers of natural gas together with the producing Tamar reservoir, and they are: the Leviathan reservoir which contains resources of approx. 21.5 TCF (2P reserves and 2C contingent resources) and which is expected to begin gas flow during Q4/2019; for further details see the Resources Report in Section 7.4.10 above; as well as the Karish and Tanin reservoirs which, to the best of the Partnership's knowledge according to estimates published by Energean, contain contingent resources and reserves (in the best estimate (2C+2P)) at a scope of approx. 2.4 TCF, and prospective resources at a scope of approx. 2.4 TCF, including approx. 1.3 TCF of natural gas in the ‘Karish North’ prospect, as specified below)[235] and which, according to public data of Energean only as aforesaid, the gas flow from the Karish reservoir is expected to begin in 2021. Note that on March 4, 2019, Energean began to carry out the drilling plan in Israel’s EEZ, which is expected to include three production drillings in the Karish reservoir and performance of an exploration drilling in the “Karish North” prospect. For further details, see Section 7.10.2 above. It is further noted that according to the provisions of the Gas Framework, the Karish and Tanin reservoirs are designated for the supply of gas to the domestic market only.

On November 15, 2016, the Minister of Energy declared the opening of the sea for oil and natural gas exploration, in a competitive proceeding (the “**Competitive Process**”), in view of the findings of independent research which was carried out for the Ministry of Energy, in which it was determined that additional resources of natural gas may be found at a total volume of 6.6 billion barrels of oil and approx. 2,137 BCM of natural gas, which have not yet been discovered in the sea basin of Israel. In the framework of the Competitive Process, 24 exploration areas were offered of a maximum size of 400 square km each, and at least 7 km from the shoreline, all in accordance with the directives of the Ministry of Energy on the matter. According to the terms and conditions of the tender, in order to encourage competition in the gas market in Israel, a body which holds more than 25% of the rights (directly or indirectly) in an offshore license with a volume of 2C reserves of more than 200 BCM on the date of publication of the tender (including the Partnership) was barred from submitting a bid in the tender.

As a result of the Competitive Process, on January 15, 2018, the Ministry of Energy granted five licenses for oil exploration in Israel’s EEZ to the

[235] It is noted that the said reservoirs also include quantities of condensate.

Greek company Energean, and on April 9, 2018, it granted an oil exploration license in one block to a consortium of Indian companies.

On November 4, 2018, the Minister of Energy announced the launch of a second competitive process for natural gas and oil exploration in the EEZ of Israel (in this section: the "**Second Competitive Process**"), in the framework of which 19 exploration licenses of a maximum area of 400 $km^2$ each will be offered in five clusters of a maximum area of 1,600 $km^2$ each. The Ministry of Energy limited the number of licenses that shall be granted to each entity to 8 licenses only. In addition, it was determined that an entity that holds more than 25% in a petroleum interest in which there are reserves of more than 200 BCM, will not be able to participate in the Second Competitive Process, and that preference will be given to a group that does not have an entity that is included in existing leases[236]. The documents of the Second Competitive Process determine that the date of submission of the bids is mid-June 2019 and the winners will be announced in July 2019. Insofar as wells that shall be drilled in the areas of existing and/or new licenses as aforesaid lead to significant natural gas findings, and insofar as these discoveries (if any) will be developed, these reservoirs may also constitute competitors operating in the domestic market and in neighboring countries.

Additionally, to the best of knowledge, the British Gas Group (currently owned by Shell) discovered, over 15 years ago, off the Gaza coast, a natural gas reservoir called Gaza Marine, the scope of the resources in which is estimated at approx. 1 TCF, and this reservoir may in the future be developed and natural gas be marketed to the domestic market and to the Palestinian Authority.

In January 2013, LNG import began to the domestic market using the LNG import buoy off the shores of Hadera. The LNG import buoy is intended to connect to a LNG tanker, which converts LNG into gas. The LNG import buoy was planned to receive regasified gas as aforesaid in an amount of up to approx. 0.5 BCF per day. The LNG import buoy was built in order to enable short-term gas supply to the domestic market, in view of the shortage that had been created at the time, due to the cancellation of the agreement for the supply of gas from Egypt with EMG, and to provide the IEC with strategic redundancy for the supply of natural gas. The main use of the LNG is as back-up fuel for the IEC during peak hours when the Tamar reservoir cannot supply the full demand in the market, and therefore, as of the report release date, it does not constitute material competition to the natural gas supplied by the Partnership.

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[236] It is noted that in view of this provision, the Partnership is barred from participating in the Second Competitive Process.

In addition, and with respect to the consumption of natural gas by the IEC, there are natural gas suppliers in competition with coal, and therefore the level of the consumption and the price of the natural gas may be affected by the price of coal worldwide[237].

In addition, the natural gas supplied by the Partnership to industrial customers, replaces the use of liquid fuels, such as diesel oil and mazut. The price of the liquid fuels is usually higher than the price of the natural gas supplied by the Partnership. However, despite their being polluting, a drop in the oil prices worldwide may render these fuels competitive relative to the natural gas which is supplied to these consumers. However, it is noted that the Ministry of Environmental Protection institutes policy measures designed to ensure that plants with infrastructure for connection that enables usage of natural gas refrain from using polluting liquid fuels. Additionally, the wish to increase production of electricity from renewable and clean energies, such as wind energy or solar energy, may also lead to competition in the natural gas. For additional details on substitutes for natural gas, see Section 7.1.8 above.

Petroleum, to the extent discovered in the future by the Partnership, is easier to transport and market, and can be sold both to the domestic market and to the international market, and therefore the competition is much greater and the opportunities for sales more extensive. Nevertheless, petroleum is a commodity whose price is dictated by global supply and demand fluctuations.

7.16.2. Discoveries of Natural Gas in Neighboring Countries

(a) Egypt

To the best of the Partnership's knowledge, the scope of the reserves and the contingent resources of natural gas in Egypt is estimated at approx. 61.5 TCF, and there is potential for additional significant discoveries following the considerable offshore and onshore exploration activity that is being carried out in Egypt[238]. In 2015, the natural gas reservoir 'Zohr' was discovered in Egypt, the scope of the recoverable resources from which, as of the report release date, and to the best of the Partnership's knowledge, based on reports released by independent consulting firms, is estimated at approx. 21.5 TCF (2P). The Zohr reservoir has completed the first development stage thereof and began producing natural gas in December 2017, and is intended, to the best of the Partnership's knowledge, for the supply of natural gas mainly to the Egyptian domestic market. According to the reports of the operator (Eni), the scope of the production from the reservoir (as of

[237] For details regarding the decision of the Minister of Energy on the reduction of coal use, see Section 7.25.5(f) below.

[238] BP Statistical Review of World Energy 2018.

Q4/2018) is estimated at approx. 2 BCF per day, and the production may increase to a pace of approx. 3.2 BCF per day after completion of the second development stage, which is expected, in its estimation, already in 2019. For details regarding the scope of the domestic demand of the Egyptian market in 2017 and 2018 and forecasts of the domestic demand in Egypt for 2019 and 2020, see Section 7.14.2(b)2.b above. For additional details on the main possible target markets for the export of natural gas by the Partnership, see Section 7.14.2(b)2 above.

(b) <u>Cyprus</u>

1. For further details regarding the Cypriot market, see Section 7.14.2(b)2.e above. It is noted that, as of the report release date, there is no consumption of natural gas in Cyprus. However, following the Aphrodite discovery, a possible source of local natural gas was created in Cyprus, but in view of the expected scope of the investment required for development of the field and in view of the limited scope of the potential local market in Cyprus, it seems that development of the Aphrodite reservoir and the supply of natural gas from it to the local market is dependent on the ability of the Cyprus authorities to promote the development of an export infrastructure that will justify the development of the reservoir and its commercialization.

   As of the report release date, in the absence of relevant regulation in Cyprus with regard to natural gas export facilities, it cannot be estimated what effect, if at all, additional discoveries, if any, may have on the manner in which natural gas is exported from Cyprus and on competition, to the extent it develops, with regard to the domestic market and the access to export infrastructures.

2. To the best of the Partnership's knowledge, the Cypriot government and the Cypriot electricity company are acting to promote the replacement of use of petroleum-based products for electricity production with the use of natural gas. In October 2018, the Cypriot government published a tender for the construction of a facility for regasification of imported LNG for the needs of the domestic Cypriot market the results of which tender have not yet been released, as of the date of the report. Accordingly, during 2019, the Cypriot government is expected to publish a tender for the import of LNG, with the target for completion of the entire project being planned for 2020.

3. In February 2018, it was publicized that a consortium of the companies Eni and Total had discovered a new natural gas discovery in block 6 in the EEZ of Cyprus, called ‘Calypso’.

Estimates of resource assessment in this discovery have not yet been published. Such a discovery may have an impact on the Partnership's activities in Cyprus and/or Egypt. In addition, the companies with the reservoir may wish to export the gas to the Egyptian domestic market and/or refer it to the Egyptian liquefaction facilities in favor of liquefaction and sale in the international markets, while such liquefaction of gas will accommodate part of the liquefaction capacity in the Egyptian liquefaction facilities.

4. In September 2018, it was publicized that a consortium headed by Exxon Mobile had begun drilling two exploration wells in block 10 in the EEZ of Cyprus[239]. In February 2019, the consortium publicized in the media that it had made a new natural gas discovery with preliminary estimates of 5 TCF – 8 TCF of gas in place, and that the consortium intends to continue the interpretation work in order to better estimate the scope of the resources. Such a discovery may have an effect on the Partnership's activity in Cyprus and/or in Egypt.

5. In addition, to the best of the Partnership's knowledge, additional exploration drillings are expected to take place during 2019 in the EEZ of Cyprus, by a consortium led by ENI in blocks 3 and 8[240]. It is noted that according to media publications, due to the existing tension between Greek Cyprus and the northern part of the island (Turkish Cyprus), there is a delay in the commencement of the performance of the drilling in block 3.

7.17. Seasonality

7.17.1. In Israel, the consumption of natural gas for electricity production of the IEC and private electricity producers is affected, *inter alia*, by seasonal fluctuations in the demands for electricity and by the maintenance plans of the electricity producers. Generally, in the third quarter of the year (the summer months) electricity consumption will be highest.

7.17.2. Following is data regarding the segmentation of natural gas sales (in terms of 100% of the Tamar Project and of the Yam Tethys project) in the past two years[241]:

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[239] Based on public releases of Exxon Mobile.

[240] Based on ENI's publications.

[241] The data relates to the total sales of natural gas of all the Yam Tethys and Tamar Partners rounded to one tenth of a BCM. It is stated that the data does not include quantities supplied from the maritime buoy to LNG imports, which usually operates mainly during the months of peak demand for natural gas.

| Period | Q1 (in BCM) | Q2 (in BCM) | Q3 (in BCM) | Q4 (in BCM) |
|---|---|---|---|---|
| 2018 | 2.4 | 2.6 | 2.8 | 2.7 |
| 2017 | 2.4 | 2.5 | 2.6 | 2.4 |

7.18. Facilities and production capacity

7.18.1. The Tamar Project

The Tamar Project facilities include, *inter alia*: six wells with a production capacity of around 250 MMCF per day each; an underwater production system that concentrates the gas production from the aforementioned wells; two underwater pipes, each with a diameter of 16 inches and 150 kilometers long (the "**Double Pipeline**"), for the transmission of gas from the Tamar field to the production platform; a production platform located about 25 km from the shore and approx. 2 kilometers north of the Mari B platform; two additional parallel pipes, each with a diameter of four inches and 150 kilometers long, for the transmission of MEG (an antifreeze substance) from the production platform to the drilling system; a pipeline with a diameter of 10[242] inches and two pipelines with a diameter of 6 inches for the transmission of gas and/or condensate and/or MEG from the production platform to the Terminal and also piping that connects the production platform to a pipe with the diameter of 30 inches in the Yam Tethys project for the transmission of gas from the platform to the Terminal; double command and control cables (umbilicals), each 150 kilometers long, that connect the production platform to the drilling system and enable the control and command of the production of natural gas from the wells and pipes with a diameter of 16 and 8 inches each to the Mari B platform and the equipment required at the Mary B platform for the purpose of insertion of natural gas and condensate, respectively, at the Mari B reservoir, insofar as required. The production platform is fixed to the seabed at a depth of around 236 meters by means of a jacket. On the upper part of the jacket, which is exposed above sea level, the topsides of the platform are assembled, which contain, *inter alia*, the natural gas production and processing facilities. In addition there are on the platform facilities to separate out water from natural gas, storage, treatment and recycling of MEG, gas dehydration systems (TEG), generators, tanks, pumps, air compressors, a helipad, workers living quarters, firefighting facilities, lifeboats, security facilities and additional facilities associated with the production and treatment system on the platform. It is noted that the Tamar platform is planned to treat approx. 1,200 MMCF of gas per day and approx. 5,400 barrels of condensate per day, while the maximum

[242] On August 29, 2016, the Minister of Energy granted the Tamar Partners a license for the operation of a 10-inch pipe to be used for the transfer of natural gas from the Tamar rig to the entry point at the natural gas processing facility in Ashdod. Before the license was granted as aforesaid, the pipe was designated for the transfer of condensate.

output of the platform, operating the four processing lines, is approx. 1,600 MMCF of gas per day and approx. 7,200 barrels of condensate per day, subject to the performance of necessary adjustments on the platform.

For further details regarding the development plan of the Tamar Project, including expansion of the supply capacity, see Section 7.3.4(b)-(c) above.

7.18.2. The Leviathan project

(a) Phase 1A of the Leviathan project development plan

The facilities planned in the Leviathan project in accordance with Phase 1A of the development plan include, *inter alia*: four wells with a production capacity of up to approx. 400 MMCF per day each[243]; a subsea production system which concentrates the gas production from the said wells; two subsea pipes, each with a diameter of 18 inches and approx. 115 kilometers long, for the transmission of gas from the Leviathan field to the production platform; a production platform located approx. 10 kilometers from the shoreline on a site designed therefor in NOP 37/H, west of the coastal connection point to INGL; two additional pipes, each with a diameter of 6 inches and approx. 115 kilometers long, for the transmission of MEG (an antifreeze substance) from the production platform to the drilling system; a pipe with a diameter of 32 inches for the transmission of the gas from the production platform to the connection point to INGL[244]; a pipeline with a diameter of 6 inches for the transmission of condensate from the production platform parallel to and alongside a pipeline with a diameter of 32 inches for the transmission of natural gas, as aforesaid, through connection to an existing EAPC pipeline which transports crude oil to the ORL site, and from the connection point to the EAPC pipeline until the Hagit site. In the absence of ability to transmit to ORL, the condensate will be stored at the Hagit site (without continued transmission thereof to ORL via the EAPC pipeline), in accordance with NOP 37/H, which is intended for storage of condensate, and insofar as necessary, for the unloading thereof through tankers. The Hagit site has a tank for the storage of condensate, and the pipes, facilities, equipment, pumps, command, control and operating systems, a tanker-filling facility, auxiliary facilities and services, as required for safe operation and without harming the environment; a group of command and control cables (umbilicals) approx. 115 km long which connect the production platform to the drilling system and enable the control and

[243] On July 30, 2017, the Leviathan-5 well was completed. In 2018, the Leviathan-3, Leviathan-4 and Leviathan-7 wells were completed.

[244] For details regarding a license for the construction and operation of a transmission system, see Section 7.25.5(m)3 below.

command of the production of the natural gas from the wells. The production platform is planned to be attached to the seabed at a water depth of approx. 86 meters via a jacket, which was installed in January 2019. On the upper part of the jacket, which is exposed above sea level, the topsides of the platform are assembled, which contain, *inter alia*, the production and full processing facilities for the natural gas. The production platform also includes facilities for separation of liquids from the natural gas and the dehydration of the gas, storage, processing and recycling of MEG, a specialized system for gas recovery/reclamation for reuse on the platform, facilities for separating, processing, stabilizing, storing and transporting the condensate, generators, tanks, pumps, air compressors, a helipad, workers' residences, fire extinguishing facilities, lifeboats, security facilities and additional facilities relating to the production and processing system of the platform, including joint facilities for Phase 1B of the development plan for the addition thereof to the platform as a module as specified below. For further details regarding the development plan for the Leviathan reservoir, see Section 7.4.5 above.

(b) Phase 1B of the Leviathan project development plan

The facilities planned in the Leviathan project in accordance with Phase 1B of the development plan include, *inter alia*: four more wells with a production capacity of up to approx. 400 MMCF per day each, that shall be connected via a sub-sea pipeline to the existing sub-sea production system; another sub-sea pipe, with a diameter of 20 inches and approx. 115 km long that shall transmit gas from the sub-sea production system to the Leviathan platform, with the daily capacity of approx. 900 MMCF; a module will be added to the platform with processing facilities similar to those existing in Phase 1A plus compressors, and with a processing capacity of approx. 900 MMCF, which are mainly intended for regional export (Regional Export Module), such that together with the Phase 1A processing facilities, the total daily processing capacity of the platform shall be approx. 2,100 MMCF. Note that the maximum gas export capacity from the platform shall be approx. 1,200 MMCF. The transmission of the gas from the platform to the export markets shall be performed, *inter alia*, via a designated pipeline, as specified in Section 7.14.2(b) above.

Regarding various alternatives for the additional stages in the Leviathan project development plan, see Section 7.4.5(c) above.

7.19. Raw materials and suppliers

An operator is appointed in every project in which the Partnership has rights. The operator engages with professional contractors and with owners of the equipment required for each and every project. In Israel today, generally, there are no drilling contractors nor contractors for seismic surveys and offshore development and infrastructure work of the kind done by the Partnership, together with its partners, in the various projects. Therefore the operator engages with contractors from overseas for the purpose of performing such works, which are instructed to retain, insofar as possible, local services and consultants. The offshore drilling facilities and other designated equipment are leased and brought in from all over the world in accordance with their availability, the work type and the project requirements. An additional important parameter that affects this matter is the crude oil price, an increase in which generally affects the scope of the activity in the industry and consequently the availability of contractors and the required equipment, and vice versa. In general, the Partnership does not directly engage with suppliers or professional contractors, and the engagement therefore is between the suppliers or the contractors and the project operator.

7.20. Human Capital

7.20.1. The Partnership is managed by the General Partner in accordance with the provisions of the Partnership Agreement. The General Partner provides the Partnership with management services including, *inter alia*, managers (the directors of the General Partner who are not outside directors, and the CEO of the General Partner), controller services, finance management and bookkeeping. In general the Partnership's workers are employed under personal employment agreements. The officers and senior management of the Partnership are employed under the terms and conditions agreed with each one of them, and include, *inter alia*, monthly salary, the right to a company car, a cellular phone, and contributions to manager's insurance and a continuing education fund. For further details regarding the employment conditions of said officers and senior management, see regulations 21, 26 and 26A of Chapter 4 hereof.

7.20.2. In accordance with the provisions of the Partnerships’ Ordinance, on June 5, 2016, the general meeting of the holders of the participation units in the Partnership approved a compensation policy for officers of the Partnership and the General Partner (which was updated in December 2018 with respect to insurance of the liability of directors and officers). For further details, see Subsection (b)(1) of Reg. 21 of Chapter D hereof.

7.20.3. As of December 31, 2017 and December 31, 2018, the Partnership employed employees as follows:

| **Department** | **Number of Employees as of December 31, 2018** | **Number of Employees as of December 31, 2017** |
|---|---|---|
| Management, Headquarters and Finance | 6 (4 of whom are officers) | 8 (4 of whom are officers) |
| Professional | 7 (2 of whom are officers) | 6 (2 of whom are officers) |
| **Total** | **13** | **14** |

7.20.4. In addition to the managers of the General Partner and the Partnerships' workers above, the Partnership uses various consultants, including geological and professional consultants, lawyers and financial consultants) to the extent that such counsel is required. In addition, it should be noted, that in the framework of operational agreements in various projects, the projects operator employs manpower to manage and operate the projects.

7.21. Working capital

7.21.1. Composition of the Partnership's capital

The Partnership's working capital is composed, on the assets' side, primarily of the cash balances, short-term investments and trade and other receivables stemming from the joint ventures, whereas, on the liabilities' side, it is primarily composed of bonds and the payables stemming from the joint ventures.

7.21.2. Working capital surplus

| | **Amount included in the financial statements as of December 31, 2018 ($ in thousands)** |
|---|---|
| Current assets | 474,960 |
| Current liabilities | 196,512 |
| Current assets in excess of current liabilities | 278,448 |

7.22. Financing

7.22.1. General

As of the report release date, the Partnership finances its activity mainly from income from the sale of natural gas and condensate to Tamar Project customers, from bank credit and from the issue of bonds to the institutional market in Israel and overseas and to the Israeli public.

In view of the adoption of a final investment decision to perform Phase 1A of the development plan for the Leviathan project, the plan to expand the supply capacity of the Tamar Project, the promotion of a development plan of the Aphrodite reservoir, and the continued exploratory activity and the over-estimation of the petroleum assets of the Partnership, it is expected that the Partnership will required significant financial resources to finance its activity, and this in accordance with its work plans and budgets, which will be approved from time to time according to the joint operating agreements that apply to the aforementioned petroleum assets. To this end, the Partnership intends to use the surplus revenues from its customers , the cash surplus and the short-term investments available thereto and has also taken and/or plans to take the following steps, to the extent possible and required:

(a) On February 20, 2017, financing documents which were amended on May 9, 2017 and on August 24, 2017 (in this Subsection (a): the "**Financing Agreement**") were signed between the Partnership and a consortium of local and foreign finance providers headed by HSBC Bank Plc. and J.P. Morgan Limited (collectively: the "**Lenders**"), whereby the Partnership shall be provided with a limited recourse loan in the sum of up to approx. $1.75 billion (in this Subsection (a): the "**Loan**"), for the purpose of financing its share in the balance of the investment in the development of the Leviathan project. The Loan was divided into four facilities (the "**Four Loan Facilities**"), which will be available for withdrawal upon fulfillment of several preconditions, including adoption of a final investment decision (FID) by the Leviathan Partners for the development of Phase 1A of the development plan and/or the signing of agreements for the supply of gas at a minimum total annual volume that was defined in the agreement, which varies according to the scope of each facility. In addition, provision of each one of the facilities will be contingent on compliance with a ratio that shall be no less than 2:1 between the value of the resources in the reservoir (which will be calculated based on the last discounted cash flow figures published by the Partnership for the project, prior to the calculation, plus the value determined in the agreement for each gas unit that was not taken into account for the purpose of the discounted cash flow) and the balance of the Loan (the "**Required Debt Coverage Ratio**"). The Financing Agreement includes another facility of $0.75 billion, which is contingent on the signing of agreements for the supply of gas at a minimum total annual volume that was defined in the agreement, and a decision to increase the capacity of the production and transmission system for Phase 1B of the development plan, or alternatives thereto, which may be given by the Lenders, in whole or in part, or by other lenders, but there is no undertaking of the Lenders to provide this facility. The loan principal will be repaid in a single installment 48 months after the date of execution of the Financing Agreement. The Loan is a dollar loan and bears variable interest to be paid every three months, which is calculated according to LIBOR plus a graded margin whose average effective rate (including fees to be paid up to 90 days from the date of the signing of the agreement) will be approx. 4.6% throughout the term of the Loan. In addition, the Partnership has undertaken to pay a commitment fee at the rate of 35% of the margin that shall apply to the Loan in respect of any amount not withdrawn.

On May 17, 2017, the Partnership performed a withdrawal out of the first facility, and on March 29, 2018 and September 4, 2018 the preconditions were fulfilled for performance of money withdrawals out of the second and third facilities, respectively. The said money withdrawals were used, *inter alia*, for payment of the payment demands issued by the operator to the partners in the Leviathan project and for the purpose of financing part of the costs of the loan. As of the report release date, the Partnership has performed withdrawals in a sum total of approx. $1.3 billion.

The Loan amounts are transferred to Delek Drilling (Leviathan Financing) Ltd., a wholly owned subsidiary of the Partnership, in accordance with calls made by the operator to the partners in the Leviathan project and for the purpose of financing part of the costs of the Loan, and are transferred as a loan to the Partnership under the same conditions (back-to-back).

The Financing Agreement determines events, upon the occurrence of any of which the Loan is required to be prepaid, and they include, *inter alia*: unlawfulness, falling below a minimal holding rate (as determined in the agreement) in the General Partner and/or in the participation units of the Partnership and partial repayment in the case of a partial sale of the Partnership’s rights in the Leviathan project. The Partnership is entitled to prepay the Loan at any time, in whole or in part, subject to the terms and conditions set forth in the agreement.

To secure repayment of the Loan, the Partnership pledged its rights in the assets relating to the Leviathan project, including, *inter alia*, the Leviathan leases, the joint operating agreement, the project equipment and the insurance policies, gas sale agreements (including agreements that shall be signed in the future, if any) and the project accounts. The Loan is a limited recourse loan and the Lenders will have no recourse to the Partnership’s assets that were not pledged in their favor. It is noted that the foregoing pledges are subject to royalty rights of the state and to rights of other royalty holders who are entitled to receive royalties from the Partnership (including interested parties), and that the pledges that the Partnership has registered on the Leviathan leases in favor of the said royalty holders in the framework of the interim financing transaction to secure their royalty rights, will continue to be in effect also throughout the term of the Financing Agreement.

As is customary in financing transactions of this type, the Partnership has assumed covenants which include, *inter alia*, the following main covenants: restrictions on the taking of additional credit (these restrictions shall not apply to non-recourse credit, inferior loans from affiliates and credit in the sum total of up to $800 million (the "**Additional Credit**")); meeting liquidity tests, whereby on test dates that were determined in the Financing Agreement, the Partnership will be required to prove that it holds sufficient financing sources to meet its liabilities in the coming 12 months and/or until commencement of the production from the Leviathan reservoir; meeting the Required Debt Coverage Ratio, which ratio will be measured upon each withdrawal (as aforesaid), on the date of provision of a resource report and on the date of the sale of rights in Leviathan, if any; restrictions on a change in the field of business; restrictions on the performance of actions that may have a material adverse effect; the exercise of certain rights by virtue of the joint operating agreement with the approval of the Lenders only, etc. Withdrawal of surpluses from the accounts pledged in favor of the Lenders will be subject to the terms and conditions set forth in the Financing Agreement and subject to partial prepayment of the Loan at the same time in accordance with the withdrawal amount defined in the agreement.

As is customary in financing transactions of this type, the Financing Agreement defined events of default, upon the occurrence of which the finance providers will be entitled to accelerate the Loan, which include, *inter alia*, the following main events: cross default of another financial non-limited recourse liability; an event which has a material adverse effect on the Partnership's ability to fulfill its material undertakings in connection with the Financing Agreement or the Project Documents (as defined in the Financing Agreement) or on its assets, business or financial position, in a manner which impairs its ability to pay its debts as they become due, or on the project in a manner which jeopardizes or is highly likely to jeopardize the ability to refinance the Loan; (in this section: "**Material Adverse Effect on the Partnership's Ability**")[245]; termination of agreements for the supply of gas and other Project Documents, if such termination shall or may have a material adverse effect on the ability to refinance the Loan; non-meeting of the liquidity tests that were defined in the agreement; non-meeting of conditions of the Additional Credit as specified above; engagement in hedging transactions, except as agreed according to the agreement; the transfer of control in the General Partner, as defined in the agreement, and a decline in the rate of holdings by the controlling interest holder of units of the limited partner to 45% or less;

[245] This event was included in the amendment to the financing agreement of May 9, 2017, in lieu of a section that determined an event of default, if an action is taken by a regulatory authority which has a Material Adverse Effect on the Partnership's Ability.

abandonment of the project; insolvency events; an ongoing *force majeure* event in connection with the project which has or may have a material adverse effect; all subject to the conditions and qualifications and/or remediation periods set forth in the agreement.

For further details regarding the Financing Agreement, see Notes 10A and 10C to the financial statements and immediate reports of November 27, 2016 and February 21, 2017 (Ref.: 2016-01-082131, 2017-01-015757, respectively), the information in which is hereby presented by way of reference.

(b) As part of the implementation of the provisions of the Gas Framework, the Partnership sold its holdings in the Karish and Tanin Leases and has commenced the sale of its holdings in the Tamar Project. The net proceeds (after tax, repayment of bonds/loans and other relevant liabilities, if any, *inter alia*, under the Partnership Agreement) to be received from the sale of such Leases shall serve, *inter alia*, to finance the Partnership's operations.

(c) As provided in Section 1.1.7(g) above, on July 20, 2017, upon fulfillment of all of the conditions precedent, the sale transaction between the Partnership and Tamar Petroleum was closed, in the framework of which the Partnership transferred to Tamar Petroleum interests at the rate of 9.25% (out of 100%) in the Tamar and Dalit leases, against, *inter alia*, cash consideration of approx. ILS 3 billion. Out of the sum of the cash consideration, the Partnership designated approx. U.S. $321 million for partial prepayment of the four bond series (series 2018, 2020, 2023 and 2025), as stated in Section (d) below.

(d) On May 19, 2014, a wholly owned subsidiary of the Partnership (Delek & Avner (Tamar Bond) Ltd.) (the "**Subsidiary**" or "**Tamar Bond**") completed a bond offering to accredited investors in the U.S., Israel and other countries, in the total amount of $2 billion in 5 different bond series in the sum of $400 million each, which are payable in December of each of the years 2016, 2018, 2020, 2023 and 2025. The issue proceeds were provided by such subsidiary as a loan to the Partnership, and under the same terms and conditions as the terms and conditions of the bonds (back-to-back). On October 6, 2016, the Partnership prepaid the first series in the total (original) amount thereof of $400 million, instead of on the original repayment date thereof on December 30, 2016. On July 27, 2017, the Partnership performed a partial repayment of the four series (2018, 2020, 2023 and 2025) at the rate of 20% of the sum of the unpaid balance of each one of the bond series (i.e. U.S. $80 million in each one of the series), plus accrued interest in the sum total of approx. $1.1 million, all in accordance with the provisions of the indenture of the bonds. On

August 31, 2018, the second series (2018) was prepaid at the total scope thereof of $320 million, instead of on the original payment due date thereof on December 30, 2018. The amount of the prepayment of the second series as aforesaid included the principal amount, plus accrued interest in the sum total of approx. $2.1 million and plus a prepayment fee in the sum of approx. $1.3 million. For further details, see the Partnership's immediate report of July 19, 2018 (Ref.: 2018-01-068986), the details appearing in which are hereby included by way of reference. The balance of the loan as of December 31, 2018 (net of raising costs) was approx. $952 million. For further details, see Notes 10A and 10B to the financial statements (Chapter C hereof) and Part Five of the Board of Directors' Report (Chapter B hereof).

(e) On December 26, 2016, the Partnership completed a bond offering to the public in the amount of approx. ILS 767.8 million and in a parallel offering of bonds of the Avner Partnership, a similar sum of approx. ILS 760.7 million was raised. Upon completion of the Merger, the Series A bonds of the Partnership were consolidated with the Series A bonds of the Avner Partnership, such that the two series shall constitute a single series of Series A bonds in the sum of approx. ILS 1.5 billion. The issue proceeds are designated for use by the Partnership for investment in and the financing of the activity in the Partnership's petroleum assets and for the financing of the Partnership's other current needs and, *inter alia*, for profit distributions. For further details, see Notes 10A and 10D to the financial statements (Chapter C hereof) and Part Five of the Board of Directors' Report (Chapter B hereof).

(f) According to the approval of the Income Tax Commission that was granted to the Partnership around the time it was formed, the Partnership undertook not to take out loans in an amount exceeding 3% of the amount that would be raised from the investors in the Partnership, other than in coordination, and with the prior approval of the Income Tax Commission. It is noted that all of the foregoing financing received the approval of the Income Tax Authority as required.

(g) On May 17, 2018, the meeting of the holders of the Participation Units in the Partnership approved the performance of an offering of Participation Units and/or securities convertible into Participation Units by way of a rights offering to the existing holders of the Participation Units, during a period from the date of the meeting's approval as aforesaid until May 6, 2021, at a scope and under conditions to be determined according to the resolution of the General Partner for the purpose of raising sums that will be required, in the opinion of the General Partner, for the financing of the Partnership's operating activity, including the making of investments in the

Partnership's petroleum assets and repayment of its existing liabilities, and authorized the General Partner to determine the structure, scope and timing of the offering, at its sole and absolute discretion, subject to the sum total of the proceeds of the offering (or offerings) in the said period not exceeding the sum in ILS equal to $300 million. Performance of such offerings may be carried out at any time in the framework of one or more prospectuses and/or one or more shelf offering reports, as shall be determined by the General Partner.

(h) With respect to non-distribution of some of the profits of the Partnership for the financing of drilling, exploration and development actions and the EMG Transaction, see Sections 4.2.4, 4.2.5 and 4.2.6 above.

7.22.2. Financial Covenants

(a) In the framework of the bond offering to the public as stated in Section 7.22.1(e) above, the Partnership has undertaken to maintain financial covenants as follows:

| Financial covenant[246] | Manner of calculation | The ratio checked as of December 31, 2018 and the report release date[247] |
|---|---|---|
| The Partnership's economic capital[248] | If the economic capital falls below $400 million (the "**Minimum Economic Capital**") for two consecutive quarters. [249] | 4,539 |

[246] As specified in the indenture, non-compliance with the financial covenants described shall constitute grounds for acceleration for the trustee and for the bondholders.

[247] The ratio was calculated, *inter alia*, based on the discounted cash flow of the Tamar Project as of December 31, 2018, that is included in this report, and the discounted cash flow of the Leviathan project as of December 31, 2018, that is included in this report.

[248] The Partnership's equity, according to the last annual or quarterly financial statements published by the Partnership, as the case may be, net of the cost of the investment recorded in the said statements in all of the projects in respect of which discounted cash flow was included in the last annual periodic report published by the Partnership, or in respect of which discounted cash flow was published on a date later than the last annual periodic report in the framework of the Partnership's reports pursuant to the provisions of the Securities Law (the "**Projects**" and the "**Last Discounted Cash Flow**", respectively), plus the sum of the Last Discounted Cash Flow of the Projects and plus the abandonment expenses recorded in the said statements in respect of the Projects. For this purpose: (a) "Discounted cash flow" – as defined in Section 36 of the Third Schedule to the Securities Regulations (Details of the Prospectus and Draft Prospectus – Structure and Form), 5729-1969; and (b) "Sum of the Discounted Cash Flow" – the sum of the discounted cash flow of the 2P probable reserves and/or of the 2C probable contingent resources of the Projects, as the case may be, after income tax at the rate applicable to companies, discounted at a rate of 10%.

[249] If, on any date, the total unpaid par value of the bonds in circulation falls below ILS 400 million, then the Minimum Economic Capital will be $250 million. The aforesaid notwithstanding, if, on any date after update of the Minimum Economic Capital as aforesaid, the bond series will be expanded such that the total unpaid par value of

| Financial covenant[246] | Manner of calculation | The ratio checked as of December 31, 2018 and the report release date[247] |
|---|---|---|
| The economic capital to debt ratio | If the ratio between the Partnership's economic capital and the Partnership's debt on a standalone basis falls below 300% (x3) for two consecutive quarters. | Approx. 11 |
| Distribution | If the Partnership performed a distribution or gave notice of an intention to perform a distribution which is one of the following: (a) a distribution contrary to the provisions of the Partnerships Ordinance and the Companies Law; (b) a distribution of revaluation profits; and (c) a distribution after which the economic capital to debt ratio will fall below 450% (x4.5). | - |

(b) In the framework of the Financing Agreement as provided in Section 7.22.1(a) above, the Partnership undertook to maintain financial covenants, as follows:

| Financial covenant | Manner of calculation | The ratio checked as of December 31, 2018 | The ratio checked as of January 28, 2019 - the date of withdrawal of the money[250] | The ratio checked as of the date of provision of the resource report and as of the report release date |
|---|---|---|---|---|
| The Required Debt Coverage Ratio | The ratio between the value of the resources in the | 3.6 | 3.4 | 3.4 |

the bonds in circulation is ILS 800 million and above, then the Minimum Economic Capital will return to $400 million.

[250] In accordance with the provisions of Section 7.22.1(a) above, compliance with the required debt coverage ratio will be measured, *inter alia*, upon each withdrawal. From May 17, 2017 until the report release date, the Partnership performed 25 withdrawals as aforesaid, with the last withdrawal being performed on January 22, 2019. In each one of the said withdrawals, the Partnership complied with the required ratio.

| Financial covenant | Manner of calculation | The ratio checked as of December 31, 2018 | The ratio checked as of January 28, 2019 - the date of withdrawal of the money[250] | The ratio checked as of the date of provision of the resource report and as of the report release date |
|---|---|---|---|---|
| | Leviathan reservoir[251] and the balance of the loan shall be no less than 2:1. | | | |

For a description of the financial covenants undertaken by the Partnership in the Leviathan Financing Agreement, see Section 7.22.1(a) above.

7.23. Taxation

For details regarding taxation, see Note 20 to the financial statements (Chapter C hereof).

The unique tax issues, including the levy pursuant to the Taxation of Profits from Natural Resources Law, related to the Partnership's activity have yet to be addressed in Israeli case law, and there is no way to anticipate or to determine how the Court will rule if and when said issues are brought before them. In addition, with regard to certain of the issues, there is no way of anticipating what the Tax Authority's position will be. Since the Partnership's activity is subject to a unique tax regime that includes tax benefits, changes caused by change of laws, case law, or a change in the position of the Tax Authority, as aforesaid, could have significant implications on the tax regime that will apply to the Partnership.

For details regarding the legal proceeding with respect to the interpretation of Section 19, see Section 4.3.2 hereof.

7.24. Environmental risks and management thereof

7.24.1. Activity of exploration, development and production of oil or natural gas naturally entails the risk of causing damage to the environment, that may occur, *inter alia*, from equipment failure and/or work procedures, and/or

[251] The value of the resources in the Leviathan reservoir for the purpose of this test shall be calculated based on the data in the last discounted cash flow that was published by the Partnership for the project, prior to the calculation, plus value that was determined in the agreement for each gas unit not taken into account for the purpose of the discounted cash flow.

unforeseen events. The severity of the risks varies from event to event, and therefore the manner of management and treatment of them varies too.

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

(a) In Israel 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. In addition, apart from the regulation prescribed by Israeli law, there are additional provisions on environmental issues determined also in the terms of the deeds of lease that were given to the Partnership and in the approvals for establishment and operation of the production systems of the Yam Tethys project and the Tamar Project and later, the Leviathan project. Upon drilling and/or in the framework of the production of petroleum and natural gas the operator purchases insurance to cover environmental damage as a result of sudden, unexpected and uncontrolled eruptions of petroleum and/or natural gas. It is noted that in 2016, the Petroleum Regulations (Principles for Offshore Petroleum Exploration and Production), 5777-2016 (an amendment to regulations of 2006) were published, which 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.

(b) In September 2016 the Ministry of Energy in coordination with the Ministry of Environmental Protection and additional government offices published directives intended to regulate the environmental aspects of the offshore exploration, development and production of petroleum and natural gas. These directives aim to instruct the offshore petroleum rights holder of the activities and documents they need to prepare in the framework of their activity in the area of their rights, and this in order to prevent or minimize, to the extent possible, environmental damage which may occur upon offshore exploration, development and production activity of petroleum and natural gas. For details regarding the environmental directives as aforesaid, see Section 7.25.5(j) below.

(c) In addition, the Partnership's activity may be subject to the provisions of various environmental laws including the Prevention of Sea Pollution (Dumping of Waste) Law, 5743-1983 and the regulations promulgated thereunder; Prevention of Sea Pollution from Land-Based Sources Law, 5748-1988 and the regulations promulgated thereunder; Prevention of Sea Water Pollution by Oil Ordinance (New Version), 5740-1980; Hazardous Substances Law, 5753-1993 and the regulations promulgated thereunder; Maintenance of Cleanliness Law, 5744-1984 and the regulations promulgated thereunder; Liability for Compensation for Oil Pollution Damage Law, 5764-2004 and the regulations promulgated thereunder; Environmental Protection (Supervision and Enforcement Powers) Law, 5771-2011 and the regulations promulgated thereunder; Prevention of Environmental Nuisances (Civil Actions) Law, 5752-1992; Clean Air Law 5768-2008 and the regulations promulgated thereunder; Environmental Protection (Emissions and Transfers to the Environment – Reporting Duty and Register) Law, 5772-2012 and the regulations promulgated thereunder; Abatement of Nuisances Law, 5721-1961 and the regulations promulgated thereunder; Protection of the Coastal Environment Law, 5764-2004; Licensing of Businesses Law, 5728-1968, the regulations and the orders promulgated thereunder.

(d) In addition to the instructions of the Ministry of Energy and the Ministry of Environmental Protection, in its activity the Partnership may 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 Lands Authority.

(e) In addition, the approval for operation of the Tamar platform and Leviathan lease deeds determine the leaseholder's duty to act, on issues of environmental protection, pursuant to the law and instructions and permits that are given pursuant to any law, and provisions were determined with respect to piping into the sea, emissions into the air, etc. The approval for operation of the Tamar platform and Leviathan lease deeds 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 protection of the environment, 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.

7.24.3. <u>Events in connection with the environment</u>

In 2018 there was no event or matter relating to the Partnership's operations which caused damage to the environment and which had a material effect on the Partnership.

7.24.4. Environmental risk management policy

The operator in the various projects, adopts a strategic environmental policy for the protection of the environment and for compliance with the provisions of the law in general, and the environmental laws in particular. This policy includes the operator taking care to act in accordance with internal procedures for environmental risk management of its activity, including education of suitable manpower, and including a work plan for the reduction of environmental damage, for the prevention of incidents and accidents and for the constant improvement of the organizational culture on issues of safety, environment and hygiene. In this framework the operator has a designated team both for the development stage and the operations stage, which is responsible for implementation of and supervision over such policy, and for fulfillment of the procedures for ensuring fulfillment of and compliance with all of the requirements and standards, including various systems for the management of environmental risks, such as SEMS (Safety & Environmental Management Systems). 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 operation facilities and the drilling rigs. The operator carries out current activities on issues of environmental protection and safety to increase awareness, knowledge and preparedness, including training of and drills for the operator's teams. The Partnership is acting to receive ongoing and specific updates, as needed, regarding the operator's activity as aforesaid. It is further noted that although the operator has a different position with respect to the legal interpretation regarding the applicability of Israeli laws, and environmental laws in particular, to its offshore activity (including its activity in the area of the EEZ) to that adopted in the framework of the opinion mentioned in Section 7.25.5(e) below, in addition to the aforesaid, the operator is acting to obtain all of the permits required by virtue of the environmental regulation, including a toxic materials permit by virtue of the Hazardous Substances Law, 5753-1993, a permit for discharge of emissions into the sea by virtue of the Prevention of Sea Pollution from Land-Based Sources Law, 5748-1988 and a permit for discharge of emissions into the air by virtue of the Clean Air Law, 5768-2008. In this regard it is noted that on December 5, 2018, the Ministry of Environmental Protection notified the operator of denial of the application for a permit for discharge of emissions into the air for the Leviathan rig. Further thereto, and according to an update that the Partnership has received, the operator submitted a new application, and is acting vis-à-vis the relevant entities at the Ministry of Environmental Protection for receipt of the permit, in accordance with the timetables agreed between the parties.

7.24.5. Environmental costs and investments

To the best of the Partnership's knowledge, 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 release date, no additional material costs are expected.

It is noted that, to the best of the Partnership's knowledge, in March 2019 is expected to see the completion of the installation and running-in of designated systems for the reduction of emissions into the air from the Tamar Platform was completed, at the budget of approx. $40 million (100%). The installation of these systems is expected, according to the operator, to reduce the emission of pollutants in accordance with the operator's commitment to the Ministry of Environmental Protection.

It is further noted that in the Leviathan project, the gas processing is different to that on the Tamar platform, because designated facilities will be installed in advance on the Leviathan platform for reduction of emissions in a manner that ensures compliance with the emission permit that is expected to be received during 2019.

7.24.6. Material legal or administrative proceedings in connection with the environment

As of the report release 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.

To the best of the Partnership's knowledge, Zalul [*Clear*] organization has filed an administrative petition against the Director of Air Quality and Climate Change Division of the Ministry of Environmental Protection and the Minister of Environmental Protection (below, in this section, the "**Ministry of Environmental Protection**"), and against the Tamar Project operator. In the context of the petition, the court was moved to issue an order *nisi* ordering the Ministry of Environmental Protection to give reasons why its authority pursuant to the Clean Air Law, 5768-2008, will not be exercised to notify the Tamar Project operator of its intention to impose a pecuniary sanction thereon subject to a hearing, and alternatively, why authority as aforesaid will not be delegated to the petitioner, since, according to the petition, the Tamar rig has been operating for about 4 years without an emission permit, in contradiction to the provisions of the law, and the Ministry has authority to impose a pecuniary sanction in the scope of close to ILS 100 million due thereto. At this stage, the chances of the petition cannot yet be evaluated.

7.24.7. Cyprus

To the best of the Partnership's knowledge, under the Cypriot Environmental Effects Of Plans And Activities Law of 2005, (which is adapted to the European Directive), a strategic environmental evaluation is required in connection with a governmental decision to perform plans that may have environmental impact. The Cyprus Ministry of Energy imposed on the companies active in the sector (after a tender) the preparation of a strategic environmental assessment in connection with petroleum exploration and production activities in Cyprus and in the Cyprus exclusive economic zone (EEZ) (the "**Environmental Report**"). The license holder for the exploration or production activity must act in accordance with the Environmental Report and perform an environmental survey prior to conducting said activities in the license area.

7.24.8. In addition, as of the report release 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.

7.25. Restrictions and Supervision of the Partnership's Activity

7.25.1. The Gas Framework

On August 16, 2015, Government Resolution No. 476 (readopted with certain changes in a Government Resolution of May 22, 2016) was adopted with respect to a framework for the increase of the natural gas quantity produced from the "Tamar" natural gas field[252] and the expeditious development of the "Leviathan", "Karish" and "Tanin" natural gas fields and other natural gas fields (in this section: the "**Government Resolution**"), which took effect on December 17, 2015, upon the grant of an exemption from certain provisions of the Economic Competition Law, 5748-1988 (the "**Economic Competition Law**") to the Partnership, Avner, Ratio and Noble (in this section: the "**Parties**") by the Prime Minister, in his capacity as Minister of Economic Affairs, pursuant to the provisions of Section 52 of the Economic Competition Law (in this section: the "**Exemption**" or the "**Exemption Pursuant to the Economic Competition Law**"), the main principles of which are presented below (the Government Resolution and the provisions of the Exemption as aforesaid shall hereinafter be referred to collectively as: the "**Gas Framework**").

[252] "Tamar" was defined in the exemption annexed to the Framework as "a natural gas reservoir situated in the area of the Tamar I/12 and the Dalit I/13 leases, and the rights held by the entities holding 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 terminal, from the Tamar reservoir to the national transmission system".

(a) The restrictive trade practices in relation to which the Exemption was granted are as follows:

1. The restrictive arrangement that was ostensibly created, according to the Competition Commissioner's position, as a result of the acquisition of the rights in the Ratio-Yam permit by the Partnership, Avner and Noble; and the restrictive arrangement that was ostensibly created as a result of the Parties' coming together as joint holders of the Ratio-Yam permit and the Leviathan reservoir.

2. The restrictive arrangement that shall ostensibly be created in a case in which the Parties or some of them jointly market the gas that shall be extracted from the Leviathan reservoir to the domestic market until January 1, 2025[253].

3. The restrictive arrangement that shall ostensibly be created in a case in which the Parties or some of them jointly market the gas that shall be extracted from the Leviathan reservoir for export only.

4. The restrictive arrangement which may be created as a result of a certain agreement for the purchase of natural gas from the Leviathan reservoir, provided that such agreement is signed by January 1, 2025.

5. With respect to their activity in the Tamar and Leviathan reservoirs only, the Partnership, Avner and Noble being the holders of a monopoly according to the Competition Commissioner's declarations[254].

(b) The Exemption from the restrictive arrangements specified in Sections 7.25.1(a)2 to 7.25.1(a)5 above, is contingent upon the fulfillment of the following conditions:

1. <u>The Karish and Tanin reservoirs</u>

   a. Pursuant to the Framework, the Partnership, Avner and Noble were obligated to transfer all of their rights in the Karish and Tanin leases to a third party not affiliated with the Parties or any of them, which shall be approved by the Petroleum Commissioner.[255]

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[253] The Minister of Energy is authorized, upon the fulfillment of certain conditions as prescribed in the Exemption, to extend the Exemption until January 1, 2030.

[254] The Minister of Energy is authorized, upon the fulfillment of certain conditions as prescribed in the Exemption, to extend the Exemption until January 1, 2030.

[255] As aforesaid, on December 26, 2016, a transaction was closed for the sale of all of the rights of the Partnership, Avner and Noble in the Tanin and Karish leases to Energean.

b. The permitted export quota from the Karish and Tanin reservoirs in the amount of 47 BCM was exchanged, as of the date of the Petroleum Commissioner's approval of the transfer of the rights in Karish and Tanin, against the duty to supply to the domestic market imposed on the holders of the Leviathan leases.

In accordance with the provisions of the Framework, the rights in the Karish and Tanin leases were fully transferred to a third party in December 2016. For further details, see Section 7.10.1 hereof.

2. <u>The Tamar Project</u>[256]

a. The Partnership and Avner[257] shall transfer, within 72 months from the date of the grant of the Exemption Pursuant to the Economic Competition Law (the "**Effective Date for Tamar**"), all of their rights in the Tamar and Dalit leases to a third party not affiliated with the Parties or any of them or with any entity that holds means of control in the Leviathan reservoir or in the Karish and Tanin reservoirs, subject to the Petroleum Commissioner's approval.[258]

b. By the Effective Date for Tamar, Noble shall deliver to the Petroleum Commissioner a binding sale contract, such that after consummation thereof, Noble's rights in the Tamar Lease will be no higher than 25% and the surplus rights will be transferred to a third party which is not affiliated with the Parties or any of them and does not hold means of control in the Leviathan reservoir or in the Karish and Tanin reservoirs, subject to the Petroleum Commissioner's approval.[259]

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[256] The Framework determined that periods in which an event of "*force majeure* in Tamar" occurred shall not be taken into account. If such an event occurs, the relevant time count in Tamar shall stop running, provided that the Partnership, Avner and Noble act quickly and diligently to remedy the damage caused by the *force majeure*. "*Force majeure* in Tamar" was defined in the framework as "war, a military action, an act of terror, a significant accident or a natural disaster, any of which result in a significant failure or significant fault in any of the facilities or systems required for the gas production, and as a result of which the gas supply was stopped or significantly reduced for a significant period and the Delek and Noble partnerships were denied the possibility of selling the relevant petroleum asset in the ordinary course of business, and a reasonable and prudent person in the shoes of the Delek and Noble partnerships could not have prevented or overcome the same".

[257] As aforesaid, on May 17, 2017, Avner was merged with and into the Partnership such that all of Avner's assets and liabilities passed, as is, to the Partnership.

[258] For the purpose of fulfillment of the provisions of the Framework, on July 20, 2017, a transaction was closed for the sale of 9.25% of the interests of the Partnership in the Tamar and Dalit leases to Tamar Petroleum. As of the date of release of this report, the Partnership holds 13.42% of the voting rights in Tamar Petroleum and 22.6% of the equity interests in Tamar Petroleum. For the purpose of fulfillment of the provisions of the Framework, the Partnership will be required to sell also its said holding in Tamar Petroleum until the Effective Date for Tamar.

[259] In December 2016, a transaction was closed for the sale of 3.5% of the rights of Noble in the Tamar and Dalit leases to Everest, in which Harel Insurance Co. Ltd. and other institutional bodies owned thereby are partners, as

c. If not all of the transferred rights are transferred as stated in Subsections a. and b. above by the Effective Date for Tamar (the "**Transferred Rights in Tamar**"), the right to transfer the Transferred Rights in Tamar that were not sold will be transferred to a trustee (as defined in the Gas Framework), which will act to find buyers and to obtain the maximum bids for the sale of the Transferred Rights in Tamar, all in accordance with the provisions of the Framework and directives that it shall receive from the Competition Commissioner. The trustee shall sell the Transferred Rights in Tamar in reference to the market value and the highest bid that is made thereto, and in any event no later than 12 months after the date of the transfer of the rights in Tamar (even if the price does not represent the real value of the Transferred Rights in Tamar).

d. Commencing on the Effective Date for Tamar or on the date of the sale of Noble's rights in the Tamar Lease as aforesaid, whichever is earlier, Noble shall not hold any veto right pertaining to the Tamar reservoir.

e. The consideration for all of the rights of the Partnership, Avner and Noble in Tamar will not be paid in royalties. The consideration may be paid in installments, provided that the milestones for payments will not be tied to the prices or to the quantities of gas sold from the Tamar reservoir. The aforesaid notwithstanding, the Partnership, Avner and Noble may retain a right to royalties from the sale of petroleum (with the exception of condensate) from the Tamar reservoir, if discovered.

3. <u>New agreements for the supply of natural gas from the Leviathan and Tamar reservoirs</u>

a. Agreements for the supply of natural gas from the Leviathan and Tamar reservoirs that shall be signed from the date of the Government Resolution will meet all of the following provisions:

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

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well as partners from the Israel Infrastructure Fund Group; On March 14, 2018, the transaction between Tamar Petroleum and Noble was closed whereby Noble sold to Tamar Petroleum 7.5% (out of 100%) of its rights in the Tamar and Dalit leases. In this context it is noted that Noble sold its shares in Tamar Petroleum and thus fulfilled its duty according to the Gas Framework in this regard. For details, see Footnote 37 above.

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

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

b. With respect to agreements for the sale of natural gas from the Tamar reservoir that shall be signed from the date of the Government Resolution until 4 years after the date on which the Petroleum Commissioner approved the transfer of the Rights in Karish and Tanin (the "**Date of Opening of the Options**"), the holders of the rights in the Tamar reservoir will be required to offer to any consumer the possibility of purchasing gas in an agreement for any period that he shall choose up to 8 years or a longer period to be agreed between the parties and the consumer. With respect to an agreement whose term exceeds 8 years, the consumer shall have a unilateral right to shorten the term of the agreement during a 3-year window commencing on the Date of Opening of the Options.

c. In relation to agreements for the sale of natural gas from the Leviathan reservoir that shall be signed from the date of the Government Resolution until the Date of Opening of the Options, the holders of the rights in the Leviathan reservoir will be required to offer to any consumer the possibility of purchasing gas in an agreement for any period that he chooses up to 8 years or a longer period to be agreed between the parties and the consumer.

d. On April 2, 2017, the Tamar Partners clarified in a notice that they sent to the Minister of Energy, to the Budget Director at the Ministry of Finance and to the Antitrust Commissioner, as follows:

1. In the event of a delay in the supply of gas for the first time by a new gas supplier, the Tamar Partners will allow their customers, in accordance with gas supply agreements that were signed from the date of the government resolution until 4 years after the date on which the Commissioner approved the transfer of the rights in the Karish and Tanin gas reservoirs (the Date of Opening of the Options), which were supposed to transition to buying gas from the new supplier, fully or partially, to extend the contract with them

until the date on which the new supplier is able to supply gas in commercial quantities (but no more than 8 years from the date of the signing of the agreement with them), without modifying the terms and conditions of the agreement.

2. The Tamar Partners further clarified that they would grant a consumer that is an electricity producer or another consumer seeking to establish new facilities and which is forced, due to requirements of the facilities' finance providers, to sign a long-term gas supply agreement, the possibility to sign an agreement with them whose term exceeds 8 years, and in accordance with the supply capacity of the Tamar Project.

(c) Additional provisions from the Government Resolution

1. Prices

a. So long as the holders of the rights in the Tamar and Leviathan leases meet the conditions of the Government Resolution and the Exemption Pursuant to the Economic Competition Law, the provisions of the Control of Prices of Commodities and Services Order (Application of the Law to Natural Gas and Determination of the Control Level), 5773-2013, which imposes control on the gas sector in terms of reporting on profitability and the gas prices, shall remain unchanged for the period from the date of the Government Resolution, i.e., as of August 16, 2015, until the date of closing of the transfer of the rights of the Partnership, Avner and Noble in the Karish and Tanin leases as specified in Section 7.25.1(b)1 above, or in the Tamar Lease as specified in Section 7.25.1(b)2 above, in accordance with the provisions of the Framework, whichever is later (the "**Transition Period**").

b. During the Transition Period, the holders of the rights in the Tamar and Leviathan leases, including the Partnership (in this Section 7.25.1(c): the "**Holders of the Rights in the Leases**") shall offer to potential consumers the following natural gas price and linkage options:

1. A base price to be calculated in accordance with a weighted average of the existing prices in the agreements between the Holders of the Rights in the Leases and their consumers, and to be updated every calendar quarter (in accordance with the calculation specified in the Government Resolution).

2. The Brent barrel price, as shall be calculated in accordance with the optimal formula for the existing consumer on the date of the Government Resolution in agreements of the Tamar Partners.

3. For a private electricity producer (conventional or cogeneration) that meets the conditions specified in the Government Resolution in addition to the alternatives specified in subsections (1) and (2) above, also an alternative which includes linkage to the electricity production tariff.

c. The provisions of Subsection (b) do not derogate from the obligation of the holders of the rights in the Tamar and Dalit leases to offer consumers in Israel, the gas price set forth in an export agreement in order to comply with the terms of the taxation mechanism as specified in Section 7.25.1(c)4 below.

2. Natural gas export

a. In the Government Resolution of June 23, 2013, which adopted the main recommendations of the Tzemach Committee (as defined below) and the amendment thereto of January 6, 2019 (following conclusions of the Adiri committee (as defined below)), clarifications and amendments were made, *inter alia*, with regards to the manner of calculation of the permitted export quotas and the manner of creation of redundancy in the gas supply system. For further details, see Section 7.25.5(a) below.

b. In addition, it was determined that the holders of the rights in the Tamar Lease will be entitled to use the Mari B rig for the entire term of the Tamar Lease for the purpose of export or supply, to the domestic market, of natural gas from the Tamar reservoir, subject to the conditions determined in the Government Resolution.

3. The Tamar SW reservoir:

The Government Resolution included the Petroleum Commissioner's announcement that he will approve the development plan for the Tamar SW reservoir (for further details, see Section 7.3.4(d) above), subject to the production of natural gas from the Tamar SW reservoir not yielding revenues in excess of $575 million. The said production restriction will be cancelled by the Petroleum Commissioner after an agreement shall be submitted between the State and the holders of the rights in the

Tamar Lease on all of the issues relating to the development of the Tamar SW reservoir. For further details regarding the Tamar SW reservoir, including the development plan that was approved, see Section 7.3.4(d) above.

4. Taxation

The Government Resolution included the Tax Authority's notice which regulates various taxation issues pertaining to activity in the Tamar and Leviathan reservoirs. In addition, the government decided to act to promote amendments to the Taxation of Profits from Natural Resources Law, whose aim, *inter alia*, is the closing of tax loopholes, various clarifications and the application of assessment and collection proceedings.

It was further determined that the price of a petroleum unit in an export agreement will be taxed according to the actual income from the export agreement and not according to the "average domestic price" for such type of petroleum, as defined in the Taxation of Profits from Natural Resources Law, and that there will be no need for an annual examination of the revenues from the export agreement for this purpose, subject to the prior approval of the Tax Authority that the price of a petroleum unit under the export agreement is not lower than the "average domestic price" or alternatively, that the holder of the export agreement shall undertake to offer the price determined in the export agreement as aforesaid to new customers in Israel, in the manner and under the conditions set forth in the Gas Framework.

5. Domestic content

The government took note of the announcement of the Minister of Economic Affairs that the holders of the rights in the Tamar and Leviathan reservoirs made a commitment to invest in domestic content in the aggregate sum of $500 million over 8 years from the date of the granting of the Exemption, namely as of December 17, 2015. The following, *inter alia*, shall be deemed as domestic content: expenses in respect of the purchase of commodities or services from bodies registered in Israel (including foreign entities registered in Israel), the purchase of goods, procurement from Israeli contractors, suppliers or producers, investments in the field of R&D in Israel (directly or indirectly), expenses for manpower (up to a cap of 20% of the total commitment as aforesaid), expenses for professional training, donations and activity in the field of social responsibility.[260]

6. Maintaining a regulatory environment that encourages investments

   a. The Israeli government undertook to maintain regulatory stability in the natural gas exploration and production segment on three issues: the public's maximum share in the profits (Government Take), export and the restructuring included in the Government Resolution – for 10 years from the date of adoption of the Government Resolution.

   b. The Petroleum Commissioner intends to postpone the date of commencement of the commercial production and the piping of natural gas to the domestic market from the Leviathan reservoir to 48 months after the date on which the Exemption was granted.[261]

7. Milestones for the development of the Leviathan reservoir – by the end of 2017, the holders of the rights in the Leviathan lease will be required to enter into binding agreements for the purchase of equipment and services for the purpose of development of the lease in the sum of at least $1.5 billion, in addition to the amounts invested until the date of the Government Resolution.[262]

Following the original Government Resolution and the grant of the Exemption, several petitions were filed with the High Court of Justice. On March 27, 2016, the judgment of the High Court of Justice was issued on the said petitions, ruling, *inter alia*, that the stability clause as worded in the Framework (the government's undertaking to limit future changes in the regulation of the natural gas sector) cannot stand, and the State was given a one-year period to act for the regulation of the stability issue in the Framework.

On May 22, 2016, the Government readopted its resolution of August 16, 2015 with respect to the Framework, while setting an alternative

[260] The Operator forwarded to the Ministry of Economy reports audited by a CPA on local suppliers' expenses in respect of 2016-2017 in the aggregate sum of approx. $448 million. On December 7, 2017, the Ministry of Economy forwarded to the Operator confirmation that it recognized the expenses in respect of 2016 in the sum of approx. $110 million. As of the report release date, the confirmation of the Ministry of Economy has not yet been received in respect of expenses of approx. $338 million in respect of 2017. In addition, the Operator has not yet submitted a report regarding such expenses in respect of 2018.

[261] In the Partnership's estimation, the date of commencement of the piping of the natural gas from the Leviathan reservoir will be during Q4/2019.

[262] As aforesaid, on April 5, 2017, the operator notified the Commissioner that the Leviathan Partners had engaged in binding agreements for the purchase of equipment and services for the purpose of development of the Leviathan reservoir in the sum total of approx. $1.52 billion, and had thus fulfilled their obligation in accordance with the government resolution.

arrangement for Chapter J of the Framework concerning a "stable regulatory environment", to secure a regulatory environment that encourages investments in the natural gas exploration and production segment.

As of the date of release of this report, the Partnership is acting to implement the provisions of the Gas Framework relevant thereto, In this context, it has sold its holdings in the Karish and Tanin leases, as specified in Section 7.27.16 above, sold 9.25% of its holdings in the Tamar and Dalit leases to Tamar Petroleum, and continues to act to sell its remaining holdings in the Tamar and Dalit reservoirs. See, in this regard, also Section 7.29.1(b)5 below.

7.25.2. Antitrust

(d) On October 12, 2000, the Competition Commissioner gave his approval to the merger transaction, in the framework of which Delek Investments and Properties Ltd.[263] ("**Delek Investments**") purchased all the rights of RB Mediterranean Ltd in the Yam Tethys project. This approval, as revised, was subject to a number of conditions, including, *inter alia*, that any purchase of a holding by the Delek Group and/or Delek Investments and/or Delek Real Estate Ltd. and/or "Delek" Israel Fuel Company Ltd. ("**Delek Israel**") of 5% or more in an entity that does exploration, production, transmission, marketing or sells natural gas in Israel, requires advance approval of the Competition Commissioner, if the corporation has natural gas discoveries; the aforesaid in this section is not applicable to a joint venture in the Yam Tethys project.

(e) The Tamar Project

1. On August 28, 2006, the Competition Commissioner granted a conditional exemption from a restrictive arrangement approval – under Section 14 of the Economic Competition Law – to an agreement regarding the cooperation of the parties with rights in the Matan and Michal license[264] (that some of the rights thereunder were transferred at a later stage to Noble). The Competition Commissioner's decision was subject to a number of conditions, summarized below:

    a. The "Local Corporations" (as defined below) will not hold collectively, whether directly or indirectly, any gas right other than a right directly and exclusively deriving from the Matan and/or Michal licenses, without a specific approval, in advance

[263] On April 16, 2012, effective since December 31, 2011, Delek Investments was merged into Delek Group pursuant to the provisions of the 1st part of the 8th part of the Companies Law, as a result of which it was liquidated.
[264] On December 2, 2009, the Tamar and Dalit leases were granted in lieu of the Matan and Michal licenses.

and in writing from the Competition Commissioner. By December 31, 2006 the “Local Corporations” will complete any joint holdings in gas rights, except for the rights deriving directly and exclusively from the Matan and Michal licenses, which at the time of the giving of the decision were held jointly, directly or with other holders, unless joint holding has been specifically permitted by the Competition Commissioner in writing.

b. In any arrangement, agreement or consent, in writing or verbally, with regard to determination of a mechanism or matter of decision making between the license holders of Matan and Michal with regard to the marketing of natural gas produced under the Matan and Michal licenses, any one of the “Local Corporations” will not hold, alone, directly or indirectly, any right or power to prevent the other holders decision making or action with regard to the marketing of natural gas produced under the Matan and Michal licenses.

c. Definitions: the “Local Corporations” – “Delek Group” and “Isramco”; “Delek Group” - Avner and/or Delek Drilling and/or any other related person; “Isramco” and any related person.

2. On November 13, 2012 the Partnership received a notice from the Competition Commissioner of its announcement as a monopoly– together with the other partners in the Tamar Project and separately – in the supply of natural gas in Israel commencing upon the date of the beginning of commercial supply from the Tamar Project.

   Due to its being a monopoly, as aforesaid, the Partnership is subject to Chapter D of the Economic Competition Law, including a prohibition on the Partnership to unreasonably refuse to supply natural gas and a prohibition on abuse of its position in the market in a manner that might reduce competition in business or harm the public.

3. In addition, the Tamar Partners are obligated to submit to the Competition Commissioner all of the agreements for the sale of natural gas to domestic customers. During 2012 and 2015, several decisions were received from the Competition Commissioner regarding the granting of a conditional exemption from approval of restrictive arrangements in connection with fourteen long-term agreements for the supply of natural gas between the Tamar Partners and private gas consumers (the “**Commissioner’s Decisions**”). Below are the main principles of the Commissioner’s

Decisions: The gas consumer shall have the option to choose, in respect of the agreement, one of the following two alternatives:

a. Shortening the term of the agreement to 7 years, from the date of commencement of the natural gas supply; or alternatively

b. Reducing the quantity of the gas stated in the “Take-or-pay” clause to a quantity equivalent to one half of the average annual consumption quantity of the gas consumer in the three years preceding the date of the notice. The reduction of the purchase quantity will take effect one year after the date of provision of such notice, until the end of the term of the agreement, as the case may be (“**Reduction of the Purchase Quantity**”). Notice of Reduction of the Purchase Quantity will be possible at any time during the period ending on the later of the following two periods: (1) the period from January 1, 2018 until December 31, 2020 (with respect to five agreements for the sale of natural gas) or the period from January 1, 2020 until December 31, 2022 (with respect to nine agreements for the sale of natural gas); or (2) the period commencing at the beginning of the fifth year from the date of supply of natural gas and concluding at the end of the seventh year as aforesaid. Such period is subject to changes due to the making of modifications and amendments to the timetables for the production of gas from other fields.

c. Upon determination of the minimum quantity for which the gas consumer shall be charged in accordance with the foregoing, the annual gas quantity and the aggregate gas quantity in the agreement shall be updated.

d. The gas consumer will be permitted to sell natural gas designated for the use of consumers of the gas distribution network, in an amount of up to 15% of the annual gas quantity per year.

e. No restriction shall apply to a gas consumer in respect of the purchase of natural gas thereby from any other supplier of natural gas who is not a Tamar partner.

f. The Tamar Partners shall not engage, directly or indirectly, in any agreement for the supply of gas from the Tamar reservoir, without receiving the prior approval of the head of Competition Control.

Following the Commissioner’s Decisions, the said agreements were amended and all of the agreements for the supply of natural gas that were signed by the Tamar Partners from such date and until the date of validation of the Gas Framework were amended and/or drawn up in keeping with the Commissioner's Decisions.

As of the report release date, most of the agreements have been amended in accordance with the aforesaid and the Tamar Partners are acting to amend the other purchase agreements with the relevant consumers accordingly[265].

4. Agreements signed as of the beginning of 2016 and until the release date hereof are in keeping with the conditions of the Framework's provisions. Such agreements have been provided to the Competition Authority for the purpose of receipt of a permit and are in the process of receiving a permit.

7.25.3. The business being subject to specific legislation in Israel

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

(f) The Petroleum Law, 5712-1952 (in this section: the "**Law**")

1. The Law provides, *inter alia*, that a person shall not explore for Petroleum except under a "preliminary permit", "license" or "lease deed" (as defined therein) and a person will not produce petroleum except for under a license or lease deed.

2. Preliminary testing (that does not include test drilling) in any area, in order to ascertain the prospects for discovering Petroleum in such area, including the conducting of seismic surveys, is subject to the receipt of a preliminary license. The Law permits the granting of priority rights to the holder of the preliminary rights for Petroleum rights 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

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[265] With respect to long-term agreements approved before October 2012, the exercise period for the option to reduce the purchase quantity will be in keeping with the provisions of previous decisions issued by the commissioner, i.e., the period between January 1, 2018 and December 31, 2020, or the period commencing at the beginning of the fifth year as of the natural gas supply date and ending at the end of such seventh year, whichever is later.

Law, and the exclusive right to conduct test and development drilling in the license area and to recover Petroleum therefrom. In general the License will be granted for an initial period of 3 years and is subject to extension, under conditions provided for by Law, for an additional term not to exceed 4 years.

4. If a licensee makes a Petroleum discovery, it is entitled to an extension of the license period for such time, not exceeding two years, as will give it sufficient time to define the borders of the Petroleum field, and the licensee is entitled to receive in a certain area within the license area, a "lease" which granting exclusivity to explore and to produce Petroleum in the leased area, for the term of the Lease. The lease is given for a period of up to 30 years from issuance, but if a lease is given pursuant to a license that was extended after a discovery in the license area, the license term will commence upon the original termination date of the license, prior to extension. A lease may be extended, under the provisions of the Law, for an additional period of up to 20 years. A lease may expire following a suitable prior notice given by the Minister of Energy, if the lease holder fails to produce or ceases to produce Petroleum in commercial quantities.

5. The Law provides, *inter alia*, that the lessee pay the State royalties of one eighth of the quantity of Petroleum produced from the leased area and utilized (excluding Petroleum used by the lease holder for operating the leased area)[266], but in any event no less than the minimal royalty provided for by Law.

6. A lease might expire following a suitable prior notice given by the Minister of Energy if the lease holder fails to produce or ceases to produce Petroleum in commercial quantities.

7. In addition, the Law provides that the Commissioner may cancel a Petroleum right 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 right 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 rights holder or preliminary permit holder sixty days previously.

8. The Commissioner will maintain a Petroleum register which will be open to the public for review (the "**Petroleum Register**"). The Petroleum Register will list all requests, grants, extensions,

[266] For further details with respect to the State royalty calculations, see Section 7.27.12 below.

revisions or expirations and transfers, pledges of Petroleum rights or benefits therein or grant of a lease deed. No such transaction shall be in force until it is registered therein.

9. The Law provides that no one person shall have more than twelve licenses, and that it will not have licenses for a total area exceeding four million thousand sqm, except upon prior approval of the Petroleum Council.

10. A preliminary permit, license and lease are personal and neither they nor any benefit therein may be pledged or transferred in any manner – other than through inheritance – other than with the Commissioner's permission, and the Commissioner will not permit the pledge or transfer of a license or of a lease other than after consulting with the Council.

11. A leaseholder may build pipelines for the transport of oil and oil products. A leaseholder shall not build an oil pipeline, other than collection pipelines which lead to tanks in or around the areas of the lease wells, other than according to a line approved by the Commissioner. An oil pipeline will be constructed according to detailed drawings in accordance with the law; the drawings will first require the approval of the Commissioner, which shall not be unreasonably withheld.

(g) <u>The Petroleum Regulations, 5713-1953 (the "**Petroleum Regulations**")</u>

The Petroleum Regulations deal with, *inter alia*, preliminary permits and priority rights, in the licenses and the leases (collectively: the "**Rights**") and set forth the manner in which applications for rights should be submitted, reports filed, fees paid, conditions with regard to the shape of the area, provisions with regard to the grant of rights by way of a competition and provisions with regard to payment of royalties pursuant the Petroleum Law.

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

1. On November 15, 2016, the Offshore Regulations, which replaced the Petroleum Regulations (Principles for Offshore Petroleum Exploration and Production), 5766-2006, came into effect. The Offshore Regulations prescribe, *inter alia*, proof of qualification of the applicant seeking operator certification.

2. The principles of the Offshore Regulations are as follows:

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

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

        2. The operator or control holder therein (subject to the conditions in the Offshore Regulations) will have at least five years of experience in the ten-year period preceding the filing of the application, in the performance of the functions of an operator, including (a) experience in offshore petroleum or natural gas exploration; (b) experience in offshore drilling; (c) experience in offshore development and production of petroleum and natural gas; (d) experience in activities for preservation of health, safety, and environmental protection relating to activities in petroleum rights.

        3. Furthermore, the Petroleum Commissioner will not certify a corporation as operator, unless it directly employs employees that have qualification and at least five years of experience in the offshore Petroleum or natural gas exploration sector, and in the offshore Petroleum 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 petroleum or natural gas development and production, as described below.

        4. The Petroleum Commissioner may, according to the stage and characteristics of the right and according to the scope of the demand for receipt of the right in that area or according to the composition of the entire group, certify a corporation as an operator even if it fails to comply with the above requirement of necessary experience in offshore Petroleum or natural gas development and production.

        5. The Petroleum Commissioner may require a certain corporation, for certification thereof as operator, greater experience than the one prescribed, if it finds it necessary according to the stage and characteristics of the right, and considering the work plan, its complexity and environmental and safety aspects.

6. The Commissioner will not certify a corporation as an operator unless it has sufficient financial capacity and financial soundness. For this purpose, an operator or the control holder thereof (subject to the conditions in the Offshore Regulations) is financially sound (as defined in the Offshore Regulations) and has financial capacity that is deemed sufficient if the total assets in the balance sheet are at least $200 million and the total equity in the balance sheet is $50 million.

b. The applicant for a Petroleum right must prove appropriate financial capacity by fulfillment of both of the following:

1. The total assets in the balance sheet of the applicant (or of all holders of the Petroleum right jointly, including a member of the group approved as the operator with respect to the Petroleum right) are at least $400 million.

2. The total equity in the balance sheet of the applicant (or of all holders of the Petroleum right jointly, including a member of the group approved as the operator with respect to the Petroleum right) is at least $100 million.

An applicant for a Petroleum right 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 soundness[267], total assets and total equity will be examined according to the data in the audited financial statement as of December 31 of the year preceding the submission of the application, or according to an average of the data in the audited financial statements as of December 31 of the two years preceding the submission of the application, according to the discretion of the Petroleum Commissioner.

c. The Petroleum Commissioner may, with approval from the Minister of Energy, withhold approval from an application to receive a Petroleum right 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.

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[267] Financial soundness is proven if the conditions specified in the Regulations are fulfilled.

d. Notwithstanding the provisions above, it is possible to approve an operator or grant a Petroleum right 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 Commissioner was convinced that there are special grounds which justify so doing.

e. The Offshore Regulations include additional provisions on the details to be included in the application for approval of an operator and reports which an operator and a holder of a Petroleum right are required to submit to the Petroleum Commissioner

(i) The Natural Gas Sector Law, 5762-2002

The Natural Gas Sector Law and the regulations promulgated thereunder set forth provisions with regard to the construction of the transmission system, marketing and supply of natural gas. The Natural Gas Sector Law provides, *inter alia*, that:

1. The following activities may not be undertaken without a license issued by the Minister of Energy (in this section: the "**Minister**") and according to its terms:

    - the construction and operation of a transmission system or part thereof;

    - the construction and operation of a distribution network or part thereof;

    - the construction and operation of an LNG facility ("**LNG License**");

    - the construction and operation of a storage facility.

    - The construction and operation of an export pipe by a person who is not a lease holder.

2. Transmission license will only be given to a company established in Israel under the Companies Law.

3. The holder of the transmission license or an electricity provider may not deal in the sale or marketing of natural gas, nor may a holder of control or a link in any of them.

4. The occupation of selling and marketing of natural gas does not require a license, however the Minister has the discretion under certain conditions set forth in the Natural Gas Sector Law, to

determine, upon agreement with the Minister of Finance and upon approval of the Knesset's Economic Affairs Committee, that for a certain determined term, natural gas marketing activity will be subject to a license.

5. In the event that a person applies for more than one license, the Minister may, upon consultation with the Director General of the Natural Gas Authority appointed under the Law (in this section: the "**Director**") make the licenses conditional on the conditions specified in the Natural Gas Sector Law.

6. The Minister, in consultation with the National Gas Authority Council, which was appointed pursuant to Section 63 of the Natural Gas Sector Law ("**National Gas Authority Council**"), may, *inter alia*, in accordance with the Government's policy, provide to a corporation, without a tender, a license for an export pipeline of a non-lease holder, for a period which will be determined in the license and subject to the provisions of the Natural Gas Sector Law.

7. A storage license and the LNG license will be granted under a tender or another upon a public proceeding; however the Minister may, with the consent of the Minister of Finance and upon consultation with the Natural Gas Sector Council, decide that the storage license or the LNG facility license be granted without a tender or said public proceeding, to the holder of the transmission license. Notwithstanding the foregoing, a lease holder, for as long as a lease is in force, may store gas produced by it in a reservoir in the area of the lease. Notwithstanding the foregoing in this section above, the Minister may grant the lease holder, without a tender or another public proceeding and for as long as the lease is in force, a license to store gas which is not produced by the reservoir in the lease area; the term of the license will be set forth therein and will not exceed the balance of the lease term. The Minister may instruct the lease holder, for as long as the lease is in force, to provide storage facilities to others in the reservoir that is in the area of the lease and to determine the conditions of the services, after giving the lease holder an opportunity to state its claims; if such an instruction is given, the lease holder will be deemed a holder of a storage license and the provisions of the Natural Gas Sector Law will apply to it.

8. Restrictions were placed on additional activities by a license; however the Minister, after consultation with the Natural Gas Sector Council, may give the license holder a permit to engage in additional activities under conditions prescribed in the Natural Gas Sector Law.

9. The term of a license not exceed 30 years, and not be extended; however this provision does not prevent the license holder from participating in a tender that takes place for the granting of a new license. Notwithstanding the foregoing, the Minister may decide not to limit the term in a transmission license, and if limited in term, it may be extended or the term limitation cancelled and to set forth conditions in the license with regard to any such decision.

10. The Minister, after consultation with the Director General of the Natural Gas Authority, may set forth conditions in the license to ensure the aims of the Natural Gas Sector Law and compliance with its instructions, including conditions that need to be met prior to commencing activity under the license. In addition, the Minister, with the consent of the Minister of Finance and in consultation with the Council, may modify, add or subtract conditions of a license if there is a vital need therefor in order to realize the objectives of the Natural Gas Sector Law or to fulfill a relevant international treaty to which Israel is a party, and considering technological, market-related and environmental changes that have occurred since the license was issued, and after the license holder shall have been given an opportunity to voice its claims.

11. The Minister, upon the consent of the Minister of Finance, may set forth mandatory royalty payment conditions in a license given under a tender, or license fees to the State Treasury, and the manner of their calculation and payment, and if any of those are subject to bidding in the tender – in accordance with the results of the tender; the Minister, upon the consent of the Minister of Finance, and subject to approval of the Knesset's Economic Affairs Committee, may provide for mandatory royalty payments by a license holder whose license was not granted under a tender.

12. The Director General of the Natural Gas Authority, after consultation with the Natural Gas Sector Council and with the Minister's approval, and after giving the license holder an opportunity to state its claims, may cancel a license at any time, if one of the following conditions is fulfilled: (a) the license holder failed to disclose to the tender committee or to the Minister material information that is required to be disclosed in connection with participation in the tender or the license application, or provided incorrect information; (b) the license holder fulfills one of the exceptions to receipt of the license or ceases to fulfill any of the required eligibility conditions, and does not remedy the same within a period that was determined by the manager in notice that he sent to the license holder; (c) an order was issued for the dissolution of the license holder or a receiver was appointed

therefor, and the order or the appointment were not cancelled within a period that was determined by the manager in notice that he sent to the license holder; (d) the license holder failed to fulfill an instruction to correct deficiencies or breached a material regulation in the license, which breach was not remedied within the period determined by the manager or the Commissioner or is irremediable; (e) the license holder committed an ongoing breach of a provision according to this law or in the license or a condition in the license, which breach was not remedied as stated in Section (d) above; (f) other grounds exist which are determined in the license as grounds for cancellation thereof.

13. A license or any part thereof cannot be transferred, pledged or attached, in any manner. Gas facilities of the license holder and assets that were determined in the license as required for the performance of the activity according to the provisions of the license, may not be transferred, pledged or attached, in any manner, other than with the prior written approval of the manager, and under such conditions as he shall determine. An action that is taken contrary to the provisions of this section is null and void.

14. Guaranties and undertakings provided by a license holder or a control holder thereof, and money received from enforcement thereof, may not be attached or pledged.

15. No person shall purchase or hold control or means of control of a license holder, and the holder of control or means of control of a license holder shall not transfer the same to another. Generally, for the purpose of such a transfer or purchase, the Minister's approval is required, after consultation with and the consent of the Council.

16. A license holder shall not condition the provision of service on the purchase of another service or gas therefrom or from another person or on the non-purchase of a service or gas from another person. However, if it was proven to the National Gas Authority Council that there is a reasonable business connection between the requested service and the fulfillment of the condition, the said Council may approve the condition.

17. The tariffs that will be charged by the license holder, and any update thereto, will be determined by the Natural Gas Sector Council, in accordance with the rules set forth in the license, and with regard to activity that was granted under a tender, the Natural Gas Sector Council will determine the tariffs according to the conditions of the tender; the Natural Gas Sector Council may determine standards or instructions with regard to the level,

quality and quantity of the services that the license holder has to provide to its consumers, and to ensure continuity during the term of the license.

18. Gas that is sold by a natural gas supplier to a Private Electricity Producer (as defined in the Electricity Sector Law, 5746-1996) is a commodity that is subject to the Supervision of Prices of Commodities and Service Law 1996-5756 (the "**Supervision Law**") and the level of supervision that will apply is in accordance with Section E of the Supervision Law.

19. The Minister, in consultation with the Council, may grant a corporation, without a tender, a license for an export pipeline of a non-leaseholder, for a period prescribed by him in the license, upon the fulfillment of all of the following:

    a. The corporation that submitted the application (including the corporation controlling it or another corporation controlled by the controlling corporation) has engaged in a natural gas purchase agreement that fulfills all of the following:

        1. A long-term engagement of significant scope for export purposes;

        2. The purchased natural gas will be produced from the area of the lease under the Petroleum Law, with the pipeline for which the license is granted being connected to the facilities used for the operation under the lease;

        3. The Minister has preapproved the engagement.

    b. All of the following are duly incorporated in Israel or in a country which is not an enemy country:

        1. The applicant for the license;

        2. The control holder of the applicant for the license – if it is a corporation;

        3. Another corporation controlled by the controlling corporation, which engaged in such an agreement, insofar as it did;

    c. If the control holder of the applicant for the license is not a corporation – he is not a citizen of an enemy country;

d. The holder of the lease, to the facilities used for the operation the pipeline will be connected, holds the approvals required for the purpose of export via the pipeline.

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

1. The Emergency Regulations are under Section 91 of the Natural Gas Sector Law, which authorizes the Minister of Energy, with approval from the Government, to announce a state of emergency in the natural gas sector and promulgate regulations applicable to the operation of the natural gas sector in a state of emergency.

2. The Emergency Regulations distinguish between a situation in which 90% of all of the natural gas supply in the sector comes from one field and one transmission system (a "**Significant Field**"), as is currently customary in the Israeli sector, and a situation in which the natural gas supply in the sector comes from at least two fields connected to INGL through at least two separate transmission systems:

a. Provisions when one Significant Field exists

Whenever the aggregate hourly demand for natural gas by the consumers of the gas supplier which is unable to supply all or part of the natural gas in the field (the "**Defaulting Supplier**") exceeds the maximum quantity that can be supplied to them, the Defaulting Supplier and INGL will allocate the existing gas quantity according to the following provisions:

1. The first allocation of natural gas will be to the distribution consumers (as defined in the Emergency Regulations). Such allocation will be performed according to the maximum quantity per hour of the natural gas that was consumed by the distribution consumers in the 12 months preceding the declaration date (as defined in the Emergency Regulations):

a) A quantity of up to 3,600 MMBTU per hour will be reserved for distribution consumers (the Director of the Gas Authority may determine how the quantity will be distributed between the distribution consumers amongst themselves);

b) A quantity of at least 3,600 MMBTU per hour will be allocated as follows:

(1) First to household consumers;

(2) The remainder of the allocation will be allocated to the distribution consumers that are not included in Subsection (a).

2. The remaining quantity will be divided between electricity producing consumers (consumers of a defaulting gas supplier who are producers of electricity using natural gas at a capacity exceeding 45 MW) and consumers which are not electricity producers, proportionately according to the aggregate daily consumption average of each one of the said types of consumers in the same month in the previous calendar year;

3. The quantity that shall be distributed to consumers who are not electricity producers (out of the quantity allocated to consumers who are not electricity producers as aforesaid) will be determined according to their share in the hourly capacity ordered for each one of them according to the transmission agreement that they signed with the holder of the transmission license, and the total hourly capacity ordered for such consumers according to the transmission agreement that they signed with the holder of the transmission license.

4. The IEC will offer LNG for sale to consumers who are not electricity producers, at the price for which it purchased the LNG plus up to 10%.

b. Provisions when at least two fields exist

Non-defaulting gas suppliers will be obligated to offer their surplus gas, if any, for sale (the available daily quantity after the supply of the quantity ordered by such supplier's consumers, provided that the ordered quantity does not exceed the maximum quantity that may be ordered under the agreements with them) to the defaulting gas supplier. If the parties fail to reach an agreement as to the price of the surplus gas, The price will be in accordance with the average market price (to be determined according to the total income from natural gas sales to consumers in Israel from all of the fields that was received in the quarter preceding the quarter that preceded the declaration date divided by the aggregate quantity of natural gas in MMBTU units that was supplied to consumers in Israel in the quarter preceding the quarter that preceded the declaration date, as published by the Natural Gas Authority from time to time on its website). Whenever the aggregate hourly demand for natural gas by the consumers of the defaulting gas supplier exceeds the maximum quantity that can be supplied to them, the Defaulting Supplier and INGL will allocate the excess gas quantity purchased to consumers in the Israeli sector only, according to the following provisions:

1. The first allocation of natural gas will be to the distribution consumers. Such allocation will be performed according to the maximum quantity per hour of the natural gas that was consumed by the distribution consumers that consume gas from the defaulting gas supplier in the 12 months preceding the declaration date, as specified below:

   A quantity that does not exceed the outcome of 3,600 MMBTU per hour minus the quantity supplied to the distribution consumers supplied by the non-defaulting gas suppliers per hour, shall be reserved for the distribution consumers;
   A maximum quantity that exceeds the product of 3,600 MMBTU per hour minus the quantity supplied by the non-defaulting gas suppliers to the distribution consumers, a quantity shall be allocated of 3,600 MMBTU per hour minus the quantity supplied by the non-defaulting gas suppliers the distribution consumers in the following manner [sic]:
   (1) First to the household consumers;
   (2) The remainder of the allocation will be allocated to the distribution consumers that are not included in Subsection (a).

2. The remaining quantity will be divided between electricity producing consumers and consumers who are not electricity producers, proportionately according to the aggregate daily consumption average of each one of the said types of consumers in the same month in the previous calendar year;

3. If surplus gas remains for supply, the defaulting gas supplier may supply natural gas from the field (the "**Additional Quantity**"), such that the daily surplus gas quantity remaining for supply shall be allocated to electricity producing consumers and consumers who are not electricity producers, proportionately according to the aggregate daily consumption average of each one of the said types of consumers in the same month in the year preceding the year in which the allocation is performed, net

of the Additional Quantity that was allocated to each one of the types.

4. The quantity that shall be distributed to consumers who are not electricity producers (out of the quantity allocated to consumers who are not electricity producers as aforesaid) will be determined according to their share in the hourly capacity ordered for each one of them according to the transmission agreement that they signed with the holder of the transmission license and the total hourly capacity reserved for such consumers according to the transmission agreement that they signed with the holder of the transmission license, net of the Additional Quantity, if allocated, for each one of the consumers who are not electricity producers.

c. General

If the Minister finds, after consultation with the Director General of the Natural Gas Authority and the Director General of the PUA-E, that the natural gas shortage continuously or extensively compromises the orderly functioning of the sector or the orderly supply of electricity to the Israeli market, which cannot be overcome by use of other fuels, or if the Minister of Environmental Protection shall have notified the Minister of Energy that the prolonged shortage of natural gas is significantly harming the environment in a manner that will be damaging to the public's health, the Minister may deviate from the provisions of the Regulations and prescribe a different allocation of the gas and LNG quantities, provided that the deviation is not excessive.

The Regulations do not exempt the defaulting gas supplier from any legal duty imposed thereupon, nor do they derogate from any and all of the remedies and reliefs included in the agreement between the defaulting gas supplier and the gas consumer.

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

On December 11, 2013 (in this section: the "**Commencement Date**") the Concentration Law was published in the Official Gazette, which prescribed, *inter alia*, that the regulators have the authority to consider sectorial competition considerations and economy-wide concentration considerations, in the framework of allocation of public assets by the State, in order to ensure an increase in sectorial competition and decentralization of the economy-wide concentration.

Under the Concentration Law, a regulator may choose to not allocate to an entity listed on the published list of concentration entities, determined on the basis of criteria set forth in the Concentration Law, a right (including a contract) in a business sector that uses of essential infrastructure or a public resource, or in the framework of which an essential service is provided to the public, listed in the Concentration Law (the "**Essential Infrastructure Sector**"), until having found that no actual damage will be caused to the sector in which the right is allocated and to the regulation of the said sector due to non-allocation, and after having taken into account considerations of prevention of the expansion of the operations of the concentration entity, bearing in mind the relevant business sectors and the link between them (the "**Economy-Wide Concentration Considerations").**

Therefore, prior to the allocation of a right in any Essential Infrastructure (including a business sector with respect to which a petroleum right 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 right to anyone having another petroleum right 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 Essential 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.

The aforesaid provisions concerning the proceedings for the allocation of a right took effect in December 2014. With respect to an extension of the term of a right, the provisions will apply from the elapse of three years as of the Commencement Date (i.e., on December 10, 2017).

On December 25, 2017, the Committee for the Reduction of Concentration published, according to the provisions of the Concentration Law, a list of the concentration entities in the market, a list of the significant real corporations and a list of the significant financial bodies, which was recently updated on December 9, 2018. From the Partnership's perusal, in proximity to the date of the report, of the lists published by the Concentration Committee (including the updates thereto), it transpires that the Partnership appears on the list of the concentration entities.

As of the report release date, the Partnership is unable to assess the scope of the effect of the Concentration Law on the oil and gas exploration sector in general and on its operations in particular.

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

1. The Law applies to a "public entity", which is, as defined by the Law, an entity listed in any of the schedules to the Law.

2. The Law imposes various duties on a "public entity": (a) Appointment of a security officer who will report directly to the director of the entity, in order to ensure the security level required for the activity of the public entity; (b) Appointment of an officer in charge of the security of essential computerized systems; (c) Appointment of a security guard in accordance with the requirements of an authorized officer.

3. The Law confers vast powers upon the security officer of a public entity, and *inter alia*: The authority to conduct a search and seize an object; the authority to require a person entering a public entity to identify himself; detainment powers (in certain circumstances specified in the Law); the authority to prohibit entry into the public entity with weapons (and, under certain circumstances specified in the Law, also while using reasonable force).

4. In accordance with the Sixth Schedule to the Law, a public entity listed in the Sixth Schedule to the Law will also be required to carry out offshore security activities. The offshore security activities are defined as activities required for the protection of a person's safety or the protection of property, in a building or on the premises of a public entity located in the maritime zone, as well as actions for the prevention of harm to any of the above.

5. In accordance with the provisions of the Sixth Schedule to the aforesaid Law, the holder of a license under the Natural Gas Sector Law, 5762-2002, which owns an offshore facility, or which operates an offshore facility, is deemed a public entity for the purpose of imposition of the duties listed in Section 2 above as well as the conduct of offshore security activities.

6. The IDF is the guiding authority on offshore security and its representative is deemed by the Law as an "authorized officer" for the purpose of offshore security activities.

7. Under the law, an offshore facility is a facility situated in the maritime zone which is used for the performance of a petroleum discovery survey or for a production well, for transmission, for

liquefaction or for gasification of petroleum, or for the processing, storage or transportation of petroleum ("petroleum" – as defined in the Petroleum Law). The maritime zone includes areas situated beyond the sovereign territory of the State of Israel, and also includes, other than the band of Israel's territorial waters, the "continental shelf" as defined in the Shipping Law (Offences against the Security of International Sea Travel and Offshore Facilities), 5768-2008.

8. Other than offshore facilities that are listed, as aforesaid, in the Sixth Schedule to the Law, Section 21 of the Second Schedule includes an "operator of an onshore facility for the processing of natural gas received by pipeline from the sea or from a foreign country, by virtue of a license or by law." Such operator is subject to requirements of physical security activities and information security activities (but not activities for the security of computerized systems or offshore security activities).

9. In accordance with the law, the holders of the lease in the Tamar and Leviathan reservoirs, including the Partnership, are responsible, *inter alia,* for the security of vital computer systems in the reservoirs, in accordance with the instructions of the Israel National Cyber Directorate (the "**INCD**"). Since it is the operator that is responsible for the operation of the production system of the Tamar project, and is building and will also be responsible for the operation of the production systems of the Leviathan project, it is the operator that actually implements the instructions of the INCD on the matter. As the Partnership has been informed, and to the best of the Partnership's knowledge, as of the date hereof, these systems comply with all of the relevant instructions received from the INCD with respect to the IT systems that are used for operation of the Tamar project, and the IT systems that are implemented in the development of the Leviathan project.

7.25.4. Directives of the Petroleum Commissioner

(a) Provision of collateral in connection with petroleum rights

1. On September 17, 2014 the Petroleum Commissioner published, in accordance with Section 57 of the Petroleum Law, a final version of directives for the provision of collateral in connection with petroleum rights, the principles of which (with respect to offshore assets) are as specified below. However, it is noted that after the said date, the Commissioner demanded insurance confirmations in the language determined by him, based on insurance plans that were submitted to him on the issue of insurance which pertain to the various leases. Below are the main directives for the provision

of collateral in connection with the petroleum rights (with respect to offshore assets):

a. Existing offshore license holders will deposit guarantees in an amount equal to $2.5 million gradually, as follows: (1) $1.25 million shall be deposited by November 30, 2014; (2) $1.25 million shall be deposited by March 31, 2015. It shall be noted that a rights holder who's approved work plan for its right, includes or shall include the performance of a drilling prior to the aforesaid dates, shall provide the base guarantee in full prior to the issuance of the drilling approval. In addition, in exceptional circumstances so justifying, the Petroleum Commissioner may demand a different guarantee amount to that set forth above.

b. Prior to performing drilling license holders will be required to provide an additional guarantee in a sum that the Petroleum Commissioner will determine in accordance with the character of the drilling and the drilling plan, which sum of the additional guarantee and the offshore license will not be less than the equivalent to $5 million. In the event that the Petroleum Commissioner believes that the drilling characteristics justify it, he will be entitled to demand a guarantee of a lower sum than aforementioned.

c. In the petroleum leases, the Petroleum Commissioner will determine the sum of the guarantee taking into account, *inter alia*, the development plan, the characteristics of the lease, the stage it is at, the size of the petroleum field, but in any event the guarantee will not be less in total, than the equivalent to $7.5 million for an offshore lease. Guarantees in respect of new leases shall be deposited upon the grant of the lease, for a term to be determined by the Petroleum Commissioner. Furthermore, the Petroleum Commissioner reserves the right to update the amount of the guarantee consequently to a change of circumstance.

d. The aforesaid guarantees will be in force even after the right for which they were given terminates, until the Commissioner advises otherwise, but no more than 7 years after expiration of the right for which they had been provided.

e. In the event that, in the opinion of the Petroleum Commissioner, a petroleum rights holder did not act in due diligence in respect of the petroleum right or caused damage in his actions due to the petroleum right or did not incur expenses or failed to fulfill obligations that he was due to incur or fulfill under the Petroleum Law, and the Petroleum Commissioner, during the period of the right, instructed the petroleum right holder by way of written notice to take actions or incur expenses or fulfill obligations pertaining to the petroleum right, and the petroleum right holder failed to follow such instruction and did not provide a proper reason for such failure, the Petroleum Commissioner may order the forfeiture of the guarantees or any part thereof, after hearing the arguments of the rights holder regarding the forfeiture of the guarantee.

f. The petroleum right holder shall make and maintain, at its expense, and throughout the entire term of the petroleum right, all of such insurances, which are customary among international companies for exploration or production of oil or gas.

g. Should a petroleum right holder fail to comply with the directives, or if it is found that the guarantee or insurance that were made were revoked or terminated for any reason whatsoever, prior to their renewal, extension or replacement by another guarantee or insurance, the Petroleum Commissioner shall be entitled to forfeit the existing guarantee in connection with the right and may act to mitigate the possible damage, at the expense of the right holder. In addition, the Petroleum Commissioner may be entitled to view such as non-compliance with the work plan and with the provisions of the right and to act in accordance with the provisions of the Petroleum Law.

h. In addition, the directives include, *inter alia*, provisions regarding applicants of new onshore licenses, existing onshore licenses, updates of guarantee amounts and extensions thereof, as well as general provisions regarding guarantees.

2. Within the publication of the Competitive Proceeding described in Section 7.16.1 above, rules were set with respect to guarantees for new offshore licenses, as follows: (a) the basic guarantee sum per license is $2.5 million; (b) insofar as the developer seeks to receive a license in bordering areas, the guarantee sum for the additional area is $0.5 million per each additional license, up to the maximum guarantee sum of $4 million (for 4 bordering areas). The amount of the guarantee required for an area with respect to which the license applicant has committed to execute a drilling is $10 million. Insofar as the license holder fails to execute a drilling during the term of the license and seeks to extend it under law, it will have to provide an additional guarantee in the sum of $5 million prior to the execution of the drilling.

In accordance with such directives and the terms and conditions of the Partnership's petroleum assets, as of the report release date, the Partnership, together with its partners in the various enterprises, deposited autonomous bank guarantees for the Ashkelon, Noa, Tamar, Dalit, Leviathan North, Leviathan South leases and also for the Alon D license[268]. The Partnership's share in said guarantees amounts to approx. $40.6 million.

(b) <u>The Transfer and Pledge of a Petroleum Asset Right and Benefit in a Petroleum Asset Right</u>

On December 31, 2015 the Petroleum Commissioner published directives for the purpose of Section 76 of the Petroleum Law, the objective of which is to regulate the procedure for the transfer and pledge of a petroleum right (preliminary permit, license and lease) and a benefit (including a right to contractual royalties) in a petroleum right[269] (in this Section: the "**Directives**") which are mainly as follows:

In this section, "license-related benefit" and "lease-related benefit" – including a holding of each one of the following: (1) control of a license holder or a lease holder, or of a corporation that has holdings in a license or a lease, or a group, as the case may be; (2) more than 25% of a specific type of the means of control of a license holder or a lease holder, or of a corporation which has holdings in a license or a lease, or a group, as the case may be; (3) a right to contractual royalties.

"Means of control" – means of control of a group or means of control of a corporation, as the case may be;

"Means of control of a group" – any one of the following: (1) a voting right at a meeting, at an operating committee or at another forum at which decisions are made that bind the group with respect to the operation of the petroleum right; (2) a right to appoint members of a meeting, operating committee or another forum at which decisions are made that bind the group with respect to the operation of the petroleum right, or to appoint a person whose role is to make such decisions; for this purpose, "operating committee" – a body in respect of which the group's members have agreed that it will direct the group's activity in

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[268] With regard to additional guarantees that the Partnership provided, together with its partners in the Tamar Project, see Sections 7.3.2(m) and 7.25.4(a) above and with regard to additional guarantees that the Partnership provided together with its partners in the Leviathan project, see Section 7.4.2(n) above. Note that in March 2019, the Partnership provided an additional guarantee (in the amount of approx. $1.2 million) due to Noble's share in the Alon D license, such that as of the report release date, the Partnership provided a guarantee due to 100% of the rights in the aforesaid license. In this context see also Sections 7.9.2 and 7.9.3 above.

[269] It is noted that directives with respect to Section 76 were also applied to the transfer of a petroleum right or a benefit between anyone who has a direct share in a petroleum right within the framework of a group by virtue of the agreement between them, and will also apply to a transfer or allotment of means of control which confer a benefit in a petroleum right or control of the corporation or group holding a petroleum right or benefit in a petroleum right.

the operation of the petroleum right or will determine the manner of operation of the petroleum right and performance of the duties imposed on the holder of the petroleum right according to the terms and conditions of the right or its policy on such matters, or will supervise the same.

"Means of control of a corporation" – each one of the following: (1) a voting right at a general meeting of a company or at a corresponding entity of another corporation; (2) a right to appoint a director of a company or its CEO, or officers corresponding thereto in another corporation.

"Control" – control of a group or control of a corporation, as the case may be;

"Control of a group" – the ability, whether alone or together with others acting in cooperation on a regular basis, to direct the group's business, with the exception of ability of an individual which derives merely from filling a position at the group or filling a position of a director or another officer at one of its members, and with the exception of ability which derives merely from filling the position of operator; without derogating from the generality of the aforesaid, a person is presumed to control a group (1) if the share that he holds in the petroleum right that is held by the group is one half or more; (2) if he holds one half or more of the means of control of the group; (3) if he has the ability to make decisions for the group which pertain to actions regarding the petroleum right and the activity for performance thereof, or to prevent the making of such decisions at the group.

"Control of a corporation" – the ability, whether alone or together with others acting in cooperation on a regular basis, to direct the corporation's business, with the exception of ability which derives merely from filling a position of a director or another officer at the corporation; without derogating from the generality of the aforesaid, a person is presumed to control a corporation (1) if he holds one half or more of a certain type of the means of control of the corporation; (2) if he has the ability to make decisions for the corporation which pertain to the operation of the petroleum right, or to prevent the making of such decisions at the corporation, by virtue of the corporation's articles or by virtue of an agreement. At a corporation that is a limited partnership – each one of the said rights in the corporation that is the general partner.

1. The Petroleum Commissioner may approve the transfer of a license and of a benefit in a license before he confirms the existence of a discovery (per its meaning in the Petroleum Law), if the following conditions are fulfilled:

a. The application was filed after at least a year passed from the day of the provision of the license and at the time of filing the application, the transferor was the holder of the transferred right for at least one year.

b. The exploration and development experience of the license holder after the transfer fulfills the requirements in the Petroleum Law and the instructions of the Petroleum Commissioner.

c. If the transferor is an operator, and following the transfer it will cease holding such capacity, the transferee will fulfill all the conditions required from the operator, in accordance with the Petroleum Law and the instructions of the Petroleum Commissioner.

d. The financial capacity of the license holder after the transfer fulfills the requirements according to the Petroleum Law and the instructions of the Petroleum Commissioner.

e. If the transferor provides a monetary commitment to prove financial capacity, also for the other partners which directly hold rights in the petroleum asset, the said partners will prove financial capacity as stated in Subsection d. above.

f. The time remaining until the expiration of the license on the date of the filing of the application exceeds three months, and in any event the validity of the license prior to the filing of the application will not exceed six and a half years.

g. If the license and the preliminary permit which preceded it, were provided without a payment to the State, and the consideration exceeds double the transferor's expenses in the purchase of the transferred rights and in the financing of the relative share, according to the percentage of the transferred rights, of the expenses in performing the acts listed in the Directives, linked to the representative rate of the dollar, the difference between the expenses and the financing, as stated, will be used for the continued performance of the acts according to the license.

2. The Petroleum Commissioner may approve a transfer of a lease or a benefit in a lease after the production of petroleum commenced in the lease area, provided that the conditions specified in Subsections 1.c-1.d above are fulfilled.

3. The Petroleum Commissioner may approve a transfer of a preliminary permit for which a preemptive right was given to an

entity which is controlled by the entity which controls the holder of the preliminary permit, provided that all of the conditions detailed in Subsections 1.c-1.e and 1.g above are fulfilled.

4. The Petroleum Commissioner may approve a transfer of petroleum rights, as stated in Subsections 1 and 2 above, even if not all the above specified conditions are fulfilled, in the case of a transfer of rights in a negligible scope (no more than 5% in a right) or if there are special grounds and additional circumstances as detailed in the Directives.

5. The Petroleum Commissioner will not approve a transfer of contractual royalties (per the meaning thereof in these Directives) whose value exceeds 5% of the value of the petroleum which will be produced and utilized in the framework of the right. In exceptional cases, the Petroleum Commissioner may approve the transfer of royalties of a value which exceeds 5% of the value of the petroleum which will be produced and utilized in the framework of the right, provided that it does not exceed 10% of the value of such petroleum. It should be noted that the Petroleum Commissioner will not allow the transfer of contractual royalties which is made as part of a transfer of a license or benefit, prior to the Petroleum Commissioner confirming the existence of a discovery (per its meaning in the Petroleum Law).

6. The Petroleum Commissioner <u>will not approve</u> a transfer of a petroleum right or of a benefit in a petroleum right, if in his opinion one of the following is fulfilled:

   a. The transfer may delay or harm the performance of the duties of the holder of the petroleum rights for exploration or production of petroleum according to the license or lease or according to the Petroleum Law, as the case may be.

   b. The transfer may significantly harm the competition in the field of exploration and production.

   c. The transfer may significantly harm the payment of the royalties which are due to the State Treasury according to the Petroleum Law and the law.

   d. The transferee or the control holder thereof breached the provisions of the Petroleum Law, or instructions and requirements made by the Petroleum Commissioner thereunder, in relation to another petroleum right which it has or had or a benefit related thereto, or the conditions of such petroleum asset, or acted with respect to such a petroleum right inefficiently or irresponsibly, and as a result it is not fit to be a holder of a petroleum right or a holder of part of a petroleum right or a holder of a benefit in a petroleum right, as the case may be.

e. The transferor or transferee have not yet paid an amount they are required to pay to the State Treasury with regards to a petroleum right which they have or had.

7. In addition, the Petroleum Commissioner may not approve a transfer, even if all the condition for providing the approval which are detailed in these Directives are fulfilled, if he is convinced that reasons of public security, national security, foreign relations or international trade relations so justify, and in this context, in the case the transferee is a corporation controlled by a foreign country or there are other special circumstance with respect to which the transfer is not in the best interests of the public or the energy sector in Israel.

8. The Petroleum Commissioner may approve a pledge of a petroleum right or benefit in a petroleum right prior to the commencement of commercial production, if the pledge is designated to serve as collateral for receiving a loan to finance activities which the petroleum right holder must perform, or to ensure the receipt of contractual royalties or on special grounds which the Petroleum Commissioner deemed fit to approve. Additionally, similar conditions were determined to approve a pledge of petroleum rights after commercial production commence.

9. Permission for a pledge does not constitute permission to transfer the pledged right, and if the conditions for realizing the pledge are fulfilled, the license or lease or any part thereof or benefit in the license or lease, as the case may be, will not be transferred to the pledge holder or any other body, unless the Petroleum Commissioner allows the transfer to the transferee in advance and in writing, pursuant to the Directives; the appointment of a receiver for the pledged rights will not be subject to the rules applicable to the transfer thereof, provided that the Petroleum Commissioner agreed in advance and in writing to the identity of the receiver and the powers provided to him.

On January 31, 2016, Noble filed an appeal with the Minister of Energy, following the publication of such Directives. It was asserted that the said Directives create an ambiguity regarding the conditions for the transfer of petroleum rights, and the scope thereof exceeds the realm recognized in Israeli law for administrative directives, and they should not be left in place. It was further argued that they are inconsistent with the customary practice on this issue worldwide. On June 4, 2017, Noble submitted a letter to the Minister of Energy complaining about the fact that no decision had yet been received in the appeal that was filed relating to the damage caused to Noble due to the lack of clarity in the directives, and again requesting, in accordance with the appeal, the cancelation of the directives or, at the very least, the amendment thereof. No decision has yet been received in the appeal.

(c) Export permit applications

On December 31, 2015, the Petroleum Commissioner published directives concerning the submission of applications for the receipt of a permit to export natural gas, which determine, *inter alia*, the date and the manner for submission of the application for receipt of a permit to export natural gas from the lease area, the details to be included in such application and the documents to be attached thereto, and in addition, clarifications pertaining to such export permit. It is emphasized that an export permit will be granted in accordance with the conditions specified in the Gas Framework, as specified in Section 7.25.1(c)2 above, and subject to any law.

It is noted that as of the report release date, export permits have been received for the export agreements that were signed by the Partnership, which are specified in Sections 7.13.5(a)1 and 7.13.5(b)1 above. The Partnership is acting, together with the other Leviathan and Tamar Partners, to obtain permits for the export of natural gas from the Leviathan and Tamar project to Dolphinus. For details see Sections 7.13.5(a)2 and 7.11.5(b)2 above.

7.25.5. Additional regulatory restrictions

(a) Government resolutions regarding adoption of recommendations of the committees for examination of the government policy on the natural gas sector

In October 2011, a committee was formed to examine the government's policy with regard to the natural gas sector in Israel and its future development, headed by Mr. Shaul Tzemach, the Director General of the Ministry of Energy at such time (in this section: the "**Tzemach Committee**"). On September 12, 2012 the Tzemach Committee published a final report. On June 23, 2013 the Israeli Government adopted the principal recommendations of the Tzemach Committee, with certain changes (in this Section: the "**Government Resolution Regarding the Tzemach Committee**"). On December 17, 2015, the Gas Framework, which is described in Section 7.25.1 above, took effect, in which several clarifications and amendments were made to the Government Resolution as aforesaid. On January 21, 2018, the Ministry of Energy announced the formation of an interministerial professional team headed by the Director General of the Ministry of Energy, Udi Adiri (the "**Adiri Committee**") for a periodic examination of the recommendations of the Tzemach Committee. The Adiri Committee examined the developments that had taken place in the natural gas sector during the five years that had passed since the adoption of the recommendations of the Tzemach Committee and reexamined the matter of natural gas supply and demand in 2018. On December 18, 2018, the Adiri Committee published its final conclusions, and on January 6, 2019 the Israeli Government adopted the principal recommendations of the Adiri Committee (the "**Government Resolution Regarding the Adiri Committee**"). The key points of the Government Resolution Regarding the Adiri Committee that may affect the Partnership's operations are as follows:

1. The quantity of natural gas that should be secured in favor of the domestic market shall remain as approved by the Government Resolution Regarding the Tzemach Committee (540 BCM), after an update due to the consumption of approx. 40 BCM to date, and will amount to 500 BCM (the "**Minimum Quantity for the Domestic Market**"), which shall allow for the supply of natural gas for the market's needs over the next 25 years. In this section, the "Natural gas Quantity" – the quantity of natural gas in the 2P and 2C categories in the aggregate, according to PRMS, in the discoveries recognized by the Petroleum Commissioner, with respect to which leases have been granted and for which the connection of the leases to the shore has been completed according to a development plan in a manner allowing for the supply thereof to the Israeli market.

2. The duty to supply the Minimum Quantity for the Domestic Market in respect of discoveries recognized prior to the approval of the Government Resolution Regarding the Adiri Committee shall remain as determined in the Government Resolution Regarding the Tzemach Committee, as specified below:

| **Amount of Natural Gas in Reservoir** | **Rate of Minimum Supply to Domestic Market out of Natural Gas Amount in Reservoir** |
|---|---|
| Exceeding 200 BCM (inclusive) | 50% |
| Exceeding or equaling 100 BCM, but lower than 200 BCM | 40% |
| Exceeding or equaling 25 BCM, but lower than 100 BCM | 25% |
| Lower than 25 BCM | To be determined by the |

| Amount of Natural Gas in Reservoir | Rate of Minimum Supply to Domestic Market out of Natural Gas Amount in Reservoir |
|---|---|
| | Petroleum Commissioner |

The duty to supply the Minimum Quantity for the Domestic Market in respect of discoveries recognized after approval of the Government Resolution Regarding the Adiri Committee will be as specified below:

| Amount of Natural Gas in Reservoir | Rate of Minimum Supply to Domestic Market out of Natural Gas Amount in Reservoir |
|---|---|
| For every additional 1 BCM exceeding 200 BCM | 55% |
| For every additional 1 BCM from 50 BCM to 200 BCM | 50% |
| Lower than 50 BCM | No duty to supply to the domestic market shall apply |

It is noted that in respect of reservoirs shared by Israel and other countries, the Petroleum Commissioner shall determine specific arrangements and conditions[270]. 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.

3. The export of natural gas will require approval from the Petroleum Commissioner[271], and the amount of gas permitted for export will be in accordance with the relative part of quantities authorized for export in the reservoirs at that time, subject to ensuring the minimum amount for the domestic market, as aforesaid.

4. Notwithstanding the aforesaid, a reservoir developed prior to the Government Resolution regarding the Tzemach Committee (i.e. Yam Tethys and Tamar Project), may export 50% of the amount for which the lease holders have not yet committed to the domestic market as of the date of the Government Resolution regarding the Tzemach Committee and no more, with immediate effect, provided that export approval is given. It is clarified that if a consumer

[270] It is noted that the permitted export quota from the Karish and Tanin reservoirs in the amount of 47 BCM was exchanged, against the obligation to supply to the domestic market that is imposed on the holders of the Leviathan leases, as of the date of approval by the Petroleum Commissioner of the transfer of rights in Karish and Tanin. For details, see Section 7.25.1(b)1.b hereof.

[271] For details about the Petroleum Commissioner Directives with respect to submission of applications for receipt of a natural gas export permit, see Section 7.25.4(c) below.

exercises the option to reduce quantities granted thereto by an agreement signed with the lease holders prior to the said date, the quantity of natural gas for which the option to reduce quantities was exercised, will be deemed as part of the quantity of natural gas for which the lease holders have not yet committed to the domestic market.

5. A lease holder in a developed reservoir may substitute his export quota in exchange for mandatory supply to the domestic market in accordance with the size thereof and the rates determined, and subject to the approval of the Petroleum Commissioner and the Competition Commissioner, after weighing all the relevant considerations.

6. It has been decided to impose an obligation to connect reservoirs to the domestic market according to the size of the reservoir, as follows: (a) Reservoirs exceeding 200 BCM shall be obligated to connect to the domestic market upon their development and prior to the date of commercial piping of the natural gas; (b) Reservoirs ranging between 50 BCM and 200 BCM that commence commercial production of natural gas by January 1, 2028 shall be obligated to connect to the domestic market by December 31, 2032, according to the discretion of the Petroleum Commissioner; such reservoirs that commence commercial production after January 1, 2028 shall be obligated to connect to the domestic market upon their development and prior to the date of commercial piping of the natural gas; (c) Reservoirs up to 50 BCM shall not be obligated to connect to the domestic market. In the case of fields that produce by means of a single production system, with at least two of the leases, in whose area such fields are situated, having an identical entity approved as the operator or holder of more than 50% of the interests, the calculation of the gas quantity in such fields for purposes of the duty to connect to the domestic market shall be made in the aggregate. Notwithstanding the aforesaid, the Commissioner may, in a reasoned decision, not calculate the natural gas quantity in the fields in the aggregate.

7. In order to encourage the connection of additional natural gas fields to the domestic market, to task the Commissioner, the Director of the Natural Gas Authority and the Budget Director at the Ministry of Finance, with examining the State's participation in the construction of an additional offshore complex in the southern polygon approved under NOP 37/H, which includes an offshore terminal and connection thereof to the shore, insofar as, in the Commissioner's opinion, exploration activity in Israel's southern offshore area shall have developed. In addition to the aforesaid, to task the Commissioner with examining additional measures to

encourage the full realization of the potential economic benefit deriving from the natural gas fields, and, *inter alia*, to encourage the connection to the domestic market of fields which are not subject to the connection obligation or whose connection obligation has been postponed according to the aforesaid.

8. In view of a projected shortage in supplying demand on an hourly basis mid-decade between 2030 and 2040, it is proposed to formulate a mix of solutions, including the imposition of a duty on the Petroleum Commissioner to address, in the export permits, the issue of demand in the domestic market on an hourly basis, to act to encourage the connection of additional fields to the domestic market (particularly toward the middle of the (2030-2040) decade), and to examine the termination of the agreement with the LNG carrier only in 2021 (at present, the agreement is effective until 2022).

9. To task the Minister of Energy, in consultation with the Minister of Finance and the Minister of Economy and Industry, with formulating the principles of the regulation required in relation to the sale of natural gas to consumers in the domestic market, which gas is designated for the production of follow-on products that are primarily designated for export[272].

10. To task the Minister of Energy, in consultation with the Minister of Finance, with initiating regulation amendments, including legislative amendments, to the extent necessary, for the purpose of regulating secondary trade in natural gas, which may be directed toward export. In this context, to task the Minister of Energy, in consultation with the Minister of Finance, with ensuring, through such regulation amendments, that secondary trade in natural gas which may be directed toward export will be allowed in a quantity limited to 3% of the total sales of natural gas to the Israeli market in the past year. Such quantity will not be counted for the purpose of calculation of the total quantity secured for the domestic market, but will be counted for the purpose of the minimum supply duty of a natural gas field to the domestic market; it is clarified that the export of such limited quantity shall not require an export permit.

11. The Government Resolution Regarding the Adiri Committee shall be examined by the Government five years after the date of approval thereof for the purpose of revisions, insofar as necessary, with respect to the policy on discoveries to be recognized by the Commissioner five years after the date of approval of the

[272] However, quantities of natural gas used by the plant to be constructed following the tender for construction of an ammonia production plant in Mishor Rotem, will not be deemed as export.

Government Resolution Regarding the Adiri Committee, according to the needs of the domestic market and considering the natural gas supply.

It is noted that the Ministry of Energy has independently examined and is examining the estimate of the reserves and the contingent resources in the Tamar reservoir and in the Leviathan reservoir, via outside consultants, *inter alia*, for the purpose of calculating the export quotas from such reservoirs according to the Government resolution, as specified in Section 7.25.1(c)2 above. It is noted that the operator in the projects forwarded to the Ministry of Energy all of the final data required for estimating resources, including data from wells, production data and data from laboratory tests. It is noted that the estimates of the natural gas resources in the Tamar reservoir and in the Leviathan reservoir presented in the report are according to resource reports which the Partnership received from an independent consultant and which were prepared in accordance with the SPE-PRMS rules.

(b) Natural Gas Price Control

On May 25, 2011, the Ministry of Energy requested the Joint Prices Committee at the Ministry of Finance and the Ministry of Energy (the "**Prices Committee**") to examine the need for the imposition of control on the prices of natural gas sold in Israel.

Further to the recommendation by the Prices Committee, Control of Prices of Commodities and Services Order (Application of the Law to Natural Gas and Determination of the Control Level), 5773-2013, was published on April 24, 2013. Such order imposes control on the gas sector in terms of reporting on profitability and prices. Such reporting duty is separately imposed in respect of every project. The need to control natural gas prices in Israel in terms of price fixing will be examined based on information to be received. According to the Gas Framework, as long as the Partnership and Noble comply with all of the terms of the Gas Framework, such reporting duty will remain as is. Such reporting duty applies to the Partnership together with its partners in the Yam Tethys project and in the Tamar Project, and also applies to each project separately.

For details regarding the effect of the imposition of price control on natural gas prices in Israel in terms of price fixing, see Section 7.31.15 below.

(c) Regulation of the use of the capacity of the gas pipeline from the production platform of the Tamar Project to the natural gas exit at the Terminal in Ashdod (the "**Regulation of Pipeline Capacity Allocation**")

On December 9, 2012 the Natural Gas Authority in the Ministry of Energy (in this section: the "**Authority**") published a decision regarding the Regulation of Pipeline Capacity Allocation, including with regard to the maintenance of gas capacity for consumers and marketers in the distribution network and in connection to the regulation of the matter of the Tamar Project shortage of supply capacity. It should be noted, that it is the Authority's position, that Tamar Partners should not refuse to sign contracts for the sale or marketing of natural gas with consumers that wish to engage with them, just because of the fact that the significance of the engagement is that the total quantity of hourly natural gas to pass through the pipeline deviates from the maximum capacity estimated as of that date at 40,000 MMBTU an hour. In the Partnership's estimation, as of the report release date, the primary parties injured by such decision may be the consumers of natural gas from the Tamar reservoir, who have binding agreements that include capacity assurance, as distinguished from consumers of natural gas based on capability (interruptible).

(d) <u>Decision of the Natural Gas Authority Council regarding the financing of export projects via the national transmission system</u>

On September 7, 2014, the Council on Natural Gas Sector Matters released its decision regarding the financing of export projects via the national transmission system. The decision determines the transmission rates that will apply to the transportation of Israeli natural gas via the national transmission system to neighboring countries or to the Palestinian Authority, as well as the financing of the construction of those segments of the transmission system designated for export of natural gas as aforesaid. The decision sets forth the following principles:

1. The exporter (the entity selling or marketing the natural gas for export) shall enter into a transmission agreement with the transmission license holder, which agreement shall be approved in advance and in writing by the Director General of the Natural Gas Authority. The exporter shall pay the transmission license holder the transmission tariff that will be the regular transmission tariff applicable to Israeli consumers, as in effect from time to time.

2. The exporter shall bear the full costs of constructing the segment of the transmission system designated for export only (the "**Segment Designated for Export**") as well as the construction costs of an additional transmission line in immediate proximity to an existing segment ("**Duplicated Segment**"), in addition to management fees at a rate of 2%.

3. For as long as the transmission agreement between the exporter and the transmission license holder is in effect, and an additional consumer shall join the Segment Designated for Export in the future, the Director General of the Natural Gas Authority will determine the cost attributed to the additional consumer out of the total cost of construction of the Segment Designated for Export, according to the ratio of the capacity of the additional consumer out of the total capacity that may be transported in the Segment Designated for Export. The exporter shall be credited by the amount of such cost that shall be attributed to the additional consumer.

4. If a certain segment of the Transmission System leading to a Segment Designated for Export shall also serve Israeli consumers in the future, but the segment leading to the Segment Designated for Export would not have been duplicated at the time of its construction had it not been for the export of the natural gas via the Transmission System, the exporter shall pay (in addition to the cost of construction of the Segment Designated for Export as aforesaid) the pro rata portion in respect of the duplication of the Segment Designated for Export. The Council shall determine the allocation of the cost between the exporter and the transmission license holder.

5. In the event that the Director General of the Natural Gas Authority is in the opinion that there is sufficient capacity in the Transmission System at the time of signing the agreement between the transmission license holder and the exporter, but that it is likely that in the ten years after the commencement date of the initial natural gas flow, there will be a shortage in the capacity of the Transmission System to the Israeli consumers in a segment leading to a Segment Designated for Export, then at the date of signature of the transmission agreement, the exporter shall choose between one of the following alternatives: (1) to pay the transmission license holder 50% of the budget of the future duplication of the relevant segment of the Transmission System, and such amount shall not be repaid to the exporter even if such segment shall eventually not be duplicated; (2) not to pay said amount and in the event of duplication of the segment as aforesaid, the provisions of Subsection (4) above shall apply.

6. The Director General of the Natural Gas Authority shall determine, in each case, the point in the Transmission System from which the beginning of the segment leading to a Segment Designated for Export be calculated, and such point will be explicitly indicated in the transmission agreement.

7. Despite the fact that the construction cost is imposed (in whole or in part) on the exporter, the exporter shall not own the segment and shall not have any type of link in such segment.

8. This decision shall not apply to export transmission agreements signed with the transmission license holder before November 2, 2014 (including the transmission agreement signed in connection with an agreement dated February 19, 2014, for the export of gas from the Tamar Project to consumers in Jordan (as specified in Section 7.13.5(a)1 above).

9. Note that within the Dolphinus Agreements specified in Sections 7.13.5(a)2 and 7.13.5(b)2 it was agreed that the Tamar partners and the Leviathan partners, as the case may be, would bear the costs of the gas piping in the INGL transmission system. In the context of the other export agreements and the non-binding letters of intent which were signed by the Partnership thus far, it was agreed that the costs of the national transmission system shall be borne by the customers of gas for export, according to mechanisms prescribed in the export agreements and said non-binding letters of intent.

(e) The Marine Zones Bill

On November 6, 2017, a government bill, the Marine Zones Bill, 5778-2017 was put before the Knesset (the "**Marine Zones Bill**"). The proposed law seeks to set forth the legal framework applying to the offshore areas (including the areas that are beyond the borders of the State), the rights that the State of Israel has in such areas and the limits of authority that it is entitled to enforce with regard to activities undertaken therein.

On November 13, 2017, the Knesset approved the Marine Zones Bill in a first reading, and since then several discussions have been held by the committee of economics toward its preparation for second and third readings. The bill, insofar as the next Knesset decides to apply continuity and it is approved by the plenum in second and third readings, may have an effect on the Partnership's operations and the costs thereof, whose scope cannot be estimated as of the report release date. In this context, it should be noted, that in January 2013 an opinion was provided by the Deputy Attorney General (Economics-Fiscal), which provided that in accordance with Israeli law and bearing in mind the instructions of international law, the laws relating to regulation of the natural gas and petroleum sector in Israel can be applied in the offshore areas beyond the State borders, as well as the laws with regarding to environmental protection of the State of Israel and the fiscal laws of Israel. This opinion did not negate the applicability of additional laws.

(f) <u>The Decision of the Minister of Energy to Reduce the Use of Coal and the Reform at the IEC and in the Electricity Sector</u>

On December 29, 2015, the Minister of Energy instructed the IEC that in 2016 the use of coal in production of electricity will be reduced by a rate of 15% relative to 2015. As of 2017, a further reduction of 5% took place, and a reduction of 20% in total relative to the use made in 2015.

On August 24, 2016, the Minister of Energy notified of his decision to shut down four coal-operated production units of the IEC, upon connection of three gas reservoirs to the shore, and the construction of alternative natural gas-operated power plants. Further thereto, on September 30, 2016, the IEC received emission permits under the Clean Air Law, 5768-2008, in respect of its coal-fired power plant sites, which permits prescribe, *inter alia*, the duty to continue installing means of emission reduction and the discontinuance of the operation of Units 1-4 in the coal-fired power plant at the "Orot Rabin" site, no later than June 1, 2022.[273]

On June 3, 2018, government resolution no. 3859 was published regarding a reform in the electricity sector and at the IEC (the "**Reform**"). The Reform includes, *inter alia*, the following steps: 1. The IEC will reduce its activity in the electricity production sector by selling five production sites with a total maximum capacity of approx. 4,000 MW, which constitute approx. one half of its electricity production capacity, as specified below: a. Alon Tavor – within 18 months from the date of approval of the Reform; b. Ramat Hovav – within two and a half years from the date of approval of the Reform; c. Reading – within three years from the date of approval of the Reform; d. Eastern Hagit – within four years from the date of approval of the Reform; e. Eshkol – within five years from the date of approval of the Reform. 2. The IEC will build two modern production units using natural gas at Orot Rabin, as part of the trend to reduce the use of coal in the electricity production process, and in lieu of coal units 1 to 4 which are expected to close down. The new production units will be operated by a new wholly-owned subsidiary of the IEC. The IEC will continue to hold and operate the transmission and distribution networks. However, the responsibility and the management of the national electricity system will be transferred to a separate government-owned company. Further to this approval, on July 29, 2018, the government approved cessation of the operation of the coal-fired units 1 to 4 at Orot Rabin no later than June 2022, subject to fulfillment of conditions precedent (connection of three natural gas reservoirs to the shore and completion of the construction of an

[273] According to an immediate report by the Israel Electric Corporation Ltd. on October 5, 2016.

alternative natural gas-powered electricity production system). During July 2018, the Knesset approved the amendments to the Electricity Sector Law, 5756-1996, for the purpose of implementation of the government resolution regarding the Reform as aforesaid. For details on the relevant provisions in the gas supply agreement between the Tamar Partners and the IEC with regard to the above-described reform outline, see 7.13.4(a)4 above.

On November 12, 2017 the Minister of Energy decided, in accordance with his authority pursuant to Sections 21A and 57A of the Electricity Sector Law, 5756-1996, on policy principles on the issue of minimum operation of coal production units pursuant to which, at all times, preference shall be given to production of electricity using natural gas over production of electricity using coal, while operating the coal units with a minimal load that enables flexibility and reliability of supply to the market. The aforesaid policy, which serves the system's administrator also today, shall continue to be implemented also after the discontinuation of operation of the coal units as aforesaid, in a manner that shall reduce the total production of electricity using coal, and subject to redundancy in natural gas infrastructures through connection of three natural gas reservoirs, each of which is connected to the national transmission system through a separate infrastructure.

On January 3, 2018, the Minister of Energy announced that he decided to instruct the IEC to reduce the use of coal in the production of electricity by a rate of 30% compared to 2015. According to the announcement of the Ministry of Energy and the Ministry of Environmental Protection, this decision shall lead to a significant reduction of air pollution from the coal power plants and is expected to increase the demands for natural gas in the market. The Ministry of Energy's 2019 work plan[274], published in February 2019, determines that in the course of the year the Ministry of Energy will act to promote the conversion of one production unit in the Rutenberg power station in Ashkelon, from coal based production to natural gas based production – pursuant to the Ministry of Energy's policy in respect of the discontinuation of coal use (see Section 7.25.5(g) below, the "Plan to Save Israel from Polluting Energy"). The 2019 work plan further determines that one of the Ministry's goals is to cause that by the end of 2019, the rate of use of polluting fuels upon production of electricity in times of routine will be 29% (similarly to 2018). In addition, the aforesaid work plan states that the Ministry of Energy intends to take steps, as a result of which, by 2030, the rate of polluting fuels for electricity production will be 0%, with polluting fuels being used only for backup.

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[274] https://www.gov.il/BlobFolder/reports/work_plans_2019/he/work_plans_2019.pdf

(g) The plan to save Israel from polluting energy

On October 9, 2018, the Energy Minister released the "Plan to save Israel from polluting energy", which mainly concerns reduction of the use of polluting fuel products by 2030. The plan set goals for 2030, specifying concrete steps and determining timetables in three main sectors, as follows:

a. In the electricity sector, the gradual reduction of electricity production using coal. From 2028, use of coal in the production of electricity at all of the coal-fired power plants will be completely stopped, and electricity production will be based on natural gas and renewable energies only, with permanent shutdown of the coal-fired plants in Hadera and Ashkelon.

b. In the transportation sector, cessation of the consumption of polluting fuel products in land transportation, and transition to use of electric vehicles and compressed natural gas-powered vehicles. Accordingly, from 2030, the entry into Israel of vehicles powered by gasoline or diesel oil will be prohibited, and 100% of the new vehicles in Israel will be powered with the assistance of electricity and compressed natural gas.

c. In the industry sector, cessation of the use of fuel oil, LPG and diesel oil and replacement thereof with more efficient and cleaner energy sources from 2030.

The plan was released for the public's comments, and will later be presented for the government's approval.

In the Partnership's estimation, approval and implementation of the plan may lead to an increase in the demand for natural gas in the Israeli economy.

(h) The Excise on Fuel (Exemption and Refund) (Tax Amendment and Temporary Provision) Order, 5778-2018 (Green Taxation); the Excise on Fuel (Imposition of Excise) (Amendment no. 2 and Temporary Provision no. 3) Order, 5778-2018 (Amendment), 5779-2019; the Customs Tariff and Exemptions and Sales Tax on Goods (Amendment no. 8) Order, 5778-2018 (Coal) (collectively: the "**Orders**")

On March 14, 2018, and in accordance with the amendment of February 21, 2019, the Finance Committee of the Knesset, and subsequently the Plenum of the Knesset, approved the Orders, in which it was determined, *inter alia*, that from January 1, 2021, the excise tax on coal will increase by approx. 125%, in view of the government's policy to gross-up external costs of fuels and to encourage expansion of uses of natural gas.

In addition, it was decided that, from January 1, 2024, the excise tax on compressed natural gas (CNG) will increase gradually, subject to the existence of no less than 25 compressed natural gas fueling stations that shall receive all of the approvals required for activity. It was further determined that from January 1, 2021, refund of the excise on diesel oil, which is mainly used for transportation purposes, will gradually be cancelled.

In the Partnership's estimation, these Orders may lead to material reduction of the use of coal for the production of electricity and to reduction of the use of diesel oil for transportation purposes, and accordingly to increased demand for natural gas in the economy, over and above the natural growth in demand for natural gas and for electricity in the Israeli economy.

(i) The Paris agreement and the PPCA agreement

In December 2018, Israel joined the initiative of the PPCA – a global coalition for the reduction of coal use – and will stand in line with modern countries such as Canada, Britain, France, Denmark and the Netherlands. The parties to the initiative have pledged to gradually reduce coal-based electricity production and to support clean energy in government and corporate policies. The coalition supports the reduction of coal use in OECD countries by 2030 and in the entire world by 2050. The most significant steps, based on which Israel's joining this initiative was approved, are *inter alia* the decision in the Government Resolution that Units 1-4 of the Orot Rabin Power Plant in Hadera, which represents one third of the coal-based production capacity in Israel, will be closed by June 2022 (as specified in Section 7.25.5(f) above); as well as the declaration that coal use will be completely stopped by 2030 (as specified in Section 7.25.5(g) above). As stated in the Ministry of Energy's announcement, Israel's joining the initiative is an opportunity to continue promoting the Government's policy of reducing coal use in the blend of electricity production fuels also in the international arena, since the reduction of coal use in Israel reduces air pollution and assists in achieving the greenhouse gas reduction target to which Israel committed in the Paris agreement of 2015. It is noted that Israel signed the Paris agreement in 2016, and the goals thereof are, *inter alia*, the enhancement of implementation of the U.N. Framework Convention on Climate Change as well as the reduction of greenhouse gas emissions (the "**Paris Agreement**"). In view of the aforesaid, the Israeli Government is promoting an environmental policy that concerns increased reliance on natural gas and use thereof in electricity production, industry and transportation. It is further noted that the central obligation of every country that signed the Paris Agreement is to submit a plan every five years which specifies the methods it will apply in order to deal with climate changes.

(j) Environmental directives for offshore petroleum and natural gas exploration and development

In September 2016, the Ministry of Energy, jointly with the Ministry of Environmental Protection and other government ministries, published directives designated to regulate the environmental aspects of the operations of offshore petroleum and natural gas exploration, development and production. Such directives are intended to instruct the holders of offshore petroleum rights 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 petroleum and natural gas exploration, development and production. Such directives constitute an integral part of the petroleum right and the work plan therefor, and deviation therefrom might lead to the revocation of the right. Therefore, the Ministry of Energy specifies, *inter alia*, the following directives:

1. Environmental directives for the performance of a seismic survey (geological and geophysical research): in view of the level and the consequences of the noise created as a result of the performance of a seismic survey, it is required to report to the Commissioner on the noise level, the routes and dates planned for the seismic survey, and to receive approval from the Commissioner for the performance thereof. In cases in which the activity is carried out in reservations or in proximity to infrastructure facilities, the activity is required to be coordinated vis-à-vis the competent entities or authorities. In addition, it is required that a plan for the performance of the survey be prepared, and the Commissioner's approval be obtained as a condition for the performance thereof.

2. Environmental directives for licenses: At the stage of grant of the license, the right is granted for petroleum exploration by means of exploration wells and appraisal wells, in the area of the license. Insofar as findings are discovered, further tests are carried out, with the purpose of examining the quantity and the quality of the findings. As a condition for the receipt of a drilling permit, the license holder will submit an application for the Commissioner's approval, which includes the following documents: (1) An environmental document that includes an environmental impact assessment plan for the marine environment; (2) An enterprise emergency plan for the treatment of sea pollution by oil, approved by the National Marine Environment Protection Division; in

addition, the license holder is also required to obtain the following permits: a permit for discharge into the sea and a poison permit.

3. Environmental directives for post-discovery licenses and for leases: As a condition for the receipt of approval for the development plan and the operation permit, the lease holder will submit the following documents to the Commissioner: (1) An environmental document that includes environmental impact assessment for the marine environment, which refers to the planned development plan and production; (2) An enterprise emergency plan for the treatment of incidents of sea pollution by oil. In addition, the lease holder is also required to obtain the following permits: a permit for discharge into the sea, a poison permit and an emission permit.

(k) National Outline Plan 37/H for the Reception and Processing of Natural Gas

In order to create the zoning infrastructure for the connection of the natural gas reservoirs to the national transmission system and construct the facilities required for such purpose, the National Planning & Building Council (in this section: the "**National Council**") and the Israeli Government approved the "detailed partial national outline plan on the reception and processing of natural gas from discoveries to the national transmission system" (in this section: the "**Plan**" or "**NOP 37/H**").

The Plan designates areas (onshore and offshore) for the construction of the facilities required in the process of production and transmission of natural gas, which include, *inter alia*, natural gas reception and processing terminals, pipelines for transmission of the gas etc. The development plan of the Leviathan reservoir in the format specified in Section 7.4.2(j) above, is in keeping with NOP 37/H.

Several petitions were filed with the High Court of Justice against the Plan. On December 22, 2015, a judgment was issued on the petitions, which determined that the Plan had overcome most of the legal hurdles placed in its path by the petitioners, and on the whole, passed the test of judicial review. However, the court accepted two specific arguments that had been raised in the aforesaid petitions, and ruled that the National Council would be granted 18 months to remedy the two specific flaws found in the Plan.

On February 2, 2016 the National Council decided to perform adjustments and additions to the Plan in accordance with the rulings of the HCJ, as aforesaid, and subject to the approval of the Government of Israel. On March 27, 2016, the Ministerial Zoning, Land and

Housing Committee (the Housing Cabinet) approved the amendments made in the Plan by the National Council according to the ruling of the High Court of Justice thereon, and on April 14, 2016, the approval was sanctioned as a government resolution. Furthermore, on April 5, 2016, the National Council approved the processing breakdown (by offshore-onshore) (the "**Development Breakdown**") noted in the development plan of the Leviathan reservoir, and the location of the principal processing facilities, according to a provision provided for this purpose in NOP 37/H. On October 31, 2016, a petition was filed with the High Court of Justice with respect to the construction of a land-based emergency condensate storage tank on the Hagit site, *inter alia*, due to the claim that the location of such tank had not been duly approved by the National Council within the approval granted thereby to the Development Breakdown. Following the filing of the petition, on December 6, 2016, the National Council approved, for the avoidance of doubt, an amendment to the Development Breakdown, such that the condensate storage tank on the Hagit site, at the location determined in NOP 37/H, would be included in the breakdown approved by the National Council. Consequently, the petition was dismissed without prejudice.

On April 3, 2017, a new petition was filed against the said National Council decision dated December 6, 2016. In the hearing that was held it was argued, *inter alia*, that the approval of an onshore tank for storing condensate contradicts the preference that was granted in NOP 37/H to the construction of offshore processing facilities, and is inconsistent with the development plan for the Karish and Tanin reservoirs, pursuant to which the condensate will be stored in an FPSO adjacent to the wellhead. Further to the Court's recommendation, the National Council held an additional discussion on December 6, 2017 regarding the Hagit facility and even approved that it be included in the breakdown of the development plan of the Leviathan reservoir. After hearing additional arguments, the High Court of Justice dismissed the petition with prejudice on December 24, 2017.

On December 25, 2017, an additional petition was filed with the High Court of Justice against the development plan of the Leviathan reservoir, based on the argument that the processing facilities of this reservoir should also be constructed at a distance from the shore, in the area of the reservoir itself. The High Court of Justice referred the petitioners to the judgment it delivered the previous day, which denied the petition against the Hagit facility. On January 30, 2018, the petitioner requested to withdraw the petition and on February 20, 2018 a judgment that dismisses the petition without prejudice was issued. Furthermore, in the past year, several petitions were filed with the Haifa District Court seated as the Court of Administrative Affairs and with the High Court of Justice, the shared goal of which is to challenge various aspects pertaining to the development plan of the Leviathan Project, both in relation to the offshore segment and in relation to the onshore segment, including regulatory approvals granted to the Operator in relation to the development plan as well as additional issues. It is noted that thus far, all petitions on which a hearing was held have been denied, either by dismissal with prejudice or dismissal without prejudice, and various motions filed by the petitioners in the various petitions for the issuance of interim orders in relation to the petitions filed have also been denied. It is noted that in the estimation of the Operator’s counsel (the Partnership is not a respondent in the petitions filed thus far), the probability that the legal proceedings not yet denied will have an adverse effect on the ability to produce gas from Leviathan on schedule is lower than 50%.

(l) <u>The PUA-E's Decision – Principles for Recognition of the Gas Costs for Private Producers Operating with Natural Gas</u>

1. On September 12, 2016, the PUA-E decided on principles for recognizing an essential service provider's costs due to natural gas purchase agreements, as follows (hereinafter in this section: the "**PUA-E's Decision**"):

   a. The manner of calculating the recognized price in Shekels for one MMBTU for a producer who is a party to a gas agreement in which the price of gas is linked to the production component.

   b. The PUA-E's Decision shall apply to license holders who meet both of the following cumulative conditions: (1) license holders who signed a gas agreement at a price that is linked to the production component by no later than December 31, 2018; (2) license holders who did not yet receive a tariff approval on August 16, 2015, and who shall complete a financial closing and receive a tariff approval by no later than December 31, 2018.

   c. The PUA-E's Decision does not derogate from any governmental entity's authority with respect to the gas agreements and particularly the price control committee's authority. It was further clarified in the PUA-E's Decision that if and to the extent control shall be imposed upon gas prices, the price recognized by the PUA-E shall be in accordance with the controlled price.

   d. It was prescribed that if and to the extent an intention of the electricity producers to sign gas agreements at a price that is not linked to the production component is identified, the PUA-

E shall act to deliver a separate decision regarding the recognized gas cost for electricity producers who are party to a gas agreement with another linkage mechanism, in accordance with the Gas Framework.

In this decision, the PUA-E prescribed a mechanism which incentivizes the private electricity producers to enter into gas sale and purchase agreements, pursuant to which the gas price shall be lower than the maximum price that was prescribed in the Gas Framework, by recognizing a price that is higher than the actual gas price. This decision also incentivizes the private electricity producers to enter into agreements with new gas suppliers (meaning, gas suppliers which are not related to the Tamar Partners), insofar as the gas price in these agreements is lower than the maximum price prescribed in the Gas Framework.

2. The PUA-E's decision dated June 12, 2017, prescribed that the PUA-E shall continue to recognize the IEC's costs that derive from the IEC agreement, including costs that derive from the minimal contractual quantity (Take or Pay), subject to the following conditions:

    a. The IEC shall reasonably act to minimize the costs of the agreement and to meet the minimal consumption undertaking, while exhausting all of the tools available thereto, including devoting all efforts to reducing the gas price at any time the agreement allows, and including secondary sale of the gas. The said decision prescribes that the gas price in a secondary sale to other electricity producers shall not exceed the cost of the purchase of the gas from the gas supplier.

    b. The IEC shall not sell natural gas to anyone who is not an electricity producer, if the system manager determined that the use of diesel oil or liquid gas is needed on the following day in the general load plan of the electricity sector, except for a situation in which the diesel oil is being used in the load plan for examination purposes only. The validity of this section shall expire on the date of commercial operation of an additional gas supplier in the market.

    c. The IEC shall not order gas in a quantity that exceeds the total quantities needed to produce electricity in accordance with a specific load plan, less that stated in Section 1 above, and the IEC shall use diesel oil and liquid gas (LNG) in accordance with the guidelines of the system manager.

3. The PUA-E's recognition of the costs of the IEC agreement shall be subject to the auditing of the annual costs which shall be performed by the PUA-E and considering the IEC's activity to minimize the costs of the agreement and the IEC's compliance with the conditions specified above.

(m) <u>Permits and licenses for the facilities of the Yam Tethys project, the Tamar Project and the Leviathan project</u>

1. In the framework of the development of the Yam Tethys project, the Yam Tethys Partners received the permits and licenses under the Petroleum Law and the Natural Gas Sector Law required for the purpose of constructing and operating the production system and transmission system from the production platform to the Terminal.

2. In addition, in the framework of the Tamar Project development plan, the Tamar Project partners received approval to construct a permanent rig for the production of natural gas and petroleum and also an approval for the operation of a production system of natural gas and condensate from the Tamar Project, according to which, the Tamar Project partners were required, *inter alia*, to provide guarantees in the amount of ILS 100 million (in 100% terms)[275].

   Furthermore, on August 29, 2016, the Minister of Energy granted Tamar 10-Inch Pipeline Ltd. (a company owned by the Tamar Partners according to their rate of interest in the lease) a temporary transmission license for the operation of a pipeline to be used for the transfer of natural gas originating in the Tamar Lease, from the Tamar rig to the inlet of the natural gas processing terminal in Ashdod, all subject to the conditions of the license. The pipeline was constructed as part of the Production System, as defined in the operation approval for Tamar, mainly in order to serve for the transfer of condensate, and its operation for the purpose of natural gas transmission is for a limited period, following which it will go back to being used for the transfer of condensate.

3. On February 21, 2017, the Minister of Energy granted Leviathan Transmission System Ltd. (a company owned by the Leviathan Partners) a license for the construction and operation of a transmission system to be used for the transfer of natural gas of the Leviathan Partners originating in the areas of the Leviathan leases, or of other natural gas suppliers, upon the fulfillment of certain conditions, all subject to the conditions of the license.

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[275] The Tamar Partners furnished a guarantee in the amount of $35 million to secure such undertaking and also to secure the terms and conditions of the Tamar Lease deed.

7.25.6. Applicability of Cypriot Legislation to the Partnership's Activity

Gas and oil exploration activity in Cyprus is subject to regulation that includes, *inter alia*, the obligation to receive permits, licenses or franchise arrangements to perform the activity, requirements in connection with the scope of investment and schedules for performance of exploration, payment of royalties to the State (under the franchise agreement detailed in Section 7.8.3 above), safety and environmental.

Exploration activity and the production of hydrocarbons in territorial waters and in the economic waters of the Cyprus Republic are regulated mainly in laws and local regulations that were promulgated under primary legislation (the "**Cyprus Legislation**"). In addition, the Republic of Cyprus is a full member of the European Community and the European Community directive with regard to the granting and use of authorizations for exploration and production of hydrocarbons (Directive 94/22/EC) and other relevant European legislation also regulates the exploratory activity and the production of hydrocarbons in the Republic of Cyprus and in the Republic of Cyprus EEZ.

In 1988 the Republic of Cyprus adopted the United Nations Convention on the Law of the Sea (UNCLOS 82) and as far as is known, signed agreement with neighboring states (Israel, Egypt and Lebanon) with regard to the definition of the Cyprus EEZ.

Under the Cyprus Legislation, a license is required for the purpose of performing seismic surveys 2D and 3D, which is granted for a period of up to one year, a license for the exploration of hydrocarbons is given for an initial period of 3 years which can be extended by two additional periods of two years each and a production (exploitation) license is given for a period of 25 years and can be extended for an additional period of 10 years, subject to meeting the conditions of the license. A production license, in connection with a commercial discovery during exploration will be given after approval of the development and production plan.

The relations between the Republic of Cyprus and the license holder are set forth in the Production Sharing Contract (the "**Production Sharing Contract**"). The Production Sharing Contract sets forth the relationship, the obligations and rights of the license holder and the fiscal conditions to which the license holder is subject. For further details with respect to the Production Sharing Contract in Block 12, see Section 7.8.3 above.

During 2014, the Republic of Cyprus decided to establish a designated government company, the Cyprus Hydrocarbons Company Ltd. ("**CHC**"), owned by the Cyprus government which is intended to be its arm in all matters regarding exploration activity in the EEZ of Cyprus, and the production and export of oil and natural gas from Cyprus.

7.26 Pledges

With regard to pledges the Partnership has given on its assets, see Note 12H to the financial statements (Chapter C of this report).

7.27 Material Agreements

The Partnership has entered into material agreement that were in force during the period commencing on January 1, 2018 until the report release date, as detailed following:

7.27.1 Agreements for the sale of natural gas from the Tamar and Leviathan projects to the domestic market (for details, see Sections 7.13.4(a) and 7.13.4(b) above).

7.27.2 Engagements for the export of natural gas from the Tamar and Leviathan projects (for details, see Section 7.13.5 above).

7.27.3 A material loan from a subsidiary of the Partnership (for details, see Notes 10B and 10C to the financial statements (Chapter C of this report)).

7.27.4 An agreement for financing of the development of the Leviathan reservoir (for details, see Section 7.22.1(a) above).

7.27.5 Commercial arrangement of the operation of and production from the Yam Tethys project and the Tamar Project (for details, see Section 7.3.4(e) above).

7.27.6 Production Sharing Contract in respect of Block 12 (for details, see Section 7.8.3 above).

7.27.7 Agreements for the purchase of EMG shares and for the purchase of rights in the EMG Pipeline

With the aim of realizing the two agreements between the Partnership and Noble and Dolphinus for the export of natural gas to Egypt from the Tamar and Leviathan reservoirs specified in Sections 7.13.5(a)2 and 7.13.5(b)2 (in this Section 7.27.7: the "**Dolphinus Agreements**"), on September 26, 2018, EMED signed agreements for the purchase of 39% of the share capital of EMG (the "**EMG Transaction**").

The closing of the EMG Transaction is contingent, *inter alia*, on the signing of a Capacity, Lease & Operatorship Agreement – CLOA, between EMED and EMG, in which EMG shall grant EMED the exclusive right to lease and operate the EMG Pipeline for the flow of natural gas from Israel to Egypt (in this Section 7.27.7: the "**CLOA**"), all as specified below:

(a) General background

EMG is a private company registered in Egypt which owns a submarine pipeline of a diameter of 26 inches and approx. 90 km long, which connects between the Israeli transmission system in the Ashkelon area and the Egyptian transmission system in the el Arīsh area, and related facilities (collectively: the "**EMG Pipeline**"). The EMG Pipeline was planned for a capacity of approx. 7 BCM per year, with an option to increase the capacity to approx. 9 BCM per year through the installation of additional systems. The flow of gas in the EMG Pipeline from Egypt to Israel was stopped in 2012, and to the best of the Partnership's knowledge, as of the report release date, EMG has no commercial activity, and it remained exposed to lawsuits[276] and debts to authorities, finance providers, suppliers and customers in significant amounts[277]. It is noted that in the framework of the transaction, the Partnership is not required to provide collateral or guaranties in relation to the existing debts of EMG.

As of the report date, EMG's registered shareholders are:

(1) EGI-EMG LP – 12%;
(2) Merhav MNF Ltd. – 8.2%;
(3) Merhav Ampal Energy Holdings, Limited Partnership – 8.6%;
(4) Merhav Ampal Group Ltd. – 8.2% (the "**Merhav Ampal Group**");
(5) PTT Energy Resources Company Limited ("**PTT**")[278] – 25%;
(6) Mediterranean Gas Pipeline Ltd. ("**MGPC**)[279] – 28%;
(7) Egyptian General Petroleum Corporation ("**EGPC**")[280] – 10%.

(Shareholders (1)-(4) above shall hereinafter be referred to collectively in Section 7.27.7 as: the "**Sellers**").

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[276] In addition, an arbitration notice was filed against EMG by a former customer, as well as several letters of warning.

[277] In accordance with EMG's financial statements as of December 31, 2017 and December 31, 2016, EMG's assets total approx. $117 million and approx. $129 million, respectively; the liabilities total approx. $505 million and approx. $487 million, respectively; and negative equity in the sum of approx. $388 million and approx. $358 million, respectively. In addition, in 2017 and 2016, EMG did not recognize income from operations and it accrued losses in the sum of approx. $30 million and $26 million, respectively. The financial statements are presented in U.S. dollars and are prepared according to Egyptian GAAP. It is noted that the figures in the financial statements as of December 31, 2017 and December 31, 2016 and for the years then ended are based on financial statements on which EMG's auditor refrained from giving his opinion due to the materiality of the issues and the reservations, as stated in his opinion. It is further noted that the said financial statements do not include a provision for possible claims on the part of customers.

[278] A public energy company partially owned by the Thai government.

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

[280] An Egyptian government-owned corporation.

It is noted that some of the Sellers, the shareholders of the Sellers and companies affiliated with the Sellers are conducting several arbitration proceedings at international arbitration institutes against the Egyptian government and companies owned thereby in connection with the cessation of the flow of the gas from Egypt to Israel (collectively in this Section 7.27.7: the "**Arbitration Proceedings**"). In addition, EMG is a party to arbitration proceedings against companies owned by the Egyptian government.

(b) Agreements for the purchase of 39% of EMG's share capital

On September 26, 2018, EMED signed four separate, mainly similar, agreements with the Sellers for the purchase of EMG shares held by the Sellers, at a total rate of 37% of the share capital of EMG (collectively in Section 7.27.7: the "**Share Purchase Agreements**"), as well as another agreement for the purchase of shares at a rate of 2% from MGPC (the "**MGPC Agreement**").

1. The main principles of the Share Purchase Agreements

a. Subject to fulfillment of the conditions precedent, the main ones of which are mentioned in Paragraph d. below, and the conditions to the closing of the EMG Transaction, the Sellers shall sell and transfer to EMED the EMG shares held thereby, at a total rate of 37% of EMG's share capital (in Section 7.27.7: the "**Purchased Shares**"), including all of the rights attached to the Purchased Shares.

b. The Sellers, the shareholders of the Sellers and the companies affiliated with the Sellers shall waive any claim, lawsuit, award, decision, order or remedy that are available to them against the Egyptian government and companies owned thereby in the framework of the Arbitration Proceedings.

c. In consideration for the Purchased Shares, for waiver of their rights in the framework of the Arbitration Proceedings, and other rights in accordance with the Share Purchase Agreements, as aforesaid, EMED shall pay the Sellers, on the date of the closing of the EMG Transaction, the sum total of U.S. $518 million (in Section 7.27.7: the "**Consideration**"), out of which each one of the Partnership and Noble shall pay a sum of approx. U.S. $185 million, and the balance will be paid by the Egyptian Partner.

d. Performance of the EMG Transaction contemplated in the Share Purchase Agreements is contingent on fulfillment of standard conditions precedent, including: receipt of all of the approvals and the consents required for the transfer of the Purchased Shares from the Sellers and registration thereof in EMED's name; receipt of the approvals and the consents required pursuant to any law in Egypt and Israel for fulfillment of the transactions contemplated in the Share Purchase Agreements and for the flow of the gas in the EMG Pipeline from Israel to Egypt (including approval of the Competition Authority); signing of the CLOA and elimination of any material impediment to performance thereof; completion of the engineering due diligence process in relation to the EMG Pipeline[281], including the performance of continuous gas flow tests from Israel to Egypt via the EMG Pipeline, in accordance with the quantities and the period determined; modification of the existing debt structure of EMG in favor of an Egyptian bank and rescheduling thereof to EMED's satisfaction; receipt of all of the formal approvals required by the Sellers, including in relation to the controlling shareholder of the Merhav Ampal Group, which is in dissolution proceedings, court approvals[282], and the closing of all of the Share Purchase Agreements. In October 2018, the Partnership and Noble approached the Ministry of Energy requesting approval of the use of the EMG Pipeline for transmission of natural gas from Israel to Egypt.

e. The deadline for fulfillment of the conditions precedent and for the closing of the EMG Transaction is June 30, 2019. The Partnership estimates that the natural gas flow from Israel to Egypt through the EMG Pipeline shall commence during Q2/2019.

f. The law that governs the Share Purchase Agreements is English law. Disputes between the parties shall be heard in arbitration in London (according to the arbitration rules of The London Court of International Arbitration).

The Partnership intends to finance its investment in the EMG Transaction by using the available cash flow of the Partnership and/or loans from banks and/or expansion of the Series A bonds which the Partnership issued on December 26, 2016. With respect to negotiations regarding the possible

[281] To the best of the Partnership's knowledge, as of the report release date, Noble has completed the external examination of the EMG Pipeline, through use of an ROV, with no unusual findings, and is acting to complete the engineering due diligence of the EMG Pipeline.
[282] On November 16, 2018, the approval required from the Bankruptcy Court in New York was received.

transmission of natural gas to the EMG Pipeline via the INGL System, see Section 7.14.2(b)2.b. above.

2. The main principles of the MGPC Agreement

Concurrently with the signing of the Share Purchase Agreements, an agreement was signed between EMED and MGPC whereby MGPC shall transfer to EMED, without financial consideration, subject to and concurrently with the closing of the Share Purchase Agreements, 2% of EMG's shares which are held thereby, against the conclusion of disputes between some of the Sellers and MGPC.

Subject to and after the closing of the EMG Transaction, EMG's shareholders will be:

(1) EMED – 39%;
(2) PTT – 25%;
(3) MGPC – 17% (controlled by Dr. Ali Evsen);
(4) The Egyptian Partner – 9%[283];
(5) EGPC – 10%.

(c) The Capacity Lease & Operatorship Agreement

As aforesaid, the closing of the EMG Transaction is contingent, *inter alia*, on the signing of the CLOA between EMED and EMG, in which EMG shall grant EMED the exclusive right to lease and operate the EMG Pipeline for the entire term of the Dolphinus Agreements, with an option to extend the agreement. According to this agreement, the costs required for refurbishment of the EMG Pipeline, up to the sum of $30 million (which reflects an initial estimate of these costs), and the current operation costs of the pipeline, shall be borne by EMED (collectively in Section 7.27.7: the "**Operation Costs**"), while EMG will be entitled to receive the current transmission fees which Dolphinus shall pay for use of the pipeline (in Section 7.27.7: the "**Transmission Fees**"), net of the Operation Costs.

(d) EMED's shareholders' agreement

In proximity to the date of the signing of the Share Purchase Agreements, EMED's shareholders signed a shareholders' agreement which regulates the relationship between them as shareholders of EMED, including provisions regarding material resolutions that shall be adopted unanimously. In addition, right of

[283] To the best of the Partnership's knowledge, MGPC is expected to transfer the said shares to the Egyptian Partner.

first refusal arrangements were determined for the transfer of shares of EMED.

(e) Term sheet for use of additional infrastructures

Concurrently with the signing of the Share Purchase Agreements, as described above, a term sheet was signed between the Partnership and Noble and the Egyptian Partner (which holds the Arab Gas Pipeline in the segment between el Arish and Aqaba, and an affiliate of Dolphinus, whereby the parties agreed that the Partnership and Noble would receive access to additional capacity in the Egyptian transmission system, through the Arab Gas Pipeline, at the entry point to the Egyptian transmission system in the Aqaba area, allowing the flow of gas in additional quantities over and above the gas quantities that would flow via the EMG Pipeline (in Section 7.27.7: the "**Additional Infrastructure**"), for the purpose of implementation of the Dolphinus agreements and other agreements for the sale of natural gas to Egypt. In addition, the parties agreed to look into other projects for the transmission of natural gas from Israel to potential customers and facilities in Egypt.

Note that as of the report release date, the Partnership and Noble are negotiating with the holders of the Additional Infrastructure for the signing of a binding agreement.

(f) MOUs with the Tamar Partners and the Leviathan Partners

In proximity to the date of the signing of the EMG Transaction, Noble and the Partnership signed a non-binding MOU with the Tamar Partners and a non-binding MOU with the Leviathan Partners in connection with the allocation of the capacity, participation in costs and other arrangements in connection with the flow of natural gas in the EMG Pipeline and in the Additional Infrastructure (as defined above).

Note that as of the report release date, Noble and the Partnership are holding advanced negotiations with the Tamar partners and the Leviathan partners regarding the allotment of capacity in the EMG Pipeline and in the Additional Infrastructure, based on the update of the Tamar-Dolphinus Agreement, and on the increase of quantities of natural gas on a firm basis in the Leviathan-Dolphinus agreement, as specified in Sections 7.13.5(a)2 and 7.13.5(b)2 above.

The MOU with the Leviathan Partners determined that subject, *inter alia*, to the signing of a binding agreement by June 30, 2019 and to the closing of the EMG Transaction, the partners in the Leviathan project would pay, on the date of the closing of the EMG

Transaction, the sum of $250 million in consideration for EMED's undertaking to allow the flow of natural gas from the Leviathan reservoir for the purpose of realization of the Leviathan-Dolphinus Agreement and securing a capacity of 350,000 MMbtu per day in the EMG Pipeline and in the Additional Infrastructure, such that further to Section (b)1.c above, on the date of the closing of the EMG Transaction, out of the sum of the consideration that shall be paid by the Partnership and Noble, the sum of approx. $250 million will be paid by the Leviathan Partners, such that the sum of the consideration that shall be paid by the Partnership on the date of the closing of the EMG Transaction will be approx. $170 million, in accordance with all of the conditions of the approval of the meeting of the holders of the participation units regarding refraining from distributing profits for the purpose of investment thereof in the purchase of EMG's rights as stated in Section 4.2.6 above.

Concurrently, Noble and the Partnership signed a non-binding MOU with partners in the Tamar project, whereby subject, *inter alia*, to the signing of a binding agreement by June 30, 2019 and to the closing of the EMG Transaction, the Tamar Partners would pay the Leviathan Partners, by June 30, 2020, the sum of $125 million (which constitutes a reimbursement of 50% of the amount due to be paid by the Leviathan Partners on the date of the closing of the EMG Transaction), in consideration for EMED's undertaking to allow the transfer of gas from the Tamar reservoir for the purpose of realization of the Tamar-Dolphinus Agreement, including sale on an interruptible basis during 2019, or a proportionately reduced amount, if the amount of the capacity of the EMG Pipeline and the Additional Infrastructure, as is approved by a competent technical entity, is lower than a capacity of 700,000 MMbtu per day. In addition, the MOUs determined mechanisms that allow the Leviathan Partners to use the capacity available above 350,000 MMbtu per day, insofar as the Tamar Partners do not use the capacity in full.

It is emphasized that the binding agreements with the Tamar Partners and the Leviathan Partners, if and insofar as signed, are expected to include specific arrangements with respect to regulation of the use of the EMG Pipeline and the Additional Infrastructure, including arrangements with respect to distribution of the capacity in different cases, investments in the Additional Infrastructure and other arrangements. The binding agreements, if and insofar as signed, will be subject to receipt of the relevant regulatory approvals, including the approval of the Competition Authority and the approval of the Ministry of Energy, insofar as required.

**<u>Caution regarding forward-looking information</u> – the information presented above, including with respect to the possibility of the flow of gas in the EMG Pipeline in the framework of the engineering due diligence investigation, the terms and conditions of the CLOA, if and insofar as signed, the options for financing the EMG Transaction, the costs of refurbishing the EMG Pipeline, the possibility of fulfillment of the conditions to the closing of the EMG Transaction, and the possible date for fulfillment thereof, and the possibility of the signing of binding agreements with the Leviathan and/or Tamar partners, constitutes forward-looking information within the meaning thereof in Section 32A of the Securities Law, which is based on preliminary estimates only. This information may not materialize, in whole or in part, or may materialize in a materially different manner, due to various factors over which the Partnership has no control.**

7.27.8 <u>Joint operating agreement in Tamar and Dalit leases</u>

(a) <u>General</u>

The exploration and production activity in the framework of the Tamar Project lease are done under a joint operating agreement (JOA) of November 16, 1999 (as amended from time to time) to which party to currently are the Partnership and the other Tamar Partners as detailed in Section 7.3.1 above (in this Section 7.27.8: the "**Agreement**" or the "**JOA**").

The purpose of the Agreement is to set forth the mutual rights and obligations of the parties in connection with activities in the areas of the Tamar Project leases (in this Section 7.27.7: the "**Petroleum Assets**").

(b) <u>Manner of accounting</u>

Unless otherwise provided for in the JOA, all the rights and interests in the Petroleum Assets, in the joint property and in all the hydrocarbons produced from them, will be subject to the terms and conditions of the Petroleum Assets and the rules that apply to them, and in accordance with the participation rates of the parties in the Petroleum Assets. Furthermore, unless otherwise provided for in the JOA, the undertakings of the parties under the JOA and the terms and conditions of the Petroleum Assets and all the liability and expenses incurred or undertaken by the Operator in connection with the joint activity[284], and all the credits to the joint account[285], will be borne by the parties,

[284] In accordance with the definition of the JOA – the "joint activity is the activities performed by the operator under the instructions of the JOA and the expenses entitled to bill from each of the parties to the JOA.

[285] In accordance with the definition of the JOA – the "joint account" are accounts held by the operator in favor of the joint project in accordance with rules set forth in the JOA and accounting rules.

between themselves, in accordance with their participation share in the Petroleum Assets, and each party will pay when due in accordance with the Accounting Procedure instructions set forth in the JOA (the "**Accounting Rules**") its share, in accordance with its participation share, of all expenses of the joint account including advances and interest owed according to the JOA. The dates of payment are of the essence. Payment by a party of another party's obligation under the JOA does not negate its right to dispute such liability at a later stage.

According to the Accounting Rules, Noble is entitled to reimbursement of all direct expenses expended thereby in connection with the fulfillment of its function as operator. The amendment of June 30, 2016 to the JOA, provides for the accounting method also in respect of Noble's indirect expenses, and determines that as of January 1, 2016, Noble will be entitled to payment at the rate of 1% of the total direct expenses, other than with respect to marketing activities and fees.

(c) <u>The identity, rights and obligations of the Operator</u>

Noble serves as the operator of the Tamar Project leases (in this section: the "**Operator**")

Subject to the conditions of the JOA, the Operator is granted all the authorities and obligations with regard to the management of joint venture, under the supervision and instructions of the joint operating committee. The Operator's position may not be assigned without the prior written consent of the parties to the JOA (which are not operator) as well as any consent that is required on behalf of the Petroleum Commissioner, with the exception of an assignment to an affiliate of the Operator, as defined in the agreement.

The Operator is exclusively responsible, for the management of the joint activity. The Operator may employ contractors and/or agents (which could be related companies of the Operator) to perform said joint activities. The Operator will be responsible, *inter alia*, for preparing a work plan, the budgets and the authorizations for payment, for the performance of the work plan according to the authorization of the joint operating committee, for the planning and getting of all approvals and material required to perform them, giving of advisory services and technical services as required for efficient performance of the joint operation.

In the joint management of the activity the Operator will be required, *inter alia*, to perform the joint activities in accordance with the terms and conditions of the Petroleum Assets and their applicable rules, the JOA and the instructions of the operational committee. The Operator will perform its role with due diligence and in accordance with the customary procedures in the petroleum industry.

The JOA sets forth various instructions regarding the manner of engagement of the Operator in contracts with third parties (according to approved budgets), and depending on the sum of the offered contract, may be required to consult with the other parties with regard to the criteria according to which the candidates for the tender will be chosen, to report to the parties with regard to the offers received and to get the operating committees' approval for the choice of candidate in a tender.

The Operator is required to take out and maintain the insurances detailed in the JOA in accordance with the general instructions therein. It is also provided, that each of the parties to the JOA must take care of itself and of additional insurance on its account to cover the risks in connection with the joint activity.

The Operator is also required, after receipt of reasonable prior notice, to permit representatives of each party, at any reasonable time and on their own expense and responsibility, access to the joint activity including the right to observe the joint activity, to examine all joint property and to audit the finances in accordance with the Accounting Rules set forth in the JOA.

Subject to the terms and conditions of the Petroleum Assets and the approved budget, the Operator will determine the number of employees and the number of contractors, choose them and determine their hours of work and the consideration to be paid to them.

The Operator will immediately advise the parties of any material actions and other actions filed as a result of the joint activity and/or are related to the activity of the Partnership, as shall be instructed by the operating committee. The Operator will represent the parties and defend said claims. The Operator may, at its sole discretion, settle any claim or series of claims in a sum that does not exceed $75,000 (including legal expenses), and will ask for permission from the operating committee for any sum(s) that exceed the aforementioned sum. No party will settle with regard to its relative share of any claim without first proving to the operating committee that this can be done without harming the interests of the joint activity.

Each party which is not an operator will immediately notify the other parties regarding any action filed against it by a third party and that relates from the joint activity or could affect the joint activity, and the party that is not an operator will defend or settle the aforementioned claim in accordance with instructions that will be given by the operating committee. The costs and damages caused in connection with the defense or settlement which can be related to the joint activity will be debited from the joint account.

The Operator will not be responsible vis-à-vis the other parties to the agreement for any action, debt, loss or damage, direct or indirect, whether under the agreement or tort (including negligence) or other that derives from the joint operation or in connection thereto unless the action, debt, loss or damage derives from willful misconduct of the Operator or the failure of the Operator to obtain the required insurance cover (unless the Operator took all reasonable means to get such insurance coverage and advised the other parties of such) and in any event will not be liable for consequential damages, including but not only the inability to produce petroleum, production loss or loss of profits. The foregoing does not exempt the Operator from responsibility for its share in accordance with its participation share, for any damage, loss or other liability.

(d) Operating committee

A joint operating committee (the "**Committee**") was formed for the supervision and giving of directions in all matters related to the joint activity in the lease area. The Committee's authority includes, *inter alia*, the making of decisions with regard to policy, processes and operating practice, approval of all notices to the public relating to the agreement or the joint operation, approval of all plans and budget requests, the determining of schedules, place and depth of drilling of wells and everything related thereto, making decisions with regard to application for licenses and leases and replacing the Operator. Each partner has a representative in the joint operating committee, whose voting rights are relative to the holdings of the partner that appointed him. The Operator's representative serves as the Committee's chairman.

The joint operating committee's decisions are passed by a vote of two or more partners that hold collectively at least 68% of the rights in the lease (related parties as defined in the agreement will be considered one party). In order to approve a decision to terminate a lease or waive any part of a lease area, unanimous agreement is required. A positive decision of any one party to the JOA is sufficient to approve any license or license renewal or lease application.

(e) Work plans and budgets

The JOA sets forth procedures and processes for the submission and approval of work plans, budgets and authorizations for expenditure (AFE) for activities in the areas to which the JOA applies. It should be noted that the Operator can deviate from the approved AFE for the work plan in a rate that does not exceed 10% of the approved sum or 1 million dollars, whichever is lower.

Exploration plan and budget – the work plan and budget will be approved by the operating committee. Authorization for expenditure (AFE) within the work plan and budget will be approved in accordance with the provisions stipulated by the JOA, unless at least 20% of the parties to the JOA deliver a notice to the Operator of their objection to the approval of the AFE. Prior an expenditure or the giving of an undertaking in a sum exceeding $250,000 for any item in the approved work plan and budget, the Operator will send all the other parties a request for an authorized expenditure approval (AFE). In the event that the Operator anticipates a deviation from the AFE for administrative purposes and for geological or geophysical operations that are not exclusive to a particular project, no AFE will be required, provided that the deviation does not exceed $50,000.

Development plan and budget – In the event that the committee should decide after a full discussion on the economic merit of the development of each offer presented to it, the Operator will provide the parties, as soon as possible after the making of such decision, a development plan and budget for the applicable discovery, which will include, inter alia, the works required in connection with the development, all the information required to submit it in accordance with the agreement, the manner of management required for the development including details with regard to the number of workers and manpower required, an estimate of the production commencement date and of the annual production volume and any other information required by the committee. Prior to expenditure or the giving of an undertaking, in any amount, with regard to the preparation of a development plan and budget or with regard to any item in the approved development plan and budget, the Operator will send all the other parties a request for an AFE. In the event that the Operator anticipates a deviation from the AFE for administrative purposes and for geological or geophysical operations that are not exclusive to a particular project, no AFE will be required, provided that the deviation does not exceed $50,000.

Production plan and budget – each year the Operator will provide the parties with the proposed production plan for the following year. The proposed production plan must include, *inter alia*, the projects, and works that need to be performed, any information required to be provided in accordance with the JOA, details regarding the number of workers and required manpower and an estimation of the total production by quarter and the maximum daily rate of production for each quarter and all other information required by the committee.

Before expenditure or the giving of an undertaking in a sum that exceeds $250,000 for each item in the work plan and approved budget, the Operator will send all the other parties a request for authorized expenditure (AFE).

The development or production plan and the proposed budgets will be subject to reconsideration, revision, amendment and approval by the committee that will be done so as soon as possible and in accordance with the schedule specified in the JOA.

In the event that the Operator anticipates a deviation from the AFE for administrative purposes and for geological or geophysical operations that are not exclusive to a particular project, no AFE will be required, provided that the deviation does not exceed $50,000 as pertains to the exploration, development and discovery stage, and that the deviation does not exceed $1 million as pertains to the production stage.

(f) <u>Sole risk operations</u>

Operations in which not all the parties take part (defined in the agreement as “Exclusive Operations” and known in the oil exploration industry as “Sole Risk” operations) will not be performed if they contradict joint operations in which all the partners participate. The agreement sets forth rules for the performance of said “Sole Risk” operations.

The agreement includes various instructions relating to Sole Risk operations - i.e. the performance of drilling, tests and development not unanimously agreed upon by all the partners in the leases , which under certain conditions specified in the agreement can be performed by some of the partners. Parties that do not join the Sole Risk operation have been given the possibility, subject to conditions and payments set forth in the agreement, to get back their share in such operation and everything deriving therefrom. Furthermore, parties who had not joined the Sole Risk activities, but decided to join after the joining date, will bear the fines and the interest specified in the JOA.

(g) <u>Resignation and removal of the Operator</u>

The Operator may resign by written notice of 180 days in advance or upon shorter notice upon the agreement of the operating committee. In addition, subject to the provisions of the agreement the committee can terminate the Operator in the following situations: (1) if the Operator ceases to hold at least 10% of the working interest in the Tamar and Dalit leases; (2) an application was made for a court order or a valid decision for reorganization of the Operator, under the bankruptcy laws; (3) if the Operator is liquidated or ceases its existence in another manner; (4) if the Operator becomes insolvent, makes an arrangement in favor of creditors or if a receiver is appointed for a significant part of its assets.

In addition, the Operator will be removed from its position upon receipt of a notice from the Petroleum Commissioner with regard to cancellation of the approval that was given to the Operator, to the extent that such an approval is required.

Furthermore, the operating committee may remove the Operator from its position by written notice to the Operator of 90 days in advance, if the Operator, in the reasonable opinion of the other parties to the JOA (that are not the Operator) shall have committed a fundamental breach of the agreement and shall not have remedied the breach within 28 days from the date it received notice detailing the occurrence of said breach. Any decision of the other parties to the JOA (that are not an operator) to give a notice of breach to the Operator requires a vote in favor of the decision of parties, excluding the Operator and which are not related thereto, holding collectively at least 68% of the total working interests.

In the event that the Operator resigns or is removed from its position, the operating committee shall elect, as soon as possible but in any event within 30 days from the date of provision of the notice regarding the Operator's resignation or its removal from its position as aforesaid, one of the parties to the JOA (which are not the Operator) who shall agree to assume the position of operator, subject to any approval that shall be required on behalf of the Petroleum Commissioner. In the event that the Operator is removed from its position, if the outgoing operator decides not to vote for one of the parties to the JOA (which are not the Operator) as the new operator, but rather to vote for itself or for a party affiliated with the outgoing operator, its vote shall not be counted. In the event that the parties do not elect a new operator, the party to the JOA (which is not the Operator) which holds the largest percentage out of the total working interests shall be appointed as operator, insofar as it agrees to assume the position and subject to any approval that shall be required on behalf of the Petroleum Commissioner. In the event that there are two parties that hold the largest percentage of the total working interests, the decision between the two will be made by a vote of the operating committee.

(h) <u>Sanctions applicable to the partners and the conditions for imposition thereof</u>

A party that fails to timely pay its relative share in the joint expenses, including advances and interest, will be deemed a breaching party (a "**Breaching Party**"). The delinquent sum will bear cumulative interest on a daily basis. Any party that is not a Breaching Party (a "**Non-Breaching Party**") must bear the relative portion (its portion relative to the portions of the other Non-Breaching Parties) of the sum that is in breach (excluding interest), and shall pay the aforesaid amount to the Operator on the first day after the expiration of 6 days on which the Breaching Party is in breach, failing which it shall become a Breaching Party itself.

So long as the breach is ongoing, the Breaching Party shall not be entitled to participate or vote in the operation committee meetings and shall not be entitled to receive data and information pertaining to the joint operations. If the breach lasts more than 6 Business Days, as such term is defined in the JOA, from the date on which the breaching notice is given to the Breaching Party, and for as long as it continues, the Breaching Party will not be entitled to receive the portion to which it is entitled of the output, and this portion will be the property of the Non-Breaching Parties and they will be entitled, while taking the steps detailed in the JOA, to collect from it what is due to them, until the payment of the sum subject to breach.

If the Breaching Party 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 Non-Breaching Parties 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 Breaching Party to resign completely from the JOA and the Petroleum Asset. If the aforementioned option is realized the Breaching Party will be deemed as having transferred, all of its rights under the JOA and the Petroleum Asset to the Non-Breaching Parties, and it will be obliged, upon first demand, to sign any document and take all action required by law in order to give validity to said transfer of shares, and to remove any attachment or pledge applicable to said rights. Rights and remedies of the Non-Breaching Parties as a result of said breach are in addition to any right or other remedy at the disposal of the Non-Breaching Parties, under law.

(i) <u>Manner of Dilution of Partners' Holdings – Transfer of Rights</u>

A party may transfer its rights to a third party, subject to approval by the other parties to the JOA, which approval shall not be unreasonably withheld.

Transfer of the working interests of a party in a Petroleum Asset, in whole or in party, will only be valid if it meets the conditions of the JOA, including *inter alia* the following conditions:

1. Notwithstanding the transfer, the transferor will remain liable vis-à-vis the other parties to the JOA for all liabilities, financial or other, that were either vested, had matured or accrued under the terms of the Petroleum Asset or the JOA prior to the date of the transfer including without limitation, any expenses approved by the operating committee prior to the transferor giving notice with regard to the transfer of the rights to other parties to the agreement.

2. The transferee will have no rights with regard to the terms of the Petroleum Asset, the area of the Petroleum Asset or under the JOA, for as long as, and until the required government approval has been received, and it has undertaken specifically in a written document to the satisfaction of the other parties, to perform the transferor's undertakings under the conditions of the Petroleum Asset and the JOA with regard to the working interest being transferred to it, and the transferor will provide the guarantees required by the government or according to the Petroleum Asset.

3. The foregoing does not preclude a party under the JOA from pledging or otherwise encumbering, all or part of its interest in the area of the Petroleum Asset or under the JOA as collateral for finance, subject to such party retaining responsibility for all undertakings relating to the said interest; the pledge will be subject to any government approval that may be required and will be specifically subordinated to the rights of the other parties under the JOA.

(j) Withdrawal from the JOA

The JOA includes provisions regulating the matter of withdrawal, full or in part, of a party from any Petroleum Asset in which it is a participant (and from the applicable JOA) and determines the situations when such withdrawal is possible, and the rights and obligations of the withdrawing party vis-à-vis the other partners in the license.

A party that wishes to withdraw from the JOA or Petroleum Assets, must notify the other parties of its decision, such notice must be unconditional and irrevocable immediately upon delivery, subject to the conditions set forth in the JOA (a "**Withdrawal Notice**"). Within 30 days from the day of delivery of a Withdrawal Notice the other parties to the JOA will be entitled to also give a Withdrawal Notice. In the event that all the parties provide a Withdrawal Notice, they will act to terminate the JOA and their remaining undertakings relating to the project and the Petroleum Asset. In the event that not all the parties decide to withdraw as aforesaid, the withdrawing party will act in order to transfer his rights to the partners that chose not to withdraw (the "**Remaining Partners**") as soon as possible. Transfer of rights as aforementioned will be for no consideration, with the withdrawing partner bearing all the expenses arising from its withdrawal as aforesaid, unless otherwise agreed. The transfer of the rights to the Remaining Partners will be in proportion to their relative holdings.

(k) Rights and obligations with respect to production

Each party has the right and the obligation to take its share in the hydrocarbons produced from the leases, unless it is agreed otherwise.

The JOA does not regulate the joint sale of natural gas or LNG that shall be produced from the leases.

(l) The governing law and settlement of disputes

The JOA is subject to the laws of England. In addition, any dispute shall be decided in an arbitration proceeding in accordance with the arbitration rules of the International Chamber of Commerce. In the framework of the arbitration proceeding, a single arbitrator will be appointed who shall not be a resident or citizen of Israel or England.

7.27.9 Joint Operating Agreement in respect of the Leviathan Leases[286]

(a) General

The activity in the framework of the Leviathan leases is carried out under a joint operating agreement of August 3, 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 7.4.1 above (in this Section 7.27.9: 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 7.27.9: the "**Petroleum Asset**").

According to the aforementioned operating agreements, Noble was appointed as the Operator.

(b) Manner of accounting

Unless otherwise provided for in the JOA, all the rights and interests in the Petroleum Assets, in the joint property and all the

[286] It should be noted that until January 1, 2012 the activity at the Leviathan leases was carried out in the framework of a single joint operating agreement.

hydrocarbons produced from them, will be subject to the terms and conditions of the Petroleum Asset and the applicable rules, and in accordance with the participation rates of the parties therein. Furthermore, unless otherwise provided for in the JOA, the party's undertakings under the Petroleum Asset conditions and the JOA and all the liabilities and expenses incurred or undertaken by the Operator in connection with the joint activity[287], and all the credits to the joint account[288], will be borne by the parties, amongst themselves, in accordance with their participation rate in the Petroleum Asset, and each party will pay, when due, in accordance with the Accounting Procedure instructions of the JOA (the "**Accounting Rules**") its share in accordance with its participation rate of all the expense of the joint account. Payment dates are of the essence of the JOA. Payment by a party of another party's obligation under the JOA does not negate its right to dispute such liability at a later stage. According to the Accounting Rules, Noble is entitled to be reimbursed for of all direct expenses paid in connection with it fulfilling its position as operator and to be reimbursed for the indirect costs derived from its shares of the expenses of the joint venture at the exploration state as follows:

| Direct Expenses (on an annual basis) | Rate of payment to Operator (as a percentage of direct expenses |
|---|---|
| Up to $4 million - | 4% |
| $4-7 million - | 3% |
| $7-12 million - | 2% |
| Above $12 million - | 1% |

The rate of indirect expenses for the development and production stage was not provided by the Agreement, and on June 30, 2016 an amendment to the JOA in the Leviathan project was signed, whereby 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. The Operator may employ contractors and/or agents (which could be related

[287] In accordance with the definition of the JOA – the "joint activity" is the activities performed by the operator under the instructions of the JOA and the expenses entitled to be billed each of the parties to the JOA.

[288] In accordance with the definition of the JOA – the "joint account" are the 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[289] 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 role is detailed following); to manage all the joint activity with diligence and in a safe and efficient manner in accordance with the acceptable principles in the international petroleum industry in similar situations. In addition, the Operator is required to get and maintain 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.

[289] In this regard, "a related party/affiliate" 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 ability to control decision making in said legal entity.

No party will settle with regard to its relative share of any claim without first proving to the operating committee that this can be done without harming the interests of the joint activity.

Each party that is not an operator will immediately advise the other parties of any action against it by a third party that derives from the joint activity or may impact the joint activity, and the non-operator party will defend or compromise on the said claim, in accordance with instructions given by the operating committee. Costs and damages which will be caused in connection with the defense or compromise and that can be attributed to the joint activity will be charged to the joint account.

Unless otherwise provided for in this section, the Operator (and in this regard – including the directors and officers therein, its related companies and the directors and officers therein, collectively: the "**Indemnified Parties**") will not bear (except as a party in the participation rate of a Petroleum Asset) any damage, loss, cost, expense or liability deriving from the performance (or lack of performance) of its position and functions as an operator, and the Indemnified Parties are free, according to the JOA from liability to parties that are not an operator, for any damages, losses, costs, expenses, and liability that are the result of or derive from said performance (or lack of performance), 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.

Nothing stated in this section will release the Operator from its part in accordance with its participation rate, in any damage, loss, cost, expense or liability deriving or the result of or deriving from joint activity. 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 up till it's working interests therein) in the debt for damages or environmental or consequential losses.

(d) <u>The operating committee</u>

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

Unless otherwise provided for specifically in the JOA, all decisions, approvals and other activities of the operating committee with regard to the proposals presented before it, will be decided by the vote in favor of at least 2 parties or more(that are not related parties/affiliates, as defined above) collectively holding r at the time of the vote at least 60% of the total of all the working interests in the area of the applicable Petroleum Asset.

(e) <u>Work plans and budgets</u>

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.

When the operating committee makes a decision that there is a discovery suitable for commercial production, the Operator will present the parties, as soon as possible after the aforementioned decision is made, with a development plan and an estimated budget with regard to such discovery which will include, *inter alia*, the works, schedules and manpower required in connection with the development of the discovery, an outline of the area from which the production will be done, an estimate with regard to the date of commencement of production and any other information required by the operating committee. Said work plan and the proposed budget will be subject to re-consideration, change, correction, and approval by the operating committee as soon as possible and in accordance with the dates set forth in the JOA.

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 must submit an AFE to the operating committee for additional approval for the excess. 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.

(f) Sole Risk operations

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 partners participate. The JOA sets forth framework rules for the performance of “Sole Risk” operations.

(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) upon the providing of a notice by a party to an agreement in the event of a court order or valid decision for reorganization under the bankruptcy laws; (3) if a receiver is appointed to a significant portion of its assets; or (4) if the Operator is liquidated or ceases to exist in another manner.

Furthermore, the Operator may be removed from its position by a decision of other parties to the JOA (that are not an 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 that it did not proceed diligently to complete the remedy of the breach. A decision of the other parties to the JOA (that are not an operator) to give a notice of breach to the Operator will require the vote in favor of at least one party out of the parties that are not an operator (or a related party or an affiliate of the Operator) that hold 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 partners and the conditions for imposition thereof

A party that fails to timely pay its relative share in the joint expenses (including advances and interest) or that fails to obtain or maintain the collateral required thereof, will be deemed a breaching party (the "**Breaching Party**").

As of 5 days from the date a Breaching Party was provided with a notice of delinquency and the delinquency is not remedied, the Breaching Party 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 breaching parties.

Any party that is not the Breaching Party (a "**Non-Breaching Party**") must bear the relative portion (its portion relative to the portions of the other Non-Breaching Parties) 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 Breaching Party.

As long as the breach is ongoing, the Breaching Party will not be entitled to receive its portion of the output, and this portion will be the property of the Non-Breaching Parties 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 Breaching Party and any shortage will remain as a debt of the Breaching Party to the Non-Breaching Parties.

If the Breaching Party 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 Non-Breaching Parties 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 Breaching Party to resign completely from the JOA and the Petroleum Asset. If the aforementioned option is realized the Breaching Party will be deemed as having assigned, on the day of the notice of the breach, all of its rights under the JOA and the Petroleum Asset to the Non-Breaching Parties, and it will be required, upon first demand, to sign 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 Non-Breaching Parties as a result of said breach are in addition to any right or other remedy at the disposal of the Non-Breaching Parties, under law.

A fundamental principle of the JOA is that each party is required to pay its relative portion (relative to its participation rate in the JOA area) of all sums it owes under the JOA when due. Therefore each party that becomes a Breaching Party waives any offset claims and will not be entitled to raise such vis-à-vis the Non-Breaching Parties which instituted the proceedings set forth in the JOA against it, for non-payment of the sums owed by it on time.

(i) <u>Transfer of rights</u>

Transfer of working interests of a party to a Petroleum Asset, in whole or in part, will be in force if it meets all the conditions set forth in the JOA, including *inter alia* the following conditions:

1. Except for in the case where a party transfers all of its working interests in a Petroleum Asset, no transfer of rights will occur where as a result the transferor retains or the transferee has received a working interest in a Petroleum Asset and in the JOA of less than 10%.

2. Notwithstanding the transfer, the transferor will retain liability vis-à-vis the other parties to the JOA for all financial and other liabilities, that were vested, had matured or accrued under the Petroleum Asset and the JOA prior to the date of the transfer including any and all expenses approved by the operating committee prior to the transferor's notice with regard to the transfer of the offered rights to the other parties under the JOA.

3. The transferee will have no rights with regard to the Petroleum Asset or under the JOA, for as long as he does not receive, and until it receives, the required government approval and 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 for as long as the transferee does not provide the guarantees required by the government or the terms and terms and conditions of the Petroleum Asset.

4. The foregoing does not preclude a party to the JOA from pledging or otherwise encumbering, any or part of its interest in the area of the Petroleum Asset or the JOA 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 transferee, except for with regard to a related party, will not have any rights in the Petroleum Asset and the JOA, unless the other parties to the JOA agree in writing to the transfer, subject to proof of qualification of the transferee to meet the undertakings under the Petroleum Asset and the JOA.

(j) Withdrawal from the JOA

The JOA includes provision regulating the matter of withdrawal, full or in part, of a party from any Petroleum Asset in which it is a participant (and from the JOA applicable) and determines the cases when withdrawal is possible, and the rights and obligations of the withdrawing party vis-à-vis the other partners for the Petroleum Asset and the JOA.

A party that wishes to withdraw from a Petroleum Asset, must provide a notice of its decision to the other parties ("**Withdrawal Notice**"). Said notice will not be unconditional and irrevocable upon delivery, subject to the conditions set forth in the JOA. Within 30 days from the day of delivery of the Withdrawal Notice the other parties to the JOA will be entitled to also present a Withdrawal Notice. In the event that all the parties present a Withdrawal Notice, they will act to terminate the JOA and the remaining undertaking connected to the Petroleum Asset and the JOA. In the event that not all the parties will decide to withdraw, all the withdrawing parties will act in order to assign as soon as possible the said rights to the partner/partners that chose not to withdraw. Transfer of said rights will be without consideration, with each of the withdrawing partners bears all expenses with regard to its withdrawal, unless otherwise resolved. The transfer of the rights to the remaining partners will be in proportion to their relative holdings.

7.27.10 Joint operating agreement in respect of the Alon D License

The joint operating agreement applicable to the Alon D License covers the same issues as included in the Leviathan project operating agreement (for details see Section 7.27.9 above), whereby decisions are made by an "effective majority", which is the affirmative vote, in favor of the decision, of at least two participants that are not related parties and collectively hold at least 60% of the total rights in the license. Noble serves as the operator in the Alon D license.

7.27.11 Joint operating agreement in Block 12

The joint operating agreement as aforesaid covers the same issues as and is in a format similar to the joint operating agreement that applies to the Leviathan project (for details see Section 7.27.9 above), whereby decisions are made by an "effective majority", which is affirmative votes in favor of the decision by at least two participants that are not related parties and collectively hold at least 65% of the total rights in the license. Noble Cyprus serves as operator.

7.27.12 Arrangements regarding Payment of Royalties to the State, Affiliates and Third Parties

(a) Following the completion of the Merger of the Partnerships, all of the undertakings with respect to the royalties apply for all of the Partnership's (existing and future) petroleum assets, however the rate of royalties therefor has been reduced by 50% compared to the rate of royalties on the eve of the Merger (since the Partnership and Avner held equal parts of these petroleum assets, except for the Ashkelon and Noa Leases, in which the Partnership held 25.5% and Avner 23%, and for which the rate of royalties was reduced by 47.42% compared to the royalties that the Partnership pays the Delek Group and Delek Energy, as defined below, and by 52.58% compared to the royalties that Avner paid prior to the Merger, as defined below).

(b) Royalties for Affiliates and Third Parties

1. Royalties of the Delek Group, Delek Energy and Delek Royalties: These royalties originate from an interest transfer agreement of 1993 between Delek Energy and Delek Israel[290] (in this section: the "**Transferors**") and the General Partner of the Partnership, under which the Transferors transferred to the Partnership interests in several licenses and the Partnership undertook to pay the Transferors (Delek Energy – 75% and Delek Israel – 25%) royalties at the rates specified below from the entire share of the Partnership in petroleum and/or gas and/or other valuable substances that shall be produced and used from the petroleum assets, in which the Partnership has or shall have any right (prior to deduction of any kind of royalties, but after deduction of the petroleum used for the production itself) (the "**Interest Transfer Agreement**"). On June 17, 2018, Delek Energy and Delek Royalties notified the Partnership that Delek Energy's right to receive royalties from the Partnership's share (22%) in oil and/or gas and/or other valuable materials that are produced or used from the Tamar and Dalit leases has been transferred to Delek Royalties, and that the registration in the Petroleum Register has been amended accordingly. In view of the aforesaid, from June 1, 2018, the Partnership pays Delek Royalties all of the said royalty income directly.

   The royalty rates that were set forth in the Interest Transfer Agreement, and in accordance with the adjustment as provided in Subsection (a) following completion of the Merger between the

[290] Following the reorganization that was carried out, Delek Group currently holds the royalty right as aforesaid of Delek Israel.

Partnership and Avner, 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 Date of the Partnership's Investment-Recovery, royalties shall be paid at a rate of 7.5% of onshore petroleum assets and 6.5% of offshore petroleum assets (the "**Royalties of the Delek Group, Delek Energy and Delek Royalties**").

Under the Interest Transfer Agreement the Partnership and the Transferors signed a deed of royalties of March 3, 2003, as amended on March 2, 2009 and on May 30, 2010, for the purpose of registration of the royalty right in the Petroleum Register maintained under the Petroleum Law.

According to the terms and conditions of the royalties, as determined in the Interest Transfer Agreement and the said deed of royalties, the following provisions shall apply with respect to determination of the Investment Recovery Date:

The term "**Investment Recovery Date**" shall mean the date after the execution of the Interest Transfer Agreement, on which the (Net) Value of the Revenues (as defined below) that the Partnership received or is entitled to receive for the petroleum and/or gas and/or other valuable substances that were produced and exploited from the petroleum asset (i.e. a license or lease) in which the discovery is found, calculated in Dollars (according to the representative rate published by the Bank of Israel), shall reach the sum equal to the Value of All of the Partnership's Expenses on that petroleum asset (as defined below), calculated in Dollars (according to the representative rate as aforesaid).

The term "**(Net) Value of the Revenues**" shall mean the value of all of the revenues, as certified by auditors of the Partnership, for petroleum and/or gas and/or other valuable substances that were produced and exploited from the petroleum asset (i.e. a license or lease) (the "**(Gross) Value of the Revenues**"), after deduction of all of the expenses for the production thereof and the royalties paid therefor.

The term "**Value of All of the Partnership's Expenses**" shall mean all of the expenses that the Partnership incurred on the petroleum asset (i.e. a license or lease), in which the petroleum and/or gas and/or other valuable substances are produced, except for expenses (up to the (Net) Value of the Revenues) that were deducted from the (Gross) Value of the Revenues for determining the sum of the (Net) Value of all of the Revenues and as shall be certified by the Partnership's auditors.

Investment Recovery Date in the Tamar Project

In view of the fact that Delek Group, Delek Energy and Delek Royalties (collectively in this section: the "**Royalty Interest Owners**") includes the control holders of the Partnership, the board of directors of the General Partner of the Partnership decided to authorize the audit committee (which consists of independent and outside directors only) to address the issue of the Investment Recovery Date in the Tamar Project, and, *inter alia*, to examine issues that arise from a report prepared at the request of the supervisor of the Partnership by an outside economic consultant (in this section: the "**Consultant on behalf of the Supervisor**" and the "**Consultant's Report**", respectively), to clarify the various issues vis-à-vis the Royalty Interest Owners, and to take any other measure as the committee shall deem fit, at its discretion, and all in accordance with the Partnership's best interests. According to the same board resolution, the audit committee is authorized to retain the services of outside and independent professional consultants, according to its discretion and at the Partnership's expense, for the purpose of supporting the proceeding legally and economically, and to determine the terms and conditions of compensation of the said consultants.

It is noted that the report of the Consultant on behalf of the Supervisor summarizes checks that he carried out with respect to the calculation of the Investment Recovery Date that was included in the draft calculation report prepared by the Partnership, whereby the Investment Recovery Date occurred in December 2017 (in this section: the "**Draft Calculation**). The main issue mentioned in the Consultant's Report is the treatment of the levy on gas and petroleum profits under the Taxation of Profits from Natural Resources Law, with respect to which the Consultant on behalf of the Supervisor noted, *inter alia*, that his conclusions do not necessarily represent flaws in the Draft Calculation and are subject to legal and economic interpretation of the royalty agreement.

It is noted that on September 4, 2018, the Audit Committee and subsequently the Board (without directors who hold office in the control holder) approved a calculation of the Investment Recovery Date in the Tamar project, whereby the date of commencement of payment of royalties to the Royalty Interest Owners at the rate of 6.5% (the "**Increased Rate**") (instead of a rate of 1.5%), falls in January 2018 (in lieu of December 2017 according to the draft calculation), such that from this date, the Partnership pays the Royalty Interest Owners royalties at the increased rate. It is noted that the calculation was approved by the Audit Committee and the Board after completion of the auditors' audit of the Partnership, and based on independent legal advice given to the Audit Committee.

The change to the Investment Recovery Date as aforesaid (in January 2018 in lieu of December 2017) derived from the correction of a calculation error that was included in the Draft Calculation in respect of the financial expenses. In this context, it is noted that further to the Partnership's request of the Royalty Interest Owners for restitution of $2 million that had been overpaid to them, on September 20, 2018, the said Royalty Interest Owners repaid the Partnership the said amount.

On September 6, 2018, a general meeting of the participation unit holders was held, which was summoned by the Partnership's supervisor, at which, *inter alia*, it was decided to approve a budget for the supervisor's work on the process of examination of the Investment Recovery Date. For further details, see the (amending) immediate reports of September 2, 2018 and September 12, 2018 (Ref.: 2018-01-081628 and 2018-01-083794, respectively), the information appearing in which is incorporated herein by way of reference.

For details regarding the legal proceedings that are being conducted in connection with the Investment Recovery Date in the Tamar project, see Section 7.28.6 below.

2. Royalties by Virtue of the Avner Partnership Agreement[291]: According to the Avner partnership agreement, the Partnership pays Cohen Development and other parties that are not affiliated with the Partnership (the "**Royalties by Virtue of the Avner Partnership Agreement**" and the "**Entities Entitled to Royalties by Virtue of the Avner Partnership Agreement**", respectively) (and in accordance with the adjustment stated in sub-section (a)) royalties at the rate of 3% of the Partnership's entire share of the petroleum 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 the deduction of royalties of any kind but after the reduction of the petroleum which shall serve for the purpose of the production itself).

[291] A limited partnership agreement of August 6, 1991 (as amended from time to time) which was signed between Avner Oil & Gas Ltd., as the general partner of Avner of the first part, and Avner Trusts Ltd., as limited partner of Avner of the second part (the "**Avner Partnership Agreement**").

Delek Group, Delek Energy and Delek Royalties and the Entities Entitled to Royalties by Virtue of the Avner Partnership Agreement shall be referred to collectively as the "**Royalty Interest Owners**".

3. Additional terms:

a. The Royalty Interest Owners or any of them shall be entitled to receive all or any of the aforesaid royalties in kind, i.e. to receive in kind a part of the petroleum 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 said Transferors shall receive the royalties. Should either of the Royalty Interest Owners not choose to receive the royalties in kind, the Partnership shall pay such Royalty Owner the market value, in Dollars or (if payment under law may not be made but in Israeli currency) in Israeli currency, calculated in Dollars according to the Dollar's representative rate upon the actual payment, at wellhead price, of the royalties due to the Royalty Owner. Such payment shall be made once every month. The measurement of the quantities of petroleum 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 petroleum 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 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).

4. Additionally, the Partnership pays Dor Chemicals Ltd. ("**Dor**") royalties from its share of the Tamar and Dalit leases, as specified in Sections 7.3.7 and 7.3.8 above.

Delek Group, Delek Energy and Delek Royalties, the Entities Entitled to Royalties by Virtue of the Avner Partnership Agreement and Dor, shall collectively be referred to in Section 7.27.12(c) below as the "**Tamar Royalty Interest Owners**".

(c) Manner of calculating the market value at the wellhead of the royalties due to the State and affiliated and third parties[292]

1. Payment of royalties from Yam Tethys project

a. The Petroleum Law prescribes, *inter alia*, that a lease holder owes royalties at the rate of one eighth (12.5%) of the quantity of oil produced from the area of the lease and used and that the lease holder shall pay to the State's treasury the "market value of the royalties at the wellhead". The method of calculation of the "market value at the wellhead" is required since the natural gas sales in Israel are priced at the point of delivery of the gas at the shore and not at the wellhead, and therefore there is no established market for pricing "at the wellhead".

b. It was agreed between Delek Energy and Delek Group and those entitled to royalties pursuant to the Avner Partnership Agreement (the "**Royalty Interest Owners in the Yam Tethys Project**") and the Partnership that the manner of calculating the market value at the wellhead of the royalties due to the Royalty Interest Owners from the Yam Tethys project shall be in accordance with the principles according to which the State's royalties are calculated.

c. Pursuant to the provisions of the Petroleum Law, and in accordance with the provisions of the Petroleum

[292] For details with respect to a claim filed by the Partnership and Noble in respect of royalty overpayments to the State, see Section 7.28.2 below.

Commissioner's letter of July 19, 2004 (in this section: the "**Commissioner's Letter**"), and from the summary of a meeting of November 15, 2004, between the Petroleum Commissioner and the representatives of Yam Tethys it arises that for calculating the value at wellhead price of the State's royalties for the natural gas reservoirs Mari B and Noa North it was agreed to adopt the principles of the English formula, whereby the State recognizes certain kinds of expenses, including the pipes, platform, onshore production facilities, underwater equipment, operation expenses and interest expenses, according to certain rates determined for the various kinds of expenses (the "**Recognized Expenses**").

d. According to the aforesaid arrangement, for calculating the value at the wellhead of the State's royalties, the Recognized Expenses shall be deducted as annual depreciation from the total sales, according to the quantity of gas that was produced and sold each year in relation to the quantity of the reserves that existed on the production commencement date. As a result of the implementation of the principles of the English formula pursuant to the aforesaid agreement, and considering the outline for the sale of gas between the Tamar Partners and the Yam Tethys Partners as specified in Section 7.3.4(e) above, the actual rate of the State's royalties in the Yam Tethys project (the Ashkelon and Noa leases), on which the Partnership relied in its financial statements, is as follows: In 2016, the actual royalty rate to the State was approx. 9.6%, and the royalties to the Royalty Interest Owners in the Yam Tethys project were also calculated in accordance therewith in such year (in 2016 in the Ashkelon Lease: approx. 5.2% to the Delek Group and Delek Energy Royalty Interest Owners and approx. 2.2% to the Royalty Interest Owners by Virtue of the Avner Partnership Agreement). In 2017, the actual royalty rate to the State was approx. 11.05%, and the royalties to the Royalty Interest Owners in the Yam Tethys project were also calculated in accordance therewith in such year (in 2017 in the Ashkelon Lease: approx. 6% to the Delek Group and Delek Energy Royalty Interest Owners and approx. 2.5% to the Royalty Interest Owners by Virtue of the Avner Partnership Agreement). In 2018, the actual royalty rate to the State was approx. 11.28%, and in this year the royalties to the Royalty Interest Owners in the Yam Tethys Project were also calculated accordingly (in 2018, in the Ashkelon lease: approx. 6.2% to Delek Group and Delek Energy royalty interest owners and approx. 2.6% to the Royalty Interest Owners under the Avner Partnership Agreement).

e. In February 2018, the Yam Tethys Partners and the Ministry of Energy signed an agreement with respect to the final royalty reports for the years 2011-2013. According to the agreement, it is provided that the Yam Tethys Partners are entitled to a refund of approx. $4.4 million (100%), which was offset against monthly royalty payments in the Yam Tethys Project.

f. From 2014 until December 2016, the Yam Tethys partners paid, under protest, advance payments on account of royalties to the State at a rate of approx. 11.96% in respect of the revenues from the Yam Tethys project.

g. In February 2017, a letter was received from the Ministry of Energy, whereby advance payments will be made for royalties from the Yam Tethys project at a rate of 0%, and it was noted that insofar as significant production takes place in the year's course, such rate will be updated.

2. Payment of royalties from the Tamar Project

a. It shall be emphasized that it is the Ministry of Energy's position that the manner of calculation of value of the State's royalties at wellhead in the Yam Tethys project, as determined between the parties as aforesaid, is specific to this project. As of the report release date, the partners in the Tamar Project, including the Partnership, are in negotiations with the Petroleum Commissioner concerning the manner of calculating the market value of the royalties at wellhead in the Tamar Project. Until the completion of the said negotiations the Tamar Partners have paid the State, under protest, advances on account of the royalties for the revenues from the Tamar Project, in 2016 and in 2017 and 2018 at a rate of 12% and approx. 11.65%, respectively. In addition, it is the position of the Operator and the other Tamar Partners that the calculation of the actual rate of the State's royalties for the revenues from the Tamar Project should reflect the complexity of the project, the risks involved therein and the amount of investments in the project, compared with the Yam Tethys project. It is noted that, according to a calculation based on the principles of the "English formula", which constitutes the most proximate estimate to the agreement signed with the State for the Yam Tethys project, the effective rate of royalties to the State in the Tamar Project, which was used as a basis by the Partnership in its financial statements, in 2016, 2017 and 2018, is approx. 11.15%, approx. 11.2% and approx. 11.16%, respectively. In addition, it shall be noted that in Tamar reservoir's discounted cash flow figures, the Partnership assumed an 11.5% royalty rate, which rate is lower than the royalty rate actually paid to the State as advance payments at the rate of 11.65% as specified above.

b. It shall be noted that the calculation of the market value at wellhead of the royalties due to the Royalty Interest Owners from Tamar, was made by the Partnership in accordance with the same principles, pursuant to which the State's royalties are calculated as aforesaid. Therefore, the average rate of royalties to the Royalty Interest Owners from Tamar is approx. 4.39%, 4.42% and 8.63% for each of the years 2016, 2017 and 2018. Until completion of the aforesaid discussions, in 2016, the Partnership paid the Royalty Interest Owners from Tamar, royalties at a rate of approx. 4.73%, in 2017 – approx. 4.59% and in 2018 – approx. 9.01%, and all for its share in the revenues from the Tamar Project.

3. The difference between the royalties actually paid to the State and to the royalty interest owners from the Tamar Project and from the Yam Tethys project, and the rate of the effective royalty which was used by the Partnership as a basis in its financial statements is approx. $27.8 million. For further details, see Note 15 to the financial statements (Chapter C hereof).

4. For details regarding a claim for restitution of royalties that were paid to the State by the Partnership, Avner and Noble in respect of their revenues deriving from the supply of natural gas from their share in the Tamar Project to their customers, under Yam Tethys project agreements, see Section 7.28.2 below.

5. <u>Payment of royalties from other projects</u>

   As of the report release date, there is no agreement with the Petroleum Commissioner concerning the manner of calculating the actual royalties to the State in other future projects to which the Partnership shall be a party. Therefore, as of the report release date, it is impossible to evaluate how the market value at wellhead of the royalties that shall be paid from other future projects to the State and the Royalty Interest Owners will be calculated.

(d) <u>Expert's decision on the definition of "Investment Recovery Date"</u>

In 2002, an expert deciding arbitrator was appointed in agreement between the Partnership and the Transferors in order to determine the right meaning of certain definitions and terms concerning the royalties that the Partnership is liable to pay as aforesaid.

In the appointed expert'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", including as follows:

1. Only revenues/receipts that were received for petroleum and/or natural gas and/or other valuable substances (jointly, "**Petroleum and/or Gas**") that were produced and exploited from the petroleum assets (and certified as such by the Partnership's auditors) should be taken into account; and

2. Only the value of the Partnership's expenses incurred in the petroleum asset (license or lease), in which the Petroleum and/or Gas was produced (and were certified as such by the Partnership's auditors) should be taken into account; and if the expense was incurred in more than one petroleum asset as aforesaid, it should be split between the petroleum assets in which it was incurred and/or which it was intended to serve. Consequently, if the expense was incurred in petroleum asset A, from which eventually no Petroleum and/or Gas was produced, this expense shall not be taken into account for determining the Investment Recovery Date in petroleum asset B, from which the Petroleum and/or Gas are produced; and

3. The expense for exploration activities (including dry holes) shall be taken into account as an expense in the petroleum asset in the area of which these activities were performed, for the purpose of determining the Investment Recovery Date, and the same applies to activities for development and determination of the field boundaries; and

4. Expenses for facilities (onshore and on the continental shelf), including for production, treatment, transmission, measurement, storage, operation, maintenance and operational expenses and marketing and sale expenses (including the sale agreements) of the Gas should be taken into account; and

5. With respect to expenses that are taken into account for determining the Investment Recovery Date, fully-incurred expenses (without depreciation) and financing expenses are to be taken into account; and

6. The determination of the Investment Recovery Date is a one-time irreversible determination, even if a situation is subsequently

created wherein the expenses in the petroleum assets exceed the revenues received from the production of the Petroleum and/or Gas from that petroleum asset.

7.27.13 Agreement for granting usage rights in the facilities of the Yam Tethys project

According to an agreement of July 23, 2012, between the Partnership together with the other Yam Tethys Partners, and the Partnership together with the other Tamar Partners (the "**Usage Agreement**"), it was agreed, *inter alia*, as follows:

(a) The Yam Tethys Partners shall grant the Tamar Partners usage rights in the existing facilities at the Yam Tethys project, including the wells, the platform of Mari-B, the compression system, the pipes and the Terminal, and the Tamar Partners were granted the right to upgrade and/or construct facilities for transportation and storage of natural gas from the Tamar Project (the "**Yam Tethys Facilities**"). The usage rights in the Yam Tethys Facilities shall be given subject to maintaining capacity for the gas produced from the Yam Tethys project in the pipes and the Terminal.

(b) The term of the Usage Agreement shall expire on the earlier of: (a) the expiration or termination of the Tamar Lease, and in case that the Dalit field is developed such that use is made of the Yam Tethys Facilities, the expiration or termination of the Dalit Lease; (2) giving of notice by the Tamar Partners of permanent discontinuation of commercial production of gas from the Tamar Project; (3) the abandonment of the Tamar Project.

(c) In consideration for the use of the Yam Tethys Facilities, the Tamar Partners have paid the Yam Tethys Partners the total sum of $380 million in installments that ended on December 31, 2015. As of the report approval date, such consideration has been fully paid.

(d) The transfer of the rights in the Tamar lease, in the joint operating agreement of the Tamar lease, in the Yam Tethys lease or in the operating agreement of Yam Tethys, of each specific party to the Usage Agreement, is subject to the assignment of its rights and undertakings according to the Usage Agreement in accordance with the proportionate share that was transferred as aforesaid. The transferee is required to agree to assume the transferor's undertakings according to the Usage Agreement.

(e) Fundamental breaches

If the Tamar Partners:

1. Shall have failed to pay the Yam Tethys partners any amount that is required according to the Usage Agreement within 10 days from the date of receipt of an invoice from the Yam Tethys partners;

2. Shall fail to supply to the Yam Tethys partners the capacity for gas that is produced from the Yam Tethys project that is reserved for them in the pipeline and at the terminal according to the Usage Agreement, which breach is not remedied within 60 days from the date of receipt of notice of the breach from the Yam Tethys partners;

3. Shall have breached the Usage Agreement (except in connection with management of the Yam Tethys Facilities by the Tamar Partners), which breach is not remedied within 60 days from the date of receipt of notice of the breach from the Yam Tethys partners.

The sole remedy available to the Yam Tethys partners with respect to these breaches by the Tamar Partners is the filing of a claim with a payment demand, or a motion for an enforcement order or an injunction, as the case may be.

If any one of the Yam Tethys partners or the operator of Yam Tethys:

1. Shall have failed to pay the Tamar Partners any amount that is required according to the Usage Agreement within 10 days from the date of receipt of an invoice from the Tamar Partners;

2. Denial of the rights to use the Yam Tethys Facilities in any manner whatsoever;

3. Shall have breached the Usage Agreement (except in connection with management of the Yam Tethys Facilities by the Yam Tethys partners), which breach is not remedied within 60 days from the date of receipt of notice of the breach from the Tamar Partners.

The sole remedy available to the Tamar Partners with respect to these breaches by the Yam Tethys partners is the filing of a claim with a payment demand, or a motion for an enforcement order or an injunction, as the case may be.

(f) In addition, the agreement contains, *inter alia*, provisions that regulate the relationship between the Tamar Partners and the Yam Tethys Partners throughout the entire period of use of the Yam Tethys Facilities, including with respect to the management of the Yam Tethys Facilities, and a mechanism for the distribution of the operating expenses of the Yam Tethys Facilities and distribution of the capital expenses of the Yam Tethys Facilities in connection with the preparation and upgrade of the Yam Tethys Facilities for receiving natural gas from the Tamar Project, which is based on the ratios of the gas output volume between the Yam Tethys project and the Tamar Project.

(g) This agreement is subject to English law. All of the disputes between the parties in connection with this agreement or the performance thereof shall be heard in arbitration before three arbitrators according to the arbitration rules of the London Court of International Arbitration. Disputes of a technical nature may be referred to an independent expert with appropriate qualifications.

(h) The ownership of the upgraded Yam Tethys Facilities shall remain with the Yam Tethys Partners and provisions were determined in the Usage Agreement regarding a mechanism of accounting in respect of the value of the said facilities at the end of the period of production from the Tamar Project. Within 90 days after the end of the Tamar period, the Yam Tethys operator is required to provide each one of the Tamar Partners with a calculation of the market value of the upgrades to the Yam Tethys Facilities. This calculation shall take into account the condition of the facilities and their lifespan, the planned use of the facilities by the Yam Tethys partners and the Yam Tethys group, the dismantling and abandonment costs and any other matter that the Yam Tethys operator deems relevant. The parties to the agreement shall conduct negotiations on the issue and shall agree on a final market value, with any dispute on the matter being referred to be decided by an expert. The payment of the Yam Tethys partners to the Tamar Partners for the upgraded Yam Tethys Facilities (or vice versa if the value is negative) shall be made within 60 days from the date of determination of a final market value for the upgraded facilities of Yam Tethys.

7.27.14 Agreement for the exercise of an option to purchase rights in the Roy License[293]

(a) According to the agreement signed on November 26, 2012, between the Partnership, of the first part, and Edison of the second part, Edison granted the Partnership an option to purchase therefrom the option granted thereto by Ratio to purchase working interests at a rate of 20%

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[293] On the signing date of the aforesaid agreement, the Edison Option also included the purchase of rights in the Neta/398 license (the "**Neta License**"), which expired on November 9, 2015, further to an application submitted to the Petroleum Commissioner by the partners in the Neta and Roy licenses for a change in the boundaries of the Roy License, including by way of an transfer of areas from the Neta License to the Roy License and the removal of other areas, such that following the requested change of boundaries, the partners in such licenses shall be left only with the Roy License within its new boundaries.

(out of 100%) in the Roy License[294] (in this section below, the "Option"). On March 19, 2019, the Partnership notified Ratio and Edison of the exercise of the Option (in this section below, the "Exercise Notice"). According to the Exercise Notice, and in accordance with certain changes in the terms and conditions of the Option that were agreed upon between Ratio and the Partnership, as specified below, the Partnership shall purchase from Ratio interests at the rate of 24.99% in the Roy License (in this section below, the "Transaction").

(b) Set forth below is a concise description of the main principles of the Transaction:

1. Subject to fulfillment of the conditions precedent specified below, Ratio shall transfer to the Partnership 24.99% of the working interests in the Roy License (below in Section 7.27.14, the "**Purchased Interests**").

2. Against the transfer of the Purchased Interests, the Partnership shall bear the following costs: (1) past costs that were borne by Ratio in connection with the Purchased Interests in the sum total of approx. $4 million, in accordance with a calculation that Ratio shall deliver to the Partnership (below in Section 7.27.14, the "**Past Costs**"). The Past Costs shall be paid by the Partnership to Ratio, assuming a commercial discovery, on the date on which final approval of the partners is received (in accordance with the provisions of the Joint Operating Agreement (the JOA) (if received) for a work plan and a budget for development of a reservoir in the area of the Roy License (FID); (2) any and all costs that shall be paid by Ratio in respect of the actions that shall be taken in the context of the Joint Operating Agreement, with respect to the Purchased Interests, from the date of the Exercise Notice until the date of completion of the process of transferring the Purchased Interests (below in Section 7.27.14, the "**Interim Costs**"). The Interim Costs shall be paid by the Partnership to Ratio on the date of completion of the transfer of the Purchased Interests.

3. The parties have agreed that they will perform the binding work plan in the Roy License for 2019-2020 (as shall be approved by the partners in the Roy License), in the framework of which an exploration well will be drilled, with the Partnership bearing its proportionate share in the costs of such well.

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[294] The Roy License is one of the licenses that were granted by the Petroleum Commissioner on April 15, 2013 *in lieu* of the preliminary permit 202/Gal.

4. The Partnership has undertaken to grant Eitan Aizenberg Ltd.[295] an overriding royalty at the rate of 2% out of a 14.99% interest (i.e. an overriding royalty at the rate of approx. 0.2998% out of 100%) in petroleum and/or gas that is produced from the area of the Roy License, according to the market value at the wellhead. It is clarified that the remainder of the Purchased Interests (at the rate of 10%) is not subject to the said overriding royalty. It is clarified that the Purchased Interests shall be subject to the Partnership's commitment to payment of overriding royalties to interested parties of the Partnership and to third parties.

5. Subject to the provisions of Paragraph 7.27.14(b)4 above, the Purchased Interests shall be transferred to the Partnership without any pledge, lawsuit, liability, right to receive a royalty (with the exception of the State's right to royalties) or any other third party right.

(c) <u>As of the Report Release Date, the holding rates of the partners in the Roy License are as follows</u>:

| | |
|---|---|
| Edison | 20.00% |
| Ratio | 70.00% |
| Israel Opportunity | 10.00% |

<u>Assuming the transaction is closed, the working interest rates in the said license shall be as follows</u>:

| | |
|---|---|
| Edison | 20.00% |
| Ratio | 45.01% |
| Israel Opportunity | 10.00% |
| The Partnership | 24.99% |

The closing of the Transaction and the transfer of the Purchased Interests to the Partnership is subject to the fulfillment of conditions precedent and receipt of approvals, including the approval of the Petroleum Commissioner, the approval of the Competition Commissioner (insofar as required) and receipt of the necessary consents from Edison and Israel Opportunity. In addition, the approval of the meeting of the holders of the Partnership's units is required for amendment of the limited partnership agreement that was signed on July 1, 1993 (as amended from time to time), in order to allow the Partnership to participate in oil and/or gas exploration and production in the Roy License.

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[295] Eitan Aizenberg Ltd. is a private company owned and controlled by Mr. Eitan Aizenberg, who serves as a geologist of Ratio.

If not all of the necessary approvals are received up to seven (7) days before commencement of the first exploration drilling in the area of the Roy License, the Option shall expire and terminate without any liability of either of the parties. The aforesaid notwithstanding, if the Partnership pays the Interim Costs in respect of the Purchased Interests and continues to bear any and all costs of the joint actions in the Roy License in respect of the Purchased Interests (and such payments are without recourse), the deadline for receipt of the necessary approvals shall be extended accordingly.

7.27.15 Agreement for the purchase of an interest in the New Ofek and New Yahel licenses

On March 19, 2019, the Partnership entered into an agreement with SOA (in this section, the "**Seller**") for the purchase of a 25% interest (out of 100%) in each of the New Ofek license and the New Yahel license, which are onshore licenses, in the center and the north of the State of Israel, respectively (in this section, the "**Petroleum Assets**", the "**Licenses**", the "**Purchased Interest**", the "**Purchase Agreement**" and the "**Transaction**", respectively).

Set forth below is a concise description of the main principles of the Purchase Agreement:

(a) On the Transaction closing date (the "**Effective Date**")[296], the Seller shall transfer to the Partnership the Purchased Interests, their being free and clear of any pledge, royalty[297], liability, claim and third party rights, apart from certain exceptions that were defined, such as the State's royalties, other mandatory payments and statutory restrictions, and from this date the Partnership shall assume and bear all of the rights and liabilities in connection with the Purchased Interests, apart from certain exceptions that were defined, such as liability for bodily injury and property damage and environmental damage in respect of the period preceding the Effective Date.

(b) On the Effective Date, the Partnership shall pay the Seller U.S. $1 million as reimbursement for past expenses which were borne by the Seller, until the Effective Date, in the framework of its activity in the Petroleum Assets.

[296] The "transaction closing date" shall occur on a business day, immediately upon fulfillment of all of the conditions precedent or waiver of the need for the fulfillment thereof or on another date on which the parties shall agree in writing.

[297] It is clarified that the Purchased Interests shall be subject to the Partnership's commitment to payment of overriding royalties to interested parties of the Partnership and to third parties.

(c) The Partnership undertook to bear the costs of production tests in the New Ofek License up to a sum total that shall not exceed U.S. $6,500,000. If the cost of the production tests exceeds the said amount, each one of the partners in the New Ofek License, including the Partnership, shall pay its proportionate share in the additional cost as aforesaid, in accordance with the provisions of the Joint Operating Agreement (JOA) which shall be signed between the Partners on the Effective Date.

The Partnership shall provide guaranties in the sum of 50% of the guaranties required in connection with the Licenses, according to the directives of the Petroleum Commissioner for provision of collateral, provided that if the Seller does not provide the remaining guaranties (50%), the Partnership shall be released from its said obligation. As of the report release date, the guaranties that have been provided in respect of the New Ofek License and the New Yahel License are in the sum of $0.5 million and $1 million, respectively (100%).

(d) The closing of the Transaction is subject to the fulfillment of several conditions precedent, including: (1) receipt of the approvals of the competent organs of the Seller and of the Partnership, including the approval of the meeting of the holders of the Partnership's participation units for amendment of the limited partnership agreement of July 1, 1993 (as amended from time to time), in order to allow the Partnership to participate in oil and/or gas exploration and production in the Petroleum Assets; (2) receipt of the consent of Globe and Capital to the transfer of the interests according to the Purchase Agreement; (3) receipt of the Commissioner's approval; and (4) receipt of the approval of the Competition Authority, insofar as required.

(e) If the conditions precedent are not fulfilled within one hundred and twenty (120) days (with an option for an extension by another thirty (30) days) from the date of the signing of the agreement (below in this section, the "**Original Period**"), at any time after such date, each party is entitled, if it fulfilled, in all material respects, its undertakings under the Purchase Agreement, to terminate the engagement in the Purchase Agreement by giving written notice to the other party.

(f) The Purchase Agreement includes additional provisions which pertain to tax duties, confidentiality, dispute resolution, representations, undertakings and indemnification arrangements between the parties in respect of a breach of the representations or undertakings that were made in the agreement, as is accepted in transactions of this type.

(g) As of the Report Release Date, the holding rates of the partners in the Licenses are as follows:

| | |
|---|---|
| SOA | 70% |
| Globe | 20% |
| Capital | 10% |

Assuming the transaction is closed, the working interest rates in the Licenses shall be as follows:

| | |
|---|---|
| SOA | 45% |
| Globe | 20% |
| Capital | 10% |
| The Partnership | 25% |

7.27.16 Agreement for the sale of the Partnership's rights in the Tanin and Karish Leases

On August 16, 2016, the Partnership and Avner (in this section: the "**Sellers**") signed an agreement with Energean, whereby Energean purchased all of the rights of the Sellers and Noble in the I/16 "Tanin" and I/17 "Karish" leases (the "**Leases**"). In consideration for the purchase of the rights in the Leases, the agreement provides that Energean will pay the Sellers a sum total of $148.5 million (in equal shares between them), which represents the reimbursement of past expenses invested in the Leases by the Sellers and Noble, plus royalties in respect of the natural gas and condensate to be produced form the Leases, as follows: (1) The Sellers were paid $40 million in cash on the transaction closing date; (2) The balance of the consideration, in the total amount of $108.5 million (in this section: the "**Balance of the Consideration**"), will be paid to the Sellers in ten equal annual installments plus interest according to the mechanism and at the rate specified in the agreement, which will commence on the date on which a final investment decision (FID) is made with respect to the development of the Leases or on the date on which the total expenses of the Buyer in connection with the development of the Leases exceeds $150 million, whichever is earlier (3) The sold rights were transferred to the Buyer along with the existing royalties in the Leases, which the Sellers had borne in respect of their original share in the Leases (26.4705%) for each of the Sellers, and accordingly, the duty to pay the same to the royalty holders will be imposed on Energean as of the transaction closing date; (4) The Buyer will transfer to each of the Sellers a royalty right in respect of the natural gas and condensate to be produced from the Leases at the rate of 3.75% (for 100% of the rights in the Leases) – prior to the payment of the petroleum profit levy under the Taxation of Profits from Natural Resources Law, 5771-2011 (the "**Levy**") in respect of the Leases, and at the rate of 4.125% (for 100% of the rights in the Leases) – immediately upon commencement of the payment of the Levy, net of the rate of the existing royalties in respect of such Seller's share in the Leases, as specified in Subsection (3) above. Furthermore, in accordance with the provisions of the Gas Framework, the Buyer transferred to the Sellers and to the other Leviathan Partners the Leases' export quota, according to the conditions specified in the agreement and its annexes.

On March 27, 2018, the Partnership received Energean's notice whereby, on March 22, 2018, Energean adopted a final investment decision (FID) in connection with development of the Leases. Therefore, in accordance with the terms and conditions of the agreement, the Partnership is entitled, from the date of adoption of such FID, to payment of the Balance of the Consideration in ten equal annual installments, plus interest according to the mechanism and at the rate determined in the agreement. For details regarding the consideration that was received upon adoption of such FID and with respect to material valuations regarding royalty receivables and debt balance from the sale of the Partnership's interests in the leases, see Note 8B to the financial statements and Regulation 8B in Chapter D of this report.

7.27.17 <u>The Agreement for the Sale of the Rights to Tamar Petroleum</u>

As aforesaid, on July 2, 2017, a sale agreement was signed by and between the Partnership, as seller, on the first part, and Tamar Petroleum, as buyer, on the second part (hereinafter in this section: the "**Sale Agreement**"), pursuant to which Tamar Petroleum purchased rights from the Partnership at a rate of 9.25% (out of 100%) of the Tamar and Dalit leases. On July 20, 2017, all of the conditions precedent specified in the Sale Agreement were met, including the receipt of the Petroleum Commissioner's approval of the transfer of the rights in the Tamar and Dalit leases and the registration thereof in the Petroleum Register, and pursuant thereto, the rights in the Tamar and Dalit leases, at a rate of 9.25% (out of 100%) were transferred.

The main points of the Sale Agreement are as follows:

(a) The Partnership undertook to sell and transfer to Tamar Petroleum, participation rights in the rate of 9.25% (of 100%) in the Tamar and Dalit leases, subject to the existing undertakings for payment of overriding royalties to affiliated parties and third parties, and the proportionate share (9.25%) of the rights and undertakings pursuant to the JOA, agreements for sale of gas from Tamar Lease, the agreement for use of the Yam Tethys facilities, shares of Tamar 10-Inch Pipeline, the Tamar Platform operation approval, and the approvals to export from Tamar (below in Section 7.27.17 the "**Object of Sale**").

(b) The consideration for the Object of Sale that was paid to the Partnership included an amount of approx. $837 million in cash (approx. ILS 3 billion), and the allotment to the Partnership of 19,990,000 ordinary shares of ILS 0.1 par value each of Tamar Petroleum.

(c) Tamar Petroleum undertook to act to allow the Partnership to make a shelf (sale) offering if the Partnership will seek to sell its shares in Tamar Petroleum to the public, subject to certain qualifications and limitations, including a lock-up period which shall apply to the shares by virtue of TASE Rules and Regulations and no less than a full 6-month lock-up (which, as of the report date, has ended).

(d) Out of the amount of the cash proceeds that were due to the Partnership, a $34 million loan was provided to Tamar Petroleum, bearing 3% annual interest, which was repaid by Tamar Petroleum in full in October 2017, plus the interest that had accrued.

(e) The effective date for the purpose of calculating the consideration amount and the transfer of the rights and obligations for the Object of Sale to Tamar Petroleum is July 1, 2017.

(f) The Partnership shall continue to bear responsibility with respect to the following issues also subsequently to the date of completion of the transaction: the arbitration regarding the production component tariff (for details see Section 7.28.4 above), the appeal in the matter of the royalties with respect to the sale of gas from the Tamar Project to customers of the Yam Tethys project, including with respect to any and all liabilities in connection with these proceedings which shall be caused in the period following the effective date; the motion for certification of a class action that was filed by an IEC consumer against the Tamar Partners (for details see Section 7.28.1 below), with respect to the amounts that were received by the Partnership during the period before the effective date; liability due to taxes and royalties to the State with respect to the period before the effective date, or with respect to any profit, income or revenue of the Partnership in connection with the Object of Sale (including if said tax assessment was made after the effective date), except for taxes that relate to reports that were filed before the effective date to the tax authorities with respect to the Taxation of Profits from Natural Resources Law; taxes which apply to the Partnership in connection with the transfer of the Object of Sale to Tamar Petroleum; liabilities to the Partnership's suppliers or customers due to the Object of Sale which relate to the period until the effective date, except if provisions were made for such liabilities in Tamar Petroleum's financial statements; and liabilities, if any, with respect to Delek and Avner (Tamar Bond) Ltd.

(g) Tamar Petroleum bore all of the payments, expenses and fees to the State (except for taxes as aforesaid) which served for the transfer of the Object of Sale to Tamar Petroleum and obtaining the approvals. Additionally, Tamar Petroleum bore all of the expenses and costs related to the issuance of the bonds. The Partnership bore the expenses and costs, *inter alia* of the legal advisors and the underwriters under the distribution agreement, all in connection with the issuance of shares of Tamar Petroleum.

(h) The Partnership made various representations in the Sale Agreement, as is customary in such transactions, including an indemnification undertaking for the breach of representations. Additionally, additional provisions were set forth as is customary in such agreements, including regarding a dispute resolution mechanism, interpretation and delivery of notices.

(i) It was further prescribed in the framework of the Sale Agreement that insofar as the Partnership shall hold Tamar Petroleum shares after the completion of the issuance of the shares, then the Partnership unilaterally waives all of the voting rights attached to all of the shares held thereby over and above shares in a quantity equal to 12% of the Tamar Petroleum shares following the completion of the issuance. For the avoidance of doubt, it was clarified that all of the equity rights attached to the shares held by the Partnership shall remain in full force, including: the right to receive dividends, bonus shares, rights, and the right to receive surplus assets upon the Company's liquidation. The shares that are in excess, above 12% (the "**Surplus Shares**") shall be deposited thereby with a trustee that shall act pursuant to an irrevocable letter of instructions that shall set forth, *inter alia*, the following: the Surplus Shares shall also include bonus shares or rights, or shares deriving from such rights, that shall be allotted to the Partnership due to the Surplus Shares as part of an issuance of bonus shares and/or rights to all of Tamar Petroleum's shareholders. With respect to a future issuance of rights, if any, the Partnership shall instruct the trustee whether to exercise or sell the right. The trustee shall transfer to the Partnership any and all dividends that it will receive due to the Surplus Shares. Whenever the Partnership will seek to sell the Surplus Shares, in whole or in part, to a third party, the trustee shall transfer such shares to whomever the Partnership instructs it, in writing, against receipt of full consideration therefor (unless the Partnership shall have instructed it to transfer the shares before receipt of the consideration), provided that the Partnership shall inform the trustee, in writing, of the transferee's details and sign any document that will be required for such transfer. Upon the sale or transfer of the Surplus Shares from the Partnership to a third party as aforesaid, they shall be entitled to all of the rights that are attached to ordinary shares in Tamar Petroleum.

The Partnership undertook to first sell the Surplus Shares (which, following their sale, shall confer on the buyer all of the rights that are attached thereto, including voting and capital rights as aforesaid) and also undertook that so long as it shall not have sold the Surplus Shares it shall not purchase additional Tamar Petroleum Shares. It is clarified in this context that shares that will be allotted to the Partnership in the context of issuance of bonus shares and/or rights shall not be deemed as a purchase for purposes of this undertaking.

Additionally, the Partnership undertook not to propose more than one director in the framework of the general meetings that convene for the purpose of appointing directors at Tamar Petroleum. The articles of association of Tamar Petroleum determine provisions that establish the Partnership's aforesaid waiver of voting rights that are attached to the shares that will be held thereby at a rate exceeding 12% of the issued capital, Tamar Petroleum's articles further determine several provisions that shall apply so long as the Partnership will hold a rate that exceeds 25% or more of Tamar Petroleum's issued and paid up share capital, *inter alia*: provisions with regard to an appointments committee that will be established insofar as Tamar Petroleum will wish to propose, to the shareholders' meeting, candidates for holding office as directors at Tamar Petroleum; limitations on directors' fitness whereby all of the directors, except one, shall not have a link to the Partnership; and a limitation on the manner of approval of unusual transactions with Delek Group Ltd. or a corporation which is controlled thereby. For additional details see Notes 6 and 7C1F to the financial statements.

For details regarding partial prepayment of the Tamar Bond bonds from the amount of the proceeds for the Object of Sale, see Section 7.22.1(c) above.

7.28 Legal Proceedings

7.28.1 On June 18, 2014, a motion for class certification was filed with the District Court in Tel Aviv by a consumer of the IEC against the Tamar Partners (the "**Petitioner**" and the "**Certification Motion**", respectively). The issue addressed in the said Motion is the price for which the Tamar Partners sell natural gas to the IEC.

The Certification Motion claims that the gas price for the IEC is an unfair price which constitutes abuse of the Tamar Partners' position as the holders of a monopoly in the Israeli natural gas supply sector in violation of Section 29A of the Economic Competition Law.

The remedies sought by the Certification Motion are: compensation for all of the electricity consumers in the sum of the difference between the price that the IEC paid for natural gas supplied by the Tamar Partners and the fair price thereof, which was estimated, on the date of the filing of the Certification Motion, at a total sum of ILS 2.456 billion (in terms of 100%), as well as declaratory orders, according to which the Tamar Partners are obligated to avoid selling the natural gas from the Tamar Project in an amount exceeding the amount stated in the Motion for Certification, and the sale thereof at a higher price constitutes abuse of their monopolistic power.

On July 7, 2016, a court hearing was held on the motion for summary dismissal, which had been filed by the Tamar Partners on April 20, 2016, after the Attorney General had filed his position whereby the Certification Motion should be summarily dismissed. In his position, the Attorney General argued that there was no call for adjudication of the class action, on the grounds that price regulation (which is one component of the Gas Framework) may not be challenged separately from the Gas Framework as a whole, and judicial review of the Gas Framework belongs with the High Court of Justice, rather than in a class action. The Attorney General further argued that adjudication of the class action might hinder the execution of the Gas Framework.

On November 23, 2016 a decision was issued denying the motion for summary dismissal of the Certification Motion, and on December 15, 2016, the Tamar Partners filed a motion for leave to appeal this decision.

On September 28, 2017, the supreme court's decision was received to deny the motion for leave to appeal and remand the case to the district court for it to hear the certification motion on the merit. On October 29, 2017, the Tamar Partners filed a motion to summon witnesses in the case on behalf of the State and a motion to add evidence[298]. On December 8, 2017 the court granted the motion to summon witnesses as aforesaid and denied the Tamar Partners' motion to add evidence. On April 12, 2018, counsel for the late Petitioner filed an agreed motion to replace him with his widow (the "**Petitioner**"), subject to the filing of a supplementary affidavit on her behalf, and on the same day, the motion was approved by the court. As of the report release date, the examination of the experts and the affiants on behalf of the parties has ended. On January 7, 2019, the Petitioner filed her summations, and as of the date of the report, the date for the filing of summations on behalf of the Tamar Partners is April 7, 2019. In the Partnership's estimation, based on the opinion of its legal

[298] On December 8, 2017, Tamar Petroleum's motion to join the aforesaid legal proceeding was granted.

counsel, the chances of the motion for class certification being accepted are lower than 50%.

7.28.2 On March 12, 2015, the Partnership and Noble (jointly in this section: the "**Plaintiffs**") filed a complaint with the District Court in Jerusalem against the State of Israel through its representatives from the Ministry of Energy (in this section: the "**Defendant**"), which mainly includes the restitution of royalties paid by the Plaintiffs, in excess and under protest, to the Defendant, for revenues that derive from gas supply agreements which were signed between third party customers (below in this section, the "**Ultimate Customers**") and the Yam Tethys partners, and that some of the gas which is the subject matter of the aforesaid agreements was supplied from the Tamar Project, according to the reconciliation mechanism, pursuant to which the consideration that was obtained from the Ultimate Customers, together with the consideration reflecting the share of the Delek Group, which is a right holder in Yam Tethys and is not a holder of direct rights in Tamar, was divided such that the Tamar partners which are not also Yam Tethys partners (i.e. Isramco, Dor Gas, Tamar Petroleum and Everest), received a natural gas price equal to the monthly average price of natural gas supplied during that month by virtue of agreements executed between the Tamar partners and their customers, and the remaining monetary balance was divided among the Yam Tethys partners that also have rights in the Tamar Project (i.e. the Plaintiffs), according to their share in the Tamar Project. This reconciliation mechanism enabled keeping the gas quantities in the Tamar Project balanced as between the partners therein according to their share. The amount of the recovery remedy, sought by the Plaintiffs, is approx. $15.3 million as of the date of filing of the claim, and reflects the royalties which the Plaintiffs shall overpay until the date of filing of the claim (the "**Recovery Amount**"). Underlying the claim is the Plaintiffs' argument that as opposed to the State's argument, the Plaintiffs as the holders of the rights in both the Yam Tethys project and the Tamar project are taking from gas in their possession such that no sale was made between the "Tamar Project" and the "Yam Tethys project", and therefore, they are required to pay royalties based on the consideration that was received from the Ultimate Customers, plus the share of Delek Group, which does not hold rights in Tamar. Consequently, the State is collecting royalties from the Plaintiffs in excess, for amounts that exceed the amounts that they receive from the Ultimate Customers, which reflects the market value of the gas, in view of the Ultimate Customers being an unaffiliated party. As of December 31, 2018, the remedy of restitution for the Plaintiffs' primary argument as aforesaid is approx. $26.9 million (the amount of the principal of the repayment of royalties that were overpaid for the period between May 2013 and September 2017, according to the Plaintiffs) (the "**Updated Recovery Amount**"), the Partnership's share being approx. $12.5 million.

Alternatively, the Plaintiffs argument is that also if there had been any kind of a sale, the sale that was performed was with respect to the share of the holders of the rights in the Tamar Project that are not the holders of the rights in Yam Tethys (Isramco and Dor – 32.75% and in part of the period also Tamar Petroleum and Everest – 45.5%) and the holders of the rights in the Yam Tethys project, while the balance of the gas that is supplied to the Ultimate Customers by the Plaintiffs (67.25% and in part of the period in which Tamar Petroleum and Everest hold rights – 54.5%) is gas that is in the Plaintiffs' possession, which they are entitled to use for the purpose of supplying gas to the Ultimate Customers as aforesaid (in this section: the "**Partial Sale Approach**").

As of December 31, 2018, the remedy of restitution with respect to the Partial Sale Approach as aforesaid is approx. $18.8 million (the amount of the principal of the repayment of royalties that were overpaid for the period between May 2013 and September 2017, according to the Partial Sale Approach), with the Partnership's share being approx. $8.7 million.

After negotiations between the Plaintiffs and the Defendant, both inside and outside the court with respect to the preliminary proceedings and the fee amount, on January 24, 2019, the court's decision was issued, ruling that the preliminary proceedings have been completed and allowing the Plaintiffs to update the remedy of restitution to the Updated Recovery Amount insofar as they will pay the fee amount as required.

On February 26, 2019, the Plaintiffs filed a notice whereby they agree to add to the fee amount such that the sought remedy of restitution will be according to the Updated Recovery Amount, and in addition, dates for a trial hearing were scheduled for September 11, 2019 and September 22, 2019.

The Partnership estimates, based on the opinion of the legal advisors, that there is a possible chance that the full Updated Recovery Amount will be received and that the chances that the Partial Sale Approach will be accepted are better than the chances that it will be rejected.

7.28.3 On December 25, 2016 a motion for class certification was filed (below in this section, the "**Certification Motion**") based on the argument that the Merger transaction between the Partnership and Avner was approved in an unfair proceeding, and the consideration that was paid to the holders of the minority units in Avner, as determined in the Merger agreement, is unfair. The motion was filed against Avner, the general partner of Avner and the members of the board of directors thereof, Delek Group as the holder of control in Avner (indirectly), and against PricewaterhouseCoopers Consulting Ltd. (**PwC**) as the economic consultants of an independent board committee that was established by Avner. Pursuant to the motion, *inter alia*, the committee members, the board of Avner and the General

Partner company breached the duty of care vis-à-vis Avner, and Avner conducted itself in a manner that was oppressive to the minority. The total damage was estimated by the petitioners to be in the amount of ILS 320 million. On February 13, 2017 the court approved a stipulation whereby the motion for class certification will be amended by adding an argument of minority oppression by Delek Group. On July 6, 2017, the court ordered to add the Partnership as a respondent in accordance with the Partnership's motion. On July 27, 2017 and November 13, 2017 answers to the Certification Motion were filed and on January 14, 2018, the petitioners filed their response to the said answers. On October 15, 2018, a pretrial hearing was held on the Certification Motion at which the parties agreed to attempt to enter into a stipulation on the petitioners' motion for an order for discovery and inspection of the documents, and to give notice to the court on the matter within 60 days. On February 26, 2019 the parties filed a motion to approve a stipulation in reference to the motion for a discovery and inspection order. The Court granted the motion. The Partnership estimates, based on the opinion of the legal advisors, that the chances that the Certification Motion will be accepted are lower than 50%.

7.28.4 The PUA-E's decision of July 22, 2013, to split the uniform electricity production tariff that existed until then into several different tariffs, led to a disagreement with all of the Tamar Project customers that are linked to the electricity production tariff with regard to the gas price linkage for quantities supplied in the period between May 2013 and February 2015. It is noted that on January 21, 2015 and September 7, 2015, the PUA-E's decisions on the update of the production tariffs which considerably reduced the differences between the various production tariffs, were published. In September 2015, the PUA-E has reinstated the structure of one electricity production tariff. Commencing from 2015, settlement agreements were signed between the Tamar Partners and the majority of the customers linked to the electricity production tariff, apart from one customer, OPC. In June 2017, the Partnership, together with the other Tamar Partners (other than Tamar Petroleum and Everest), filed an international arbitration proceeding with OPC. Due to the aforesaid dispute, the Partnership included in its financial statements as of December 31, 2018, a long-term trade receivables balance of approx. $8.6 million (based, *inter alia*, on the last agreed tariff that prevailed prior to the split). It is noted that the disputed amounts bear interest according to the terms and conditions of the gas agreements that were signed with such customers. In the estimation of the Partnership, based on an assessment by its legal advisors, there is a chance of more than 50% that the Partnership's position in the arbitration proceeding vis-à-vis OPC, according to which the amounts of gas supplied during the period from May 2013 up to February 2015 will be subject to the last electricity production tariff which prevailed prior to the split, will be accepted.

7.28.5 On February 5, 2019 the Partnership learned of the filing of a class action and a motion for class certification thereof (in this section: the "**Certification Motion**"), which was filed with the Tel Aviv District Court (Economic Department) by a shareholder of Tamar Petroleum and the Public Representatives Association (in this section collectively: the "**Petitioners**"), against Tamar Petroleum, the Partnership, the CEO of the General Partner of the Partnership and a director of Tamar Petroleum, the CEO of Tamar Petroleum, the CFO of Tamar Petroleum and Leader Issues (1993) Ltd. (in this section collectively: the "**Respondents**"), in connection with the issue of the shares of Tamar Petroleum in July 2017 (in this section: the "**IPO**").

According to the Petitioners, in essence, the Respondents misled the investing public in the IPO with respect to the ability of Tamar Petroleum to distribute a dividend to its shareholders, for the period commencing on the IPO date and ending at the end of 2021 (in this section: the "**Period**"), and breached duties under various laws, *inter alia* a breach of the duty of care of the said officers and breach of the Partnership's duties as shareholder and holder of control of Tamar Petroleum before the IPO.

The remedies sought in the said class action mainly include a financial remedy in the sum of at least $53 million which is, according to the Petitioners, the difference between the total dividend which Tamar Petroleum was expected to distribute for the Period, as stated in the offering to institutional investors document of July 12, 2017, and the total dividend which, according to an expert opinion that was attached to the Certification Motion, Tamar Petroleum is expected to distribute for the Period. The date for the filing of a response was scheduled for April 10, 2019. As of the report release date, no pleadings have yet been filed by the Partnership and the other respondents. 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%.

7.28.6 <u>Legal proceedings regarding the Investment Recovery Date in the Tamar project</u>

(a) On November 29, 2018, a motion for approval of the filing of a derivative suit was received at the Partnership's offices, which had been filed with the Tel Aviv District Court against the Partnership, the Partnership's general partner, Delek Group, Delek Energy, and Delek Royalties (Delek Group, Delek Energy and Delek Royalties shall hereinafter be referred to collectively in Section 7.28.6 as the "**Royalty Interest Owners**"), the directors of the Partnership's general partner, the CEO of the Partnership's general partner, and the Partnership's auditors, in connection with payment of royalties to the Royalty Interest Owners at the rate of 6.5% (instead of a rate of 1.5%) from January 2018, the Investment Recovery Date in the Tamar project (in this section: the "**Approval Motion**"). The petitioner claims, in summary, that there were defects in the determination and approval of the Investment Recovery Date in the Tamar project, including in the non-inclusion of the levy on gas and petroleum profits by virtue of the Taxation of Profits from Natural Resources Law (in this section: the "**Sheshinski Levy**") in the calculation of the Investment Recovery Date. In addition, the petitioner claims that the general partner and the officers breached the duty of care and the fiduciary duty imposed on them vis-à-vis the Partnership in that they prepared a draft calculation of the Investment Recovery Date which is wrong and/or does not include the Sheshinski Levy. The petitioner further claims a breach of the duty of fairness that is imposed on the Royalty Interest Owners and a breach of the duty of care that is imposed on the Partnership's auditors.

The remedies sought in the Approval Motion include declaratory remedies, including a determination that it is necessary to include the Sheshinski Levy in the calculation of the Investment Recovery Date, and accordingly to calculate the Investment Recovery Date as occurring at a later date, only after which the royalty rate of 6.5% shall apply, and that until such later date, the Royalty Interest Owners shall not be entitled to receive royalties at a rate of more than 1.5%, a financial remedy in an amount equal to the difference between the amount of the royalties paid by the Partnership from the Investment Recovery Date at the rate of 6.5% and the amount of the royalties at the rate of 1.5%.

It is noted that on December 27, 2018, the Partnership filed a motion for summary dismissal of the motion (and for a stay of the proceedings pending decision of the motion for summary dismissal) due to the absence of a preliminary request pursuant to Section 194(b) of the Companies Law, and due to authorization of the Audit Committee of July 8, 2018 to handle the issue of the Investment Recovery Date, and the resolution of the general meeting of the holders of the participation units which was summoned by the Partnership's supervisor as specified in Section 7.27.12(b)1 above. On December 30, 2018, the court granted the motion for a stay of the proceedings, and ordered the filing of the petitioner's response to the motion for summary dismissal, and thereafter a reply on behalf of the Partnership, which have been filed. The Royalty Interest Owners have also filed their response. On January 6, 2019, the supervisor filed a complaint and an urgent motion for provisional injunction, as described in Subsection (b) below. Consequently, the Petitioner moved the Court to consolidate the aforesaid Supervisors' claim and the Certification Motion. A decision has not yet been issued on the matter.

(b) On January 6, 2019, the supervisor on behalf of the holders of the participation units in the Partnership, filed with the Tel Aviv District Court (Economic Department) a complaint and an urgent motion for a provisional injunction (the "**Complaint**" and the "**Motion for a Provisional Injunction**", respectively) pursuant to Section 65W(b) of the Partnerships Ordinance, against the Partnership, the Partnership's general partner and the Royalty Interest Owners.

In the Complaint, the supervisor moves the court, *inter alia*: to declare that the calculation of the "Investment Recovery Date" in the Tamar project must include the payments that the Partnership is required to make to the State by virtue of the Taxation of Profits from Natural Resources Law; to declare that the Investment Recovery Date in the Tamar project has not yet arrived; to determine from what date the Royalty Interest Owners are entitled to receive the overriding royalty at the increased rate (a rate of 6.5% in lieu of a rate of 1.5%); and to declare that the Royalty Interest Owners are required to return the amounts that they were overpaid to the Partnership, plus linkage differentials and interest. In addition, in the Motion for a Provisional Injunction, the supervisor moves the court to issue an order that will prevent any action which may deprive the rights of the holders of the participation units, such that it order the Partnership and the Partnership's general partner to refrain from transferring to the Royalty Interest Owners the overriding royalty at the increased rate, and to transfer the same to an escrow account held by the Partnership, and order Delek Group and Delek Royalties to return the increased overriding royalty that they received until now from the Partnership and deposit it in the escrow account.

The Complaint states, *inter alia*, that the supervisor acted in an attempt to reach an agreement with the Royalty Interest Owners to resolve the dispute regarding the Investment Recovery Date by way of arbitration before an agreed arbitrator. However, after the filing of the motion for approval of a derivative suit by a holder of participation units on November 29, 2018 (as stated in Section 7.28.6(a) above) (in this section: the "**Derivative Motion**"), the Royalty Interest Owners clarified to the supervisor that they were not prepared to conduct the arbitration proceeding concurrently with the hearing of the Derivative Motion, and that they would agree to begin the arbitration proceeding only if the Derivative Motion was withdrawn and not heard simultaneously. The Complaint stated that it is the supervisor's position that the Derivative Motion ought not to have been filed when the meeting of the holders of the participation units had authorized the supervisor to clarify the matter of the Investment Recovery Date, but after it had been filed and in view of the position of the Royalty Interest Owners in relation to the Derivative Motion, as specified above, the supervisor had decided to file with the court the Complaint and the Motion for a Provisional Injunction. On January 22, 2019, responses to the Motion for a Provisional Injunction were filed with the Court by the Respondents. The response filed by the Partnership and the General Partner of the Partnership claims that the motion should be denied, *inter alia* as it does not meet the case law tests for the granting of a provisional remedy and is tainted by severe *laches*. The Royalty Interest Owners' response claims that for the purpose of determination of the Investment Recovery Date, the payments in respect of the "Sheshinski Levy" that shall be made by the Partnership in the future should not be taken into account. The Royalty Interest Owners further claimed, *inter alia*, that the calculation made by the Partnership, whereby the Investment Recovery Date fell in January 2018, included many expenses that should not be taken into account (including financial, transmission, marketing, removal and clearing of facilities and HQ expenses), and that according to an alternative calculation made by experts on behalf of the Royalty Interest Owners, the Investment Recovery Date already fell in August 2015, such that from such date, they were entitled to receive royalties at an increased rate, and that they intend to file a claim against the Partnership in connection therewith with the appropriate court.

On February 6, 2019, the Partnership and the General Partner filed a motion for a stay of proceedings in the claim, due to the existence of a binding arbitration clause in the transfer of rights agreement between the Partnership and the control holders of August 2, 1993. Concurrently with the filing of this motion, a motion was also filed for extension of the timeframe for the filing of pleadings on behalf of the Partnership and the General Partner pending decision of the said motion for a stay of the proceedings, and no decision has yet been issued therein.

On February 26, 2019, a hearing was held at the court on the motion for a provisional remedy, at which the court clarified that no provisional remedy will be granted with respect to a date earlier than the date of the hearing of the motion. The court requested that the parties hold talks in an attempt to reach agreements regarding the provisional remedy, and insofar as such agreements are reached, decisions will be issued in the motions of the Partnership and the General Partner. If agreements are not reached, the hearing of the motion for a stay of proceedings and of the motion for a provisional remedy is expected to be held in May or June 2019.

7.28.7 The following are legal and/or administrative proceedings submitted with respect to licenses in which the Partnership had rights:

(a) On October 3, 2013, following the Petroleum Commissioner's decision not to extend the term of the Eran License, the holders of rights in the Eran License (including the Partnership) submitted an appeal to the Minister of Energy with respect to the aforesaid decision by the Petroleum Commissioner. On August 10, 2014, the Minister of Energy denied such appeal. On November 17, 2014, the holders of the rights in the Eran License, including the Partnership, filed a petition on this decision with the High Court of Justice. On June 2, 2016, the High Court of Justice sanctioned as a decision the parties' agreement to defer to a mediation proceeding as proposed thereby. With the parties' consent, (retired) 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 the mediation arrangement. On March 20, 2019 this mediation arrangement was filed with the Court, which was moved to enter a judgment on the arrangement. In the mediation arrangement, the parties to the mediation agreed (with the consent of the Tamar partners) on the division of the Tamar SW reservoir between the areas of the Tamar lease (78%) and the area of the Eran license (22%). It was further agreed that the interests in the Eran license area shall 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. As of the report release date, the Court's approval of the said mediation arrangement has not yet been received.

7.29 Goals and Business Strategy

The Partnership's strategy and goals are, exhaustion of the economic potential of the petroleum assets held thereby alongside examination of acquisition of additional petroleum assets. The strategy is realized mainly through promotion of the development of the petroleum assets owned thereby, primarily the Leviathan and Aphrodite reservoirs, within the planned schedules and budgets, continued optimal production from the producing petroleum assets owned thereby, chief of which is the Tamar 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 in LNG form.

For this purpose, the Partnership acts, *inter alia*, for the increase of the demands for natural gas, both by means of expansion and assimilation of the use of natural gas in the domestic market and by means of natural gas export to neighboring countries through pipelines and/or through the liquefaction and marketing thereof to global markets.

In addition, the Partnership intends to act for examination of the potential for additional gas and/or petroleum 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 addition, the Partnership is considering the possibility of becoming directly or indirectly listed, or listing all or any of its assets, on an additional stock exchange in the world, which is more suitable for the operation of natural gas and petroleum exploration, production and export. In this context, the Partnership is considering and promoting a plan to split its assets, as specified in Section 2.3 above. It shall be noted that there is no certainty that the Partnership will succeed in such processes. The necessary investments in the Partnerships' operations require it to invest considerable financial resources and acquire further know-how and expertise in the existing and future business segments. The Partnership intends to consider using the various means available thereto for raising funds, by way or debt and/or equity, in addition to using the surplus future revenues from the Tamar Project and in retained cash available thereto, and in the proceeds received and to be received from the sale of assets in accordance with the Gas Framework, as specified in Section 7.22.1 above.

7.29.1 <u>In the Tamar Project</u>

(a) The Partnership commenced with the sale of its rights in the Tamar Project (in this section: the "**Project**") in accordance with the provisions of the Gas Framework (as specified in Section 7.25.1(b)2 above), and in July 2017 the transaction of the sale of 9.25% (of 100%) of Tamar and Dalit leases to Tamar Petroleum was closed. For additional details on the transaction see Section 1.1.7(g) above.

(b) Until the sale of its other rights in the project, the Partnership is acting to maximize the Project's value *inter alia*, in the following ways:

1. Continued optimal supply of natural gas and condensate from the Project in accordance with the signed agreements and the conduct of negotiations and engagement in additional agreements for the sale of natural gas and condensate to the various potential consumers in Israel and in the region.

2. Continued promotion of projects for export by means of pipelines from the Project, to consumers in Egypt and in Jordan. For details on an agreement for export from the Tamar Project to Dolphinus, for details see Section 7.13.5(a)2 above.

3. Expansion of the production capacity of the Project, as specified in Section 7.3.4(c) above, based *inter alia* on the export to Dolphinus agreement, as specified above or by means of other alternatives.

4. Exhaustion of the geological potential in the natural gas layers – the Partnership intends to examine and exhaust the full geological

potential in the area of the Tamar lease, both in the Oligo-Miocene gas layers and in deeper layers, in which oil targets may be possible, over and above the existing potential included in the reserves report for the Tamar project. As of the report release date, a reinterpretation is made of seismic surveys, which may lead to an update of the mapping of the Tamar and Tamar SW reservoirs and the mapping of potential deep prospects. In addition, the Partnership regularly updates, interprets and analyses the regional database available thereto, inter alia, in order to update the geological success changes of leads within the area of the lease.

Note that the Partnership estimates that a petroleum discovery in the deep layers in the Leviathan lease may constitute a positive indication for finding petroleum in the deep layers in Israel's EEZ, *inter alia* in the Tamar Lease.

5. Examination and promotion of various alternatives for the sale of all of the Partnership's rights in the Project according to the provisions of the Gas Framework (as specified in Section 7.25.2(e) above), including by way of the establishment of an SPC which shall issue debt and equity, which shall be listed on a foreign stock exchange and/or on TASE and/or sale to a third party and/or via splitting the Partnership's assets, subject to the controlling shareholder selling its holdings in the General Partner and the Partnership to third parties, as specified in Section 2.3 above.

7.29.2 <u>In the Leviathan project</u>

(a) The Partnership is acting to quickly complete development of Phase 1A of the development plan for the Leviathan project (in this section: the "**Reservoir**"), aiming for the flow of natural gas to commence during Q4/2019 (for a description of the development plan, see Section 7.4.5 above).

(b) The Partnership is simultaneously acting to market the natural gas and condensate to be produced from the Reservoir, to additional customers beyond those with whom agreements or letters of intent have been signed as specified in Section 7.13.5(b) above, and mainly to the domestic market and to countries in the region (primarily Jordan, Egypt and the Palestinian Authority).

(c) Promotion of the development of additional development phases of the Leviathan reservoir (beyond Phase 1A of the Leviathan reservoir development plan), to a scope of production of approx. 16 BCM per year and/or a scope of production of approx. 24 BCM per year, as specified in Section 7.4.5(b)3 above, for the purpose of natural gas supply to additional target markets and customers, including the

Egyptian domestic market or the existing ELNG liquefaction plant in Egypt, which is operated by Shell (for further details, see Section 7.13.5(b)3 above), or to the Turkish market by means of a designated pipeline to be constructed (for further details, see Section 7.14.2(b)2.d above), and according to the present and expected demand in other target markets.

(d) Examination of the techno-economic feasibility of construction of a FLNG facility based on natural gas from the Leviathan reservoir. For further details, see Section 7.14.2(c) above.

(e) Promotion of the adoption of a decision and performance of an exploration drilling for petroleum purposes in the Leviathan leases, as specified in Section 7.4.10(e) above.

7.29.3 In Block 12 – Cyprus

Promotion of a development plan for the Aphrodite reservoir as specified in Section 7.8.11 above, and commercialization of the gas to the target markets: namely, the local Cypriot market and export to the Egyptian market, and at the same time, examination of further options for development of the Aphrodite reservoir, including, the option to combine the development thereof with development plans of adjacent reservoirs located within the EEZ of Israel, including the Leviathan reservoir.

7.29.4 Optimization of infrastructures

The Partnership intends to examine, jointly with its partners in the various petroleum assets and other owners of infrastructures, the possibilities for optimization of existing infrastructures in the various projects, including the joint transmission infrastructure for export of natural gas to the various target markets and *inter alia* for the purpose of reducing transmission costs and increasing the feasibility of advancing various projects. For instance, the Partnership is examining, together with its partners in the Leviathan project and the Aphrodite reservoir, the possibility of constructing a joint pipeline for transmission of natural gas to consumers in Egypt. For details regarding the possibilities of piping the gas to Egypt which are being examined by the Partnership, see Section 7.14.2(b)2.b below.

7.29.5 Petroleum and gas exploration

The Partnership is acting to continue natural gas and/or petroleum exploration activity in the areas of its petroleum assets and in new licenses in Israel and worldwide, 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, while focusing on the prospects having the greatest potential and planning the performance of additional drilling exploration, if approved, including drilling for petroleum purposes, chief of which is a drilling for petroleum purposes in the Leviathan leases.

7.29.6 Increasing the Demand for Natural Gas

The Partnership is working to increase demand for natural gas, *inter alia*, in the following methods:

(a) Transportation: The Partnership is working to promote projects to increase the use of natural gas for transportation, including public transport vehicles and trucks powered by compressed natural gas, as well as electric transportation, such as electric buses and passenger cars in the Israeli transportation market.

In the Partnership's estimation, since the consumption of diesel for transportation in Israel in 2018 was equivalent to approx. 3.6 BCM of natural gas per year[299], such projects may lead to an increase in the potential demand for natural gas.

(b) Conversion of coal-fired power plants to use of natural gas: In the Partnership's estimation, the continuation of the Government's policy to reduce the use of polluting coal for the production of electricity, including discontinuation of all coal-fired electricity generation by 2030, in favor of transition to natural gas in power generation, may increase the use of natural gas in Israel in significant quantities, estimated at up to approx. 5 BCM per year compared to 2019.

(c) Residential: The Partnership is examining the promotion of projects that encourage the residential use of natural gas in new neighborhoods.

(d) Additional industries: The Partnership is examining additional projects, both in the areas of industries in which the natural gas serves as a raw material, such as the production of ammonia and methanol, and in energy-intensive industries, such as the production of primary aluminum. 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.

The Partnership's strategy and goals as specified above constitute general intentions and goals and as such there is no certainty that they will be realized, *inter alia*, due to changes in the various projects, changes in the market conditions, geopolitical changes, changes in regulation and in tax laws, changes in priorities resulting from the results of the drillings and surveys that will be performed and due to unpredicted events and the risk factors specified in Section 7.31 below.

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[299] The Partnership's interpretation of data from the Fuel Administration at the Ministry of Energy https://www.gov.il/he/departments/guides/fuel_market?chapterIndex=6

7.30 Insurance coverage

From time to time, the Partnership takes out the insurance policies generally accepted in Israel for the energy sector for natural gas exploration, development and production, *mutatis mutandis* to the requirements of the law, the regulation, the conditions of the license, the requirements of the financing entities and the scopes of the Partnership's operations and its exposures in Israel and overseas.

The insurance is taken out in group insurance policies that cover several insured, which cover the assets and liabilities in the Partnership's various activities, only against some of the possible risks, as is the common practice in the industry of exploration, development and production of natural gas, all subject to the provisions of this section. The insurance system covers, *inter alia*, expenses for loss of control of well, certain coverage for political risks, property damage and certain consequential damage related to the insured property damage at the production phase, risks to construction work in the development of the assets (including 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.

The above-specified insurance policies are taken out partly independently and partly in the framework of Noble's insurance system. The insurance policies are subject to the agreements of pledge and assignment of rights in accordance with financing agreements that are signed from time to time.

It is noted that the Partnership monitors, from time to time, changes in the value of the insured property, and the amounts of the consequential damage that is entailed by damage to the insured property and/or to the property of a customer and/or of a supplier, in order to adjust the scope of the purchased insurance according to the exposure subject to the insurance costs and the global supply of insurance for the energy sector. Consequently, the Partnership can decide on a decrease of the purchased coverage and/or a reduction of the sum of the purchased insurance and/or decide not to purchase any insurance at all for this risk or another.

It is further noted, that the Partnership engaged with Delek Group (in this section: the "**Guarantor**") in an agreement, whereby the Guarantor granted a performance guarantee in favor of the Republic of Cyprus with respect to the Partnership's activity in Block 12 as specified in Section 7.8.3(m) above. As a condition for granting the aforesaid guarantee, the Partnership was required to take out additional insurance to the Guarantor's satisfaction, beyond the insurance system applicable thereat, so as to cover, within higher liability caps at the stage of performing the drilling work, with respect to the insurance of liabilities to third parties as well as expenses for regaining control over an out-of-control well, including coverage of bodily and property damage and cleaning expenses resulting from the risks of accidental pollution.

For details with respect to the risk in the absence of sufficient insurance coverage, see Section 7.31.8 below.

7.31 Risk Factors

Petroleum and natural gas explorations and the development of petroleum and natural gas discoveries and production therefrom entails considerable financial expenses and a very high level of financial risk, mainly for the reasons specified below. This is especially true with respect to the operations of offshore exploration, development and production of oil and natural gas.

7.31.1 Changes in the global fuel prices and/or Electricity Production Tariff and/or U.S. CPI and/or other energy sources

The prices paid by the consumers for the natural gas in the reservoirs in which the Partnership is a partner are derived, *inter alia*, from the Electricity Production Tariff to which the gas agreements with private electricity customers are linked, the U.S. CPI, and the price of a Brent barrel (the "**Indices**"). For details with respect to the various linkages in the natural gas price formulas, see Section 6.8.1 above. In relation to the Electricity Production Tariff, it is noted that the frequent methodological changes made by the PUA-E in the manner of calculation thereof place difficulties on the ability to predict it, and may lead to disputes between gas suppliers and customers with respect to the manner of calculation thereof.

A decrease in the Electricity Production Tariff (*inter alia* as a result of an adjustment that the IEC shall request, if any, of the price in accordance with the mechanism determined in the agreement that was signed therewith as stated in Section 7.13.4(a)4 above) and/or the Brent prices and/or the U.S. CPI may adversely affect the Partnership's income from the existing and future gas sale agreements. In addition, a significant change in the prices of other energy sources (including coal and other gas substitutes), the reforms and resolutions relating to the electricity sector as specified in Section 7.25.5(f) above, including changes in the environmental laws, may cause a change in the consumption model of the IEC and of other large customers, which may reduce the demand for natural gas and lead to a decline in the natural gas prices in the market.

7.31.2 Geopolitics

The security and economic situation in Israel, as well as the political situation in the Middle East, 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 impair the Partnership's ability to promote its business with such countries and entities and to export gas to neighboring countries.

7.31.3 <u>Difficulties in obtaining financing</u>

For the promotion of additional development phases in the development plan of the Leviathan reservoir and/or the expansion of the Tamar Project and/or the development of additional reservoirs in the future, such as Aphrodite, 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. Insofar as additional financing is required as aforesaid, the Partnership may face difficulties in obtaining the same under conditions that are suited thereto, particularly in the event of an economic crisis expressed in the reduction of available credit sources and the toughening of requirements of the financing bodies for provision of the financing. In addition, the Partnership's ability to obtain additional debt is subject to the covenants and the other undertakings set forth in the terms and conditions of its existing bonds, and the financing agreements as specified in Section 7.22 above.

7.31.4 <u>Competition in gas supply</u>

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. Furthermore, additional reservoirs may be discovered in the future, both in Israel and in additional countries in the eastern basin of the Mediterranean, the development of which may lead to the entry of additional competitors in natural gas supply to the domestic market. For details on competitive proceedings for petroleum and natural gas exploration in Israel's EEZ, see Section 7.16.1 above.

In addition, in accordance with the Gas Framework, the Partnership is required to sell its remaining holdings in the Tamar and Dalit reservoirs to unrelated third parties (as specified in Section 7.25.1(b)2 above).

In Israel there are currently, in addition to the Tamar reservoir, two additional reservoirs that are in development phases: the Leviathan reservoir and the Karish and Tanin reservoirs, which are expected to constitute additional significant suppliers of natural gas to the domestic market.

In view of the scope of the demand for natural gas in the domestic market, the entry of additional competitors to the domestic gas market and the restrictions on the scope of exportable gas, the Partnership may face considerable competition in selling gas reserves that were or will be discovered thereby in the future. In addition, the Partnership may face competition vis-à-vis alternative energy sources, such as coal, liquid fuels (such as diesel oil and mazut), and sources of renewable energy. Competition in natural gas supply may undermine the Partnership's ability to market the gas reserves discovered thereby or which shall be discovered (if any) thereby in the future and/or lead to a reduction of the price at which the Partnership will sell the natural gas, thereby reducing its revenues. For further details about the competition in gas supply in Israel and Cyprus, see Section 0 above. For details with respect to an option granted to natural gas purchasers to reduce the quantities under the gas agreements signed therewith, see Sections 7.13.4(a)3 and 7.13.4(b)1.b above. For details on the PUA-E's decision that incentivizes the private electricity producers to engage in gas sale and purchase agreements at a price which is lower than the maximum price set forth in the Gas Framework, and in addition incentivizes private electricity producers to engage in agreements to purchase natural gas with new gas suppliers that are not Tamar Partners, see Section 7.25.5(l) above.

7.31.5 Restrictions on export

In the natural gas reservoirs in which the Partnership is a partner there is a greater scope of gas reserves than the demand expected in the potential markets in Israel and Cyprus in the coming years. Therefore, the results of the Partnership's activity depend to a great extent on the possibility of exporting the gas and selling it in the regional and international market. The Government Resolution on Export, which is specified in Section 7.25.1(c)2.a above, limits the quantity of gas that may be exported. Decreasing the quantities of natural gas for export could lead to significant damage to the Partnership's business. In addition, the possibility of exporting and selling the gas depends on many highly uncertain factors, such as the foreign relations between the State of Israel and the Republic of Cyprus with countries that are potential target markets for gas export, construction of an export and transportation system and receipt of the relevant regulatory authorizations, 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.

7.31.6 Dependence on the good working order of the transmission system

The Partnership's ability to supply the gas discovered thereby to the existing consumers and to additional potential consumers in and outside of

Israel, is contingent, *inter alia*, on the development and good working order of the national transmission system for gas supply, the regional distribution networks, and transmission pipelines to consumers in neighboring countries (collectively: the "**Transmission Systems**"). Any significant malfunction of or disruption to the Transmission Systems that are used and/or shall be used by the Partnership in the future may limit the Partnership's ability to supply gas to its customers, while exposing it to loss of revenues and potential legal proceedings which may have an adverse effect on the Partnership's business and its results of operations.

7.31.7 <u>Operational risks</u>

The activities of petroleum and gas exploration, and development and production of natural gas in deep water usually entail many more operating risks than on land. Drilling in deep water generally takes longer, the drilling costs are higher, and advanced drilling technologies are generally required, entailing a higher risk of technological failure. Continued development and production of natural gas from the reservoirs entails a range of risks which include, *inter alia*, an uncontrolled outburst of liquids and gas from a well, explosion, collapse of a well and combustion, breakdowns, accidents and other events that may disrupt the functioning of the production and transmission system, performance below the expected or efficient level, contractor or operator errors, work disputes or disruptions, injuries, casualties or deaths, a delay or non-receipt of permits, non-receipt of approvals or licenses, a breach of requirements of permits or the licenses, a shortage of manpower, equipment or spare parts, delays in the delivery of equipment or spare parts, pollution and other environmental risks, security breaches, cyber attacks or acts of terrorism, and natural disasters.

The occurrence of any one of the events as aforesaid may significantly reduce or halt the production or supply of the natural gas, prejudice the timetable and the budget for the development of reservoirs, damage the quality of the gas that is produced from the reservoirs, and consequently may lead to termination of the existing gas sale agreements of the Partnership.

7.31.8 <u>Lack of sufficient insurance coverage</u>

Even though the Partnership is insured with coverage of various kinds of damage that may be caused in connection with its operations, not all of the possible risks are or can be fully covered by the various insurance policies that were taken out, and therefore, the insurance payments, if received, will not necessarily cover the entire scope of the damage and/or all of the possible losses (with respect to third party damage (including during the crossing of infrastructures), with respect to possible loss of income, with respect to the costs of the construction of the production system in the case of an event due to which damage is caused to the production system, including due to terror, war and loss of control of the well, and with respect to damage to any kind of property in the well). In addition, there is no certainty that suitable policies may be purchased in the future on reasonable commercial terms or at all.

The Partnership's expected activity in Jordan (as specified in Section 7.13.5(b)1 above) and in Egypt (as specified in Section 7.27.7 above) creates exposure that cannot be insured at all or fully, and *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. Thus, in the case of large-scale loss or damage, the insurance policies taken out may be insufficient for covering all of the damage to the Partnership and/or third parties, including with respect to environmental pollution damage. These risks, if they materialize, may cause postponements and delays in the Partnership's exploration, development and production activities, damage the Partnership's business or have a material adverse effect on the Partnership's business, financial position, results of operations or its forecasts, and in an extreme case may even lead the Partnership to insolvency.

It shall be noted that the decision on the type and scope of the insurance is usually made separately for each activity, taking into consideration, *inter alia*, the insurance costs, type and scope of the offered coverage, the regulatory requirements, the ability to obtain suitable coverage in the insurance market, the capacity available to the Partnership in the insurance market and the foreseeable risks.

7.31.9 Construction risks, dependence on contractors and on professional services and equipment providers

There are currently in Israel no contractors for the performance of most of the actions of the type performed by the Partnership and therefore the Partnership engages with foreign contractors for the performance of such work. Thus, for example, the Partnership engages through the Operator, with contractors and equipment providers for the purpose of constructing the production system of the Leviathan project. Moreover, 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 no certainty that a suitable facility will be found for performing the aforesaid actions on the dates to be scheduled therefor. Consequently, the aforesaid actions may entail high costs and/or considerable delays may be caused in the schedule that is determined for the performance of the work. In addition, most of the equipment and manpower that are suitable for the performance of the aforesaid actions may not be ordered within short periods of time and therefore it is necessary to order professional equipment and manpower services from overseas a considerable time in advance, which significantly increases the costs of and delays the activities. The engagement with foreign contractors for the performance of offshore petroleum and/or natural gas explorations, development and production (including contractors for the performance of maintenance and repair work) may encounter difficulties also due to the political and security situation of the State of Israel. The price of the services and the costs of exploration, development and production activities are determined according to the supply and demand in the markets that are affected *inter alia* by the commodity prices, regulation changes, supply of alternative products and level of activity in the industry.

7.31.10 Risks of exploration activity and reliance on partial and estimated data

Petroleum and gas explorations are not an exact science and therefore entail a high level of risk, *inter alia*, in the event of failure in exploration and appraisal wells, and may result in a total loss of the entire investment. The geological and geophysical means and techniques do not provide an exact projection of the location, form, characteristics or size of petroleum or gas reservoirs, such that the determination of the exploration goals and the estimates concerning the size of reservoirs and the gas and/or petroleum resources therein are based to a great extent on partial or estimated data and assumptions. It is of course impossible to guarantee that as a result of these explorations any petroleum or gas will be discovered, or such that may be commercially produced and exploited. Furthermore, there is a lack of direct geological and geophysical information about some of the offshore areas of the Partnership's petroleum assets, *inter alia* due to the small number of drillings performed in these areas and the scarce information obtainable therefrom. In addition, in accordance with the aforesaid, some changes may also occur from time to time in the estimates concerning the scope of the petroleum resources in the reservoirs. The estimated petroleum and gas quantity in the petroleum and gas producing reservoirs in the reported period, is examined on a continuous basis, and may be updated, *inter alia*, according to the opinion of independent experts estimating the resources of petroleum and gas reservoirs. The estimation of the gas resources as aforesaid is a subjective procedure that is based on various assumptions and partial information and therefore estimations by different experts concerning the same reservoirs may sometimes vary significantly. In light of the aforesaid, it shall be noted that the information appearing in the report on the gas resources in the various reservoirs is an estimate only and may not be considered as information on exact quantities, and therefore changes may occur from time to time in the estimates of the scope of the gas resources and the condensate that may be produced from the various reservoirs. In addition, the gas reserves estimate 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.

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

Estimated costs for performing exploration, development, operation and maintenance activities, and estimated timetables for performance thereof, are based on general estimates only, and considerable deviations may occur therein, including due to events that are beyond the Partnership's control. Development and exploration plans may change considerably, *inter alia*, following findings arising from such activities, and cause considerable deviations in the estimated timetables and costs of such activities. Faults during exploration, development, operation or maintenance activities as well as other factors may cause the timetable to be extended far beyond the plan, and the actual expenditure required for completion of the activities to be considerably higher than the costs planned therefor.

7.31.12 Forfeiture of the Partnership's rights in its petroleum assets

Exploration, development and expansion actions and preservation of the supply capacity 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, thereby breaching the agreement, the Partnership may be required to pay sums that considerably exceed its proportionate share, to supplement the missing amounts, according to the percentage of its participation in the petroleum asset/s with respect to which the breach was committed, and should it fail to make this payment on time – it will risk losing all of its rights in such assets. Due to the especially high cost of development expenses and of offshore drillings, as a result of the deviations (both foreseeable and unforeseeable) the Partnership may be unable to fulfill its financial obligations and as a result shall lose its rights.

7.31.13 Dependence on obtaining approvals of external entities

The performance of actions in the Partnership's petroleum assets requires various approvals, and *inter alia* approvals under the Petroleum Law and the Natural Gas Sector Law, approvals of the security authorities and the IDF, Israel Nature and Parks Authority, the environmental authorities, the Civil Aviation Authority, local authorities and/or zoning committees, the Ministry of Agriculture – Department of Fishing, the Ports Authority and shipping functions at the Ministry of Transportation. Obtaining these approvals may entail additional expenses beyond the budgets designated for the aforesaid actions or cause delays in the date of performance of the planned actions.

It is noted that as of the date of the report, not all of the approvals required for the completion of the construction, operation and flow of natural gas in the Leviathan Project have yet been received. In this regard, see also Section 7.25.5(k) above. Furthermore, as of the date of the report, not all of the approvals required for the closing of the EMG Transaction and for the closing of the Dolphinus Agreements have yet been received.

7.31.14 Regulatory changes

Many regulatory approvals are required in the Partnership's field of business in Israel, mainly from the entities authorized pursuant to the Petroleum Law and the Natural Gas Sector Law, as well as related approvals from the state authorities (including the Ministry of Defense, the Ministry of Environmental Protection, the tax authorities and the various planning authorities). In recent years, there has been an increase in the scope of regulation in the energy sector in Israel. For further details with respect to the regulation applicable to the Partnership's operations, see Section 6.8.2 above. The tightening of regulation with respect, *inter alia*, to exploration, development and production of gas and petroleum, the terms of natural gas supply, natural gas export, taxation of petroleum and gas profits, rules for allocation, insurance and guaranties, transfer and pledge of petroleum rights, 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 or policy, or a delay in the receipt of any regulatory approval, or the Partnership or its customers do not receive the regulatory approvals required or do not fulfill the terms and conditions thereof, the Partnership or its customers may not be able to fulfill their undertakings according to the existing agreements for the sale of natural gas.

7.31.15 Potential control of natural gas prices

As provided in Section 7.25.5(b) above, on April 22, 2013, the Control of Prices of Commodities and Services Order (Application of the Law to Natural Gas and Determination of the Control Level), 5773-2013, was published, which imposes control on the gas sector in terms of profitability and price reporting. Such reporting duty is separately imposed in respect of every project, while it is necessary to report semiannually on the prices and on the profit margins of the sold natural gas. According to information to be received, the need to impose control on natural gas prices in Israel at the level of fixing a maximum price for the sale of natural gas, will be examined. In the event that price control is imposed and a maximum price is determined, which is lower than the prices set forth in the Partnership's natural gas sale agreements, and insofar as such determination withstands judicial review, this may adversely affect the Partnership's business, the scope of which shall be derived from the maximum price to be determined. In accordance with the Gas Framework, the Price Control Committee was approached, and it decided that for as long as the Partnership and Noble comply with all of the conditions of the Framework, control should be kept on the level of reporting on profitability and prices for the duration of the transition period as defined in Section 7.25.1(c)1 above.

7.31.16 Motion to Certify a Class Action regarding the Price in the Agreement with the IEC

On June 18, 2014, a motion for class action certification was filed with the Tel Aviv District Court against the Tamar Partners by an IEC consumer, as set forth in Section 7.28.1 above (in this section: the "**Certification Motion**"). Insofar as the Certification Motion is granted, and subsequently a final non-appealable judgment is issued against the Tamar Partners, this may have a material adverse effect on the Partnership's financial position, its revenues, its results of operations, its ability to meet its obligations, and the prices at which the Partnership sells natural gas to its customers.

7.31.17 Applicable environmental regulation

The Partnership, in its field of business, is subject to various laws, regulations and guidelines concerning environmental protection, relating to various issues, such as: leakage of petroleum, natural gas or other pollutants into the sea, emission into the sea of pollutants and waste of different kinds (wastewater, remains of drilling equipment, drilling mud, mortar and so forth), chemical substances used in various stages of the work, emission of pollutants into the air, light and noise nuisances, construction of pipe infrastructure on the seabed and related facilities. In addition, the Partnership is required, through the operator of the projects, to obtain approvals for its activity 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 Partnership and its partners in the various petroleum assets to various enforcement measures, which also include lawsuits, penalties and various sanctions, including criminal, as well as to delays and even the discontinuation of the Partnership's activity. In addition, the Partnership may be responsible for the acts of others such as the Operator or third-party contractors that are affiliated with the Operator, and for pollution relating to the Partnership's facilities or deriving from its activity.

Petroleum and natural gas exploration, and production of natural gas in deep water entail various risks, including the emission of hazardous waste and substances into the environment, and exposure of humans to such hazardous waste and substances. Consequently, the Partnership may be responsible for some or all of the repercussions deriving from the risks of exposure or emission of such hazardous waste and substances.

As aforesaid, in September 2016, the Ministry of Energy, in cooperation with the Ministry of Environmental Protection and other government ministries, published directives that regulate the environmental aspects of the offshore petroleum and natural gas exploration, development and production activity. Such directives may have an effect on the costs and manner of the Partnership's activity, the scope of which cannot be estimated as of the report release date.

In addition, as stated in Section 7.25.5(e) above, on November 13, 2017, the Knesset approved, in a first reading, the Marine Zones Bill, and since then, several discussions were held at the Economic Affairs Committee, in preparation for the second and third readings. The proposed law, if the next Knesset decides to apply the continuity law and it is approved by the plenum in the second and third readings, may have an adverse effect on the Partnership's activity and its costs.

There is no certainty that the costs that will be required from the Partnership in connection with the existing and foreseeable laws, regulations and guidelines in the field of environmental protection, and in connection with the repercussions deriving from the emission of substances into the environment, will not exceed the amounts allocated by the Partnership for these purposes, or that these costs will not have a material adverse effect on the financial position of the Partnership and its results of operations. It is further noted that the interpretation and enforcement of the environmental regulations and laws change from time to time and may be tougher in the future.

7.31.18 Dependence on weather and sea conditions

The offshore activity is subject to a variety of operating risks that are unique to the marine environment such as capsize, collision and damage or loss that are caused by harsh weather conditions and the sea conditions. Such conditions may cause significant damage to the facilities and disrupt the activity.

Stormy sea conditions and unusual weather conditions may cause damage to the production and transmission system and to the (existing or under construction) exploration equipment as well as delays in the timetable planned for the work plan of the offshore projects and the prolongation of its execution period. Such delays may cause the increase of the projected costs and even non-compliance with timetables to which the Partnership is committed.

7.31.19 Information security risks

The partners in the Partnership's petroleum assets, including the Partnership and the Operator thereof (directly and via subcontractors) (in this section: the "**Corporations**"), rely in their activity on information systems. For example, computer software is used for analyzing seismic surveys, for operating drillings, production and transportation systems and so forth. Industrial control systems such as computer systems that are used for supervision, control and data collection in industry ("**SCADA**"), which currently monitor and control large-scale processes which include, *inter alia*, electricity production and petroleum and gas transmission pipeline monitoring. The Partnership and the operator are dependent on digital technology, including IT systems and infrastructures, as well as cloud services, with respect to the processing and documentation of financial and operating data, engagement with the reservoirs' workers and business partners, analysis of seismic and drilling information, evaluation of quantities of petroleum and gas reserves and many other activities relating to the Partnership's business. The Partnership's business partners, including suppliers, service providers, the gas buyers and the financial institutions, are also dependent on the digital technology. As the dependency on digital technology increases, so do cyber attacks (both intentional and unintentional). A cyber attack may include unauthorized access to digital systems for purposes of inappropriate exploitation of assets or sensitive information, corruption of data or causing operating damage. SCADA-based systems are more exposed to cyber attacks due to the increase in the number of intranet and internet connections.

Breakdowns in information systems and failures of information security, including by break-in into the Corporations' computer systems, may cause interruptions and damage to the information and the current operation of the systems supporting the business activity, including interruption and in extreme cases even the discontinuation of the gas supply and loss of information, and cause material costs for the recovery of the information systems. In addition, intentional harm to the Corporations' IT systems may cause damage to the administrative networks of the Partnership and Operator, leak of information to unauthorized entities and damage to the integrity of the information held thereby, which may have a material adverse effect on the Partnership's business, financial position, results of operations or capabilities. As of the report release date, the Corporations take action to prevent failures in the information systems, *inter alia* by means of back-up and security mechanisms, mechanisms for preventing failures in their computer system and increasing the level of information security. Furthermore, the Partnership (which does not in fact have direct access to the Operator's information systems), is acting to implement the recommendations of the National Cyber Directorate (the "Corporate Defense Methodology"), which include a five-step work plan that consists of mapping out the defense objectives, the required defense level, correct defense methods, defining the current defense gaps and a work plan.

7.31.20 Tax risks

Tax issues, including the mandatory payment under the Taxation of Profits from Natural Resources Law, which are related to the Partnership's activity have not yet been discussed in the case law of the courts in Israel and it is impossible to foresee or determine how the courts will rule if and when the aforesaid legal issued are brought to their decision. In addition, with respect to some of the legal issues, it is impossible to foresee the position of the tax authorities. Since the Partnership's business is subject to a unique tax regime, changes that will result from chanted legislation or case law or from a change in the position of the Tax Authority, as aforesaid, may have material implications to the tax arrangement applicable to the Partnership and its Unit Holders.

7.31.21 Financing-related undertakings

The Partnership's non-compliance with undertakings assumed thereby in connection with the financing agreements in which it has engaged (see Notes 10 and 12H to the financial statements and Part Five of the board of directors' report (Chapter B of this report)), may lead to acceleration of the sums due under such financing agreements, to the raising of the rates of the interest on the Partnership's liabilities and to enforcement of the collateral provided by the Partnership. In addition, the Partnership is exposed to changes in the LIBOR interest rate, mainly in the Leviathan Financing Agreement as specified in Section 7.22.1(a), which may affect its cash flow in the coming years.

For details with respect to financial covenants with which the Partnership is required to comply, see Section 7.22.2 above.

7.31.22 Dependence on a key customer

The IEC is presently the Partnership's main gas consumer. The Partnership's income from the IEC in 2016, 2017 and 2018 constituted approx. 55%, approx. 54% and approx. 50% of its total income from the Tamar Project, respectively. In the Partnership's estimation, its revenues from the IEC in the next three years are expected to constitute approx. 37% of its total revenues during such period from the Tamar Project. The Partnership cannot foresee what changes (if any) will occur in the terms of the IEC's license and how these changes will affect the IEC's economic situation. It is noted that significant fluctuations in the prices of alternative energy sources to natural gas (including coal and other gas substitutes) relative to the price of natural gas, including those which occur as a result of reforms in the electricity sector and at the IEC or as a result of directives of the Ministry of Energy, may lead the IEC to produce electricity through natural gas substitutes, subject to its obligation to take or pay for the minimal annual quantity set forth in the agreement therewith (as stated in Section 7.13.4(a)4 above), which may adversely affect the Partnership, its financial position and its results of operations. It shall be further noted that the government's policy of increasing the competition in the electricity sector by introducing private electricity producers, and the government's intention to take action for privatizing the IEC may damage the IEC's economic solidity and as a result damage its ability to fulfill its obligations pursuant to the agreement of natural gas purchase with the Tamar Partners. For details regarding the reform in the electricity sector and at the IEC, see Section 7.25.5(f) above.

The agreement with IEC provides for several events of "force majeure", upon the occurrence of which IEC will not be obligated to continue making payments under the agreement. In addition, in the agreement with the IEC, two dates were determined on which each party to the agreement may request an adjustment of the price. Insofar as the IEC requests an adjustment of the price of gas that is purchased thereby in accordance with the mechanism set forth in the agreement, this may have an adverse effect on the Partnership's business and results of operations (for additional details see Section 7.13.4(a)4 above). Therefore, loss or material damage to the Partnership's revenues from the IEC may materially affect the Partnership's business, financial position, results of operations or capabilities.

Nevertheless, it shall be noted that the Tamar Partners and the Leviathan Partners have signed gas supply agreements with other significant customers, which mitigate the Partnership's dependency on IEC. Insofar as the Tamar Partners and the Leviathan Partners exercise the export options available thereto, as specified in Section 7.13.5 above, the dependency on the IEC shall be significantly reduced. Furthermore, such dependency is expected to decrease upon the increase of the gas supply following the commencement of flow of gas from the Leviathan reservoir. For details regarding the RFP for the supply of natural gas that was delivered on December 2, 2018 by the IEC to the Tamar and Leviathan partners, see Section 7.13.4(a)4 above.

It is noted that impairment of the ability of the Leviathan project customers in Jordan and Egypt to fulfill their undertakings under the gas supply agreements signed with them, may have a material effect on the Partnership's business, financial position, results of operations or abilities.

7.31.23 Financial soundness of the Partnership's customers

Non-compliance of the Partnership's customers from the Tamar Project with their undertakings, while the Partnership is unable to sell the contractual quantity determined in the aforesaid agreements to other customers, will adversely affect the Partnership's revenues.

7.31.24 Dependence on the Operator

The Partnership relies to a great extent on Noble in the petroleum rights, in which it serves as operator, including in the projects Tamar, Leviathan and Block 12 in Cyprus, both in light of the provisions of the joint operation agreements and as a result of the experience accumulated by Noble in carrying out projects on a similar magnitude elsewhere around the world. An operator's withdrawal, for any reason whatsoever, from the Tamar Project and/or Leviathan project and/or Cyprus project and/or other petroleum assets held by the Partnership or any change in its status and/or rights, such that it ceases from being the operator of the various projects may undermine the Partnership's ability to fulfill its undertakings according to the work plans of the petroleum assets and/or under the gas sale agreements. In such a case, the Partnership cannot guarantee that a substitute operator will be found, either at all or on the same terms. The Partnership's inability to find a substitute operator may adversely affect the activity of the various projects as aforesaid and the undertakings to produce gas for the existing gas sale agreements, and consequently may lead to a decline in the Partnership's income.

7.31.25 Risk in development and production in the case of a discovery

The process of making a decision as to whether there is room to perform an investment in the development and commercial production of a field, and interim activities up to the 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 sums. Note that there is no certainty that in every case of a discovery which may be 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 obligation to pay royalties to third parties. Note further that the development and production in deep water (such as the water depth in the Tamar, Leviathan and Aphrodite natural gas findings) is complex, high-risk activity that requires the establishment of special production facilities in significant amounts.

7.31.26 Sale of rights in petroleum assets without obtaining full consideration therefor

Exploration and production activity requires considerable sums, which in many cases cannot be raised by means of loans or debt and therefore some cases may require that additional partners join the rights in the Partnership's various petroleum assets, while selling some of its rights in the petroleum assets at a lower price than the market value of such rights.

7.31.27 Revocation or expiration of petroleum rights and assets

Petroleum rights are granted under the Petroleum Law for a limited period of time and the validity thereof is conditioned on the fulfillment of obligations on dates set forth in the terms of the petroleum asset. In case of non-compliance with the terms, the petroleum right may be revoked, subject to the Petroleum Law. Non-compliance with the terms set forth in the petroleum rights may lead to a loss of the rights and all of the funds that were invested in such rights may be lost.

7.31.28 Overflow of reservoirs

Petroleum or natural gas reservoirs discovered or to be discovered in areas in which the Partnership holds rights may "overflow" (in terms of the geological structure and scope 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 as to joint utilization and production from the reservoir, in order to achieve efficient utilization of the petroleum or natural gas reserves and consequently may cause postponements and delays in development activities the Partnership intends to perform[300].

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[300] In this context, see Section 7.28.7(a) in relation to the runoff of a small part of the Tamar SW reservoir into the area of the Eran license.

7.31.29 Security risk

The production facilities of the Yam Tethys project and Tamar Project are located at sea in relative proximity to the maritime and land border between Israel and the Gaza Strip and are therefore exposed to security risks, including terrorist attacks. Furthermore, the Terminal is exposed to security risks, including terrorist attacks. The materialization of such security risks may, *inter alia*, undermine the Partnership's ability to find and retain the appropriate human capital, cause damage and/or harm to the production facilities, the Terminal and other equipment, which may disrupt the gas supply and even lead to the termination of gas sale agreements or to the reduction of sums payable by customers due to a claim of an event of "force majeure", and may limit the ability of service providers and equipment suppliers to provide their services or the items required for the activity of the Tamar project. In addition, the transmission infrastructures to Jordan and to Egypt (including EMG's gas transmission pipeline), the terminal in Egypt and the related infrastructures in Egypt, are also exposed to security risks, including terrorism and sabotage, which may impair the Partnership's ability to export gas and disrupt the gas supply in the context of the agreements for export to Egypt and Jordan.

7.31.30 Fluctuations in the dollar exchange rate

Changes in the dollar exchange rate may affect the Partnership's results as follows: (a) The Partnership's functional currency is the U.S. dollar. Since some of the Partnership's expenses and revenues are stated in NIS or are affected by the NIS/dollar exchange rate, an increase in the NIS to the dollar increases expenses and reduces revenues; (b) Since the Partnership reports its taxable income in New Israeli Shekels, changes in the NIS/dollar exchange rate affect the amount of the Partnership's taxable income.

7.31.31 The Partnership's belonging to the Delek Group and to the control holder thereof

The Partnership's belonging to the Delek Group and to the control holder affects the Partnership's ability to raise credit, *inter alia*, due to the "single borrower" limitation, as a result of which the Partnership's bank credit sources in Israel may be limited, as well as other regulatory restrictions imposed on the banking system and institutional bodies by the Ministry of Finance and the Bank of Israel. For details regarding the manner of financing of the Partnership's activity, see Section 7.22 above.

7.31.32 The Partnership's status as a monopoly in natural gas supply in Israel

The Partnership together with the other Tamar Partners were declared as monopoly holders in natural gas supply in Israel. Due to this declaration, limitations may be imposed on the Partnership's activity, including a prohibition on unreasonably refusing to supply natural gas as well as a prohibition on abusing its market position in a manner that may undermine business competition or damage the public (for example, by a determination of an unfair price level or by determining different engagement terms for similar transactions which may grant certain customers an unfair advantage over their competitors). Restrictions on the Partnership in light of its monopoly in natural gas supply in Israel may affect its ability to expand its activity in Israel. For further details regarding the restrictive trade practices, see Section 7.25.2 above.

7.31.33 <u>"*Force majeure*" events clause under the existing natural gas sale agreements</u>

In accordance with the existing natural gas sale agreements, some of the Partnership's customers, including the IEC, are obligated to take or pay for a minimal annual quantity of natural gas in the amount and according to the mechanism set forth in the supply agreement. However, this obligation may be suspended upon the occurrence of "*force majeure*" events, as defined in the existing natural gas sale agreements, which affect customers of the Partnership or the Partnership. A "*force majeure*" event may derive, *inter alia*, from war, acts of terrorism, and from other events which may prevent the Partnership from supplying natural gas, or a customer from receiving or using the natural gas, or not allow the transmission of the natural gas as a result of a failure or deficiency in the national transmission system.

If a "*force majeure*" event lasts for a prolonged period as determined in the agreement, and such event prevents the supply of the natural gas, this may lead to termination of the relevant natural gas sale agreement of the Partnership. It is clarified that a "*force majeure*" event which affects the customer may be relevant also with respect to the flow of the gas after the delivery point (the point of connection to the national transmission system). Therefore, the occurrence of a "*force majeure*" event which suspends the customer's undertakings to buy a significant quantity of natural gas may have a material adverse effect on the Partnership's income in the short-term or in the long-term when the same leads to the termination of a specific gas sale agreement as aforesaid.

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 their effect on the Partnership (significant, medium, small):

| | Degree of Risk Factor's Effect on Partnership's Business | | |
|---|---|---|---|
| | **Significant Effect** | **Medium Effect** | **Small Effect** |
| **Macro Risks** | | | |
| Changes in the global fuel prices and/or Electricity Production Tariff and/or U.S. CPI and/or other energy sources | | X | |
| Geopolitics | X | | |
| **Industry Risks** | | | |
| Difficulties in Obtaining Financing | | | X |
| Competition in Gas Supply | X | | |
| Restrictions on Export | X | | |
| Dependence on the transmission systems being in good working order | | X | |
| Operational Risks | | X | |
| Lack of Adequate Insurance Coverage | | X | |
| Construction Risks, Dependence on Contractors and on Professional Services and Equipment Providers | X | | |
| Exploration Activity Risks and Reliance on Partial and Estimated Data | | X | |
| Only Estimated Costs and Timetables and the Eventuality of Lack of Means | | X | |
| Forfeiture of the Partnership's Rights in its Petroleum Assets | | | X |
| Dependence on Obtaining Approvals of External Entities | X | | |
| Regulatory Changes | X | | |
| Potential Control of Natural Gas Prices | | X | |
| Motion for Class Certification in connection with the price in the agreement with the IEC | X | | |
| Applicable Environmental Regulation | X | | |
| Dependence on Weather and Sea Conditions | | | X |
| Information Security Risks | | X | |
| **Risks Specific to the Partnership** | | | |
| Tax Risks | | X | |
| Financing-related Undertakings | | X | |
| Dependence on Key Customer | | X | |
| Financial Soundness of the Partnership's Other Customers | | X | |
| Dependence on the Operator | | X | |
| Risk in Development and Production in the case of a Discovery | | | X |
| Sale of Rights in Petroleum Assets without Obtaining Full Consideration therefor | | X | |
| Revocation or Expiration of Petroleum Rights and Assets | | | X |
| Overflow of Reservoirs | | X | |

| | **Degree of Risk Factor's Effect on Partnership's Business** | | |
|---|---|---|---|
| | **Significant Effect** | **Medium Effect** | **Small Effect** |
| Security Risk | X | | |
| Fluctuations in the Dollar Rate | | X | |
| The Partnership's Belonging to the Delek Group and the Controlling Shareholder thereof | | X | |
| The Partnership's Status as a Monopoly in Natural Gas Supply in Israel | | X | |
| "*Force majeure*" events clause under the existing natural gas sale agreements | | X | |

The extent of the effect of the aforesaid risk factors on the Partnership's operations is based on estimation only and the actual extent of the effect may be different.

## Professional Terms Annex

"**Exploration**" **–** Sum total of the activities connected with oil and gas exploration.

"**Participation unit holders**" **–** Persons who are registered in the Participation Units Register as holders of the Participation Units.

"**LNG**" **–** Liquefied natural gas.

"**Hydrocarbons**" **–** Hydrocarbons; A general name for oil and gas that are carbon and hydrogen compounds.

"**Preliminary permit**" **–** As defined in the Petroleum Law.

"**Working interest**" **–** An interest in a petroleum asset that grants its owner the right to participate, proportionally to his share, in the exploitation of the petroleum asset for the purpose of petroleum exploration, development and petroleum production, subject to his participation in a proportional share of the related expenses that will be incurred, after the purchase of the working interest.

"**Petroleum right**" **–** A license or lease as defined in the Petroleum Law.

"**Preemptive right to receive license**" **–** As defined in the Petroleum Law.

"**Lease**" **–** As defined in the Petroleum Law.

"**Petroleum exploration**" **–**

Any and all operations designed to identify and prove the existence of petroleum reservoirs, including geological, geophysical, geochemical and engineering surveys and analyses, etc. The exploration stage is customarily determined to have been completed at the end of a successful exploration well, and after the explorers are able to prove the commerciality of the discovery, which may require additional wells.

"**Commercial quantities**" – Sufficient quantities of gas and/or oil allowing the commercial recovery thereof.

"**Logs**" – Various tests performed in the context of the drilling operations for the ongoing recording of the various properties and content of the drilled rocks.

"**Petroleum Resources Management System 2007 (SPE-PRMS)**" – A system for reporting petroleum resources and reserves evaluation, as published by the Society of Petroleum Engineers (SPE), the American Association of Petroleum Geologists (AAPG), the World Petroleum Council (WPC) and the Society of Petroleum Evaluation Engineers (SPEE), as amended from time to time.

"**Contingent resources**" **–** Defined according to the SPE-PRMS as the petroleum quantities that are evaluated from time to time as potentially producible from known reservoirs by implementing a development plan, but that are not yet considered economically producible, due to one or more conditions.

"**Prospective resources**" – Defined according to the SPE-PRMS as the petroleum quantities that are evaluated from time to time as potentially producible from reservoirs that have not yet been discovered/drilled, by implementing future development plans.

"**Petroleum asset**" – The direct or indirect holding of a preliminary permit, license or lease; In another country – the direct or indirect holding of a right of a similar nature that was granted by the body authorized to do so. As petroleum asset shall also be deemed a right to receive benefits resulting from the direct or indirect holding of a petroleum asset or a right of a similar nature (as the case may be).

"**Petroleum**" – Flowing petroleum, either liquid or vaporous, including oil, natural gas, natural gasoline, condensates and hydrocarbons, flowing thereto, and also asphalt and other solid petroleum carbons dissolved within flowing petroleum and producible together with it.

"**Seismic survey**" – A method enabling (onshore or offshore) sub-surface imaging and detecting of geological structures. The survey is performed by transmitting sound waves into the sub-surface and recording the waves returned from the various horizons in the examined section. To date, the surveys conducted and used are mainly 2D and 3D. The 2D surveys mainly serve for preliminary reconnaissance of the sub-surface in the surveyed area and for general detection of structures that may serve as petroleum traps. 3D surveys (the cost of which is higher than a 2D survey and the data and results of a higher quality) are performed in areas that were detected as promising in the 2D surveys and the image obtained therein is detailed and allows, *inter alia*, finding an optimal position for performing the drillings and for a more accurate estimation of the size of the structure.

"**Reserves**" – Defined according to the SPE-PRMS as petroleum quantities that are expected to be producible by implementing a development plan on accumulations discovered from a certain date on, under defined conditions. Reserves must fulfill four conditions: (1) They must be discovered; (2) producible; (3) commercial and stable/permanent (from the evaluation day); (4) based on the implemented development project.

"**Development**" – The drilling and equipping of the area of a petroleum asset in order to determine its productive capacity, produce gas therefrom and market the same.

"**Condensate**" – (1) Hydrocarbon compound that is produced from natural gas, separated from the gas and liquefied by cooling and expansion procedures; (2) Hydrocarbons which are in the gaseous state under reservoir conditions but which are liquefied in the transition from the reservoir to the surface; (3) Condensed hydrocarbons from petroleum refining.

"**Exploration drilling**" – a drilling, the purpose of which is to prove the existence of petroleum in a prospect, and the calibration of the geological model that led to the drilling thereof. Constitutes the peak of the exploration activity. According to the field size and complexity, there may be more than one test drilling in a field.

“**Confirmation well**” or “Appraisal well”– A well whose purpose is to confirm the size, quality and continuity of a petroleum field discovered by the successful test drilling. The stage of evaluating the reservoir officially ends upon the adoption of a decision to invest in the field’s development.

“**License**” **–** As defined in the Petroleum Law.

“**Petroleum field**” **–** An accumulation or accumulations of petroleum below the ground, that are generally comprised of reservoir rocks covered by a sealing layer. Mostly used to designate reservoirs, the production from which may be commercial.

“**Miocene layers**” **–** Rock layers of the Miocene age (the designation of a geological period) that were created 5 to 24 million years ago.

“**FPSO (Floating Production Storage & Offloading Vessel**)” **–** An offshore production system which is usually built in the shape of a ship carrying gas and/or petroleum storage containers.

**“Petroleum”; “Discovered”; “Discovery”; “Proved reserves”; “Probable reserves”; “Possible reserves”; “Low estimate”; “Best estimate”; “High estimate”; “Contingent resources in 1C, 2C, 3C categories (1C, 2C, 3C)”; “On production”; “Approved for development”; “Justified for development”; “Development pending”; Development unclarified or on hold”; “Well abandonment”; “Development not viable”; “Condensate”; “Dry hole”; “Reserves in 1P/2P/3P categories (1P/2P/3P)**” **–** In the meaning of these terms in the SPE-PRMS.

“**BCF**” **–** One billion cubic feet which are 0.001 TCF or approx. BCM 0.0283.

“**BCM**” **–** One billion cubic meter.

“**Mmcf/D**” **–** One million cubic feet per day.

“**TCF**” **–** One trillion cubic feet which are 1,000 BCF or approx. 28.32 BCM.

“**MMCF**” **–** One million cubic feet which are 0.001 BCF or approx. 0.00003 BCM.

“**MMBBL**” **–** Million Barrels.

“**MMBTU**” **–** Million British Thermal Units.

The following are the conversion coefficients for the units used in the report above:

| BCM | BCF | MMCF |
|---|---|---|
| 1 | 35.3107 | 35310.7 |

| BCF | MMCF | BCM |
|---|---|---|
| 1 | 1000 | 0.0283 |

| MMCF | BCF | BCM |
|---|---|---|
| 1 | 0.001 | 0.00003 |

# Annex A

# NSAI Consent

**NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.**
WORLDWIDE PETROLEUM CONSULTANTS
ENGINEERING • GEOLOGY • GEOPHYSICS • PETROPHYSICS

EXECUTIVE COMMITTEE
ROBERT C. BARG · MIKE K. NORTON
P. SCOTT FROST · DAN PAUL SMITH
JOHN G. HATTNER · JOSEPH J. SPELLMAN
J. CARTER HENSON, JR. · DANIEL T. WALKER

CHAIRMAN & CEO
C.H. (SCOTT) REES III
PRESIDENT & COO
DANNY D. SIMMONS
EXECUTIVE VP
G. LANCE BINDER

March 21, 2019

Delek Drilling Limited Partnership
19 Abba Eban Boulevard
Herzelia 4612001
Israel

Ladies and Gentlemen:

As independent consultants, Netherland, Sewell & Associates, Inc. (NSAI) hereby grants permission to Delek Drilling Limited Partnership (Delek Drilling) to use the following NSAI reports in the 2018 Annual Report of Delek Drilling to be published in March 2019 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 21, 2019, sets forth our estimates of:

- The proved undeveloped, probable, and possible reserves and future revenue, as of December 31, 2018, to the Delek Drilling working interest in certain gas properties located in Leviathan Field, Leases I/14 and I/15, offshore Israel. The March 21 reports also sets forth our estimates of the contingent resources and cash flow, as of December 31, 2018, to the Delek Drilling working interest for these properties.

The report dated February 19, 2019, sets forth our estimates of:

- The proved, probable, and possible reserves and future revenue, as of December 31, 2018, to the Delek Drilling working interest in certain gas properties located in Tamar and Tamar Southwest Fields, Tamar Lease I/12, offshore Israel.

The reports dated March 19, 2018, set forth our estimates of:

- The unrisked prospective resources, as of December 31, 2017, to the Delek Drilling working interest, in two prospective reservoirs located in the Leviathan Deep Prospect, offshore Israel.

- The unrisked contingent and prospective gas resources, as of December 31, 2017, to the Delek Drilling working interest in a discovery and prospects located in the Dalit Discovery area, offshore Israel.

- The unrisked contingent and prospective resources, as of December 31, 2017, to the Delek Drilling working interest for the discovery and prospective reservoirs located in the Aphrodite Discovery, Cypriot Block 12, offshore Cyprus.

In addition to the reports listed above, NSAI hereby grants permission to Delek Drilling to use our No Material Change letter dated March 21, 2019, which sets forth our opinion that there are no material changes to our production profiles for each category and our proved, proved plus probable, and proved plus probable plus possible reserves referenced in our February 19, 2019, report for properties located in Tamar and Tamar Southwest Fields, issued to Delek Drilling.

2100 ROSS AVENUE, SUITE 2200 • DALLAS, TEXAS 75201 • PH: 214-969-5401 • FAX: 214-969-5411
1301 MCKINNEY STREET, SUITE 3200 • HOUSTON, TEXAS 77010 • PH: 713-654-4950 • FAX: 713-654-4951
info@nsai-petro.com
netherlandsewell.com

As of the date hereof, nothing has come to our attention that could cause us to make any material revisions in our reports or in our conclusions based on data available when our reports were prepared.

Sincerely,

**NETHERLAND, SEWELL & ASSOCIATES, INC.**

By: Richard B. Talley, Jr.

Richard B. Talley, Jr., P.E.
Senior Vice President

RBT:MAG

# Annex B

# Reserves Report
# Tamar Project

EXECUTIVE COMMITTEE
ROBERT C. BARG  MIKE K. NORTON
P. SCOTT FROST  DAN PAUL SMITH
JOHN G. HATTNER  JOSEPH J. SPELLMAN
J. CARTER HENSON, JR.  DANIEL T. WALKER

CHAIRMAN & CEO
C.H. (SCOTT) REES III
PRESIDENT & COO
DANNY D. SIMMONS
EXECUTIVE VP
G. LANCE BINDER

February 19, 2019

Delek Drilling Limited Partnership
19 Abba Eban Boulevard
Herzelia 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, 2018, to the Delek Drilling Limited Partnership (Delek Drilling) working interest in certain gas properties located in Tamar and Tamar Southwest Fields, Tamar Lease I/12, offshore Israel. It is our understanding that Delek Drilling owns a 22 percent direct working interest and a 3.7855 percent indirect working interest in these properties; this indirect working interest is through Delek Drilling's 22.6 percent ownership of Tamar Petroleum Ltd. Reserves in Tamar Southwest Field that extend into the Eran License have not been included in this report. We completed our evaluation on or about the date of this letter. This report has been prepared using price and cost parameters specified by Delek Drilling, as discussed in subsequent paragraphs of this letter. The estimates in this report have been prepared in accordance with the definitions and guidelines set forth in the 2018 Petroleum Resources Management System (PRMS) approved by the Society of Petroleum Engineers (SPE) and in accordance with internationally recognized standards, as stipulated by the Israel Securities Authority (ISA). Definitions are presented immediately following this letter. This report has been prepared for Delek Drilling's use in filing with the ISA; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

We estimate the gross (100 percent) reserves and the working interest reserves to the Delek Drilling interest in these properties, as of December 31, 2018, to be:

| | Gas Reserves (BCF) | | Condensate Reserves (MMBBL) | |
|---|---|---|---|---|
| Category | Gross (100%) | Working Interest | Gross (100%) | Working Interest |
| Proved (1P) | 8,108.9 | 2,090.9 | 10.5 | 2.7 |
| Probable | 3,030.1 | 781.3 | 3.9 | 1.0 |
| Proved + Probable (2P) | 11,139.0 | 2,872.2 | 14.5 | 3.7 |
| Possible | 2,468.3 | 636.5 | 3.2 | 0.8 |
| Proved + Probable + Possible (3P) | 13,607.3 | 3,508.7 | 17.7 | 4.6 |

*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 Delek Drilling interest in these properties, as of December 31, 2018, to be:

| | Future Net Revenue After Levy and Corporate Income Taxes (MM$) | | | | |
|---|---|---|---|---|---|
| Category | Discounted at 0% | Discounted at 5% | Discounted at 10% | Discounted at 15% | Discounted at 20% |
| Proved (1P) | 4,152.7 | 2,617.6 | 1,838.1 | 1,400.6 | 1,132.8 |
| Probable | 1,850.9 | 601.9 | 218.7 | 90.9 | 44.8 |
| Proved + Probable (2P) | 6,003.6 | 3,219.4 | 2,056.8 | 1,491.5 | 1,177.7 |
| Possible | 1,641.9 | 385.0 | 102.1 | 32.3 | 13.3 |
| Proved + Probable + Possible (3P) | 7,645.5 | 3,604.4 | 2,158.9 | 1,523.7 | 1,191.0 |

*Totals may not add because of rounding.*

We estimate the gross (100 percent) reserves for these properties by field, as of December 31, 2018, to be:

| | Tamar | | Tamar Southwest | | Total | |
|---|---|---|---|---|---|---|
| Category | Gas (BCF) | Condensate (MMBBL) | Gas (BCF) | Condensate (MMBBL) | Gas (BCF) | Condensate (MMBBL) |
| Proved (1P) | 7,312.4 | 9.5 | 796.4 | 1.0 | 8,108.9 | 10.5 |
| Probable | 2,871.0 | 3.7 | 159.1 | 0.2 | 3,030.1 | 3.9 |
| Proved + Probable (2P) | 10,183.4 | 13.2 | 955.6 | 1.2 | 11,139.0 | 14.5 |
| Possible | 2,366.0 | 3.1 | 102.2 | 0.1 | 2,468.3 | 3.2 |
| Proved + Probable + Possible (3P) | 12,549.5 | 16.3 | 1,057.8 | 1.4 | 13,607.3 | 17.7 |

*Totals may not add because of rounding.*

Gas volumes are expressed in billions of cubic feet (BCF) at standard temperature and pressure bases. Condensate volumes are expressed in millions of barrels (MMBBL); a barrel is equivalent to 42 United States gallons. Monetary values shown in this report are expressed in United States dollars ($), thousands of United States dollars (M$), or millions of United States dollars (MM$). For reference, the February 18, 2019, exchange rate was 3.62 Israeli New Shekels per United States dollar.

Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. The 1P reserves are inclusive of proved developed producing, proved developed non-producing, and proved undeveloped reserves. The project maturity subclass for these reserves is on production. The estimates of reserves and future revenue included herein have not been adjusted for risk. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated.

Working interest revenue shown in this report is Delek Drilling's share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for Delek Drilling's share of royalties, capital costs, abandonment costs, operating expenses, and Delek Drilling's estimates of its oil and gas profits levy and corporate income taxes. The future net revenue has been discounted at annual rates of 0, 5, 10, 15, and 20 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties. Tables I through V present revenue, costs, and taxes by reserves category. Table VI presents Delek Drilling's historical production and operating expense data.

As requested, this report has been prepared using gas and condensate price parameters specified by Delek Drilling. Gas prices are based on a weighted average of all sales contracts according to their relative volume. These contract prices are mainly derived from various formulae that include indexation to the Consumer Price Index, the Power Generation Tariff, or an average of long-term forecasts for Brent Crude prices provided by various institutions. Condensate prices are based on Brent Crude prices and are adjusted for quality, transportation fees, and market differentials.

Operating costs used in this report are based on operating expense records of Delek Drilling. Operating costs are limited to direct project-level costs, insurance costs, and Delek Drilling's estimate of the portion of the operator's headquarters general and administrative overhead expenses that can be directly attributed to this project; Noble Energy Mediterranean Ltd. is the operator of the properties. Based on a review of the records provided to us and our knowledge of similar properties, we regard these estimated operating costs to be reasonable. Operating costs have been divided into field-level costs and per-unit-of-production costs and, as requested, are not escalated for inflation.

Capital costs used in this report were provided by Delek Drilling and are based on estimates of future expenditures for the purpose of preserving and expanding the production capacity. Capital costs are those amounts of expenditures already authorized by the partners and amounts forecasted by Delek Drilling that are required for the above purpose, including new development wells, additional infrastructure, and production equipment. It is our understanding that Tamar and Tamar Southwest Fields are being developed under the Tamar Development Plan. Based on our understanding of this future development plan, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Abandonment costs used in this report are Delek Drilling's estimates of the costs to abandon the wells, platform, and production facilities; these estimates do not include any salvage value for the lease and well equipment. As requested, capital costs and abandonment costs are not escalated for inflation.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; however, we are not currently aware of any possible environmental liability that would have any material effect on the reserves estimated in this report or the commerciality of such estimates. Therefore, our estimates do not include any costs due to such possible liability.

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the Delek Drilling interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on Delek Drilling receiving its net revenue interest share of estimated future gross production.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be commercially recoverable; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. There is a 10 percent chance that the quantities will be equal to, or greater than, the quantities of the proved plus probable plus possible reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with the current development plan as provided to us by Delek Drilling, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report. The near-term gas sales forecasts used in this report were provided by Delek Drilling. It should be noted that the actual production profile for each category may be lower or higher than the production profile used to calculate the estimates of future net revenue used in this report, and no sensitivity analysis was performed with respect to the production profile of the wells.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, seismic data, core data, well test data, production data, historical price and cost information, and property ownership interests. We were provided with all the necessary data to prepare the estimates for these properties, and we were not limited from access to any material we believe may be relevant. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with generally accepted petroleum engineering and evaluation principles set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the SPE (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, analogy, and reservoir modeling, that we considered to be appropriate and necessary to classify, categorize, and estimate reserves in accordance with the 2018 PRMS definitions and guidelines. Certain

NETHERLAND, SEWELL & ASSOCIATES, INC.



parameters used in our volumetric analyses are summarized in Tables VII and VIII. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

Netherland, Sewell & Associates, Inc. (NSAI) was engaged on November 14, 2018, by Mr. Yossi Abu, Chief Executive Officer of Delek Drilling, to perform this assessment. The data used in our estimates were obtained from Noble Energy Mediterranean Ltd., Delek Drilling, other interest owners, public data sources, and the nonconfidential files of NSAI and were accepted as accurate. Supporting work data are on file in our office. We have not examined the contractual rights to the properties or independently confirmed the actual degree or type of interest owned. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis. Furthermore, no limitations or restrictions were placed upon NSAI by officials of Delek Drilling.

## QUALIFICATIONS

NSAI performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. We provide a complete range of geological, geophysical, petrophysical, and engineering services, and we have the technical expertise and ability to perform these services in any oil and gas producing area in the world. The staff are familiar with the recognized industry reserves and resources definitions, specifically those promulgated by the U.S. Securities and Exchange Commission, by the Alberta Securities Commission, and by the SPE, Society of Petroleum Evaluation Engineers, World Petroleum Council, and American Association of Petroleum Geologists. The technical persons primarily responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards.

This assessment has been led by Mr. Richard B. Talley, Jr. and Mr. Zachary R. Long. Mr. Talley is a Senior Vice President and Mr. Long is a Vice President in the firm's Houston office at 1301 McKinney Street, Suite 3200, Houston, Texas 77010, USA. Mr. Talley is a Licensed Professional Engineer (Texas Registration No. 102425). He has been practicing consulting petroleum engineering at NSAI since 2004 and has over 5 years of prior industry experience. Mr. Long is a Licensed Professional Geoscientist (Texas Registration No. 11792). He has been practicing consulting petroleum geoscience at NSAI since 2007 and has over 2 years of prior industry experience.

Sincerely,

**NETHERLAND, SEWELL & ASSOCIATES, INC.**
Texas Registered Engineering Firm F-2699

By:
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

By:
Richard B. Talley, Jr., P.E. 102425
Senior Vice President

Date Signed: February 19, 2019

STATE OF TEXAS
R. B. TALLEY, JR.
102425
LICENSED
PROFESSIONAL ENGINEER

By:
Zachary R. Long, P.G. 11792
Vice President

Date Signed: February 19, 2019

STATE OF TEXAS
Z. R. LONG
GEOLOGY
11792
LICENSED
PROFESSIONAL GEOSCIENTIST

RBT:MAG

# PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the Petroleum Resources Management System Approved by
the Society of Petroleum Engineers (SPE) Board of Directors, June 2018

This document contains information excerpted from definitions and guidelines prepared by the Oil and Gas Reserves Committee of the Society of Petroleum Engineers (SPE) and reviewed and jointly sponsored by the SPE, World Petroleum Council, American Association of Petroleum Geologists, Society of Petroleum Evaluation Engineers, Society of Exploration Geophysicists, Society of Petrophysicists and Well Log Analysts, and European Association of Geoscientists & Engineers.

### Preamble

Petroleum resources are the quantities of hydrocarbons naturally occurring on or within the Earth's crust. Resources assessments estimate quantities in known and yet-to-be-discovered accumulations. Resources evaluations are focused on those quantities that can potentially be recovered and marketed by commercial projects. A petroleum resources management system provides a consistent approach to estimating petroleum quantities, evaluating projects, and presenting results within a comprehensive classification framework.

This updated PRMS provides fundamental principles for the evaluation and classification of petroleum reserves and resources. If there is any conflict with prior SPE and PRMS guidance, approved training, or the Application Guidelines, the current PRMS shall prevail. It is understood that these definitions and guidelines allow flexibility for entities, governments, and regulatory agencies to tailor application for their particular needs; however, any modifications to the guidance contained herein must be clearly identified. The terms "shall" or "must" indicate that a provision herein is mandatory for PRMS compliance, while "should" indicates a recommended practice and "may" indicates that a course of action is permissible. The definitions and guidelines contained in this document must not be construed as modifying the interpretation or application of any existing regulatory reporting requirements.

## 1.0 Basic Principles and Definitions

1.0.0.1 A classification system of petroleum resources is a fundamental element that provides a common language for communicating both the confidence of a project's resources maturation status and the range of potential outcomes to the various entities. The PRMS provides transparency by requiring the assessment of various criteria that allow for the classification and categorization of a project's resources. The evaluation elements consider the risk of geologic discovery and the technical uncertainties together with a determination of the chance of achieving the commercial maturation status of a petroleum project.

1.0.0.2 The technical estimation of petroleum resources quantities involves the assessment of quantities and values that have an inherent degree of uncertainty. These quantities are associated with exploration, appraisal, and development projects at various stages of design and implementation. The commercial aspects considered will relate the project's maturity status (e.g., technical, economical, regulatory, and legal) to the chance of project implementation.

1.0.0.3 The use of a consistent classification system enhances comparisons between projects, groups of projects, and total company portfolios. The application of PRMS must consider both technical and commercial factors that impact the project's feasibility, its productive life, and its related cash flows.

### 1.1 Petroleum Resources Classification Framework

1.1.0.1 Petroleum is defined as a naturally occurring mixture consisting of hydrocarbons in the gaseous, liquid, or solid state. Petroleum may also contain non-hydrocarbons, common examples of which are carbon dioxide, nitrogen, hydrogen sulfide, and sulfur. In rare cases, non-hydrocarbon content can be greater than 50%.

1.1.0.2 The term resources as used herein is intended to encompass all quantities of petroleum naturally occurring within the Earth's crust, both discovered and undiscovered (whether recoverable or unrecoverable), plus those quantities already produced. Further, it includes all types of petroleum whether currently considered as conventional or unconventional resources.

1.1.0.3 Figure 1.1 graphically represents the PRMS resources classification system. The system classifies resources into discovered and undiscovered and defines the recoverable resources classes: Production, Reserves, Contingent Resources, and Prospective Resources, as well as Unrecoverable Petroleum.

1.1.0.4 The horizontal axis reflects the range of uncertainty of estimated quantities potentially recoverable from an accumulation by a project, while the vertical axis represents the chance of commerciality, $P_c$, which is the chance that a project will be committed for development and reach commercial producing status.

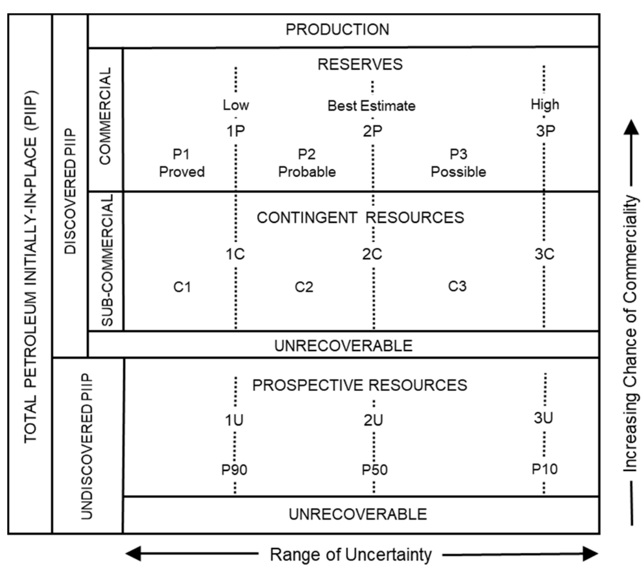


Figure 1.1—Resources classification framework

# PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

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1.1.0.5 The following definitions apply to the major subdivisions within the resources classification:

A. **Total Petroleum Initially-In-Place** (PIIP) is all quantities of petroleum that are estimated to exist originally in naturally occurring accumulations, discovered and undiscovered, before production.

B. **Discovered PIIP** is the quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations before production.

C. **Production** is the cumulative quantities of petroleum that have been recovered at a given date. While all recoverable resources are estimated, and production is measured in terms of the sales product specifications, raw production (sales plus non-sales) quantities are also measured and required to support engineering analyses based on reservoir voidage (see Section 3.2, Production Measurement).

1.1.0.6 Multiple development projects may be applied to each known or unknown accumulation, and each project will be forecast to recover an estimated portion of the initially-in-place quantities. The projects shall be subdivided into commercial, sub-commercial, and undiscovered, with the estimated recoverable quantities being classified as Reserves, Contingent Resources, or Prospective Resources respectively, as defined below.

A. 1. **Reserves** are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must satisfy four criteria: discovered, recoverable, commercial, and remaining (as of the evaluation's effective date) based on the development project(s) applied.

2. Reserves are recommended as sales quantities as metered at the reference point. Where the entity also recognizes quantities consumed in operations (CiO) (see Section 3.2.2), as Reserves these quantities must be recorded separately. Non-hydrocarbon quantities are recognized as Reserves only when sold together with hydrocarbons or CiO associated with petroleum production. If the non-hydrocarbon is separated before sales, it is excluded from Reserves.

3. Reserves are further categorized in accordance with the range of uncertainty and should be sub-classified based on project maturity and/or characterized by development and production status.

B. **Contingent Resources** are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, by the application of development project(s) not currently considered to be commercial owing to one or more contingencies. Contingent Resources have an associated chance of development. Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the range of uncertainty associated with the estimates and should be sub-classified based on project maturity and/or economic status.

C. **Undiscovered PIIP** is that quantity of petroleum estimated, as of a given date, to be contained within accumulations yet to be discovered.

D. **Prospective Resources** are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of geologic discovery and a chance of development. Prospective Resources are further categorized in accordance with the range of uncertainty associated with recoverable estimates, assuming discovery and development, and may be sub-classified based on project maturity.

E. **Unrecoverable Resources** are that portion of either discovered or undiscovered PIIP evaluated, as of a given date, to be unrecoverable by the currently defined project(s). A portion of these quantities may become recoverable in the future as commercial circumstances change, technology is developed, or additional data are acquired. The remaining portion may never be recovered because of physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

1.1.0.7 The sum of Reserves, Contingent Resources, and Prospective Resources may be referred to as "remaining recoverable resources." Importantly, these quantities should not be aggregated without due consideration of the technical and commercial risk involved with their classification. When such terms are used, each classification component of the summation must be provided.

1.1.0.8 Other terms used in resource assessments include the following:

A. **Estimated Ultimate Recovery (EUR)** is not a resources category or class, but a term that can be applied to an accumulation or group of accumulations (discovered or undiscovered) to define those quantities of petroleum estimated, as of a given date, to be potentially recoverable plus those quantities already produced from the accumulation or group of accumulations. For clarity, EUR must reference the associated technical and commercial conditions for the resources; for example, proved EUR is Proved Reserves plus prior production.

B. **Technically Recoverable Resources (TRR)** are those quantities of petroleum producible using currently available technology and industry practices, regardless of commercial considerations. TRR may be used for specific Projects or for groups of Projects, or, can be an undifferentiated estimate within an area (often basin-wide) of recovery potential.

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### 1.2 Project-Based Resources Evaluations

1.2.0.1 The resources evaluation process consists of identifying a recovery project or projects associated with one or more petroleum accumulations, estimating the quantities of PIIP, estimating that portion of those in-place quantities that can be recovered by each project, and classifying the project(s) based on maturity status or chance of commerciality.

1.2.0.2 The concept of a project-based classification system is further clarified by examining the elements contributing to an evaluation of net recoverable resources (see Figure 1.2).

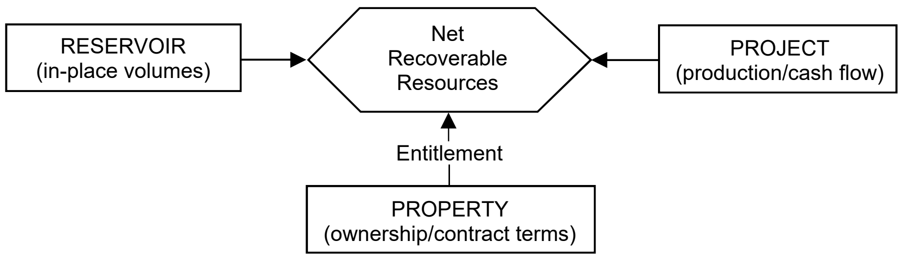


Figure 1.2—Resources evaluation

1.2.0.3 **The reservoir** (contains the petroleum accumulation): Key attributes include the types and quantities of PIIP and the fluid and rock properties that affect petroleum recovery.

1.2.0.4 **The project:** A project may constitute the development of a well, a single reservoir, or a small field; an incremental development in a producing field; or the integrated development of a field or several fields together with the associated processing facilities (e.g., compression). Within a project, a specific reservoir's development generates a unique production and cash-flow schedule at each level of certainty. The integration of these schedules taken to the project's earliest truncation caused by technical, economic, or the contractual limit defines the estimated recoverable resources and associated future net cash flow projections for each project. The ratio of EUR to total PIIP quantities defines the project's recovery efficiency. Each project should have an associated recoverable resources range (low, best, and high estimate).

1.2.0.5 **The property** (lease or license area): Each property may have unique associated contractual rights and obligations, including the fiscal terms. This information allows definition of each participating entity's share of produced quantities (entitlement) and share of investments, expenses, and revenues for each recovery project and the reservoir to which it is applied. One property may encompass many reservoirs, or one reservoir may span several different properties. A property may contain both discovered and undiscovered accumulations that may be spatially unrelated to a potential single field designation.

1.2.0.6 An entity's net recoverable resources are the entitlement share of future production legally accruing under the terms of the development and production contract or license.

1.2.0.7 In the context of this relationship, the project is the primary element considered in the resources classification, and the net recoverable resources are the quantities derived from each project. A project represents a defined activity or set of activities to develop the petroleum accumulation(s) and the decisions taken to mature the resources to reserves. In general, it is recommended that an individual project has assigned to it a specific maturity level sub-class (See Section 2.1.3.5, Project Maturity Sub-Classes) at which a decision is made whether or not to proceed (i.e., spend more money) and there should be an associated range of estimated recoverable quantities for the project (See Section 2.2.1, Range of Uncertainty). For completeness, a developed field is also considered to be a project.

1.2.0.8 An accumulation or potential accumulation of petroleum is often subject to several separate and distinct projects that are at different stages of exploration or development. Thus, an accumulation may have recoverable quantities in several resources classes simultaneously.

1.2.0.10 Not all technically feasible development projects will be commercial. The commercial viability of a development project within a field's development plan is dependent on a forecast of the conditions that will exist during the time period encompassed by the project (see Section 3.1, Assessment of Commerciality). Conditions include technical, economic (e.g., hurdle rates, commodity prices), operating and capital costs, marketing, sales route(s), and legal, environmental, social, and governmental factors forecast to exist and impact the project during the time period being evaluated. While economic factors can be summarized as forecast costs and product prices, the underlying influences include, but are not limited to, market conditions (e.g., inflation, market factors, and contingencies), exchange rates, transportation and processing infrastructure, fiscal terms, and taxes.

1.2.0.11 The resources being estimated are those quantities producible from a project as measured according to delivery specifications at the point of sale or custody transfer (see Section 3.2.1, Reference Point) and may permit forecasts of CiO quantities (see Section 3.2.2., Consumed in Operations). The cumulative production forecast from the effective date forward to cessation of production is the remaining recoverable resources quantity (see Section 3.1.1, Net Cash-Flow Evaluation).

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1.2.0.12 The supporting data, analytical processes, and assumptions describing the technical and commercial basis used in an evaluation must be documented in sufficient detail to allow, as needed, a qualified reserves evaluator or qualified reserves auditor to clearly understand each project's basis for the estimation, categorization, and classification of recoverable resources quantities and, if appropriate, associated commercial assessment.

## 2.0 Classification and Categorization Guidelines

### 2.1 Resources Classification

2.1.0.1 The PRMS classification establishes criteria for the classification of the total PIIP. A determination of a discovery differentiates between discovered and undiscovered PIIP. The application of a project further differentiates the recoverable from unrecoverable resources. The project is then evaluated to determine its maturity status to allow the classification distinction between commercial and sub-commercial projects. PRMS requires the project's recoverable resources quantities to be classified as either Reserves, Contingent Resources, or Prospective Resources.

#### 2.1.1 Determination of Discovery Status

2.1.1.1 A discovered petroleum accumulation is determined to exist when one or more exploratory wells have established through testing, sampling, and/or logging the existence of a significant quantity of potentially recoverable hydrocarbons and thus have established a known accumulation. In the absence of a flow test or sampling, the discovery determination requires confidence in the presence of hydrocarbons and evidence of producibility, which may be supported by suitable producing analogs (see Section 4.1.1, Analogs). In this context, "significant" implies that there is evidence of a sufficient quantity of petroleum to justify estimating the in-place quantity demonstrated by the well(s) and for evaluating the potential for commercial recovery.

2.1.1.2 Where a discovery has identified potentially recoverable hydrocarbons, but it is not considered viable to apply a project with established technology or with technology under development, such quantities may be classified as Discovered Unrecoverable with no Contingent Resources. In future evaluations, as appropriate for petroleum resources management purposes, a portion of these unrecoverable quantities may become recoverable resources as either commercial circumstances change or technological developments occur.

#### 2.1.2 Determination of Commerciality

2.1.2.1 Discovered recoverable quantities (Contingent Resources) may be considered commercially mature, and thus attain Reserves classification, if the entity claiming commerciality has demonstrated a firm intention to proceed with development. This means the entity has satisfied the internal decision criteria (typically rate of return at or above the weighted average cost-of-capital or the hurdle rate). Commerciality is achieved with the entity's commitment to the project and all of the following criteria:

A. Evidence of a technically mature, feasible development plan.
B. Evidence of financial appropriations either being in place or having a high likelihood of being secured to implement the project.
C. Evidence to support a reasonable time-frame for development.
D. A reasonable assessment that the development projects will have positive economics and meet defined investment and operating criteria. This assessment is performed on the estimated entitlement forecast quantities and associated cash flow on which the investment decision is made (see Section 3.1.1, Net Cash-Flow Evaluation).
E. A reasonable expectation that there will be a market for forecast sales quantities of the production required to justify development. There should also be similar confidence that all produced streams (e.g., oil, gas, water, $CO2$) can be sold, stored, re-injected, or otherwise appropriately disposed.
F. Evidence that the necessary production and transportation facilities are available or can be made available.
G. Evidence that legal, contractual, environmental, regulatory, and government approvals are in place or will be forthcoming, together with resolving any social and economic concerns.

2.1.2.2 The commerciality test for Reserves determination is applied to the best estimate (P50) forecast quantities, which upon qualifying all commercial and technical maturity criteria and constraints become the 2P Reserves. Stricter cases [e.g., low estimate (P90)] may be used for decision purposes or to investigate the range of commerciality (see Section 3.1.2, Economic Criteria). Typically, the low- and high-case project scenarios may be evaluated for sensitivities when considering project risk and upside opportunity.

2.1.2.3 To be included in the Reserves class, a project must be sufficiently defined to establish both its technical and commercial viability as noted in Section 2.1.2.1. There must be a reasonable expectation that all required internal and external approvals will be forthcoming and evidence of firm intention to proceed with development within a reasonable time-frame. A reasonable time-frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While five years is recommended as a benchmark, a longer time-frame could be applied where justifiable; for example, development of economic projects that take longer than five years to be developed or are deferred to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented.

2.1.2.4 While PRMS guidelines require financial appropriations evidence, they do not require that project financing be confirmed before classifying projects as Reserves. However, this may be another external reporting requirement. In many cases, financing is conditional upon the same criteria as above. In general, if there is not a reasonable expectation that financing or other forms of commitment (e.g., farm-outs) can be arranged so that the development will be initiated within a reasonable time-frame, then the project should be classified as Contingent Resources. If financing is reasonably expected to be in place at the time of the final investment decision (FID), the project's resources may be classified as Reserves.

## 2.2 Resources Categorization

2.2.0.1 The horizontal axis in the resources classification in Figure 1.1 defines the range of uncertainty in estimates of the quantities of recoverable, or potentially recoverable, petroleum associated with a project or group of projects. These estimates include the uncertainty components as follows:

A. The total petroleum remaining within the accumulation (in-place resources).
B. The technical uncertainty in the portion of the total petroleum that can be recovered by applying a defined development project or projects (i.e., the technology applied).
C. Known variations in the commercial terms that may impact the quantities recovered and sold (e.g., market availability; contractual changes, such as production rate tiers or product quality specifications) are part of project's scope and are included in the horizontal axis, while the chance of satisfying the commercial terms is reflected in the classification (vertical axis).

2.2.0.2 The uncertainty in a project's recoverable quantities is reflected by the 1P, 2P, 3P, Proved (P1), Probable (P2), Possible (P3), 1C, 2C, 3C, C1, C2, and C3; or 1U, 2U, and 3U resources categories. The commercial chance of success is associated with resources classes or sub-classes and not with the resources categories reflecting the range of recoverable quantities.

### 2.2.1 Range of Uncertainty

2.2.1.1 Uncertainty is inherent in a project's resources estimation and is communicated in PRMS by reporting a range of category outcomes. The range of uncertainty of the recoverable and/or potentially recoverable quantities may be represented by either deterministic scenarios or by a probability distribution (see Section 4.2, Resources Assessment Methods).

2.2.1.2 When the range of uncertainty is represented by a probability distribution, a low, best, and high estimate shall be provided such that:

A. There should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate.
B. There should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate.
C. There should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

2.2.1.3 In some projects, the range of uncertainty may be limited, and the three scenarios may result in resources estimates that are not significantly different. In these situations, a single value estimate may be appropriate to describe the expected result.

2.2.1.4 When using the deterministic scenario method, typically there should also be low, best, and high estimates, where such estimates are based on qualitative assessments of relative uncertainty using consistent interpretation guidelines. Under the deterministic incremental method, quantities for each confidence segment are estimated discretely (see Section 2.2.2, Category Definitions and Guidelines).

2.2.1.5 Project resources are initially estimated using the above uncertainty range forecasts that incorporate the subsurface elements together with technical constraints related to wells and facilities. The technical forecasts then have additional commercial criteria applied (e.g., economics and license cutoffs are the most common) to estimate the entitlement quantities attributed and the resources classification status: Reserves, Contingent Resources, and Prospective Resources.

### 2.2.2 Category Definitions and Guidelines

2.2.2.1 Evaluators may assess recoverable quantities and categorize results by uncertainty using the deterministic incremental method, the deterministic scenario (cumulative) method, geostatistical methods, or probabilistic methods (see Section 4.2, Resources Assessment Methods). Also, combinations of these methods may be used.

2.2.2.2 Use of consistent terminology (Figures 1.1 and 2.1) promotes clarity in communication of evaluation results. For Reserves, the general cumulative terms low/best/high forecasts are used to estimate the resulting 1P/2P/3P quantities, respectively. The associated incremental quantities are termed Proved (P1), Probable (P2) and Possible (P3). Reserves are a subset of, and must be viewed within the context of, the complete resources classification system. While the categorization criteria are proposed specifically for Reserves, in most cases, the criteria can be equally applied to Contingent and Prospective Resources. Upon satisfying the commercial maturity criteria for discovery and/or development, the project quantities will then move to the appropriate resources sub-class. Table 3 provides criteria for the Reserves categories determination.

2.2.2.3 For Contingent Resources, the general cumulative terms low/best/high estimates are used to estimate the resulting 1C/2C/3C quantities, respectively. The terms C1, C2, and C3 are defined for incremental quantities of Contingent Resources.

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2.2.2.4 For Prospective Resources, the general cumulative terms low/best/high estimates also apply and are used to estimate the resulting 1U/2U/3U quantities. No specific terms are defined for incremental quantities within Prospective Resources.

2.2.2.5 Quantities in different classes and sub-classes cannot be aggregated without considering the varying degrees of technical uncertainty and commercial likelihood involved with the classification(s) and without considering the degree of dependency between them (see Section 4.2.1, Aggregating Resources Classes).

2.2.2.6 Without new technical information, there should be no change in the distribution of technically recoverable resources and the categorization boundaries when conditions are satisfied to reclassify a project from Contingent Resources to Reserves.

2.2.2.7 All evaluations require application of a consistent set of forecast conditions, including assumed future costs and prices, for both classification of projects and categorization of estimated quantities recovered by each project (see Section 3.1, Assessment of Commerciality).

### Table 1—Recoverable Resources Classes and Sub-Classes

| Class/Sub-Class | Definition | Guidelines |
|---|---|---|
| **Reserves** | Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. | Reserves must satisfy four criteria: discovered, recoverable, commercial, and remaining based on the development project(s) applied. Reserves are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by the development and production status.<br><br>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.<br><br>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.<br><br>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.<br><br>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.<br><br>The project decision gate is the decision to start investing capital in the construction of production facilities and/or drilling development wells. |

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| Class/Sub-Class | Definition | Guidelines |
|---|---|---|
| **Justified for Development** | Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals/contracts will be obtained. | To move to this level of project maturity, and hence have Reserves associated with it, the development project must be commercially viable at the time of reporting (see Section 2.1.2, Determination of Commerciality) and the specific circumstances of the project. All participating entities have agreed and there is evidence of a committed project (firm intention to proceed with development within a reasonable time-frame). There must be no known contingencies that could preclude the development from proceeding (see Reserves class).<br><br>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.<br><br>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.<br><br>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.<br><br>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.<br><br>This sub-class requires active appraisal or evaluation and should not be maintained without a plan for future evaluation. The sub-class should reflect the actions required to move a project toward commercial maturity and economic production. |

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| Class/Sub-Class | Definition | Guidelines |
|---|---|---|
| **Development Not Viable** | A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time because of limited production potential. | The project is not seen to have potential for eventual commercial development at the time of reporting, but the theoretically recoverable quantities are recorded so that the potential opportunity will be recognized in the event of a major change in technology or commercial conditions.<br><br>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.<br><br>In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well. |

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| Status | Definition | Guidelines |
|---|---|---|
| **Undeveloped Reserves** | Quantities expected to be recovered through future significant investments. | Undeveloped Reserves are to be produced (1) from new wells on undrilled acreage in known accumulations, (2) from deepening existing wells to a different (but known) reservoir, (3) from infill wells that will increase recovery, or (4) where a relatively large expenditure (e.g., when compared to the cost of drilling a new well) is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects. |

## Table 3—Reserves Category Definitions and Guidelines

| Category | Definition | Guidelines |
|---|---|---|
| **Proved Reserves** | Those quantities of petroleum that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable from a given date forward from known reservoirs and under defined economic conditions, operating methods, and government regulations. | If deterministic methods are used, the term "reasonable certainty" is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the estimate.<br><br>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.<br><br>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.<br><br>Reserves in undeveloped locations may be classified as Proved provided that:<br>A. The locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially mature and economically productive.<br>B. Interpretations of available geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with drilled Proved locations.<br><br>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.<br><br>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.<br><br>Probable estimates also include incremental recoveries associated with project recovery efficiencies beyond that assumed for Proved. |

## PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the Petroleum Resources Management System Approved by
the Society of Petroleum Engineers (SPE) Board of Directors, June 2018

| Category | Definition | Guidelines |
|---|---|---|
| **Possible Reserves** | Those additional reserves that analysis of geoscience and engineering data indicates are less likely to be recoverable than Probable Reserves. | The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high-estimate scenario. When probabilistic methods are used, there should be at least a 10% probability (P10) that the actual quantities recovered will equal or exceed the 3P estimate.<br><br>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.<br><br>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.<br><br>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.<br><br>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.<br><br>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. |

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.

REVENUE, COSTS, AND TAXES
PROVED (1P) RESERVES
DELEK DRILLING LIMITED PARTNERSHIP
TAMAR AND TAMAR SOUTHWEST FIELDS, TAMAR LEASE I/12, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2018

| Period Ending | Working Interest Revenue (M$) | Royalties: State (M$) | Royalties: Interested Party (M$) | Royalties: Third Party (M$) | Royalties: Total (M$) | Net Capital Costs (M$) | Net Abandonment Costs (M$) | Net Operating Expenses[1] (M$) | Net Revenue Before Levy and Corporate Income Taxes Discounted at 0% (M$) |
|---|---|---|---|---|---|---|---|---|---|
| 12-31-2019 | 543,380.2 | 62,488.7 | 37,072.0 | 9,281.7 | 108,842.3 | 31,017.6 | - | 44,046.1 | 359,474.1 |
| 12-31-2020 | 528,307.1 | 60,755.3 | 36,043.6 | 9,024.2 | 105,823.1 | 63,545.8 | - | 40,847.7 | 318,090.5 |
| 12-31-2021 | 521,630.6 | 59,987.5 | 35,588.1 | 8,910.1 | 104,485.8 | 208.3 | - | 39,959.4 | 376,977.1 |
| 12-31-2022 | 540,522.2 | 62,160.0 | 36,877.0 | 9,232.8 | 108,269.9 | 74,704.3 | - | 40,055.6 | 317,492.4 |
| 12-31-2023 | 546,903.2 | 62,893.9 | 37,312.3 | 9,341.8 | 109,548.0 | 69,796.2 | - | 40,055.6 | 327,503.4 |
| 12-31-2024 | 552,028.1 | 63,483.2 | 37,662.0 | 9,429.4 | 110,574.6 | - | - | 40,055.6 | 401,397.9 |
| 12-31-2025 | 553,775.3 | 63,684.2 | 37,781.2 | 9,459.2 | 110,924.6 | - | - | 40,055.6 | 402,795.2 |
| 12-31-2026 | 559,640.7 | 64,358.7 | 38,181.3 | 9,559.4 | 112,099.4 | - | - | 40,055.6 | 407,485.7 |
| 12-31-2027 | 624,460.9 | 71,813.0 | 42,603.7 | 10,666.6 | 125,083.3 | - | - | 40,055.6 | 459,322.1 |
| 12-31-2028 | 631,608.0 | 72,634.9 | 43,091.3 | 10,788.7 | 126,514.9 | - | - | 40,055.6 | 465,037.5 |
| 12-31-2029 | 635,058.7 | 73,031.8 | 43,326.7 | 10,847.6 | 127,206.1 | - | - | 40,055.6 | 467,797.1 |
| 12-31-2030 | 649,909.5 | 74,739.6 | 44,339.9 | 11,101.3 | 130,180.8 | - | - | 40,055.6 | 479,673.1 |
| 12-31-2031 | 668,438.2 | 76,870.4 | 45,604.0 | 11,417.8 | 133,892.2 | - | - | 40,055.6 | 494,490.4 |
| 12-31-2032 | 692,392.6 | 79,625.2 | 47,238.3 | 11,827.0 | 138,690.4 | - | - | 40,055.6 | 513,646.6 |
| 12-31-2033 | 712,656.4 | 81,955.5 | 48,620.8 | 12,173.1 | 142,749.4 | 52,086.7 | - | 40,055.6 | 477,764.8 |
| 12-31-2034 | 703,289.0 | 80,878.2 | 47,981.7 | 12,013.1 | 140,873.0 | - | - | 40,055.6 | 522,360.4 |
| 12-31-2035 | 576,058.5 | 66,246.7 | 39,301.4 | 9,839.8 | 115,388.0 | - | - | 40,055.6 | 420,614.9 |
| 12-31-2036 | 398,227.0 | 45,796.1 | 27,168.9 | 6,802.2 | 79,767.3 | - | - | 40,055.6 | 278,404.2 |
| 12-31-2037 | 402,450.4 | 46,281.8 | 27,457.1 | 6,874.4 | 80,613.3 | - | - | 40,055.6 | 281,781.6 |
| 12-31-2038 | 399,767.4 | 45,973.2 | 27,274.0 | 6,828.6 | 80,075.8 | - | - | 40,055.6 | 279,636.0 |
| 12-31-2039 | 390,468.3 | 44,903.9 | 26,639.6 | 6,669.7 | 78,213.2 | - | - | 40,055.6 | 272,199.6 |
| 12-31-2040 | 370,846.7 | 42,647.4 | 25,300.9 | 6,334.6 | 74,282.8 | - | - | 40,055.6 | 256,508.3 |
| 12-31-2041 | 258,160.3 | 29,688.4 | 17,612.9 | 4,409.7 | 51,711.1 | - | - | 40,055.6 | 166,393.6 |
| 12-31-2042 | 215,082.1 | 24,734.4 | 14,673.9 | 3,673.9 | 43,082.2 | - | - | 40,055.6 | 131,944.3 |
| 12-31-2043 | 148,014.0 | 17,021.6 | 10,098.2 | 2,528.3 | 29,648.1 | - | - | 40,055.6 | 78,310.3 |
| 12-31-2044 | 119,849.7 | 13,782.7 | 8,176.7 | 2,047.2 | 24,006.6 | - | 16,412.1 | 40,055.6 | 39,375.4 |
| 12-31-2045 | 101,087.7 | 11,625.1 | 6,896.7 | 1,726.7 | 20,248.5 | - | 16,412.1 | 40,055.6 | 24,371.6 |
| 12-31-2046 | 51,462.3 | 5,918.2 | 3,511.0 | 879.0 | 10,308.2 | - | 16,412.1 | 40,055.6 | -15,313.6 |
| 12-31-2047 | - | - | - | - | - | - | - | - | - |
| 12-31-2048 | - | - | - | - | - | - | - | - | - |
| 12-31-2049 | - | - | - | - | - | - | - | - | - |
| 12-31-2050 | - | - | - | - | - | - | - | - | - |
| 12-31-2051 | - | - | - | - | - | - | - | - | - |
| 12-31-2052 | - | - | - | - | - | - | - | - | - |
| 12-31-2053 | - | - | - | - | - | - | - | - | - |
| 12-31-2054 | - | - | - | - | - | - | - | - | - |
| Total | 13,095,475.1 | 1,505,979.6 | 893,435.2 | 223,688.0 | 2,623,102.9 | 291,359.0 | 49,236.3 | 1,126,242.4 | 9,005,534.5 |

[1] Operating expenses are limited to direct project-level costs, insurance costs, and Delek Drilling's estimate of the portion of the operator's headquarters general and administrative overhead expenses that can be directly attributed to this project.



*All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.*

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.

REVENUE, COSTS, AND TAXES
PROVED (1P) RESERVES
DELEK DRILLING LIMITED PARTNERSHIP
TAMAR AND TAMAR SOUTHWEST FIELDS, TAMAR LEASE I/12, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2018

| | | | | | | Future Net Revenue After Levy and Corporate Income Taxes | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Period Ending | Levy Rate (%) | Levy (M$) | Net Revenue After Levy and Before Corporate Income Taxes Discounted at 0% (M$) | Corporate Income Tax Rate[1] (%) | Corporate Income Taxes[1] (M$) | Discounted at 0% (M$) | Discounted at 5% (M$) | Discounted at 10% (M$) | Discounted at 15% (M$) | Discounted at 20% (M$) |
| 12-31-2019 | - | - | 359,474.1 | 23.0 | 60,543.0 | 298,931.1 | 291,726.9 | 285,019.6 | 278,754.7 | 272,885.5 |
| 12-31-2020 | 3.5 | 11,140.6 | 306,949.9 | 23.0 | 71,509.9 | 235,440.0 | 218,824.7 | 204,075.7 | 190,912.1 | 179,105.3 |
| 12-31-2021 | 27.2 | 102,351.1 | 274,625.9 | 23.0 | 47,937.5 | 226,688.4 | 200,657.8 | 178,627.2 | 159,839.7 | 143,706.4 |
| 12-31-2022 | 35.4 | 112,336.6 | 205,155.8 | 23.0 | 49,578.6 | 155,577.2 | 131,154.5 | 111,447.8 | 95,390.1 | 82,188.6 |
| 12-31-2023 | 41.5 | 136,019.4 | 191,483.9 | 23.0 | 47,926.6 | 143,557.4 | 115,258.7 | 93,488.5 | 76,539.4 | 63,198.9 |
| 12-31-2024 | 46.5 | 186,496.5 | 214,901.4 | 23.0 | 36,431.7 | 178,469.7 | 136,465.7 | 105,658.6 | 82,742.1 | 65,473.8 |
| 12-31-2025 | 46.8 | 188,508.2 | 214,287.1 | 23.0 | 36,296.1 | 177,990.9 | 129,618.6 | 95,795.6 | 71,756.6 | 54,415.1 |
| 12-31-2026 | 46.8 | 190,703.3 | 216,782.4 | 23.0 | 37,411.8 | 179,370.6 | 124,403.2 | 87,761.9 | 62,880.7 | 45,697.5 |
| 12-31-2027 | 46.8 | 214,962.7 | 244,359.3 | 23.0 | 45,143.3 | 199,216.0 | 131,587.7 | 88,610.8 | 60,728.5 | 42,294.5 |
| 12-31-2028 | 46.8 | 217,637.6 | 247,400.0 | 23.0 | 48,533.4 | 198,866.6 | 125,101.8 | 80,413.9 | 52,714.8 | 35,183.6 |
| 12-31-2029 | 46.8 | 218,929.0 | 248,868.0 | 23.0 | 49,077.8 | 199,790.2 | 119,697.9 | 73,443.1 | 46,051.8 | 29,455.8 |
| 12-31-2030 | 46.8 | 224,487.0 | 255,186.1 | 23.0 | 51,233.3 | 203,952.7 | 116,373.1 | 68,157.5 | 40,879.4 | 25,057.9 |
| 12-31-2031 | 46.8 | 231,421.5 | 263,068.9 | 23.0 | 54,942.3 | 208,126.6 | 113,099.7 | 63,229.4 | 36,274.8 | 21,309.0 |
| 12-31-2032 | 46.8 | 240,386.6 | 273,260.0 | 23.0 | 57,284.5 | 215,975.5 | 111,776.1 | 59,649.0 | 32,732.8 | 18,427.1 |
| 12-31-2033 | 46.8 | 223,593.9 | 254,170.9 | 23.0 | 65,962.4 | 188,208.5 | 92,767.2 | 47,254.7 | 24,803.9 | 13,381.7 |
| 12-31-2034 | 46.8 | 244,464.7 | 277,895.7 | 23.0 | 60,506.7 | 217,389.0 | 102,047.7 | 49,619.3 | 24,912.7 | 12,880.4 |
| 12-31-2035 | 46.8 | 196,847.8 | 223,767.1 | 23.0 | 48,484.3 | 175,282.9 | 78,363.9 | 36,371.4 | 17,467.3 | 8,654.6 |
| 12-31-2036 | 46.8 | 130,293.2 | 148,111.0 | 23.0 | 31,650.5 | 116,460.5 | 49,586.8 | 21,968.8 | 10,091.7 | 4,791.9 |
| 12-31-2037 | 46.8 | 131,873.8 | 149,907.8 | 23.0 | 32,067.2 | 117,840.6 | 47,785.2 | 20,208.3 | 8,879.4 | 4,040.6 |
| 12-31-2038 | 46.8 | 130,869.6 | 148,766.3 | 23.0 | 31,828.7 | 116,937.7 | 45,161.0 | 18,230.4 | 7,662.1 | 3,341.3 |
| 12-31-2039 | 46.8 | 127,389.4 | 144,810.2 | 23.0 | 30,959.0 | 113,851.2 | 41,875.2 | 16,135.7 | 6,486.8 | 2,711.0 |
| 12-31-2040 | 46.8 | 120,045.9 | 136,462.4 | 23.0 | 29,108.5 | 107,353.9 | 37,605.2 | 13,831.7 | 5,318.8 | 2,130.2 |
| 12-31-2041 | 46.8 | 77,872.2 | 88,521.4 | 23.0 | 18,419.3 | 70,102.2 | 23,386.9 | 8,211.0 | 3,020.2 | 1,159.2 |
| 12-31-2042 | 46.8 | 61,749.9 | 70,194.4 | 23.0 | 12,635.2 | 57,559.1 | 18,288.0 | 6,129.0 | 2,156.3 | 793.1 |
| 12-31-2043 | 46.8 | 36,649.2 | 41,661.1 | 23.0 | 6,268.3 | 35,392.8 | 10,709.7 | 3,426.1 | 1,153.0 | 406.4 |
| 12-31-2044 | 46.8 | 18,427.7 | 20,947.7 | 23.0 | 6,560.1 | 14,387.6 | 4,146.3 | 1,266.1 | 407.6 | 137.7 |
| 12-31-2045 | 46.8 | 11,405.9 | 12,965.7 | 23.0 | 4,779.6 | 8,186.1 | 2,246.8 | 654.9 | 201.6 | 65.3 |
| 12-31-2046 | 46.8 | -7,166.8 | -8,146.8 | 23.0 | 61.5 | -8,208.3 | -2,145.6 | -597.0 | -175.8 | -54.5 |
| 12-31-2047 | - | - | - | 23.0 | - | - | - | - | - | - |
| 12-31-2048 | - | - | - | 23.0 | - | - | - | - | - | - |
| 12-31-2049 | - | - | - | 23.0 | - | - | - | - | - | - |
| 12-31-2050 | - | - | - | 23.0 | - | - | - | - | - | - |
| 12-31-2051 | - | - | - | 23.0 | - | - | - | - | - | - |
| 12-31-2052 | - | - | - | 23.0 | - | - | - | - | - | - |
| 12-31-2053 | - | - | - | 23.0 | - | - | - | - | - | - |
| 12-31-2054 | - | - | - | 23.0 | - | - | - | - | - | - |
| Total | | 3,779,696.7 | 5,225,837.9 | | 1,073,141.1 | 4,152,696.8 | 2,617,570.6 | 1,838,089.1 | 1,400,583.3 | 1,132,837.9 |

(1) Corporate income tax rates and estimates of corporate income taxes are provided by Delek Drilling and are its expected corporate income taxes per year.



*All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.*

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.

REVENUE, COSTS, AND TAXES
PROBABLE RESERVES
DELEK DRILLING LIMITED PARTNERSHIP
TAMAR AND TAMAR SOUTHWEST FIELDS, TAMAR LEASE I/12, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2018

| Period Ending | Working Interest Revenue (M$) | Royalties: State (M$) | Royalties: Interested Party (M$) | Royalties: Third Party (M$) | Royalties: Total (M$) | Net Capital Costs (M$) | Net Abandonment Costs (M$) | Net Operating Expenses[(1)] (M$) | Net Revenue Before Levy and Corporate Income Taxes Discounted at 0% (M$) |
|---|---|---|---|---|---|---|---|---|---|
| 12-31-2019 | - | - | - | - | - | - | - | - | - |
| 12-31-2020 | - | - | - | - | - | - | - | - | - |
| 12-31-2021 | - | - | - | - | - | - | - | - | - |
| 12-31-2022 | - | - | - | - | - | -75,525.7 | - | - | 75,525.7 |
| 12-31-2023 | - | - | - | - | - | -69,796.2 | - | - | 69,796.2 |
| 12-31-2024 | - | - | - | - | - | 75,525.7 | - | - | -75,525.7 |
| 12-31-2025 | - | - | - | - | - | 26,043.4 | - | - | -26,043.4 |
| 12-31-2026 | - | - | - | - | - | 43,752.8 | - | - | -43,752.8 |
| 12-31-2027 | - | - | - | - | - | - | - | - | - |
| 12-31-2028 | - | - | - | - | - | - | - | - | - |
| 12-31-2029 | - | - | - | - | - | - | - | - | - |
| 12-31-2030 | - | - | - | - | - | - | - | - | - |
| 12-31-2031 | - | - | - | - | - | - | - | - | - |
| 12-31-2032 | - | - | - | - | - | - | - | - | - |
| 12-31-2033 | - | - | - | - | - | -52,086.7 | - | - | 52,086.7 |
| 12-31-2034 | 21,366.7 | 2,457.2 | 1,457.7 | 365.0 | 4,279.9 | - | - | - | 17,086.9 |
| 12-31-2035 | 159,582.9 | 18,352.0 | 10,887.5 | 2,725.9 | 31,965.4 | 52,086.7 | - | - | 75,530.7 |
| 12-31-2036 | 349,352.4 | 40,175.5 | 23,834.5 | 5,967.4 | 69,977.4 | - | - | - | 279,375.0 |
| 12-31-2037 | 353,097.0 | 40,606.2 | 24,089.9 | 6,031.4 | 70,727.5 | - | - | - | 282,369.5 |
| 12-31-2038 | 365,896.7 | 42,078.1 | 24,963.2 | 6,250.0 | 73,291.3 | - | - | - | 292,605.3 |
| 12-31-2039 | 383,588.3 | 44,112.7 | 26,170.2 | 6,552.2 | 76,835.1 | 49,482.4 | - | - | 257,270.9 |
| 12-31-2040 | 413,777.3 | 47,584.4 | 28,229.8 | 7,067.9 | 82,882.1 | - | - | - | 330,895.2 |
| 12-31-2041 | 516,282.0 | 59,372.4 | 35,223.2 | 8,818.8 | 103,414.4 | - | - | - | 412,867.6 |
| 12-31-2042 | 455,481.3 | 52,380.3 | 31,075.1 | 7,780.2 | 91,235.7 | - | - | - | 364,245.6 |
| 12-31-2043 | 509,332.8 | 58,573.3 | 34,749.1 | 8,700.1 | 102,022.4 | - | - | - | 407,310.3 |
| 12-31-2044 | 524,123.9 | 60,274.2 | 35,758.2 | 8,952.7 | 104,985.2 | - | -16,412.1 | - | 435,550.8 |
| 12-31-2045 | 382,301.2 | 43,964.6 | 26,082.4 | 6,530.2 | 76,577.2 | - | -16,412.1 | - | 322,136.0 |
| 12-31-2046 | 384,201.1 | 44,183.1 | 26,212.0 | 6,562.7 | 76,957.8 | - | -16,412.1 | - | 323,655.4 |
| 12-31-2047 | 434,419.2 | 49,958.2 | 29,638.1 | 7,420.5 | 87,016.8 | - | - | 40,055.6 | 307,346.8 |
| 12-31-2048 | 351,876.5 | 40,465.8 | 24,006.7 | 6,010.5 | 70,483.0 | - | 17,523.7 | 40,055.6 | 223,814.3 |
| 12-31-2049 | 212,170.6 | 24,399.6 | 14,475.3 | 3,624.2 | 42,499.1 | - | 17,523.7 | 40,055.6 | 112,092.3 |
| 12-31-2050 | 106,467.8 | 12,243.8 | 7,263.7 | 1,818.6 | 21,326.1 | - | 17,523.7 | 40,055.6 | 27,562.4 |
| 12-31-2051 | - | - | - | - | - | - | - | - | - |
| 12-31-2052 | - | - | - | - | - | - | - | - | - |
| 12-31-2053 | - | - | - | - | - | - | - | - | - |
| 12-31-2054 | - | - | - | - | - | - | - | - | - |
| Total | 5,923,317.6 | 681,181.5 | 404,116.7 | 101,178.1 | 1,186,476.4 | 49,482.4 | 3,334.7 | 160,222.3 | 4,523,801.9 |

(1) Operating expenses are limited to direct project-level costs, insurance costs, and Delek Drilling's estimate of the portion of the operator's headquarters general and administrative overhead expenses that can be directly attributed to this project.

*All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.*

NETHERLAND, SEWELL & ASSOCIATES, INC.

REVENUE, COSTS, AND TAXES
PROBABLE RESERVES
DELEK DRILLING LIMITED PARTNERSHIP
TAMAR AND TAMAR SOUTHWEST FIELDS, TAMAR LEASE I/12, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2018

| | | | | | | Future Net Revenue After Levy and Corporate Income Taxes | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Period Ending | Levy Rate (%) | Levy (M$) | Net Revenue After Levy and Before Corporate Income Taxes Discounted at 0% (M$) | Corporate Income Tax Rate[1] (%) | Corporate Income Taxes[1] (M$) | Discounted at 0% (M$) | Discounted at 5% (M$) | Discounted at 10% (M$) | Discounted at 15% (M$) | Discounted at 20% (M$) |
| 12-31-2019 | - | - | - | 23.0 | - | - | - | - | - | - |
| 12-31-2020 | 3.5 | - | - | 23.0 | - | - | - | - | - | - |
| 12-31-2021 | 27.2 | - | - | 23.0 | - | - | - | - | - | - |
| 12-31-2022 | 36.4 | 30,812.0 | 44,713.8 | 23.0 | -7,086.8 | 51,800.5 | 43,668.8 | 37,107.3 | 31,760.8 | 27,365.3 |
| 12-31-2023 | 43.9 | 38,528.0 | 31,268.2 | 23.0 | -7,779.3 | 39,047.4 | 31,350.2 | 25,428.8 | 20,818.6 | 17,190.0 |
| 12-31-2024 | 46.8 | -33,988.3 | -41,537.4 | 23.0 | 11,097.9 | -52,635.3 | -40,247.2 | -31,161.4 | -24,402.8 | -19,309.9 |
| 12-31-2025 | 46.8 | -12,188.3 | -13,855.1 | 23.0 | 4,939.8 | -18,794.9 | -13,687.0 | -10,115.5 | -7,577.1 | -5,746.0 |
| 12-31-2026 | 46.8 | -20,476.3 | -23,276.5 | 23.0 | 6,840.2 | -30,116.7 | -20,887.5 | -14,735.4 | -10,557.8 | -7,672.7 |
| 12-31-2027 | 46.8 | - | - | 23.0 | -61.8 | 61.8 | 40.9 | 27.5 | 18.9 | 13.1 |
| 12-31-2028 | 46.8 | - | - | 23.0 | -61.8 | 61.8 | 38.9 | 25.0 | 16.4 | 10.9 |
| 12-31-2029 | 46.8 | - | - | 23.0 | -61.8 | 61.8 | 37.1 | 22.7 | 14.3 | 9.1 |
| 12-31-2030 | 46.8 | - | - | 23.0 | -61.8 | 61.8 | 35.3 | 20.7 | 12.4 | 7.6 |
| 12-31-2031 | 46.8 | - | - | 23.0 | -61.8 | 61.8 | 33.6 | 18.8 | 10.8 | 6.3 |
| 12-31-2032 | 46.8 | - | - | 23.0 | -61.8 | 61.8 | 32.0 | 17.1 | 9.4 | 5.3 |
| 12-31-2033 | 46.8 | 24,376.6 | 27,710.1 | 23.0 | -6,750.6 | 34,460.8 | 16,985.6 | 8,652.3 | 4,541.6 | 2,450.2 |
| 12-31-2034 | 46.8 | 7,996.6 | 9,090.2 | 23.0 | -53.7 | 9,143.9 | 4,292.4 | 2,087.1 | 1,047.9 | 541.8 |
| 12-31-2035 | 46.8 | 35,348.4 | 40,182.3 | 23.0 | 20,814.6 | 19,367.8 | 8,658.8 | 4,018.8 | 1,930.0 | 956.3 |
| 12-31-2036 | 46.8 | 130,747.5 | 148,627.5 | 23.0 | 31,398.8 | 117,228.7 | 49,913.9 | 22,113.7 | 10,158.3 | 4,823.5 |
| 12-31-2037 | 46.8 | 132,148.9 | 150,220.6 | 23.0 | 34,550.7 | 115,669.9 | 46,904.9 | 19,836.1 | 8,715.9 | 3,966.1 |
| 12-31-2038 | 46.8 | 136,939.3 | 155,666.0 | 23.0 | 35,803.2 | 119,862.9 | 46,290.7 | 18,686.5 | 7,853.7 | 3,424.9 |
| 12-31-2039 | 46.8 | 120,402.8 | 136,868.1 | 23.0 | 42,860.6 | 94,007.5 | 34,576.6 | 13,323.3 | 5,356.2 | 2,238.4 |
| 12-31-2040 | 46.8 | 154,858.9 | 176,036.2 | 23.0 | 39,350.2 | 136,686.0 | 47,880.0 | 17,610.9 | 6,772.1 | 2,712.2 |
| 12-31-2041 | 46.8 | 193,222.0 | 219,645.5 | 23.0 | 49,380.4 | 170,265.2 | 56,802.4 | 19,943.0 | 7,335.4 | 2,815.4 |
| 12-31-2042 | 46.8 | 170,466.9 | 193,778.7 | 23.0 | 45,131.2 | 148,647.5 | 47,229.0 | 15,828.1 | 5,568.8 | 2,048.3 |
| 12-31-2043 | 46.8 | 190,621.2 | 216,689.1 | 23.0 | 50,400.6 | 166,288.5 | 50,318.1 | 16,096.9 | 5,417.1 | 1,909.5 |
| 12-31-2044 | 46.8 | 203,837.8 | 231,713.0 | 23.0 | 48,883.3 | 182,829.7 | 52,689.0 | 16,089.2 | 5,179.1 | 1,749.5 |
| 12-31-2045 | 46.8 | 150,759.7 | 171,376.4 | 23.0 | 35,005.9 | 136,370.5 | 37,428.6 | 10,909.7 | 3,359.1 | 1,087.5 |
| 12-31-2046 | 46.8 | 151,470.7 | 172,184.7 | 23.0 | 34,689.6 | 137,495.1 | 35,940.3 | 9,999.7 | 2,945.1 | 913.7 |
| 12-31-2047 | 46.8 | 143,838.3 | 163,508.5 | 23.0 | 34,768.7 | 128,739.8 | 32,049.2 | 8,511.8 | 2,397.9 | 712.9 |
| 12-31-2048 | 46.8 | 104,745.1 | 119,069.2 | 23.0 | 28,578.1 | 90,491.1 | 21,454.7 | 5,439.0 | 1,465.6 | 417.6 |
| 12-31-2049 | 46.8 | 52,459.2 | 59,633.1 | 23.0 | 14,907.8 | 44,725.3 | 10,099.0 | 2,443.9 | 629.9 | 172.0 |
| 12-31-2050 | 46.8 | 12,899.2 | 14,663.2 | 23.0 | 5,702.8 | 8,960.4 | 1,926.9 | 445.1 | 109.7 | 28.7 |
| 12-31-2051 | - | - | - | 23.0 | - | - | - | - | - | - |
| 12-31-2052 | - | - | - | 23.0 | - | - | - | - | - | - |
| 12-31-2053 | - | - | - | 23.0 | - | - | - | - | - | - |
| 12-31-2054 | - | - | - | 23.0 | - | - | - | - | - | - |
| Total | | 2,119,826.3 | 2,403,975.5 | | 553,062.9 | 1,850,912.7 | 601,855.0 | 218,690.7 | 90,907.1 | 44,847.9 |

(1) Corporate income tax rates and estimates of corporate income taxes are provided by Delek Drilling and are its expected corporate income taxes per year.



*All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.*

NETHERLAND, SEWELL & ASSOCIATES, INC.

REVENUE, COSTS, AND TAXES
PROVED + PROBABLE (2P) RESERVES
DELEK DRILLING LIMITED PARTNERSHIP
TAMAR AND TAMAR SOUTHWEST FIELDS, TAMAR LEASE I/12, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2018

| | | Royalties | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Period Ending | Working Interest Revenue (M$) | State (M$) | Interested Party (M$) | Third Party (M$) | Total (M$) | Net Capital Costs (M$) | Net Abandonment Costs (M$) | Net Operating Expenses[1] (M$) | Net Revenue Before Levy and Corporate Income Taxes Discounted at 0% (M$) |
| 12-31-2019 | 543,380.2 | 62,488.7 | 37,072.0 | 9,281.7 | 108,842.3 | 31,017.6 | - | 44,046.1 | 359,474.1 |
| 12-31-2020 | 528,307.1 | 60,755.3 | 36,043.6 | 9,024.2 | 105,823.1 | 63,545.8 | - | 40,847.7 | 318,090.5 |
| 12-31-2021 | 521,630.6 | 59,987.5 | 35,588.1 | 8,910.1 | 104,485.8 | 208.3 | - | 39,959.4 | 376,977.1 |
| 12-31-2022 | 540,522.2 | 62,160.0 | 36,877.0 | 9,232.8 | 108,269.9 | -821.4 | - | 40,055.6 | 393,018.1 |
| 12-31-2023 | 546,903.2 | 62,893.9 | 37,312.3 | 9,341.8 | 109,548.0 | - | - | 40,055.6 | 397,299.6 |
| 12-31-2024 | 552,028.1 | 63,483.2 | 37,662.0 | 9,429.4 | 110,574.6 | 75,525.7 | - | 40,055.6 | 325,872.2 |
| 12-31-2025 | 553,775.3 | 63,684.2 | 37,781.2 | 9,459.2 | 110,924.6 | 26,043.4 | - | 40,055.6 | 376,751.9 |
| 12-31-2026 | 559,640.7 | 64,358.7 | 38,181.3 | 9,559.4 | 112,099.4 | 43,752.8 | - | 40,055.6 | 363,732.9 |
| 12-31-2027 | 624,460.9 | 71,813.0 | 42,603.7 | 10,666.6 | 125,083.3 | - | - | 40,055.6 | 459,322.1 |
| 12-31-2028 | 631,608.0 | 72,634.9 | 43,091.3 | 10,788.7 | 126,514.9 | - | - | 40,055.6 | 465,037.5 |
| 12-31-2029 | 635,058.7 | 73,031.8 | 43,326.7 | 10,847.6 | 127,206.1 | - | - | 40,055.6 | 467,797.1 |
| 12-31-2030 | 649,909.5 | 74,739.6 | 44,339.9 | 11,101.3 | 130,180.8 | - | - | 40,055.6 | 479,673.1 |
| 12-31-2031 | 668,438.2 | 76,870.4 | 45,604.0 | 11,417.8 | 133,892.2 | - | - | 40,055.6 | 494,490.4 |
| 12-31-2032 | 692,392.6 | 79,625.2 | 47,238.3 | 11,827.0 | 138,690.4 | - | - | 40,055.6 | 513,646.6 |
| 12-31-2033 | 712,656.4 | 81,955.5 | 48,620.8 | 12,173.1 | 142,749.4 | - | - | 40,055.6 | 529,851.5 |
| 12-31-2034 | 724,655.8 | 83,335.4 | 49,439.4 | 12,378.1 | 145,152.9 | - | - | 40,055.6 | 539,447.3 |
| 12-31-2035 | 735,641.4 | 84,598.8 | 50,188.9 | 12,565.7 | 147,353.4 | 52,086.7 | - | 40,055.6 | 496,145.7 |
| 12-31-2036 | 747,579.4 | 85,971.6 | 51,003.4 | 12,769.6 | 149,744.7 | - | - | 40,055.6 | 557,779.2 |
| 12-31-2037 | 755,547.4 | 86,888.0 | 51,547.0 | 12,905.7 | 151,340.7 | - | - | 40,055.6 | 564,151.1 |
| 12-31-2038 | 765,664.0 | 88,051.4 | 52,237.2 | 13,078.6 | 153,367.1 | - | - | 40,055.6 | 572,241.3 |
| 12-31-2039 | 774,056.6 | 89,016.5 | 52,809.8 | 13,221.9 | 155,048.2 | 49,482.4 | - | 40,055.6 | 529,470.4 |
| 12-31-2040 | 784,623.9 | 90,231.7 | 53,530.8 | 13,402.4 | 157,164.9 | - | - | 40,055.6 | 587,403.4 |
| 12-31-2041 | 774,442.3 | 89,060.9 | 52,836.1 | 13,228.5 | 155,125.5 | - | - | 40,055.6 | 579,261.2 |
| 12-31-2042 | 670,563.4 | 77,114.8 | 45,749.0 | 11,454.1 | 134,317.9 | - | - | 40,055.6 | 496,189.9 |
| 12-31-2043 | 657,346.8 | 75,594.9 | 44,847.3 | 11,228.4 | 131,670.5 | - | - | 40,055.6 | 485,620.7 |
| 12-31-2044 | 643,973.6 | 74,057.0 | 43,934.9 | 10,999.9 | 128,991.8 | - | - | 40,055.6 | 474,926.2 |
| 12-31-2045 | 483,388.9 | 55,589.7 | 32,979.1 | 8,256.9 | 96,825.7 | - | - | 40,055.6 | 346,507.6 |
| 12-31-2046 | 435,663.4 | 50,101.3 | 29,723.0 | 7,441.7 | 87,266.0 | - | - | 40,055.6 | 308,341.8 |
| 12-31-2047 | 434,419.2 | 49,958.2 | 29,638.1 | 7,420.5 | 87,016.8 | - | - | 40,055.6 | 307,346.8 |
| 12-31-2048 | 351,876.5 | 40,465.8 | 24,006.7 | 6,010.5 | 70,483.0 | - | 17,523.7 | 40,055.6 | 223,814.3 |
| 12-31-2049 | 212,170.6 | 24,399.6 | 14,475.3 | 3,624.2 | 42,499.1 | - | 17,523.7 | 40,055.6 | 112,092.3 |
| 12-31-2050 | 106,467.8 | 12,243.8 | 7,263.7 | 1,818.6 | 21,326.1 | - | 17,523.7 | 40,055.6 | 27,562.4 |
| 12-31-2051 | - | - | - | - | - | - | - | - | - |
| 12-31-2052 | - | - | - | - | - | - | - | - | - |
| 12-31-2053 | - | - | - | - | - | - | - | - | - |
| 12-31-2054 | - | - | - | - | - | - | - | - | - |
| Total | 19,018,792.7 | 2,187,161.2 | 1,297,552.0 | 324,866.1 | 3,809,579.3 | 340,841.4 | 52,571.0 | 1,286,464.7 | 13,529,336.4 |

[1] Operating expenses are limited to direct project-level costs, insurance costs, and Delek Drilling's estimate of the portion of the operator's headquarters general and administrative overhead expenses that can be directly attributed to this project.



*All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.*

NETHERLAND, SEWELL & ASSOCIATES, INC.

REVENUE, COSTS, AND TAXES
PROVED + PROBABLE (2P) RESERVES
DELEK DRILLING LIMITED PARTNERSHIP
TAMAR AND TAMAR SOUTHWEST FIELDS, TAMAR LEASE I/12, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2018

| | | | | | | Future Net Revenue After Levy and Corporate Income Taxes | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Period Ending | Levy Rate (%) | Levy (M$) | Net Revenue After Levy and Before Corporate Income Taxes Discounted at 0% (M$) | Corporate Income Tax Rate[1] (%) | Corporate Income Taxes[1] (M$) | Discounted at 0% (M$) | Discounted at 5% (M$) | Discounted at 10% (M$) | Discounted at 15% (M$) | Discounted at 20% (M$) |
| 12-31-2019 | - | - | 359,474.1 | 23.0 | 60,543.0 | 298,931.1 | 291,726.9 | 285,019.6 | 278,754.7 | 272,885.5 |
| 12-31-2020 | 3.5 | 11,140.6 | 306,949.9 | 23.0 | 71,509.9 | 235,440.0 | 218,824.7 | 204,075.7 | 190,912.1 | 179,105.3 |
| 12-31-2021 | 27.2 | 102,351.1 | 274,625.9 | 23.0 | 47,937.5 | 226,688.4 | 200,657.8 | 178,627.2 | 159,839.7 | 143,706.4 |
| 12-31-2022 | 36.4 | 143,148.6 | 249,869.5 | 23.0 | 42,491.9 | 207,377.7 | 174,823.4 | 148,555.1 | 127,150.9 | 109,553.9 |
| 12-31-2023 | 43.9 | 174,547.5 | 222,752.1 | 23.0 | 40,147.3 | 182,604.8 | 146,608.9 | 118,917.3 | 97,358.1 | 80,389.0 |
| 12-31-2024 | 46.8 | 152,508.2 | 173,364.0 | 23.0 | 47,529.6 | 125,834.4 | 96,218.5 | 74,497.2 | 58,339.3 | 46,163.9 |
| 12-31-2025 | 46.8 | 176,319.9 | 200,432.0 | 23.0 | 41,236.0 | 159,196.0 | 115,931.6 | 85,680.1 | 64,179.5 | 48,669.2 |
| 12-31-2026 | 46.8 | 170,227.0 | 193,505.9 | 23.0 | 44,251.9 | 149,254.0 | 103,515.7 | 73,026.5 | 52,322.9 | 38,024.8 |
| 12-31-2027 | 46.8 | 214,962.7 | 244,359.3 | 23.0 | 45,081.4 | 199,277.9 | 131,628.5 | 88,638.3 | 60,747.4 | 42,307.6 |
| 12-31-2028 | 46.8 | 217,637.6 | 247,400.0 | 23.0 | 48,471.6 | 198,928.4 | 125,140.7 | 80,438.9 | 52,731.2 | 35,194.5 |
| 12-31-2029 | 46.8 | 218,929.0 | 248,868.0 | 23.0 | 49,016.0 | 199,852.1 | 119,735.0 | 73,465.8 | 46,066.1 | 29,464.9 |
| 12-31-2030 | 46.8 | 224,487.0 | 255,186.1 | 23.0 | 51,171.5 | 204,014.6 | 116,408.4 | 68,178.2 | 40,891.8 | 25,065.5 |
| 12-31-2031 | 46.8 | 231,421.5 | 263,068.9 | 23.0 | 54,880.4 | 208,188.5 | 113,133.3 | 63,248.2 | 36,285.6 | 21,315.3 |
| 12-31-2032 | 46.8 | 240,386.6 | 273,260.0 | 23.0 | 57,222.7 | 216,037.3 | 111,808.1 | 59,666.1 | 32,742.2 | 18,432.4 |
| 12-31-2033 | 46.8 | 247,970.5 | 281,881.0 | 23.0 | 59,211.7 | 222,669.2 | 109,752.7 | 55,907.0 | 29,345.5 | 15,831.9 |
| 12-31-2034 | 46.8 | 252,461.3 | 286,985.9 | 23.0 | 60,453.1 | 226,532.9 | 106,340.1 | 51,706.4 | 25,960.6 | 13,422.1 |
| 12-31-2035 | 46.8 | 232,196.2 | 263,949.5 | 23.0 | 69,298.8 | 194,650.7 | 87,022.7 | 40,390.3 | 19,397.3 | 9,610.9 |
| 12-31-2036 | 46.8 | 261,040.7 | 296,738.5 | 23.0 | 63,049.3 | 233,689.2 | 99,500.6 | 44,082.5 | 20,250.1 | 9,615.4 |
| 12-31-2037 | 46.8 | 264,022.7 | 300,128.4 | 23.0 | 66,617.9 | 233,510.5 | 94,690.1 | 40,044.4 | 17,595.3 | 8,006.7 |
| 12-31-2038 | 46.8 | 267,808.9 | 304,432.4 | 23.0 | 67,631.9 | 236,800.5 | 91,451.6 | 36,916.9 | 15,515.8 | 6,766.3 |
| 12-31-2039 | 46.8 | 247,792.2 | 281,678.3 | 23.0 | 73,819.6 | 207,858.7 | 76,451.8 | 29,459.0 | 11,843.0 | 4,949.4 |
| 12-31-2040 | 46.8 | 274,904.8 | 312,498.6 | 23.0 | 68,458.8 | 244,039.9 | 85,485.2 | 31,442.6 | 12,090.9 | 4,842.4 |
| 12-31-2041 | 46.8 | 271,094.2 | 308,167.0 | 23.0 | 67,799.6 | 240,367.3 | 80,189.3 | 28,154.0 | 10,355.6 | 3,974.6 |
| 12-31-2042 | 46.8 | 232,216.9 | 263,973.0 | 23.0 | 57,766.4 | 206,206.6 | 65,517.0 | 21,957.1 | 7,725.1 | 2,841.5 |
| 12-31-2043 | 46.8 | 227,270.5 | 258,350.2 | 23.0 | 56,668.8 | 201,681.4 | 61,027.8 | 19,522.9 | 6,570.1 | 2,315.9 |
| 12-31-2044 | 46.8 | 222,265.5 | 252,660.7 | 23.0 | 55,443.4 | 197,217.4 | 56,835.3 | 17,355.3 | 5,586.6 | 1,887.2 |
| 12-31-2045 | 46.8 | 162,165.6 | 184,342.0 | 23.0 | 39,785.5 | 144,556.6 | 39,675.4 | 11,564.6 | 3,560.8 | 1,152.7 |
| 12-31-2046 | 46.8 | 144,304.0 | 164,037.8 | 23.0 | 34,751.1 | 129,286.8 | 33,794.7 | 9,402.8 | 2,769.3 | 859.2 |
| 12-31-2047 | 46.8 | 143,838.3 | 163,508.5 | 23.0 | 34,768.7 | 128,739.8 | 32,049.2 | 8,511.8 | 2,397.9 | 712.9 |
| 12-31-2048 | 46.8 | 104,745.1 | 119,069.2 | 23.0 | 28,578.1 | 90,491.1 | 21,454.7 | 5,439.0 | 1,465.6 | 417.6 |
| 12-31-2049 | 46.8 | 52,459.2 | 59,633.1 | 23.0 | 14,907.8 | 44,725.3 | 10,099.0 | 2,443.9 | 629.9 | 172.0 |
| 12-31-2050 | 46.8 | 12,899.2 | 14,663.2 | 23.0 | 5,702.8 | 8,960.4 | 1,926.9 | 445.1 | 109.7 | 28.7 |
| 12-31-2051 | - | - | - | 23.0 | - | - | - | - | - | - |
| 12-31-2052 | - | - | - | 23.0 | - | - | - | - | - | - |
| 12-31-2053 | - | - | - | 23.0 | - | - | - | - | - | - |
| 12-31-2054 | - | - | - | 23.0 | - | - | - | - | - | - |
| Total | | 5,899,523.0 | 7,629,813.4 | | 1,626,204.0 | 6,003,609.4 | 3,219,425.5 | 2,056,779.8 | 1,491,490.4 | 1,177,685.8 |

(1) Corporate income tax rates and estimates of corporate income taxes are provided by Delek Drilling and are its expected corporate income taxes per year.

*All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.*

NETHERLAND, SEWELL & ASSOCIATES, INC.

REVENUE, COSTS, AND TAXES
POSSIBLE RESERVES
DELEK DRILLING LIMITED PARTNERSHIP
TAMAR AND TAMAR SOUTHWEST FIELDS, TAMAR LEASE I/12, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2018

| Period Ending | Working Interest Revenue (M$) | Royalties: State (M$) | Royalties: Interested Party (M$) | Royalties: Third Party (M$) | Royalties: Total (M$) | Net Capital Costs (M$) | Net Abandonment Costs (M$) | Net Expenses[1] Expenses[1] (M$) | Net Revenue Before Levy and Corporate Income Taxes Discounted at 0% (M$) |
|---|---|---|---|---|---|---|---|---|---|
| 12-31-2019 | - | - | - | - | - | - | - | - | - |
| 12-31-2020 | - | - | - | - | - | - | - | - | - |
| 12-31-2021 | - | - | - | - | - | - | - | - | - |
| 12-31-2022 | - | - | - | - | - | - | - | - | - |
| 12-31-2023 | - | - | - | - | - | - | - | - | - |
| 12-31-2024 | - | - | - | - | - | -75,525.7 | - | - | 75,525.7 |
| 12-31-2025 | - | - | - | - | - | - | - | - | - |
| 12-31-2026 | - | - | - | - | - | 75,525.7 | - | - | -75,525.7 |
| 12-31-2027 | - | - | - | - | - | - | - | - | - |
| 12-31-2028 | - | - | - | - | - | - | - | - | - |
| 12-31-2029 | - | - | - | - | - | - | - | - | - |
| 12-31-2030 | - | - | - | - | - | - | - | - | - |
| 12-31-2031 | - | - | - | - | - | - | - | - | - |
| 12-31-2032 | - | - | - | - | - | - | - | - | - |
| 12-31-2033 | - | - | - | - | - | - | - | - | - |
| 12-31-2034 | - | - | - | - | - | - | - | - | - |
| 12-31-2035 | - | - | - | - | - | -52,086.7 | - | - | 52,086.7 |
| 12-31-2036 | - | - | - | - | - | - | - | - | - |
| 12-31-2037 | - | - | - | - | - | 52,086.7 | - | - | -52,086.7 |
| 12-31-2038 | - | - | - | - | - | - | - | - | - |
| 12-31-2039 | - | - | - | - | - | -49,482.4 | - | - | 49,482.4 |
| 12-31-2040 | - | - | - | - | - | - | - | - | - |
| 12-31-2041 | 17,485.8 | 2,010.9 | 1,193.0 | 298.7 | 3,502.5 | 49,482.4 | - | - | -35,499.1 |
| 12-31-2042 | 130,989.9 | 15,063.8 | 8,936.8 | 2,237.5 | 26,238.1 | - | - | - | 104,751.8 |
| 12-31-2043 | 153,947.0 | 17,703.9 | 10,503.0 | 2,629.6 | 30,836.5 | - | - | - | 123,110.5 |
| 12-31-2044 | 179,572.9 | 20,650.9 | 12,251.3 | 3,067.3 | 35,969.5 | - | - | - | 143,603.4 |
| 12-31-2045 | 347,734.2 | 39,989.4 | 23,724.1 | 5,939.8 | 69,653.3 | - | - | - | 278,080.9 |
| 12-31-2046 | 405,550.6 | 46,638.3 | 27,668.6 | 6,927.3 | 81,234.2 | - | - | - | 324,316.4 |
| 12-31-2047 | 417,005.6 | 47,955.6 | 28,450.1 | 7,123.0 | 83,528.7 | - | - | - | 333,476.8 |
| 12-31-2048 | 512,396.3 | 58,925.6 | 34,958.1 | 8,752.4 | 102,636.1 | - | -17,523.7 | - | 427,283.9 |
| 12-31-2049 | 583,454.3 | 67,097.2 | 39,806.0 | 9,966.2 | 116,869.4 | - | -17,523.7 | - | 484,108.5 |
| 12-31-2050 | 645,125.4 | 74,189.4 | 44,013.5 | 11,019.6 | 129,222.5 | - | -17,523.7 | - | 533,426.5 |
| 12-31-2051 | 652,024.2 | 74,982.8 | 44,484.2 | 11,137.4 | 130,604.4 | - | - | 40,055.6 | 481,364.2 |
| 12-31-2052 | 549,932.0 | 63,242.2 | 37,519.0 | 9,393.6 | 110,154.7 | - | 17,523.7 | 40,055.6 | 382,198.1 |
| 12-31-2053 | 389,611.6 | 44,805.3 | 26,581.1 | 6,655.1 | 78,041.6 | - | 17,523.7 | 40,055.6 | 253,990.8 |
| 12-31-2054 | 243,061.2 | 27,952.0 | 16,582.8 | 4,151.8 | 48,686.6 | - | 17,523.7 | 40,055.6 | 136,795.3 |
| Total | 5,227,891.0 | 601,207.5 | 356,671.4 | 89,299.3 | 1,047,178.2 | - | - | 160,222.3 | 4,020,490.5 |

(1) Operating expenses are limited to direct project-level costs, insurance costs, and Delek Drilling's estimate of the portion of the operator's headquarters general and administrative overhead expenses that can be directly attributed to this project.

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.

REVENUE, COSTS, AND TAXES
POSSIBLE RESERVES
DELEK DRILLING LIMITED PARTNERSHIP
TAMAR AND TAMAR SOUTHWEST FIELDS, TAMAR LEASE I/12, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2018

| Period Ending | Levy Rate (%) | Levy (M$) | Net Revenue After Levy and Before Corporate Income Taxes Discounted at 0% (M$) | Corporate Income Rate[1] Rate[1] (%) | Corporate Taxes[1] Taxes[1] (M$) | Future Net Revenue After Levy and Corporate Income Taxes: Discounted at 0% (M$) | Discounted at 5% (M$) | Discounted at 10% (M$) | Discounted at 15% (M$) | Discounted at 20% (M$) |
|---|---|---|---|---|---|---|---|---|---|---|
| 12-31-2019 | - | - | - | 23.0 | - | - | - | - | - | - |
| 12-31-2020 | 3.5 | - | - | 23.0 | - | - | - | - | - | - |
| 12-31-2021 | 27.2 | - | - | 23.0 | - | - | - | - | - | - |
| 12-31-2022 | 36.4 | - | - | 23.0 | - | - | - | - | - | - |
| 12-31-2023 | 43.9 | - | - | 23.0 | - | - | - | - | - | - |
| 12-31-2024 | 46.8 | 35,346.0 | 40,179.7 | 23.0 | -8,129.6 | 48,309.3 | 36,939.4 | 28,600.3 | 22,397.1 | 17,722.9 |
| 12-31-2025 | 46.8 | - | - | 23.0 | 1,144.0 | -1,144.0 | -833.1 | -615.7 | -461.2 | -349.7 |
| 12-31-2026 | 46.8 | -35,346.0 | -40,179.7 | 23.0 | 9,273.6 | -49,453.3 | -34,298.5 | -24,196.4 | -17,336.5 | -12,599.0 |
| 12-31-2027 | 46.8 | - | - | 23.0 | - | - | - | - | - | - |
| 12-31-2028 | 46.8 | - | - | 23.0 | - | - | - | - | - | - |
| 12-31-2029 | 46.8 | - | - | 23.0 | - | - | - | - | - | - |
| 12-31-2030 | 46.8 | - | - | 23.0 | - | - | - | - | - | - |
| 12-31-2031 | 46.8 | - | - | 23.0 | - | - | - | - | - | - |
| 12-31-2032 | 46.8 | - | - | 23.0 | - | - | - | - | - | - |
| 12-31-2033 | 46.8 | - | - | 23.0 | - | - | - | - | - | - |
| 12-31-2034 | 46.8 | - | - | 23.0 | - | - | - | - | - | - |
| 12-31-2035 | 46.8 | 24,376.6 | 27,710.1 | 23.0 | -7,343.7 | 35,053.8 | 15,671.6 | 7,273.7 | 3,493.2 | 1,730.8 |
| 12-31-2036 | 46.8 | - | - | 23.0 | 647.0 | -647.0 | -275.5 | -122.1 | -56.1 | -26.6 |
| 12-31-2037 | 46.8 | -24,376.6 | -27,710.1 | 23.0 | 6,804.6 | -34,514.7 | -13,996.0 | -5,918.9 | -2,600.7 | -1,183.5 |
| 12-31-2038 | 46.8 | - | - | 23.0 | - | - | - | - | - | - |
| 12-31-2039 | 46.8 | 23,157.8 | 26,324.6 | 23.0 | -5,326.3 | 31,650.9 | 11,641.4 | 4,485.8 | 1,803.4 | 753.7 |
| 12-31-2040 | 46.8 | - | - | 23.0 | 1,138.1 | -1,138.1 | -398.7 | -146.6 | -56.4 | -22.6 |
| 12-31-2041 | 46.8 | -16,613.6 | -18,885.5 | 23.0 | 8,175.4 | -27,060.9 | -9,027.8 | -3,169.6 | -1,165.8 | -447.5 |
| 12-31-2042 | 46.8 | 49,023.9 | 55,728.0 | 23.0 | 12,817.4 | 42,910.5 | 13,633.8 | 4,569.2 | 1,607.6 | 591.3 |
| 12-31-2043 | 46.8 | 57,615.7 | 65,494.8 | 23.0 | 15,063.8 | 50,431.0 | 15,260.2 | 4,881.8 | 1,642.9 | 579.1 |
| 12-31-2044 | 46.8 | 67,206.4 | 76,397.0 | 23.0 | 17,571.3 | 58,825.7 | 16,952.7 | 5,176.7 | 1,666.4 | 562.9 |
| 12-31-2045 | 46.8 | 130,141.9 | 147,939.0 | 23.0 | 34,026.0 | 113,913.1 | 31,264.9 | 9,113.1 | 2,806.0 | 908.4 |
| 12-31-2046 | 46.8 | 151,780.1 | 172,536.3 | 23.0 | 40,185.5 | 132,350.8 | 34,595.6 | 9,625.6 | 2,834.9 | 879.5 |
| 12-31-2047 | 46.8 | 156,067.2 | 177,409.7 | 23.0 | 41,306.4 | 136,103.3 | 33,882.4 | 8,998.6 | 2,535.0 | 753.7 |
| 12-31-2048 | 46.8 | 199,968.9 | 227,315.0 | 23.0 | 49,952.2 | 177,362.9 | 42,051.2 | 10,660.5 | 2,872.6 | 818.5 |
| 12-31-2049 | 46.8 | 226,562.8 | 257,545.7 | 23.0 | 56,905.2 | 200,640.5 | 45,304.9 | 10,963.3 | 2,825.8 | 771.6 |
| 12-31-2050 | 46.8 | 249,643.6 | 283,782.9 | 23.0 | 60,101.5 | 223,681.4 | 48,102.4 | 11,111.2 | 2,739.4 | 716.8 |
| 12-31-2051 | 46.8 | 225,278.5 | 256,085.8 | 23.0 | 56,061.5 | 200,024.3 | 40,966.7 | 9,032.8 | 2,130.1 | 534.2 |
| 12-31-2052 | 46.8 | 178,868.7 | 203,329.4 | 23.0 | 50,796.2 | 152,533.2 | 29,752.5 | 6,261.9 | 1,412.5 | 339.5 |
| 12-31-2053 | 46.8 | 118,867.7 | 135,123.1 | 23.0 | 35,108.8 | 100,014.4 | 18,579.4 | 3,732.6 | 805.4 | 185.5 |
| 12-31-2054 | 46.8 | 64,020.2 | 72,775.1 | 23.0 | 20,768.7 | 52,006.4 | 9,201.0 | 1,764.5 | 364.2 | 80.4 |
| Total | | 1,881,589.6 | 2,138,900.9 | | 497,047.7 | 1,641,853.3 | 384,970.3 | 102,082.3 | 32,259.4 | 13,299.8 |

[1] Corporate income tax rates and estimates of corporate income taxes are provided by Delek Drilling and are its expected corporate income taxes per year.

*All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.*

NETHERLAND, SEWELL & ASSOCIATES, INC.

REVENUE, COSTS, AND TAXES
PROVED + PROBABLE + POSSIBLE (3P) RESERVES
DELEK DRILLING LIMITED PARTNERSHIP
TAMAR AND TAMAR SOUTHWEST FIELDS, TAMAR LEASE I/12, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2018

| Period Ending | Working Interest Revenue (M$) | Royalties: State (M$) | Royalties: Interested Party (M$) | Royalties: Third Party (M$) | Royalties: Total (M$) | Net Capital Costs (M$) | Net Abandonment Costs (M$) | Net Operating Expenses[1] (M$) | Net Revenue Before Levy and Corporate Income Taxes Discounted at 0% (M$) |
|---|---|---|---|---|---|---|---|---|---|
| 12-31-2019 | 543,380.2 | 62,488.7 | 37,072.0 | 9,281.7 | 108,842.3 | 31,017.6 | - | 44,046.1 | 359,474.1 |
| 12-31-2020 | 528,307.1 | 60,755.3 | 36,043.6 | 9,024.2 | 105,823.1 | 63,545.8 | - | 40,847.7 | 318,090.5 |
| 12-31-2021 | 521,630.6 | 59,987.5 | 35,588.1 | 8,910.1 | 104,485.8 | 208.3 | - | 39,959.4 | 376,977.1 |
| 12-31-2022 | 540,522.2 | 62,160.0 | 36,877.0 | 9,232.8 | 108,269.9 | -821.4 | - | 40,055.6 | 393,018.1 |
| 12-31-2023 | 546,903.2 | 62,893.9 | 37,312.3 | 9,341.8 | 109,548.0 | - | - | 40,055.6 | 397,299.6 |
| 12-31-2024 | 552,028.1 | 63,483.2 | 37,662.0 | 9,429.4 | 110,574.6 | - | - | 40,055.6 | 401,397.9 |
| 12-31-2025 | 553,775.3 | 63,684.2 | 37,781.2 | 9,459.2 | 110,924.6 | 26,043.4 | - | 40,055.6 | 376,751.9 |
| 12-31-2026 | 559,640.7 | 64,358.7 | 38,181.3 | 9,559.4 | 112,099.4 | 119,278.6 | - | 40,055.6 | 288,207.2 |
| 12-31-2027 | 624,460.9 | 71,813.0 | 42,603.7 | 10,666.6 | 125,083.3 | - | - | 40,055.6 | 459,322.1 |
| 12-31-2028 | 631,608.0 | 72,634.9 | 43,091.3 | 10,788.7 | 126,514.9 | - | - | 40,055.6 | 465,037.5 |
| 12-31-2029 | 635,058.7 | 73,031.8 | 43,326.7 | 10,847.6 | 127,206.1 | - | - | 40,055.6 | 467,797.1 |
| 12-31-2030 | 649,909.5 | 74,739.6 | 44,339.9 | 11,101.3 | 130,180.8 | - | - | 40,055.6 | 479,673.1 |
| 12-31-2031 | 668,438.2 | 76,870.4 | 45,604.0 | 11,417.8 | 133,892.2 | - | - | 40,055.6 | 494,490.4 |
| 12-31-2032 | 692,392.6 | 79,625.2 | 47,238.3 | 11,827.0 | 138,690.4 | - | - | 40,055.6 | 513,646.6 |
| 12-31-2033 | 712,656.4 | 81,955.5 | 48,620.8 | 12,173.1 | 142,749.4 | - | - | 40,055.6 | 529,851.5 |
| 12-31-2034 | 724,655.8 | 83,335.4 | 49,439.4 | 12,378.1 | 145,152.9 | - | - | 40,055.6 | 539,447.3 |
| 12-31-2035 | 735,641.4 | 84,598.8 | 50,188.9 | 12,565.7 | 147,353.4 | - | - | 40,055.6 | 548,232.4 |
| 12-31-2036 | 747,579.4 | 85,971.6 | 51,003.4 | 12,769.6 | 149,744.7 | - | - | 40,055.6 | 557,779.2 |
| 12-31-2037 | 755,547.4 | 86,888.0 | 51,547.0 | 12,905.7 | 151,340.7 | 52,086.7 | - | 40,055.6 | 512,064.4 |
| 12-31-2038 | 765,664.0 | 88,051.4 | 52,237.2 | 13,078.6 | 153,367.1 | - | - | 40,055.6 | 572,241.3 |
| 12-31-2039 | 774,056.6 | 89,016.5 | 52,809.8 | 13,221.9 | 155,048.2 | - | - | 40,055.6 | 578,952.8 |
| 12-31-2040 | 784,623.9 | 90,231.7 | 53,530.8 | 13,402.4 | 157,164.9 | - | - | 40,055.6 | 587,403.4 |
| 12-31-2041 | 791,928.1 | 91,071.7 | 54,029.1 | 13,527.2 | 158,628.0 | 49,482.4 | - | 40,055.6 | 543,762.2 |
| 12-31-2042 | 801,553.3 | 92,178.6 | 54,685.8 | 13,691.6 | 160,556.0 | - | - | 40,055.6 | 600,941.7 |
| 12-31-2043 | 811,293.7 | 93,298.8 | 55,350.3 | 13,858.0 | 162,507.0 | - | - | 40,055.6 | 608,731.1 |
| 12-31-2044 | 823,546.5 | 94,707.8 | 56,186.2 | 14,067.3 | 164,961.3 | - | - | 40,055.6 | 618,529.6 |
| 12-31-2045 | 831,123.0 | 95,579.2 | 56,703.1 | 14,196.7 | 166,479.0 | - | - | 40,055.6 | 624,588.5 |
| 12-31-2046 | 841,214.0 | 96,739.6 | 57,391.6 | 14,369.0 | 168,500.3 | - | - | 40,055.6 | 632,658.2 |
| 12-31-2047 | 851,424.8 | 97,913.9 | 58,088.2 | 14,543.5 | 170,545.5 | - | - | 40,055.6 | 640,823.7 |
| 12-31-2048 | 864,272.9 | 99,391.4 | 58,964.8 | 14,762.9 | 173,119.1 | - | - | 40,055.6 | 651,098.2 |
| 12-31-2049 | 795,624.9 | 91,496.9 | 54,281.3 | 13,590.3 | 159,368.5 | - | - | 40,055.6 | 596,200.8 |
| 12-31-2050 | 751,593.2 | 86,433.2 | 51,277.2 | 12,838.2 | 150,548.7 | - | - | 40,055.6 | 560,988.9 |
| 12-31-2051 | 652,024.2 | 74,982.8 | 44,484.2 | 11,137.4 | 130,604.4 | - | - | 40,055.6 | 481,364.2 |
| 12-31-2052 | 549,932.0 | 63,242.2 | 37,519.0 | 9,393.6 | 110,154.7 | - | 17,523.7 | 40,055.6 | 382,198.1 |
| 12-31-2053 | 389,611.6 | 44,805.3 | 26,581.1 | 6,655.1 | 78,041.6 | - | 17,523.7 | 40,055.6 | 253,990.8 |
| 12-31-2054 | 243,061.2 | 27,952.0 | 16,582.8 | 4,151.8 | 48,686.6 | - | 17,523.7 | 40,055.6 | 136,795.3 |
| Total | 24,246,683.7 | 2,788,368.6 | 1,654,223.4 | 414,165.4 | 4,856,757.5 | 340,841.4 | 52,571.0 | 1,446,687.0 | 17,549,826.9 |

[1] Operating expenses are limited to direct project-level costs, insurance costs, and Delek Drilling's estimate of the portion of the operator's headquarters general and administrative overhead expenses that can be directly attributed to this project.



*All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.*

NETHERLAND, SEWELL & ASSOCIATES, INC.

REVENUE, COSTS, AND TAXES
PROVED + PROBABLE + POSSIBLE (3P) RESERVES
DELEK DRILLING LIMITED PARTNERSHIP
TAMAR AND TAMAR SOUTHWEST FIELDS, TAMAR LEASE I/12, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2018

| Period Ending | Levy Rate (%) | Levy (M$) | Net Revenue After Levy and Before Corporate Income Taxes Discounted at 0% (M$) | Corporate Income Tax Rate[1] (%) | Corporate Income Taxes[1] (M$) | Future Net Revenue After Levy and Corporate Income Taxes | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | Discounted at 0% (M$) | Discounted at 5% (M$) | Discounted at 10% (M$) | Discounted at 15% (M$) | Discounted at 20% (M$) |
| 12-31-2019 | - | - | 359,474.1 | 23.0 | 60,543.0 | 298,931.1 | 291,726.9 | 285,019.6 | 278,754.7 | 272,885.5 |
| 12-31-2020 | 3.5 | 11,140.6 | 306,949.9 | 23.0 | 71,509.9 | 235,440.0 | 218,824.7 | 204,075.7 | 190,912.1 | 179,105.3 |
| 12-31-2021 | 27.2 | 102,351.1 | 274,625.9 | 23.0 | 47,937.5 | 226,688.4 | 200,657.8 | 178,627.2 | 159,839.7 | 143,706.4 |
| 12-31-2022 | 36.4 | 143,148.6 | 249,869.5 | 23.0 | 42,491.9 | 207,377.7 | 174,823.4 | 148,555.1 | 127,150.9 | 109,553.9 |
| 12-31-2023 | 43.9 | 174,547.5 | 222,752.1 | 23.0 | 40,147.3 | 182,604.8 | 146,608.9 | 118,917.3 | 97,358.1 | 80,389.0 |
| 12-31-2024 | 46.8 | 187,854.2 | 213,543.7 | 23.0 | 39,400.0 | 174,143.7 | 133,157.8 | 103,097.5 | 80,736.5 | 63,886.8 |
| 12-31-2025 | 46.8 | 176,319.9 | 200,432.0 | 23.0 | 42,380.0 | 158,052.0 | 115,098.5 | 85,064.3 | 63,718.3 | 48,319.4 |
| 12-31-2026 | 46.8 | 134,881.0 | 153,326.2 | 23.0 | 53,525.6 | 99,800.7 | 69,217.1 | 48,830.2 | 34,986.4 | 25,425.8 |
| 12-31-2027 | 46.8 | 214,962.7 | 244,359.3 | 23.0 | 45,081.4 | 199,277.9 | 131,628.5 | 88,638.3 | 60,747.4 | 42,307.6 |
| 12-31-2028 | 46.8 | 217,637.6 | 247,400.0 | 23.0 | 48,471.6 | 198,928.4 | 125,140.7 | 80,438.9 | 52,731.2 | 35,194.5 |
| 12-31-2029 | 46.8 | 218,929.0 | 248,868.0 | 23.0 | 49,016.0 | 199,852.1 | 119,735.0 | 73,465.8 | 46,066.1 | 29,464.9 |
| 12-31-2030 | 46.8 | 224,487.0 | 255,186.1 | 23.0 | 51,171.5 | 204,014.6 | 116,408.4 | 68,178.2 | 40,891.8 | 25,065.5 |
| 12-31-2031 | 46.8 | 231,421.5 | 263,068.9 | 23.0 | 54,880.4 | 208,188.5 | 113,133.3 | 63,248.2 | 36,285.6 | 21,315.3 |
| 12-31-2032 | 46.8 | 240,386.6 | 273,260.0 | 23.0 | 57,222.7 | 216,037.3 | 111,808.1 | 59,666.1 | 32,742.2 | 18,432.4 |
| 12-31-2033 | 46.8 | 247,970.5 | 281,881.0 | 23.0 | 59,211.7 | 222,669.2 | 109,752.7 | 55,907.0 | 29,345.5 | 15,831.9 |
| 12-31-2034 | 46.8 | 252,461.3 | 286,985.9 | 23.0 | 60,453.1 | 226,532.9 | 106,340.1 | 51,706.4 | 25,960.6 | 13,422.1 |
| 12-31-2035 | 46.8 | 256,572.8 | 291,659.6 | 23.0 | 61,955.1 | 229,704.5 | 102,694.2 | 47,664.0 | 22,890.5 | 11,341.7 |
| 12-31-2036 | 46.8 | 261,040.7 | 296,738.5 | 23.0 | 63,696.4 | 233,042.2 | 99,225.1 | 43,960.5 | 20,194.0 | 9,588.8 |
| 12-31-2037 | 46.8 | 239,646.2 | 272,418.3 | 23.0 | 73,422.5 | 198,995.8 | 80,694.1 | 34,125.5 | 14,994.6 | 6,823.2 |
| 12-31-2038 | 46.8 | 267,808.9 | 304,432.4 | 23.0 | 67,631.9 | 236,800.5 | 91,451.6 | 36,916.9 | 15,515.8 | 6,766.3 |
| 12-31-2039 | 46.8 | 270,949.9 | 308,002.9 | 23.0 | 68,493.3 | 239,509.6 | 88,093.2 | 33,944.8 | 13,646.4 | 5,703.1 |
| 12-31-2040 | 46.8 | 274,904.8 | 312,498.6 | 23.0 | 69,596.9 | 242,901.8 | 85,086.5 | 31,295.9 | 12,034.5 | 4,819.9 |
| 12-31-2041 | 46.8 | 254,480.7 | 289,281.5 | 23.0 | 75,975.0 | 213,306.5 | 71,161.4 | 24,984.4 | 9,189.7 | 3,527.2 |
| 12-31-2042 | 46.8 | 281,240.7 | 319,701.0 | 23.0 | 70,583.8 | 249,117.2 | 79,150.8 | 26,526.2 | 9,332.6 | 3,432.8 |
| 12-31-2043 | 46.8 | 284,886.2 | 323,845.0 | 23.0 | 71,732.6 | 252,112.4 | 76,288.0 | 24,404.7 | 8,212.9 | 2,895.0 |
| 12-31-2044 | 46.8 | 289,471.8 | 329,057.7 | 23.0 | 73,014.7 | 256,043.1 | 73,788.0 | 22,532.0 | 7,253.0 | 2,450.1 |
| 12-31-2045 | 46.8 | 292,307.4 | 332,281.1 | 23.0 | 73,811.5 | 258,469.6 | 70,940.3 | 20,677.8 | 6,366.7 | 2,061.1 |
| 12-31-2046 | 46.8 | 296,084.0 | 336,574.1 | 23.0 | 74,936.6 | 261,637.5 | 68,390.3 | 19,028.4 | 5,604.1 | 1,738.7 |
| 12-31-2047 | 46.8 | 299,905.5 | 340,918.2 | 23.0 | 76,075.1 | 264,843.1 | 65,931.6 | 17,510.4 | 4,932.9 | 1,466.6 |
| 12-31-2048 | 46.8 | 304,714.0 | 346,384.3 | 23.0 | 78,530.3 | 267,854.0 | 63,505.9 | 16,099.6 | 4,338.2 | 1,236.1 |
| 12-31-2049 | 46.8 | 279,022.0 | 317,178.8 | 23.0 | 71,813.0 | 245,365.8 | 55,403.9 | 13,407.2 | 3,455.7 | 943.6 |
| 12-31-2050 | 46.8 | 262,542.8 | 298,446.1 | 23.0 | 65,804.4 | 232,641.8 | 50,029.3 | 11,556.3 | 2,849.1 | 745.6 |
| 12-31-2051 | 46.8 | 225,278.5 | 256,085.8 | 23.0 | 56,061.5 | 200,024.3 | 40,966.7 | 9,032.8 | 2,130.1 | 534.2 |
| 12-31-2052 | 46.8 | 178,868.7 | 203,329.4 | 23.0 | 50,796.2 | 152,533.2 | 29,752.5 | 6,261.9 | 1,412.5 | 339.5 |
| 12-31-2053 | 46.8 | 118,867.7 | 135,123.1 | 23.0 | 35,108.8 | 100,014.4 | 18,579.4 | 3,732.6 | 805.4 | 185.5 |
| 12-31-2054 | 46.8 | 64,020.2 | 72,775.1 | 23.0 | 20,768.7 | 52,006.4 | 9,201.0 | 1,764.5 | 364.2 | 80.4 |
| Total | | 7,781,112.5 | 9,768,714.4 | | 2,123,251.7 | 7,645,462.7 | 3,604,395.8 | 2,158,862.2 | 1,523,749.8 | 1,190,985.6 |

(1) Corporate income tax rates and estimates of corporate income taxes are provided by Delek Drilling and are its expected corporate income taxes per year.



*All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.*

HISTORICAL PRODUCTION AND OPERATING EXPENSE DATA
DELEK DRILLING LIMITED PARTNERSHIP
TAMAR AND TAMAR SOUTHWEST FIELDS, TAMAR LEASE I/12, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2018

| Year | Delek Drilling Working Interest Production (BCF) | Average Price Received Per Production Unit ($/MCF) | Average Royalties Paid Per Production Unit ($/MCF) | Average Production Costs Per Production Unit ($/MCF) | Average Net Revenue Per Production Unit ($/MCF) | Reserves Depletion Rate[1] (%) |
|---|---|---|---|---|---|---|
| 2018[2] | 93.36 | 5.53 | 1.07 | 0.39 | 4.08 | 3.3 |
| 2017 | 98.40 | 5.36 | 0.85 | 0.37 | 4.14 | 3.4 |
| 2016 | 103.79 | 5.20 | 0.82 | 0.38 | 4.00 | 3.2 |

Notes: The per-production-unit ($/MCF) estimates shown in this report are provided by Delek Drilling. These estimates are based on historical production data since January 2016 and include condensate revenue and costs.

(1) The reserves depletion rate is the percentage of yearly gas produced to the estimated proved plus probable reserves at the beginning of the year.
(2) The 2018 data is representative of unaudited financial data.



*All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.*

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.

VOLUMETRIC INPUT SUMMARY
TAMAR FIELD, TAMAR LEASE I/12, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2018

| Reservoir | Gross Rock Volume (acre-feet) Low Estimate | Gross Rock Volume (acre-feet) Best Estimate | Gross Rock Volume (acre-feet) High Estimate | Area (acres) Low Estimate | Area (acres) Best Estimate | Area (acres) High Estimate | Average Gross Thickness[1] (feet) Low Estimate | Average Gross Thickness[1] (feet) Best Estimate | Average Gross Thickness[1] (feet) High Estimate | Net-to-Gross Ratio (decimal) Low Estimate | Net-to-Gross Ratio (decimal) Best Estimate | Net-to-Gross Ratio (decimal) High Estimate |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A Sand | 2,309,629 | 2,594,825 | 2,845,871 | 20,275 | 21,711 | 22,935 | 114 | 120 | 124 | 0.88 | 0.93 | 0.93 |
| B Sand | 1,576,608 | 1,693,767 | 1,782,698 | 14,263 | 15,027 | 15,158 | 111 | 113 | 118 | 0.72 | 0.85 | 0.85 |
| C Sand | 1,839,279 | 1,964,971 | 2,063,220 | 9,095 | 9,095 | 9,095 | 202 | 216 | 227 | 0.87 | 0.90 | 0.90 |

| Reservoir | Porosity[2] (decimal) Low Estimate | Porosity[2] (decimal) Best Estimate | Porosity[2] (decimal) High Estimate | Gas Saturation (decimal) Low Estimate | Gas Saturation (decimal) Best Estimate | Gas Saturation (decimal) High Estimate | Gas Formation Volume Factor (SCF/RCF)[3] Low Estimate | Gas Formation Volume Factor (SCF/RCF)[3] Best Estimate | Gas Formation Volume Factor (SCF/RCF)[3] High Estimate | Gas Recovery Factor (decimal) Low Estimate | Gas Recovery Factor (decimal) Best Estimate | Gas Recovery Factor (decimal) High Estimate |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A Sand | 0.26 | 0.26 | 0.25 | 0.75 | 0.78 | 0.83 | 372 | 372 | 372 | 0.62 | 0.67 | 0.72 |
| B Sand | 0.25 | 0.24 | 0.24 | 0.76 | 0.79 | 0.82 | 372 | 372 | 372 | 0.62 | 0.67 | 0.72 |
| C Sand | 0.25 | 0.24 | 0.24 | 0.78 | 0.81 | 0.83 | 372 | 372 | 372 | 0.62 | 0.67 | 0.72 |

Note: For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, seismic data, core data, well test data, production data, historical price and cost information, and property ownership interests.

(1) Average gross thickness is calculated by dividing the gross rock volume by the area.
(2) The increasing net-to-gross ratio between cases includes lower porosity rock which results in a lower porosity in the best and high estimate cases relative to the low estimate case.
(3) The abbreviation SCF/RCF represents standard cubic feet per reservoir cubic feet.



*All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.*

NETHERLAND, SEWELL & ASSOCIATES, INC.

VOLUMETRIC INPUT SUMMARY
TAMAR SOUTHWEST FIELD, TAMAR LEASE I/12, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2018

| | Gross Rock Volume (acre-feet) | | | Area (acres) | | | Average Gross Thickness[1] (feet) | | | Net-to-Gross Ratio (decimal) | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Reservoir | Low Estimate | Best Estimate | High Estimate | Low Estimate | Best Estimate | High Estimate | Low Estimate | Best Estimate | High Estimate | Low Estimate | Best Estimate | High Estimate |
| A Sand | 300,301 | 318,108 | 318,108 | 2,517 | 2,517 | 2,517 | 119 | 126 | 126 | 0.99 | 1.00 | 1.00 |
| B Sand | 128,228 | 137,183 | 137,183 | 1,065 | 1,065 | 1,065 | 120 | 129 | 129 | 0.82 | 0.87 | 0.88 |

| | Porosity (decimal) | | | Gas Saturation (decimal) | | | Gas Formation Volume Factor (SCF/RCF)[2] | | | Gas Recovery Factor (decimal) | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Reservoir | Low Estimate | Best Estimate | High Estimate | Low Estimate | Best Estimate | High Estimate | Low Estimate | Best Estimate | High Estimate | Low Estimate | Best Estimate | High Estimate |
| A Sand | 0.24 | 0.24 | 0.24 | 0.84 | 0.87 | 0.89 | 372 | 372 | 372 | 0.62 | 0.67 | 0.72 |
| B Sand | 0.22 | 0.22 | 0.22 | 0.78 | 0.81 | 0.85 | 372 | 372 | 372 | 0.62 | 0.67 | 0.72 |

Note: For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, seismic data, core data, well test data, production data, historical and cost information, and property ownership interests.

[1] Average gross thickness is calculated by dividing the gross rock volume by the area.
[2] The abbreviation SCF/RCF represents standard cubic feet per reservoir cubic feet.



*All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.*

Annex C

# NSAI Letter – No Material Changes in the Tamar Project

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.
WORLDWIDE PETROLEUM CONSULTANTS
ENGINEERING • GEOLOGY • GEOPHYSICS • PETROPHYSICS

EXECUTIVE COMMITTEE
ROBERT C. BARG MIKE K. NORTON
P. SCOTT FROST DAN PAUL SMITH
JOHN G. HATTNER JOSEPH J. SPELLMAN
J. CARTER HENSON, JR. DANIEL T. WALKER

CHAIRMAN & CEO
C.H. (SCOTT) REES III
PRESIDENT & COO
DANNY D. SIMMONS
EXECUTIVE VP
G. LANCE BINDER

March 21, 2019

Delek Drilling Limited Partnership
19 Abba Eban Boulevard
Herzelia 4612001
Israel

Ladies and Gentlemen:

This no material change letter is regarding new well data for certain gas properties in Tamar and Tamar Southwest Fields, located in the Tamar Lease I/12, offshore Israel. Since our report dated February 19, 2019, we, Netherland, Sewell & Associates, Inc. (NSAI) have received daily well production data through March 12, 2019. This daily well production data has been reviewed by NSAI and it is our opinion that there are no material changes to our production profile for each category and our proved, proved plus probable, and proved plus probable plus possible reserves referenced in our February 19 report.

The February 19 report sets forth our estimates of the proved, probable, and possible reserves and future revenue, as of December 31, 2018, to the Delek Drilling Limited Partnership working interest in certain gas properties located in Tamar and Tamar Southwest Fields, Tamar Lease I/12, offshore Israel.

Sincerely,

**NETHERLAND, SEWELL & ASSOCIATES, INC.**

By: Danny D. Simmons
Danny D. Simmons, P.E.
President and Chief Operating Officer

RBT:MAG

2100 ROSS AVENUE, SUITE 2200 • DALLAS, TEXAS 75201 • PH: 214-969-5401 • FAX: 214-969-5411
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info@nsai-petro.com
netherlandsewell.com

Annex D

# Contingent Resources and Reserves Report

# Leviathan Leases

EXECUTIVE COMMITTEE
ROBERT C. BARG MIKE K. NORTON
P. SCOTT FROST DAN PAUL SMITH
JOHN G. HATTNER JOSEPH J. SPELLMAN
J. CARTER HENSON, JR. DANIEL T. WALKER

CHAIRMAN & CEO
C.H. (SCOTT) REES III
PRESIDENT & COO
DANNY D. SIMMONS
EXECUTIVE VP
G. LANCE BINDER

March 21, 2019

Delek Drilling Limited Partnership
19 Abba Eban Boulevard
Herzelia 4612001
Israel

Ladies and Gentlemen:

In accordance with your request, we have estimated the proved undeveloped, probable, and possible reserves and future revenue, as of December 31, 2018, to the Delek Drilling Limited Partnership (Delek Drilling) working 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, 2018, to the Delek Drilling working interest in these properties. It is our understanding that Delek Drilling owns a direct interest in these properties. We completed our evaluation on or about the date of this letter. For the reserves and the Phase I – First Stage contingent resources, this report has been prepared using price and cost parameters specified by Delek Drilling, as discussed in subsequent paragraphs of this letter. Monetary values shown in this report are expressed in United States dollars ($), thousands of United States dollars (M$), or millions of United States dollars (MM$). For your reference, the March 20, 2019, exchange rate was 3.61 Israeli New 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 Delek Drilling's use in filing with the ISA; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

## 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 working interest reserves to the Delek Drilling interest in these properties, as of December 31, 2018, to be:

| Category | Gas Reserves (BCF) Gross (100%) | Gas Reserves (BCF) Working Interest | Condensate Reserves(MMBBL) Gross (100%) | Condensate Reserves(MMBBL) Working Interest |
|---|---|---|---|---|
| Proved Undeveloped | 9,425.8 | 4,273.7 | 16.9 | 7.7 |
| Probable | 3,959.4 | 1,795.2 | 7.1 | 3.2 |
| Proved + Probable (2P) | 13,385.1 | 6,068.8 | 24.0 | 10.9 |
| Possible | 819.1 | 371.4 | 1.5 | 0.7 |
| Proved + Probable + Possible (3P) | 14,204.3 | 6,440.2 | 25.5 | 11.6 |

*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 Delek Drilling interest in these properties, as of December 31, 2018, to be:

| | Future Net Revenue After Levy and Corporate Income Taxes (MM$) | | | | |
|---|---|---|---|---|---|
| Category | Discounted at 0% | Discounted at 5% | Discounted at 10% | Discounted at 15% | Discounted at 20% |
| Proved Undeveloped | 11,458.4 | 4,548.7 | 2,397.5 | 1,463.1 | 954.2 |
| Probable | 4,226.4 | 1,950.9 | 1,285.8 | 991.1 | 817.7 |
| Proved + Probable (2P) | 15,684.9 | 6,499.6 | 3,683.3 | 2,454.2 | 1,772.0 |
| Possible | 644.3 | 454.4 | 306.5 | 226.7 | 181.5 |
| Proved + Probable + Possible (3P) | 16,329.2 | 6,954.0 | 3,989.7 | 2,680.9 | 1,953.4 |

*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 project maturity subclass for these reserves is approved for development. The estimates of reserves and future revenue included herein have not been adjusted for risk.

Working interest revenue shown in this report is Delek Drilling's share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for royalties, capital costs, abandonment costs, operating expenses, and Delek Drilling's estimates of its 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.

## CONTINGENT RESOURCES

Contingent resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by the application of development project(s) not currently considered to be commercial owing to one or more contingencies. The contingent resources shown in this report are contingent upon finalization of additional gas contracts, sanctioning of additional Phase I – First Stage drilling, and project sanctioning for additional future development. If these contingencies are successfully addressed, some portion of the contingent resources estimated in this report may be reclassified as reserves; our estimates have not been risked to account for the possibility that the contingencies are not successfully addressed. 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 in these properties by development phase, as of December 31, 2018, 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] | 7,370.7 | 4,700.0 | 4,465.5 | 13.2 | 8.4 | 8.0 |
| Future Development | 186.6 | 3,410.1 | 7,174.1 | 0.3 | 6.1 | 12.9 |
| Total | 7,557.3 | 8,110.1 | 11,639.6 | 13.6 | 14.6 | 20.9 |

*Totals may not add because of rounding.*

[1] The contingent resources shown in this report represent volumes that are incrementally recoverable over volumes classified as reserves. For the Phase I – First Stage, the 2C and 3C contingent resources are less than the 1C contingent resources because a larger portion of the estimated volumes for the best and high estimate cases have been classified as reserves.

We estimate the working interest contingent resources to the Delek Drilling interest in these properties by development phase, as of December 31, 2018, 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] | 3,341.9 | 2,131.0 | 2,024.7 | 6.0 | 3.8 | 3.6 |
| Future Development | 84.6 | 1,546.1 | 3,252.7 | 0.2 | 2.8 | 5.8 |
| Total | 3,426.5 | 3,677.1 | 5,277.4 | 6.2 | 6.6 | 9.5 |

*Totals may not add because of rounding.*

[1] The contingent resources shown in this report represent volumes that are incrementally recoverable over volumes classified as reserves. For the Phase I – First Stage, the 2C and 3C contingent resources are less than the 1C contingent resources because a larger portion of the estimated volumes for the best and high estimate cases have been classified as reserves.

As requested, economic analysis was only performed on the Phase I – First Stage contingent resources. The costs required to resolve the contingencies have not been included in this report; estimates of cash flow are based on the assumption that all contingencies will be successfully addressed. For the Phase I – First Stage, we estimate the net contingent cash flow after levy and corporate income taxes, discounted at 0, 5, 10, 15, and 20 percent, to the Delek Drilling interest in these properties, as of December 31, 2018, 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) | 7,064.1 | 3,096.3 | 1,835.3 | 1,308.4 | 1,031.5 |
| Best Estimate (2C) | 4,640.1 | 1,394.6 | 589.9 | 325.6 | 216.1 |
| High Estimate (3C) | 4,791.7 | 1,108.3 | 331.0 | 116.9 | 43.5 |

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 Delek Drilling's share of the gross (100 percent) revenue from the properties prior to any deductions. Net contingent cash flow is after deductions for royalties, capital costs, abandonment costs, operating expenses, and Delek Drilling'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 determine its present worth, which is shown 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 VI through VIII present cash flow, costs, and taxes by resources category for the Phase I – First Stage contingent resources. As requested, we have included an appendix to this report that presents tables of cash flow, costs, and taxes resulting from aggregating our estimates of reserves and the Phase I - First Stage contingent resources.

## ECONOMIC PARAMETERS

As requested, this report has been prepared using gas and condensate prices specified by Delek Drilling. Gas prices are based on Delek Drilling's estimates of expected approved and future sales contracts. These contract prices are derived from various formulae that include indexation mainly to the Power Generation Tariffs, published by The Electricity Authority, or to an average of long-term forecasts for Brent Crude prices provided by various institutions. Condensate prices are based on Brent Crude prices and are adjusted for quality, transportation fees, and market differentials.

Operating costs used in this report are based on operating expense estimates of Delek Drilling. Operating costs are intended to include Delek Drilling's estimates of direct project-level costs, indirect headquarters general and administrative overhead expenses, and the portion of the operator's headquarters general and administrative overhead expenses that can be directly attributed to this project; Noble Energy Mediterranean Ltd. is the operator of the properties. Based on 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, per-well costs, and per-unit-of-production costs and, as requested, are not escalated for inflation.

Capital costs used in this report were provided by Delek Drilling and are based on authorizations for expenditure and actual costs from recent activity. Capital costs are included as required for new development wells, production equipment, initial platform construction and installation, and gas transportation pipelines. 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 Delek Drilling's estimates of the costs to abandon the wells, platform, and production facilities, net of any salvage value. As requested, capital costs and abandonment costs are not escalated for inflation.

## 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 Delek Drilling, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the 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. Such sensitivity analysis could lead to the conclusion that the reserves are not economic.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, seismic data, well test data, and property ownership interests. We were provided with all the necessary data to prepare the estimates for 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 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. Certain parameters used in our volumetric analysis are summarized in Table IX. The reserves and contingent resources 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. 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 February 5, 2019, by Mr. Yossi Abu, Chief Executive Officer of Delek Drilling, to perform this assessment. The data used in our estimates were obtained from Noble Energy Mediterranean Ltd., Delek Drilling, other interest owners, public data sources, and the nonconfidential files of NSAI and were accepted as accurate. Supporting work data are on file in our office. We have not examined the contractual rights to the properties or independently confirmed the actual degree or type of interest owned. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis. Furthermore, no limitations or restrictions were placed upon NSAI by officials of Delek Drilling.

## QUALIFICATIONS

NSAI performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. We provide a complete range of geological, geophysical, petrophysical, and engineering services, and we have the technical expertise and ability to perform these services in any oil and gas producing area in the world. The staff are familiar with the recognized industry reserves and resources definitions, specifically those promulgated by the U.S. Securities and Exchange Commission, by the Alberta Securities Commission, and by the SPE, Society of Petroleum Evaluation Engineers, World Petroleum Council, and American Association of Petroleum Geologists. The technical persons responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards.

This assessment has been led by Mr. Richard B. Talley, Jr. and Mr. Zachary R. Long. Mr. Talley is a Senior Vice President and Mr. Long is a Vice President in the firm's Houston office at 1301 McKinney Street, Suite 3200, Houston, Texas 77010, USA. Mr. Talley is a Licensed Professional Engineer (Texas Registration No. 102425). He has been practicing petroleum engineering consulting at NSAI since 2004 and has over 5 years of prior industry experience. Mr. Long is a Licensed Professional Geoscientist (Texas Registration No. 11792). He has been practicing petroleum geoscience consulting at NSAI since 2007 and has over 2 years of prior industry experience.

Sincerely,

**NETHERLAND, SEWELL & ASSOCIATES, INC.**
Texas Registered Engineering Firm F-2699

By: 
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

By: 
Richard B. Talley, Jr., P.E. 102425
Senior Vice President

Date Signed: March 21, 2019

STATE OF TEXAS
R. B. TALLEY, JR.
102425
LICENSED
PROFESSIONAL ENGINEER

By: 
Zachary R. Long, P.G. 11792
Vice President

Date Signed: March 21, 2019

STATE OF TEXAS
Z. R. LONG
GEOLOGY
11792
LICENSED
PROFESSIONAL GEOSCIENTIST

RBT:MAG

# PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the Petroleum Resources Management System Approved by
the Society of Petroleum Engineers (SPE) Board of Directors, June 2018

This document contains information excerpted from definitions and guidelines prepared by the Oil and Gas Reserves Committee of the Society of Petroleum Engineers (SPE) and reviewed and jointly sponsored by the SPE, World Petroleum Council, American Association of Petroleum Geologists, Society of Petroleum Evaluation Engineers, Society of Exploration Geophysicists, Society of Petrophysicists and Well Log Analysts, and European Association of Geoscientists & Engineers.

### Preamble

Petroleum resources are the quantities of hydrocarbons naturally occurring on or within the Earth's crust. Resources assessments estimate quantities in known and yet-to-be-discovered accumulations. Resources evaluations are focused on those quantities that can potentially be recovered and marketed by commercial projects. A petroleum resources management system provides a consistent approach to estimating petroleum quantities, evaluating projects, and presenting results within a comprehensive classification framework.

This updated PRMS provides fundamental principles for the evaluation and classification of petroleum reserves and resources. If there is any conflict with prior SPE and PRMS guidance, approved training, or the Application Guidelines, the current PRMS shall prevail. It is understood that these definitions and guidelines allow flexibility for entities, governments, and regulatory agencies to tailor application for their particular needs; however, any modifications to the guidance contained herein must be clearly identified. The terms "shall" or "must" indicate that a provision herein is mandatory for PRMS compliance, while "should" indicates a recommended practice and "may" indicates that a course of action is permissible. The definitions and guidelines contained in this document must not be construed as modifying the interpretation or application of any existing regulatory reporting requirements.

## 1.0 Basic Principles and Definitions

1.0.0.1 A classification system of petroleum resources is a fundamental element that provides a common language for communicating both the confidence of a project's resources maturation status and the range of potential outcomes to the various entities. The PRMS provides transparency by requiring the assessment of various criteria that allow for the classification and categorization of a project's resources. The evaluation elements consider the risk of geologic discovery and the technical uncertainties together with a determination of the chance of achieving the commercial maturation status of a petroleum project.

1.0.0.2 The technical estimation of petroleum resources quantities involves the assessment of quantities and values that have an inherent degree of uncertainty. These quantities are associated with exploration, appraisal, and development projects at various stages of design and implementation. The commercial aspects considered will relate the project's maturity status (e.g., technical, economical, regulatory, and legal) to the chance of project implementation.

1.0.0.3 The use of a consistent classification system enhances comparisons between projects, groups of projects, and total company portfolios. The application of PRMS must consider both technical and commercial factors that impact the project's feasibility, its productive life, and its related cash flows.

### 1.1 Petroleum Resources Classification Framework

1.1.0.1 Petroleum is defined as a naturally occurring mixture consisting of hydrocarbons in the gaseous, liquid, or solid state. Petroleum may also contain non-hydrocarbons, common examples of which are carbon dioxide, nitrogen, hydrogen sulfide, and sulfur. In rare cases, non-hydrocarbon content can be greater than 50%.

1.1.0.2 The term resources as used herein is intended to encompass all quantities of petroleum naturally occurring within the Earth's crust, both discovered and undiscovered (whether recoverable or unrecoverable), plus those quantities already produced. Further, it includes all types of petroleum whether currently considered as conventional or unconventional resources.

1.1.0.3 Figure 1.1 graphically represents the PRMS resources classification system. The system classifies resources into discovered and undiscovered and defines the recoverable resources classes: Production, Reserves, Contingent Resources, and Prospective Resources, as well as Unrecoverable Petroleum.

1.1.0.4 The horizontal axis reflects the range of uncertainty of estimated quantities potentially recoverable from an accumulation by a project, while the vertical axis represents the chance of commerciality, $P_c$, which is the chance that a project will be committed for development and reach commercial producing status.

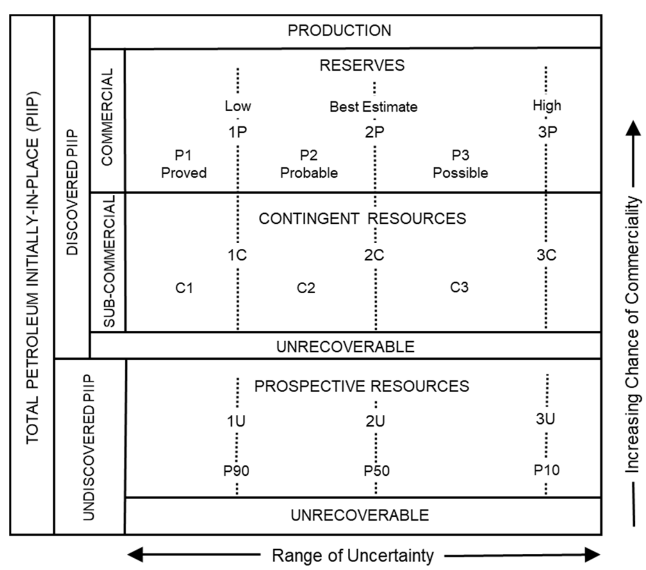


Figure 1.1—Resources classification framework

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1.1.0.5 The following definitions apply to the major subdivisions within the resources classification:

A. **Total Petroleum Initially-In-Place** (PIIP) is all quantities of petroleum that are estimated to exist originally in naturally occurring accumulations, discovered and undiscovered, before production.

B. **Discovered PIIP** is the quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations before production.

C. **Production** is the cumulative quantities of petroleum that have been recovered at a given date. While all recoverable resources are estimated, and production is measured in terms of the sales product specifications, raw production (sales plus non-sales) quantities are also measured and required to support engineering analyses based on reservoir voidage (see Section 3.2, Production Measurement).

1.1.0.6 Multiple development projects may be applied to each known or unknown accumulation, and each project will be forecast to recover an estimated portion of the initially-in-place quantities. The projects shall be subdivided into commercial, sub-commercial, and undiscovered, with the estimated recoverable quantities being classified as Reserves, Contingent Resources, or Prospective Resources respectively, as defined below.

A. 1. **Reserves** are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must satisfy four criteria: discovered, recoverable, commercial, and remaining (as of the evaluation's effective date) based on the development project(s) applied.

2. Reserves are recommended as sales quantities as metered at the reference point. Where the entity also recognizes quantities consumed in operations (CiO) (see Section 3.2.2), as Reserves these quantities must be recorded separately. Non-hydrocarbon quantities are recognized as Reserves only when sold together with hydrocarbons or CiO associated with petroleum production. If the non-hydrocarbon is separated before sales, it is excluded from Reserves.

3. Reserves are further categorized in accordance with the range of uncertainty and should be sub-classified based on project maturity and/or characterized by development and production status.

B. **Contingent Resources** are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, by the application of development project(s) not currently considered to be commercial owing to one or more contingencies. Contingent Resources have an associated chance of development. Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the range of uncertainty associated with the estimates and should be sub-classified based on project maturity and/or economic status.

C. **Undiscovered PIIP** is that quantity of petroleum estimated, as of a given date, to be contained within accumulations yet to be discovered.

D. **Prospective Resources** are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of geologic discovery and a chance of development. Prospective Resources are further categorized in accordance with the range of uncertainty associated with recoverable estimates, assuming discovery and development, and may be sub-classified based on project maturity.

E. **Unrecoverable Resources** are that portion of either discovered or undiscovered PIIP evaluated, as of a given date, to be unrecoverable by the currently defined project(s). A portion of these quantities may become recoverable in the future as commercial circumstances change, technology is developed, or additional data are acquired. The remaining portion may never be recovered because of physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

1.1.0.7 The sum of Reserves, Contingent Resources, and Prospective Resources may be referred to as "remaining recoverable resources." Importantly, these quantities should not be aggregated without due consideration of the technical and commercial risk involved with their classification. When such terms are used, each classification component of the summation must be provided.

1.1.0.8 Other terms used in resource assessments include the following:

A. **Estimated Ultimate Recovery (EUR)** is not a resources category or class, but a term that can be applied to an accumulation or group of accumulations (discovered or undiscovered) to define those quantities of petroleum estimated, as of a given date, to be potentially recoverable plus those quantities already produced from the accumulation or group of accumulations. For clarity, EUR must reference the associated technical and commercial conditions for the resources; for example, proved EUR is Proved Reserves plus prior production.

B. **Technically Recoverable Resources (TRR)** are those quantities of petroleum producible using currently available technology and industry practices, regardless of commercial considerations. TRR may be used for specific Projects or for groups of Projects, or, can be an undifferentiated estimate within an area (often basin-wide) of recovery potential.

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### 1.2 Project-Based Resources Evaluations

1.2.0.1 The resources evaluation process consists of identifying a recovery project or projects associated with one or more petroleum accumulations, estimating the quantities of PIIP, estimating that portion of those in-place quantities that can be recovered by each project, and classifying the project(s) based on maturity status or chance of commerciality.

1.2.0.2 The concept of a project-based classification system is further clarified by examining the elements contributing to an evaluation of net recoverable resources (see Figure 1.2).

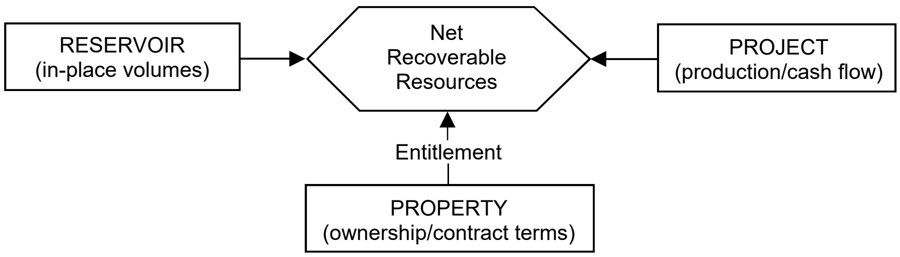


Figure 1.2—Resources evaluation

1.2.0.3 **The reservoir** (contains the petroleum accumulation): Key attributes include the types and quantities of PIIP and the fluid and rock properties that affect petroleum recovery.

1.2.0.4 **The project:** A project may constitute the development of a well, a single reservoir, or a small field; an incremental development in a producing field; or the integrated development of a field or several fields together with the associated processing facilities (e.g., compression). Within a project, a specific reservoir's development generates a unique production and cash-flow schedule at each level of certainty. The integration of these schedules taken to the project's earliest truncation caused by technical, economic, or the contractual limit defines the estimated recoverable resources and associated future net cash flow projections for each project. The ratio of EUR to total PIIP quantities defines the project's recovery efficiency. Each project should have an associated recoverable resources range (low, best, and high estimate).

1.2.0.5 **The property** (lease or license area): Each property may have unique associated contractual rights and obligations, including the fiscal terms. This information allows definition of each participating entity's share of produced quantities (entitlement) and share of investments, expenses, and revenues for each recovery project and the reservoir to which it is applied. One property may encompass many reservoirs, or one reservoir may span several different properties. A property may contain both discovered and undiscovered accumulations that may be spatially unrelated to a potential single field designation.

1.2.0.6 An entity's net recoverable resources are the entitlement share of future production legally accruing under the terms of the development and production contract or license.

1.2.0.7 In the context of this relationship, the project is the primary element considered in the resources classification, and the net recoverable resources are the quantities derived from each project. A project represents a defined activity or set of activities to develop the petroleum accumulation(s) and the decisions taken to mature the resources to reserves. In general, it is recommended that an individual project has assigned to it a specific maturity level sub-class (See Section 2.1.3.5, Project Maturity Sub-Classes) at which a decision is made whether or not to proceed (i.e., spend more money) and there should be an associated range of estimated recoverable quantities for the project (See Section 2.2.1, Range of Uncertainty). For completeness, a developed field is also considered to be a project.

1.2.0.8 An accumulation or potential accumulation of petroleum is often subject to several separate and distinct projects that are at different stages of exploration or development. Thus, an accumulation may have recoverable quantities in several resources classes simultaneously.

1.2.0.10 Not all technically feasible development projects will be commercial. The commercial viability of a development project within a field's development plan is dependent on a forecast of the conditions that will exist during the time period encompassed by the project (see Section 3.1, Assessment of Commerciality). Conditions include technical, economic (e.g., hurdle rates, commodity prices), operating and capital costs, marketing, sales route(s), and legal, environmental, social, and governmental factors forecast to exist and impact the project during the time period being evaluated. While economic factors can be summarized as forecast costs and product prices, the underlying influences include, but are not limited to, market conditions (e.g., inflation, market factors, and contingencies), exchange rates, transportation and processing infrastructure, fiscal terms, and taxes.

1.2.0.11 The resources being estimated are those quantities producible from a project as measured according to delivery specifications at the point of sale or custody transfer (see Section 3.2.1, Reference Point) and may permit forecasts of CiO quantities (see Section 3.2.2., Consumed in Operations). The cumulative production forecast from the effective date forward to cessation of production is the remaining recoverable resources quantity (see Section 3.1.1, Net Cash-Flow Evaluation).

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1.2.0.12 The supporting data, analytical processes, and assumptions describing the technical and commercial basis used in an evaluation must be documented in sufficient detail to allow, as needed, a qualified reserves evaluator or qualified reserves auditor to clearly understand each project's basis for the estimation, categorization, and classification of recoverable resources quantities and, if appropriate, associated commercial assessment.

## 2.0 Classification and Categorization Guidelines

### 2.1 Resources Classification

2.1.0.1 The PRMS classification establishes criteria for the classification of the total PIIP. A determination of a discovery differentiates between discovered and undiscovered PIIP. The application of a project further differentiates the recoverable from unrecoverable resources. The project is then evaluated to determine its maturity status to allow the classification distinction between commercial and sub-commercial projects. PRMS requires the project's recoverable resources quantities to be classified as either Reserves, Contingent Resources, or Prospective Resources.

#### 2.1.1 Determination of Discovery Status

2.1.1.1 A discovered petroleum accumulation is determined to exist when one or more exploratory wells have established through testing, sampling, and/or logging the existence of a significant quantity of potentially recoverable hydrocarbons and thus have established a known accumulation. In the absence of a flow test or sampling, the discovery determination requires confidence in the presence of hydrocarbons and evidence of producibility, which may be supported by suitable producing analogs (see Section 4.1.1, Analogs). In this context, "significant" implies that there is evidence of a sufficient quantity of petroleum to justify estimating the in-place quantity demonstrated by the well(s) and for evaluating the potential for commercial recovery.

2.1.1.2 Where a discovery has identified potentially recoverable hydrocarbons, but it is not considered viable to apply a project with established technology or with technology under development, such quantities may be classified as Discovered Unrecoverable with no Contingent Resources. In future evaluations, as appropriate for petroleum resources management purposes, a portion of these unrecoverable quantities may become recoverable resources as either commercial circumstances change or technological developments occur.

#### 2.1.2 Determination of Commerciality

2.1.2.1 Discovered recoverable quantities (Contingent Resources) may be considered commercially mature, and thus attain Reserves classification, if the entity claiming commerciality has demonstrated a firm intention to proceed with development. This means the entity has satisfied the internal decision criteria (typically rate of return at or above the weighted average cost-of-capital or the hurdle rate). Commerciality is achieved with the entity's commitment to the project and all of the following criteria:

A. Evidence of a technically mature, feasible development plan.
B. Evidence of financial appropriations either being in place or having a high likelihood of being secured to implement the project.
C. Evidence to support a reasonable time-frame for development.
D. A reasonable assessment that the development projects will have positive economics and meet defined investment and operating criteria. This assessment is performed on the estimated entitlement forecast quantities and associated cash flow on which the investment decision is made (see Section 3.1.1, Net Cash-Flow Evaluation).
E. A reasonable expectation that there will be a market for forecast sales quantities of the production required to justify development. There should also be similar confidence that all produced streams (e.g., oil, gas, water, CO2) can be sold, stored, re-injected, or otherwise appropriately disposed.
F. Evidence that the necessary production and transportation facilities are available or can be made available.
G. Evidence that legal, contractual, environmental, regulatory, and government approvals are in place or will be forthcoming, together with resolving any social and economic concerns.

2.1.2.2 The commerciality test for Reserves determination is applied to the best estimate (P50) forecast quantities, which upon qualifying all commercial and technical maturity criteria and constraints become the 2P Reserves. Stricter cases [e.g., low estimate (P90)] may be used for decision purposes or to investigate the range of commerciality (see Section 3.1.2, Economic Criteria). Typically, the low- and high-case project scenarios may be evaluated for sensitivities when considering project risk and upside opportunity.

2.1.2.3 To be included in the Reserves class, a project must be sufficiently defined to establish both its technical and commercial viability as noted in Section 2.1.2.1. There must be a reasonable expectation that all required internal and external approvals will be forthcoming and evidence of firm intention to proceed with development within a reasonable time-frame. A reasonable time-frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While five years is recommended as a benchmark, a longer time-frame could be applied where justifiable; for example, development of economic projects that take longer than five years to be developed or are deferred to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented.

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2.1.2.4 While PRMS guidelines require financial appropriations evidence, they do not require that project financing be confirmed before classifying projects as Reserves. However, this may be another external reporting requirement. In many cases, financing is conditional upon the same criteria as above. In general, if there is not a reasonable expectation that financing or other forms of commitment (e.g., farm-outs) can be arranged so that the development will be initiated within a reasonable time-frame, then the project should be classified as Contingent Resources. If financing is reasonably expected to be in place at the time of the final investment decision (FID), the project's resources may be classified as Reserves.

## 2.2 Resources Categorization

2.2.0.1 The horizontal axis in the resources classification in Figure 1.1 defines the range of uncertainty in estimates of the quantities of recoverable, or potentially recoverable, petroleum associated with a project or group of projects. These estimates include the uncertainty components as follows:

A. The total petroleum remaining within the accumulation (in-place resources).
B. The technical uncertainty in the portion of the total petroleum that can be recovered by applying a defined development project or projects (i.e., the technology applied).
C. Known variations in the commercial terms that may impact the quantities recovered and sold (e.g., market availability; contractual changes, such as production rate tiers or product quality specifications) are part of project's scope and are included in the horizontal axis, while the chance of satisfying the commercial terms is reflected in the classification (vertical axis).

2.2.0.2 The uncertainty in a project's recoverable quantities is reflected by the 1P, 2P, 3P, Proved (P1), Probable (P2), Possible (P3), 1C, 2C, 3C, C1, C2, and C3; or 1U, 2U, and 3U resources categories. The commercial chance of success is associated with resources classes or sub-classes and not with the resources categories reflecting the range of recoverable quantities.

### 2.2.1 Range of Uncertainty

2.2.1.1 Uncertainty is inherent in a project's resources estimation and is communicated in PRMS by reporting a range of category outcomes. The range of uncertainty of the recoverable and/or potentially recoverable quantities may be represented by either deterministic scenarios or by a probability distribution (see Section 4.2, Resources Assessment Methods).

2.2.1.2 When the range of uncertainty is represented by a probability distribution, a low, best, and high estimate shall be provided such that:

A. There should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate.
B. There should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate.
C. There should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

2.2.1.3 In some projects, the range of uncertainty may be limited, and the three scenarios may result in resources estimates that are not significantly different. In these situations, a single value estimate may be appropriate to describe the expected result.

2.2.1.4 When using the deterministic scenario method, typically there should also be low, best, and high estimates, where such estimates are based on qualitative assessments of relative uncertainty using consistent interpretation guidelines. Under the deterministic incremental method, quantities for each confidence segment are estimated discretely (see Section 2.2.2, Category Definitions and Guidelines).

2.2.1.5 Project resources are initially estimated using the above uncertainty range forecasts that incorporate the subsurface elements together with technical constraints related to wells and facilities. The technical forecasts then have additional commercial criteria applied (e.g., economics and license cutoffs are the most common) to estimate the entitlement quantities attributed and the resources classification status: Reserves, Contingent Resources, and Prospective Resources.

### 2.2.2 Category Definitions and Guidelines

2.2.2.1 Evaluators may assess recoverable quantities and categorize results by uncertainty using the deterministic incremental method, the deterministic scenario (cumulative) method, geostatistical methods, or probabilistic methods (see Section 4.2, Resources Assessment Methods). Also, combinations of these methods may be used.

2.2.2.2 Use of consistent terminology (Figures 1.1 and 2.1) promotes clarity in communication of evaluation results. For Reserves, the general cumulative terms low/best/high forecasts are used to estimate the resulting 1P/2P/3P quantities, respectively. The associated incremental quantities are termed Proved (P1), Probable (P2) and Possible (P3). Reserves are a subset of, and must be viewed within the context of, the complete resources classification system. While the categorization criteria are proposed specifically for Reserves, in most cases, the criteria can be equally applied to Contingent and Prospective Resources. Upon satisfying the commercial maturity criteria for discovery and/or development, the project quantities will then move to the appropriate resources sub-class. Table 3 provides criteria for the Reserves categories determination.

2.2.2.3 For Contingent Resources, the general cumulative terms low/best/high estimates are used to estimate the resulting 1C/2C/3C quantities, respectively. The terms C1, C2, and C3 are defined for incremental quantities of Contingent Resources.

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2.2.2.4 For Prospective Resources, the general cumulative terms low/best/high estimates also apply and are used to estimate the resulting 1U/2U/3U quantities. No specific terms are defined for incremental quantities within Prospective Resources.

2.2.2.5 Quantities in different classes and sub-classes cannot be aggregated without considering the varying degrees of technical uncertainty and commercial likelihood involved with the classification(s) and without considering the degree of dependency between them (see Section 4.2.1, Aggregating Resources Classes).

2.2.2.6 Without new technical information, there should be no change in the distribution of technically recoverable resources and the categorization boundaries when conditions are satisfied to reclassify a project from Contingent Resources to Reserves.

2.2.2.7 All evaluations require application of a consistent set of forecast conditions, including assumed future costs and prices, for both classification of projects and categorization of estimated quantities recovered by each project (see Section 3.1, Assessment of Commerciality).

### Table 1—Recoverable Resources Classes and Sub-Classes

| Class/Sub-Class | Definition | Guidelines |
|---|---|---|
| **Reserves** | Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. | Reserves must satisfy four criteria: discovered, recoverable, commercial, and remaining based on the development project(s) applied. Reserves are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by the development and production status.<br><br>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.<br><br>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.<br><br>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.<br><br>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.<br><br>The project decision gate is the decision to start investing capital in the construction of production facilities and/or drilling development wells. |

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| Class/Sub-Class | Definition | Guidelines |
|---|---|---|
| **Justified for Development** | Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals/contracts will be obtained. | To move to this level of project maturity, and hence have Reserves associated with it, the development project must be commercially viable at the time of reporting (see Section 2.1.2, Determination of Commerciality) and the specific circumstances of the project. All participating entities have agreed and there is evidence of a committed project (firm intention to proceed with development within a reasonable time-frame). There must be no known contingencies that could preclude the development from proceeding (see Reserves class).<br><br>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.<br><br>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.<br><br>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.<br><br>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.<br><br>This sub-class requires active appraisal or evaluation and should not be maintained without a plan for future evaluation. The sub-class should reflect the actions required to move a project toward commercial maturity and economic production. |

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| Class/Sub-Class | Definition | Guidelines |
|---|---|---|
| **Development Not Viable** | A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time because of limited production potential. | The project is not seen to have potential for eventual commercial development at the time of reporting, but the theoretically recoverable quantities are recorded so that the potential opportunity will be recognized in the event of a major change in technology or commercial conditions.<br><br>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.<br><br>In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well. |

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| Status | Definition | Guidelines |
|---|---|---|
| **Undeveloped Reserves** | Quantities expected to be recovered through future significant investments. | Undeveloped Reserves are to be produced (1) from new wells on undrilled acreage in known accumulations, (2) from deepening existing wells to a different (but known) reservoir, (3) from infill wells that will increase recovery, or (4) where a relatively large expenditure (e.g., when compared to the cost of drilling a new well) is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects. |

## Table 3—Reserves Category Definitions and Guidelines

| Category | Definition | Guidelines |
|---|---|---|
| **Proved Reserves** | Those quantities of petroleum that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable from a given date forward from known reservoirs and under defined economic conditions, operating methods, and government regulations. | If deterministic methods are used, the term "reasonable certainty" is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the estimate.<br><br>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.<br><br>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.<br><br>Reserves in undeveloped locations may be classified as Proved provided that:<br>A. The locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially mature and economically productive.<br>B. Interpretations of available geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with drilled Proved locations.<br><br>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.<br><br>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.<br><br>Probable estimates also include incremental recoveries associated with project recovery efficiencies beyond that assumed for Proved. |

## PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the Petroleum Resources Management System Approved by
the Society of Petroleum Engineers (SPE) Board of Directors, June 2018

| Category | Definition | Guidelines |
|---|---|---|
| **Possible Reserves** | Those additional reserves that analysis of geoscience and engineering data indicates are less likely to be recoverable than Probable Reserves. | The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high-estimate scenario. When probabilistic methods are used, there should be at least a 10% probability (P10) that the actual quantities recovered will equal or exceed the 3P estimate.<br><br>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.<br><br>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.<br><br>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.<br><br>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.<br><br>In conventional accumulations, where drilling has defined a highest known oil elevation and there exists the potential for an associated gas cap, Proved Reserves of oil should only be assigned in the structurally higher portions of the reservoir if there is reasonable certainty that such portions are initially above bubble point pressure based on documented engineering analyses. Reservoir portions that do not meet this certainty may be assigned as Probable and Possible oil and/or gas based on reservoir fluid properties and pressure gradient interpretations. |

NETHERLAND, SEWELL & ASSOCIATES, INC.

REVENUE, COSTS, AND TAXES
PROVED UNDEVELOPED RESERVES
DELEK DRILLING LIMITED PARTNERSHIP
LEVIATHAN FIELD, LEASES I/14 AND I/15, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2018

| | | Royalties | | | | | | | Net Revenue Before Levy and Corporate Income Taxes |
|---|---|---|---|---|---|---|---|---|---|
| Period Ending | Working Interest Revenue (M$) | State (M$) | Interested Party (M$) | Third Party (M$) | Total (M$) | Net Capital Costs (M$) | Net Abandonment Costs (M$) | Net Operating Expenses[1] (M$) | Discounted at 0% (M$) |
| 12-31-2019 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 707,614.1 | 0.0 | 0.0 | -707,614.1 |
| 12-31-2020 | 481,757.9 | 55,402.2 | 13,019.5 | 6,925.3 | 75,346.9 | 37,458.1 | 0.0 | 70,655.1 | 298,297.8 |
| 12-31-2021 | 523,721.6 | 60,228.0 | 14,153.6 | 7,528.5 | 81,910.1 | 0.0 | 0.0 | 70,987.2 | 370,824.4 |
| 12-31-2022 | 621,128.2 | 71,429.7 | 16,786.0 | 8,928.7 | 97,144.4 | 0.0 | 0.0 | 71,888.3 | 452,095.5 |
| 12-31-2023 | 628,910.7 | 72,324.7 | 16,996.3 | 9,040.6 | 98,361.6 | 0.0 | 0.0 | 66,788.1 | 463,760.9 |
| 12-31-2024 | 634,904.6 | 73,014.0 | 17,158.3 | 9,126.8 | 99,299.1 | 0.0 | 0.0 | 66,828.0 | 468,777.5 |
| 12-31-2025 | 638,085.8 | 73,379.9 | 17,244.3 | 9,172.5 | 99,796.6 | 0.0 | 0.0 | 66,841.0 | 471,448.2 |
| 12-31-2026 | 645,481.1 | 74,230.3 | 17,444.1 | 9,278.8 | 100,953.2 | 0.0 | 0.0 | 66,883.6 | 477,644.3 |
| 12-31-2027 | 657,319.4 | 75,591.7 | 44,328.2 | 9,449.0 | 129,368.9 | 0.0 | 0.0 | 66,951.7 | 460,998.8 |
| 12-31-2028 | 672,344.3 | 77,319.6 | 49,097.9 | 9,664.9 | 136,082.5 | 0.0 | 0.0 | 67,043.6 | 469,218.2 |
| 12-31-2029 | 680,949.6 | 78,309.2 | 49,726.3 | 9,788.7 | 137,824.2 | 0.0 | 0.0 | 87,694.9 | 455,430.5 |
| 12-31-2030 | 691,198.5 | 79,487.8 | 50,474.8 | 9,936.0 | 139,898.6 | 0.0 | 0.0 | 67,148.6 | 484,151.3 |
| 12-31-2031 | 703,193.4 | 80,867.2 | 51,350.7 | 10,108.4 | 142,326.3 | 0.0 | 0.0 | 67,216.0 | 493,651.1 |
| 12-31-2032 | 718,822.2 | 82,664.5 | 52,492.0 | 10,333.1 | 145,489.6 | 0.0 | 0.0 | 67,311.3 | 506,021.2 |
| 12-31-2033 | 731,427.7 | 84,114.2 | 53,412.5 | 10,514.3 | 148,041.0 | 0.0 | 0.0 | 67,378.6 | 516,008.1 |
| Subtotal | 9,029,244.9 | 1,038,363.2 | 463,684.5 | 129,795.4 | 1,631,843.1 | 745,072.2 | 0.0 | 971,615.9 | 5,680,713.7 |
| Remaining | 25,296,382.9 | 2,909,084.0 | 1,847,268.4 | 363,635.5 | 5,119,987.9 | 0.0 | 60,592.4 | 2,220,881.3 | 17,894,921.3 |
| Total | 34,325,627.8 | 3,947,447.2 | 2,310,952.9 | 493,430.9 | 6,751,831.0 | 745,072.2 | 60,592.4 | 3,192,497.3 | 23,575,635.0 |

| | | | | | | Future Net Revenue After Levy and Corporate Income Taxes | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Period Ending | Levy Rate (%) | Levy (M$) | Net Revenue After Levy and Before Corporate Income Taxes Discounted at 0% (M$) | Corporate Income Tax Rate[2] (%) | Corporate Income Taxes[2] (M$) | Discounted at 0% (M$) | Discounted at 5% (M$) | Discounted at 10% (M$) | Discounted at 15% (M$) | Discounted at 20% (M$) |
| 12-31-2019 | - | 0.0 | -707,614.1 | 23.0 | 0.0 | -707,614.1 | -690,560.7 | -674,683.6 | -659,853.6 | -645,960.3 |
| 12-31-2020 | - | 0.0 | 298,297.8 | 23.0 | 0.0 | 298,297.8 | 277,246.5 | 258,559.8 | 241,881.8 | 226,922.8 |
| 12-31-2021 | - | 0.0 | 370,824.4 | 23.0 | 20,264.5 | 350,559.9 | 310,305.2 | 276,236.2 | 247,182.5 | 222,233.3 |
| 12-31-2022 | - | 0.0 | 452,095.5 | 23.0 | 59,287.8 | 392,807.6 | 331,144.4 | 281,388.0 | 240,844.9 | 207,513.1 |
| 12-31-2023 | - | 0.0 | 463,760.9 | 23.0 | 61,970.9 | 401,790.0 | 322,587.3 | 261,656.8 | 214,219.4 | 176,882.0 |
| 12-31-2024 | - | 0.0 | 468,777.5 | 23.0 | 63,124.7 | 405,652.8 | 310,179.7 | 240,156.7 | 188,068.6 | 148,818.7 |
| 12-31-2025 | - | 0.0 | 471,448.2 | 23.0 | 63,739.0 | 407,709.2 | 296,906.8 | 219,431.1 | 164,367.0 | 124,644.3 |
| 12-31-2026 | - | 0.0 | 477,644.3 | 23.0 | 65,164.1 | 412,480.2 | 286,077.3 | 201,817.1 | 144,600.3 | 105,085.7 |
| 12-31-2027 | - | 0.0 | 460,998.8 | 23.0 | 61,335.6 | 399,663.2 | 263,988.6 | 177,769.1 | 121,832.3 | 84,850.3 |
| 12-31-2028 | - | 0.0 | 469,218.2 | 23.0 | 63,226.1 | 405,992.2 | 255,399.1 | 164,167.5 | 107,618.8 | 71,828.3 |
| 12-31-2029 | 14.7 | 67,091.5 | 388,339.1 | 23.0 | 44,623.9 | 343,715.2 | 205,926.0 | 126,350.1 | 79,226.7 | 50,675.2 |
| 12-31-2030 | 26.7 | 129,205.6 | 354,945.7 | 23.0 | 81,206.7 | 273,738.9 | 156,192.3 | 91,478.8 | 54,867.0 | 33,632.0 |
| 12-31-2031 | 31.5 | 155,734.1 | 337,917.0 | 23.0 | 77,720.9 | 260,196.1 | 141,395.1 | 79,048.2 | 45,350.0 | 26,640.1 |
| 12-31-2032 | 35.9 | 181,703.8 | 324,317.4 | 23.0 | 74,593.0 | 249,724.4 | 129,242.5 | 68,969.9 | 37,847.8 | 21,306.6 |
| 12-31-2033 | 40.0 | 206,369.1 | 309,639.0 | 23.0 | 71,217.0 | 238,422.0 | 117,517.2 | 59,862.2 | 31,421.6 | 16,951.9 |
| Subtotal | | 740,104.1 | 4,940,609.6 | | 807,474.1 | 4,133,135.5 | 2,713,547.2 | 1,832,207.9 | 1,259,475.2 | 872,024.0 |
| Remaining | | 8,379,629.8 | 9,515,291.5 | | 2,189,996.4 | 7,325,295.1 | 1,835,159.3 | 565,271.5 | 203,613.9 | 82,223.1 |
| Total | | 9,119,733.9 | 14,455,901.1 | | 2,997,470.5 | 11,458,430.6 | 4,548,706.6 | 2,397,479.4 | 1,463,089.1 | 954,247.1 |

Notes: Remaining represents estimates after December 31, 2033, through the end of production in 2064.
Totals may not add because of rounding.

(1) Operating costs are intended to include Delek Drilling's estimates of direct project-level costs, indirect headquarters general and administrative overhead expenses, and the portion of the operator's headquarters general and administrative overhead expenses that can be directly attributed to this project.

(2) Corporate income tax rates and estimates of corporate income taxes are provided by Delek Drilling and are its expected corporate income taxes per year.



*All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.*

NETHERLAND, SEWELL & ASSOCIATES, INC.

REVENUE, COSTS, AND TAXES
PROBABLE RESERVES
DELEK DRILLING LIMITED PARTNERSHIP
LEVIATHAN FIELD, LEASES I/14 AND I/15, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2018

| Period Ending | Working Interest Revenue (M$) | Royalties: State (M$) | Royalties: Interested Party (M$) | Royalties: Third Party (M$) | Royalties: Total (M$) | Net Capital Costs (M$) | Net Abandonment Costs (M$) | Net Operating Expenses[(1)] (M$) | Net Revenue Before Levy and Corporate Income Taxes Discounted at 0% (M$) |
|---|---|---|---|---|---|---|---|---|---|
| 12-31-2019 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 12-31-2020 | 421,419.4 | 48,463.2 | 11,388.9 | 6,057.9 | 65,910.0 | 0.0 | 0.0 | 3,920.0 | 351,589.3 |
| 12-31-2021 | 466,777.1 | 53,679.4 | 12,614.7 | 6,709.9 | 73,003.9 | 0.0 | 0.0 | 4,233.5 | 389,539.7 |
| 12-31-2022 | 306,309.8 | 35,225.6 | 8,278.0 | 4,403.2 | 47,906.9 | 0.0 | 0.0 | 2,659.7 | 255,743.3 |
| 12-31-2023 | 407,836.8 | 46,901.2 | 12,526.8 | 5,862.7 | 65,290.7 | 0.0 | 0.0 | 3,567.8 | 338,978.4 |
| 12-31-2024 | 524,004.7 | 60,260.5 | 67,471.1 | 7,532.6 | 135,264.2 | 0.0 | 0.0 | 4,585.4 | 384,155.2 |
| 12-31-2025 | 456,242.8 | 52,467.9 | 62,669.1 | 6,558.5 | 121,695.5 | 0.0 | 0.0 | 3,980.6 | 330,566.7 |
| 12-31-2026 | 417,007.5 | 47,955.9 | 60,144.1 | 5,994.5 | 114,094.4 | 0.0 | 0.0 | 3,591.3 | 299,321.7 |
| 12-31-2027 | 395,403.4 | 45,471.4 | 32,546.9 | 5,683.9 | 83,702.2 | 0.0 | 0.0 | 3,364.0 | 308,337.2 |
| 12-31-2028 | 390,095.2 | 44,860.9 | 28,486.7 | 5,607.6 | 78,955.3 | 0.0 | 0.0 | 3,292.5 | 307,847.4 |
| 12-31-2029 | 380,771.1 | 43,788.7 | 27,805.8 | 5,473.6 | 77,068.1 | 0.0 | 0.0 | 3,200.7 | 300,502.3 |
| 12-31-2030 | 372,243.2 | 42,808.0 | 27,183.1 | 5,351.0 | 75,342.0 | 0.0 | 0.0 | 3,111.8 | 293,789.4 |
| 12-31-2031 | 362,895.9 | 41,733.0 | 26,500.5 | 5,216.6 | 73,450.1 | 0.0 | 0.0 | 3,013.8 | 286,431.9 |
| 12-31-2032 | 348,622.4 | 40,091.6 | 25,458.1 | 5,011.4 | 70,561.2 | 0.0 | 0.0 | 2,874.9 | 275,186.3 |
| 12-31-2033 | 329,164.8 | 37,854.0 | 24,037.3 | 4,731.7 | 66,623.0 | 0.0 | 0.0 | 2,691.7 | 259,850.2 |
| Subtotal | 5,578,794.2 | 641,561.3 | 427,110.9 | 80,195.2 | 1,148,867.4 | 0.0 | 0.0 | 48,087.8 | 4,381,839.1 |
| Remaining | 7,789,546.9 | 895,797.9 | 568,831.7 | 111,974.7 | 1,576,604.3 | 0.0 | 0.0 | 62,723.4 | 6,150,219.2 |
| Total | 13,368,341.1 | 1,537,359.2 | 995,942.6 | 192,169.9 | 2,725,471.7 | 0.0 | 0.0 | 110,811.2 | 10,532,058.3 |

| Period Ending | Levy Rate (%) | Levy (M$) | Net Revenue After Levy and Before Corporate Income Taxes Discounted at 0% (M$) | Corporate Income Tax Rate[(2)] (%) | Corporate Income Taxes[(2)] (M$) | Future Net Revenue After Levy and Corporate Income Taxes: Discounted at 0% (M$) | Discounted at 5% (M$) | Discounted at 10% (M$) | Discounted at 15% (M$) | Discounted at 20% (M$) |
|---|---|---|---|---|---|---|---|---|---|---|
| 12-31-2019 | - | 0.0 | 0.0 | 23.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 12-31-2020 | - | 0.0 | 351,589.3 | 23.0 | 60,534.6 | 291,054.8 | 270,514.7 | 252,281.7 | 236,008.7 | 221,412.9 |
| 12-31-2021 | - | 0.0 | 389,539.7 | 23.0 | 109,925.1 | 279,614.6 | 247,506.5 | 220,332.3 | 197,158.4 | 177,258.3 |
| 12-31-2022 | - | 0.0 | 255,743.3 | 23.0 | 58,820.9 | 196,922.3 | 166,009.3 | 141,065.4 | 120,740.4 | 104,030.5 |
| 12-31-2023 | - | 0.0 | 338,978.4 | 23.0 | 77,965.0 | 261,013.4 | 209,561.2 | 169,979.1 | 139,162.6 | 114,907.2 |
| 12-31-2024 | - | 0.0 | 384,155.2 | 23.0 | 88,355.7 | 295,799.5 | 226,181.1 | 175,120.8 | 137,138.5 | 108,517.7 |
| 12-31-2025 | 18.4 | 165,561.3 | 165,005.4 | 23.0 | 37,951.2 | 127,054.1 | 92,524.8 | 68,381.1 | 51,221.6 | 38,842.8 |
| 12-31-2026 | 33.6 | 260,133.5 | 39,188.2 | 23.0 | 9,013.3 | 30,174.9 | 20,927.9 | 14,763.9 | 10,578.2 | 7,687.5 |
| 12-31-2027 | 42.1 | 315,131.2 | -6,794.0 | 23.0 | -1,562.6 | -5,231.4 | -3,455.5 | -2,326.9 | -1,594.7 | -1,110.6 |
| 12-31-2028 | 46.7 | 359,655.8 | -51,808.4 | 23.0 | -11,915.9 | -39,892.4 | -25,095.3 | -16,131.0 | -10,574.5 | -7,057.8 |
| 12-31-2029 | 46.8 | 286,685.1 | 13,817.2 | 23.0 | 3,178.0 | 10,639.3 | 6,374.2 | 3,911.0 | 2,452.4 | 1,568.6 |
| 12-31-2030 | 46.8 | 234,870.6 | 58,918.8 | 23.0 | 13,551.3 | 45,367.5 | 25,886.2 | 15,161.0 | 9,093.3 | 5,573.9 |
| 12-31-2031 | 46.8 | 209,344.7 | 77,087.2 | 23.0 | 17,730.1 | 59,357.1 | 32,255.7 | 18,032.9 | 10,345.5 | 6,077.3 |
| 12-31-2032 | 46.8 | 183,901.3 | 91,284.9 | 23.0 | 20,995.5 | 70,289.4 | 36,377.6 | 19,412.8 | 10,652.9 | 5,997.1 |
| 12-31-2033 | 46.8 | 156,732.5 | 103,117.6 | 23.0 | 23,717.1 | 79,400.6 | 39,136.2 | 19,935.6 | 10,464.2 | 5,645.4 |
| Subtotal | | 2,172,016.2 | 2,209,822.9 | | 508,259.3 | 1,701,563.6 | 1,344,704.6 | 1,099,919.8 | 922,847.2 | 789,350.8 |
| Remaining | | 2,880,622.9 | 3,269,596.3 | | 744,739.5 | 2,524,856.7 | 606,166.7 | 185,865.6 | 68,270.5 | 28,369.7 |
| Total | | 5,052,639.1 | 5,479,419.1 | | 1,252,998.8 | 4,226,420.4 | 1,950,871.3 | 1,285,785.3 | 991,117.6 | 817,720.5 |

Notes: Remaining represents estimates after December 31, 2033, through the end of production in 2064.
Totals may not add because of rounding.

(1) Operating costs are intended to include Delek Drilling's estimates of direct project-level costs, indirect headquarters general and administrative overhead expenses, and the portion of the operator's headquarters general and administrative overhead expenses that can be directly attributed to this project.

(2) Corporate income tax rates and estimates of corporate income taxes are provided by Delek Drilling and are its expected corporate income taxes per year.



*All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.*

REVENUE, COSTS, AND TAXES
PROVED + PROBABLE (2P) RESERVES
DELEK DRILLING LIMITED PARTNERSHIP
LEVIATHAN FIELD, LEASES I/14 AND I/15, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2018

| Period Ending | Working Interest Revenue (M$) | Royalties: State (M$) | Royalties: Interested Party (M$) | Royalties: Third Party (M$) | Royalties: Total (M$) | Net Capital Costs (M$) | Net Abandonment Costs (M$) | Net Operating Expenses[1] (M$) | Net Revenue Before Levy and Corporate Income Taxes Discounted at 0% (M$) |
|---|---|---|---|---|---|---|---|---|---|
| 12-31-2019 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 707,614.1 | 0.0 | 0.0 | -707,614.1 |
| 12-31-2020 | 903,177.2 | 103,865.4 | 24,408.4 | 12,983.2 | 141,256.9 | 37,458.1 | 0.0 | 74,575.1 | 649,887.1 |
| 12-31-2021 | 990,498.8 | 113,907.4 | 26,768.2 | 14,238.4 | 154,914.0 | 0.0 | 0.0 | 75,220.6 | 760,364.1 |
| 12-31-2022 | 927,438.0 | 106,655.4 | 25,064.0 | 13,331.9 | 145,051.3 | 0.0 | 0.0 | 74,548.0 | 707,838.7 |
| 12-31-2023 | 1,036,747.5 | 119,226.0 | 29,523.1 | 14,903.2 | 163,652.3 | 0.0 | 0.0 | 70,355.9 | 802,739.3 |
| 12-31-2024 | 1,158,909.3 | 133,274.6 | 84,629.4 | 16,659.3 | 234,563.2 | 0.0 | 0.0 | 71,413.3 | 852,932.7 |
| 12-31-2025 | 1,094,328.5 | 125,847.8 | 79,913.3 | 15,731.0 | 221,492.1 | 0.0 | 0.0 | 70,821.5 | 802,014.9 |
| 12-31-2026 | 1,062,488.6 | 122,186.2 | 77,588.2 | 15,273.3 | 215,047.7 | 0.0 | 0.0 | 70,474.9 | 776,966.0 |
| 12-31-2027 | 1,052,722.8 | 121,063.1 | 76,875.1 | 15,132.9 | 213,071.1 | 0.0 | 0.0 | 70,315.7 | 769,336.0 |
| 12-31-2028 | 1,062,439.6 | 122,180.5 | 77,584.6 | 15,272.6 | 215,037.8 | 0.0 | 0.0 | 70,336.1 | 777,065.7 |
| 12-31-2029 | 1,061,720.7 | 122,097.9 | 77,532.2 | 15,262.2 | 214,892.3 | 0.0 | 0.0 | 90,895.6 | 755,932.9 |
| 12-31-2030 | 1,063,441.7 | 122,295.8 | 77,657.8 | 15,287.0 | 215,240.6 | 0.0 | 0.0 | 70,260.4 | 777,940.7 |
| 12-31-2031 | 1,066,089.3 | 122,600.3 | 77,851.2 | 15,325.0 | 215,776.5 | 0.0 | 0.0 | 70,229.8 | 780,083.0 |
| 12-31-2032 | 1,067,444.5 | 122,756.1 | 77,950.1 | 15,344.5 | 216,050.8 | 0.0 | 0.0 | 70,186.3 | 781,207.5 |
| 12-31-2033 | 1,060,592.5 | 121,968.1 | 77,449.8 | 15,246.0 | 214,663.9 | 0.0 | 0.0 | 70,070.3 | 775,858.3 |
| Subtotal | 14,608,039.1 | 1,679,924.5 | 890,795.4 | 209,990.6 | 2,780,710.5 | 745,072.2 | 0.0 | 1,019,703.7 | 10,062,552.8 |
| Remaining | 33,085,929.8 | 3,804,881.9 | 2,416,100.0 | 475,610.2 | 6,696,592.2 | 0.0 | 60,592.4 | 2,283,604.7 | 24,045,140.5 |
| Total | 47,693,968.9 | 5,484,806.4 | 3,306,895.4 | 685,600.8 | 9,477,302.7 | 745,072.2 | 60,592.4 | 3,303,308.4 | 34,107,693.3 |

| Period Ending | Levy Rate (%) | Levy (M$) | Net Revenue After Levy and Before Corporate Income Taxes Discounted at 0% (M$) | Corporate Income Tax Rate[2] (%) | Corporate Income Taxes[2] (M$) | Future Net Revenue After Levy and Corporate Income Taxes: Discounted at 0% (M$) | Discounted at 5% (M$) | Discounted at 10% (M$) | Discounted at 15% (M$) | Discounted at 20% (M$) |
|---|---|---|---|---|---|---|---|---|---|---|
| 12-31-2019 | - | 0.0 | -707,614.1 | 23.0 | 0.0 | -707,614.1 | -690,560.7 | -674,683.6 | -659,853.6 | -645,960.3 |
| 12-31-2020 | - | 0.0 | 649,887.1 | 23.0 | 60,534.6 | 589,352.5 | 547,761.1 | 510,841.5 | 477,890.5 | 448,335.7 |
| 12-31-2021 | - | 0.0 | 760,364.1 | 23.0 | 130,189.6 | 630,174.5 | 557,811.6 | 496,568.4 | 444,340.8 | 399,491.7 |
| 12-31-2022 | - | 0.0 | 707,838.7 | 23.0 | 118,108.8 | 589,729.9 | 497,153.6 | 422,453.4 | 361,585.3 | 311,543.6 |
| 12-31-2023 | - | 0.0 | 802,739.3 | 23.0 | 139,935.9 | 662,803.4 | 532,148.5 | 431,636.0 | 353,382.0 | 291,789.1 |
| 12-31-2024 | - | 0.0 | 852,932.7 | 23.0 | 151,480.4 | 701,452.3 | 536,360.8 | 415,277.5 | 325,207.1 | 257,336.4 |
| 12-31-2025 | 20.6 | 165,561.3 | 636,453.6 | 23.0 | 101,690.2 | 534,763.4 | 389,431.6 | 287,812.2 | 215,588.5 | 163,487.1 |
| 12-31-2026 | 33.5 | 260,133.5 | 516,832.5 | 23.0 | 74,177.3 | 442,655.1 | 307,005.2 | 216,581.0 | 155,178.6 | 112,773.3 |
| 12-31-2027 | 41.0 | 315,131.2 | 454,204.8 | 23.0 | 59,773.0 | 394,431.8 | 260,533.1 | 175,442.2 | 120,237.6 | 83,739.7 |
| 12-31-2028 | 46.3 | 359,655.8 | 417,409.9 | 23.0 | 51,310.1 | 366,099.7 | 230,303.8 | 148,036.5 | 97,044.3 | 64,770.5 |
| 12-31-2029 | 46.8 | 353,776.6 | 402,156.3 | 23.0 | 47,801.8 | 354,354.5 | 212,300.1 | 130,261.1 | 81,679.0 | 52,243.8 |
| 12-31-2030 | 46.8 | 364,076.2 | 413,864.4 | 23.0 | 94,758.1 | 319,106.4 | 182,078.5 | 106,639.9 | 63,960.3 | 39,205.9 |
| 12-31-2031 | 46.8 | 365,078.9 | 415,004.2 | 23.0 | 95,451.0 | 319,553.2 | 173,650.9 | 97,081.1 | 55,695.5 | 32,717.3 |
| 12-31-2032 | 46.8 | 365,605.1 | 415,602.4 | 23.0 | 95,588.5 | 320,013.8 | 165,620.2 | 88,382.7 | 48,500.7 | 27,303.7 |
| 12-31-2033 | 46.8 | 363,101.7 | 412,756.6 | 23.0 | 94,934.0 | 317,822.6 | 156,653.4 | 79,797.8 | 41,885.7 | 22,597.3 |
| Subtotal | | 2,912,120.3 | 7,150,432.4 | | 1,315,733.4 | 5,834,699.1 | 4,058,251.8 | 2,932,127.7 | 2,182,322.4 | 1,661,374.8 |
| Remaining | | 11,260,252.7 | 12,784,887.8 | | 2,934,735.9 | 9,850,151.9 | 2,441,326.0 | 751,137.0 | 271,884.4 | 110,592.8 |
| Total | | 14,172,373.0 | 19,935,320.2 | | 4,250,469.3 | 15,684,851.0 | 6,499,577.9 | 3,683,264.7 | 2,454,206.8 | 1,771,967.6 |

Notes: Remaining represents estimates after December 31, 2033, through the end of production in 2064.
Totals may not add because of rounding.

[1] Operating costs are intended to include Delek Drilling's estimates of direct project-level costs, indirect headquarters general and administrative overhead expenses, and the portion of the operator's headquarters general and administrative overhead expenses that can be directly attributed to this project.

[2] Corporate income tax rates and estimates of corporate income taxes are provided by Delek Drilling and are its expected corporate income taxes per year.



*All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.*

**NETHERLAND, SEWELL & ASSOCIATES, INC.**

REVENUE, COSTS, AND TAXES
POSSIBLE RESERVES
DELEK DRILLING LIMITED PARTNERSHIP
LEVIATHAN FIELD, LEASES I/14 AND I/15, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2018

| Period Ending | Working Interest Revenue (M$) | Royalties: State (M$) | Royalties: Interested Party (M$) | Royalties: Third Party (M$) | Royalties: Total (M$) | Net Capital Costs (M$) | Net Abandonment Costs (M$) | Net Operating Expenses[1] (M$) | Net Revenue Before Levy and Corporate Income Taxes Discounted at 0% (M$) |
|---|---|---|---|---|---|---|---|---|---|
| 12-31-2019 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 12-31-2020 | 109,210.9 | 12,559.3 | 2,951.4 | 1,569.9 | 17,080.6 | 0.0 | 0.0 | 1,043.1 | 91,087.2 |
| 12-31-2021 | 132,076.2 | 15,188.8 | 3,569.4 | 1,898.6 | 20,656.7 | 0.0 | 0.0 | 1,229.9 | 110,189.6 |
| 12-31-2022 | 70,923.8 | 8,156.2 | 1,916.7 | 1,019.5 | 11,092.5 | 0.0 | 0.0 | 669.7 | 59,161.6 |
| 12-31-2023 | 140,996.0 | 16,214.5 | 28,498.8 | 2,026.8 | 46,740.2 | 0.0 | 0.0 | 1,253.8 | 93,002.1 |
| 12-31-2024 | 26,829.3 | 3,085.4 | 1,959.2 | 385.7 | 5,430.2 | 0.0 | 0.0 | 230.8 | 21,168.2 |
| 12-31-2025 | 91,610.5 | 10,535.2 | 6,689.9 | 1,316.9 | 18,542.0 | 0.0 | 0.0 | 795.5 | 72,273.1 |
| 12-31-2026 | 104,992.7 | 12,074.2 | 7,667.1 | 1,509.3 | 21,250.5 | 0.0 | 0.0 | 948.6 | 82,793.6 |
| 12-31-2027 | 103,599.9 | 11,914.0 | 7,565.4 | 1,489.2 | 20,968.6 | 0.0 | 0.0 | 955.6 | 81,675.7 |
| 12-31-2028 | 92,375.2 | 10,623.2 | 6,745.7 | 1,327.9 | 18,696.7 | 0.0 | 0.0 | 853.0 | 72,825.5 |
| 12-31-2029 | 81,621.6 | 9,386.5 | 5,960.4 | 1,173.3 | 16,520.2 | 0.0 | 0.0 | 736.1 | 64,365.3 |
| 12-31-2030 | 83,958.4 | 9,655.2 | 6,131.1 | 1,206.9 | 16,993.2 | 0.0 | 0.0 | 743.5 | 66,221.7 |
| 12-31-2031 | 88,239.8 | 10,147.6 | 6,443.7 | 1,268.4 | 17,859.7 | 0.0 | 0.0 | 765.0 | 69,615.1 |
| 12-31-2032 | 104,126.9 | 11,974.6 | 7,603.9 | 1,496.8 | 21,075.3 | 0.0 | 0.0 | 888.5 | 82,163.1 |
| 12-31-2033 | 119,976.2 | 13,797.3 | 8,761.3 | 1,724.7 | 24,283.2 | 0.0 | 0.0 | 1,007.8 | 94,685.2 |
| Subtotal | 1,350,537.4 | 155,311.8 | 102,463.9 | 19,414.0 | 277,189.6 | 0.0 | 0.0 | 12,120.8 | 1,061,227.0 |
| Remaining | 728,855.7 | 83,818.4 | 53,224.7 | 10,477.3 | 147,520.4 | 0.0 | 0.0 | 6,851.3 | 574,484.0 |
| Total | 2,079,393.1 | 239,130.2 | 155,688.6 | 29,891.3 | 424,710.0 | 0.0 | 0.0 | 18,972.1 | 1,635,711.0 |

| Period Ending | Levy Rate (%) | Levy (M$) | Net Revenue After Levy and Before Corporate Income Taxes Discounted at 0% (M$) | Corporate Income Tax Rate[2] (%) | Corporate Income Taxes[2] (M$) | Future Net Revenue After Levy and Corporate Income Taxes: Discounted at 0% (M$) | Discounted at 5% (M$) | Discounted at 10% (M$) | Discounted at 15% (M$) | Discounted at 20% (M$) |
|---|---|---|---|---|---|---|---|---|---|---|
| 12-31-2019 | - | 0.0 | 0.0 | 23.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 12-31-2020 | - | 0.0 | 91,087.2 | 23.0 | 20,950.1 | 70,137.2 | 65,187.5 | 60,793.8 | 56,872.4 | 53,355.2 |
| 12-31-2021 | - | 0.0 | 110,189.6 | 23.0 | 25,343.6 | 84,846.0 | 75,103.1 | 66,857.4 | 59,825.6 | 53,787.1 |
| 12-31-2022 | - | 0.0 | 59,161.6 | 23.0 | 13,607.2 | 45,554.4 | 38,403.3 | 32,632.9 | 27,931.1 | 24,065.6 |
| 12-31-2023 | - | 0.0 | 93,002.1 | 23.0 | 21,390.5 | 71,611.6 | 57,495.2 | 46,635.4 | 38,180.6 | 31,525.9 |
| 12-31-2024 | 3.5 | 63,579.6 | -42,411.4 | 23.0 | -9,754.6 | -32,656.7 | -24,970.8 | -19,333.6 | -15,140.3 | -11,980.5 |
| 12-31-2025 | 28.2 | 92,298.3 | -20,025.2 | 23.0 | -4,605.8 | -15,419.4 | -11,228.9 | -8,298.8 | -6,216.3 | -4,714.0 |
| 12-31-2026 | 38.7 | 75,966.7 | 6,826.9 | 23.0 | 1,570.2 | 5,256.7 | 3,645.8 | 2,572.0 | 1,842.8 | 1,339.2 |
| 12-31-2027 | 45.8 | 74,728.1 | 6,947.5 | 23.0 | 1,597.9 | 5,349.6 | 3,533.6 | 2,379.5 | 1,630.8 | 1,135.7 |
| 12-31-2028 | 46.8 | 38,093.3 | 34,732.3 | 23.0 | 7,988.4 | 26,743.8 | 16,823.8 | 10,814.2 | 7,089.2 | 4,731.5 |
| 12-31-2029 | 46.8 | 30,123.0 | 34,242.3 | 23.0 | 7,875.7 | 26,366.6 | 15,796.7 | 9,692.4 | 6,077.5 | 3,887.3 |
| 12-31-2030 | 46.8 | 30,991.8 | 35,230.0 | 23.0 | 8,102.9 | 27,127.1 | 15,478.4 | 9,065.4 | 5,437.2 | 3,332.9 |
| 12-31-2031 | 46.8 | 32,579.8 | 37,035.2 | 23.0 | 8,518.1 | 28,517.1 | 15,496.7 | 8,663.6 | 4,970.3 | 2,919.7 |
| 12-31-2032 | 46.8 | 38,452.3 | 43,710.8 | 23.0 | 10,053.5 | 33,657.3 | 17,419.0 | 9,295.6 | 5,101.0 | 2,871.7 |
| 12-31-2033 | 46.8 | 44,312.7 | 50,372.5 | 23.0 | 11,585.7 | 38,786.9 | 19,117.9 | 9,738.5 | 5,111.7 | 2,757.8 |
| Subtotal | | 521,125.6 | 540,101.4 | | 124,223.3 | 415,878.1 | 307,301.3 | 241,508.2 | 198,713.6 | 169,015.0 |
| Remaining | | 274,303.6 | 300,180.4 | | 71,717.5 | 228,462.9 | 147,089.1 | 64,959.2 | 27,959.7 | 12,443.8 |
| Total | | 795,429.2 | 840,281.8 | | 195,940.8 | 644,341.0 | 454,390.4 | 306,467.4 | 226,673.3 | 181,458.8 |

Notes: Remaining represents estimates after December 31, 2033, through the end of production in 2064.
Totals may not add because of rounding.

(1) Operating costs are intended to include Delek Drilling's estimates of direct project-level costs, indirect headquarters general and administrative overhead expenses, and the portion of the operator's headquarters general and administrative overhead expenses that can be directly attributed to this project.

(2) Corporate income tax rates and estimates of corporate income taxes are provided by Delek Drilling and are its expected corporate income taxes per year.

NETHERLAND, SEWELL & ASSOCIATES, INC.

REVENUE, COSTS, AND TAXES
PROVED + PROBABLE + POSSIBLE (3P) RESERVES
DELEK DRILLING LIMITED PARTNERSHIP
LEVIATHAN FIELD, LEASES I/14 AND I/15, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2018

| Period Ending | Working Interest Revenue (M$) | Royalties: State (M$) | Royalties: Interested Party (M$) | Royalties: Third Party (M$) | Royalties: Total (M$) | Net Capital Costs (M$) | Net Abandonment Costs (M$) | Net Operating Expenses[1] (M$) | Net Revenue Before Levy and Corporate Income Taxes Discounted at 0% (M$) |
|---|---|---|---|---|---|---|---|---|---|
| 12-31-2019 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 707,614.1 | 0.0 | 0.0 | -707,614.1 |
| 12-31-2020 | 1,012,388.1 | 116,424.6 | 27,359.8 | 14,553.1 | 158,337.5 | 37,458.1 | 0.0 | 75,618.2 | 740,974.3 |
| 12-31-2021 | 1,122,575.0 | 129,096.1 | 30,337.6 | 16,137.0 | 175,570.7 | 0.0 | 0.0 | 76,450.5 | 870,553.7 |
| 12-31-2022 | 998,361.8 | 114,811.6 | 26,980.7 | 14,351.5 | 156,143.8 | 0.0 | 0.0 | 75,217.7 | 767,000.3 |
| 12-31-2023 | 1,177,743.5 | 135,440.5 | 58,021.9 | 16,930.1 | 210,392.5 | 0.0 | 0.0 | 71,609.7 | 895,741.4 |
| 12-31-2024 | 1,185,738.6 | 136,359.9 | 86,588.6 | 17,045.0 | 239,993.5 | 0.0 | 0.0 | 71,644.1 | 874,101.0 |
| 12-31-2025 | 1,185,939.0 | 136,383.0 | 86,603.2 | 17,047.9 | 240,034.1 | 0.0 | 0.0 | 71,617.0 | 874,287.9 |
| 12-31-2026 | 1,167,481.3 | 134,260.3 | 85,255.3 | 16,782.5 | 236,298.2 | 0.0 | 0.0 | 71,423.5 | 859,759.6 |
| 12-31-2027 | 1,156,322.7 | 132,977.1 | 84,440.5 | 16,622.1 | 234,039.7 | 0.0 | 0.0 | 71,271.3 | 851,011.7 |
| 12-31-2028 | 1,154,814.8 | 132,803.7 | 84,330.4 | 16,600.5 | 233,734.5 | 0.0 | 0.0 | 71,189.1 | 849,891.2 |
| 12-31-2029 | 1,143,342.3 | 131,484.4 | 83,492.6 | 16,435.5 | 231,412.5 | 0.0 | 0.0 | 91,631.7 | 820,298.2 |
| 12-31-2030 | 1,147,400.1 | 131,951.0 | 83,788.9 | 16,493.9 | 232,233.8 | 0.0 | 0.0 | 71,003.9 | 844,162.4 |
| 12-31-2031 | 1,154,329.1 | 132,747.8 | 84,294.9 | 16,593.5 | 233,636.2 | 0.0 | 0.0 | 70,994.8 | 849,698.1 |
| 12-31-2032 | 1,171,571.5 | 134,730.7 | 85,554.0 | 16,841.3 | 237,126.1 | 0.0 | 0.0 | 71,074.8 | 863,370.6 |
| 12-31-2033 | 1,180,568.8 | 135,765.4 | 86,211.0 | 16,970.7 | 238,947.1 | 0.0 | 0.0 | 71,078.1 | 870,543.5 |
| Subtotal | 15,958,576.5 | 1,835,236.3 | 993,259.3 | 229,404.5 | 3,057,900.1 | 745,072.2 | 0.0 | 1,031,824.5 | 11,123,779.7 |
| Remaining | 33,814,785.5 | 3,888,700.3 | 2,469,324.7 | 486,087.5 | 6,844,112.6 | 0.0 | 60,592.4 | 2,290,456.1 | 24,619,624.5 |
| Total | 49,773,362.0 | 5,723,936.6 | 3,462,584.0 | 715,492.1 | 9,902,012.7 | 745,072.2 | 60,592.4 | 3,322,280.5 | 35,743,404.2 |

| Period Ending | Levy Rate (%) | Levy (M$) | Net Revenue After Levy and Before Corporate Income Taxes Discounted at 0% (M$) | Corporate Income Tax Rate[2] (%) | Corporate Income Taxes[2] (M$) | Future Net Revenue After Levy and Corporate Income Taxes: Discounted at 0% (M$) | Discounted at 5% (M$) | Discounted at 10% (M$) | Discounted at 15% (M$) | Discounted at 20% (M$) |
|---|---|---|---|---|---|---|---|---|---|---|
| 12-31-2019 | - | 0.0 | -707,614.1 | 23.0 | 0.0 | -707,614.1 | -690,560.7 | -674,683.6 | -659,853.6 | -645,960.3 |
| 12-31-2020 | - | 0.0 | 740,974.3 | 23.0 | 81,484.6 | 659,489.7 | 612,948.6 | 571,635.2 | 534,762.9 | 501,690.8 |
| 12-31-2021 | - | 0.0 | 870,553.7 | 23.0 | 155,533.2 | 715,020.5 | 632,914.8 | 563,425.9 | 504,166.4 | 453,278.8 |
| 12-31-2022 | - | 0.0 | 767,000.3 | 23.0 | 131,716.0 | 635,284.4 | 535,556.9 | 455,086.3 | 389,516.4 | 335,609.2 |
| 12-31-2023 | - | 0.0 | 895,741.4 | 23.0 | 161,326.4 | 734,415.0 | 589,643.7 | 478,271.4 | 391,562.6 | 323,315.0 |
| 12-31-2024 | 7.3 | 63,579.6 | 810,521.4 | 23.0 | 141,725.8 | 668,795.6 | 511,390.0 | 395,943.9 | 310,066.8 | 245,355.9 |
| 12-31-2025 | 29.5 | 257,859.6 | 616,428.3 | 23.0 | 97,084.4 | 519,343.9 | 378,202.7 | 279,513.4 | 209,372.2 | 158,773.1 |
| 12-31-2026 | 39.1 | 336,100.2 | 523,659.3 | 23.0 | 75,747.5 | 447,911.8 | 310,651.0 | 219,153.0 | 157,021.3 | 114,112.5 |
| 12-31-2027 | 45.8 | 389,859.3 | 461,152.3 | 23.0 | 61,370.9 | 399,781.4 | 264,066.6 | 177,821.7 | 121,868.4 | 84,875.4 |
| 12-31-2028 | 46.8 | 397,749.1 | 452,142.1 | 23.0 | 59,298.6 | 392,843.6 | 247,127.6 | 158,850.7 | 104,133.4 | 69,502.1 |
| 12-31-2029 | 46.8 | 383,899.5 | 436,398.6 | 23.0 | 55,677.6 | 380,721.1 | 228,096.8 | 139,953.5 | 87,756.6 | 56,131.1 |
| 12-31-2030 | 46.8 | 395,068.0 | 449,094.4 | 23.0 | 102,860.9 | 346,233.5 | 197,556.9 | 115,705.3 | 69,397.5 | 42,538.7 |
| 12-31-2031 | 46.8 | 397,658.7 | 452,039.4 | 23.0 | 103,969.1 | 348,070.3 | 189,147.6 | 105,744.7 | 60,665.8 | 35,637.0 |
| 12-31-2032 | 46.8 | 404,057.4 | 459,313.2 | 23.0 | 105,642.0 | 353,671.1 | 183,039.2 | 97,678.4 | 53,601.7 | 30,175.4 |
| 12-31-2033 | 46.8 | 407,414.4 | 463,129.2 | 23.0 | 106,519.7 | 356,609.5 | 175,771.3 | 89,536.3 | 46,997.4 | 25,355.1 |
| Subtotal | | 3,433,245.9 | 7,690,533.8 | | 1,439,956.7 | 6,250,577.1 | 4,365,553.1 | 3,173,635.9 | 2,381,035.9 | 1,830,389.8 |
| Remaining | | 11,534,556.3 | 13,085,068.2 | | 3,006,453.4 | 10,078,614.8 | 2,588,415.1 | 816,096.2 | 299,844.1 | 123,036.6 |
| Total | | 14,967,802.2 | 20,775,602.0 | | 4,446,410.1 | 16,329,191.9 | 6,953,968.3 | 3,989,732.1 | 2,680,880.0 | 1,953,426.5 |

Notes: Remaining represents estimates after December 31, 2033, through the end of production in 2064.
Totals may not add because of rounding.

[1] Operating costs are intended to include Delek Drilling's estimates of direct project-level costs, indirect headquarters general and administrative overhead expenses, and the portion of the operator's headquarters general and administrative overhead expenses that can be directly attributed to this project.

[2] Corporate income tax rates and estimates of corporate income taxes are provided by Delek Drilling and are its expected corporate income taxes per year.



*All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.*

CASH FLOW, COSTS, AND TAXES
PHASE 1 - FIRST STAGE
LOW ESTIMATE (1C) CONTINGENT RESOURCES
DELEK DRILLING LIMITED PARTNERSHIP
LEVIATHAN FIELD, LEASES I/14 AND I/15, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2018

| Period Ending | Working Interest Revenue (M$) | Royalties: State (M$) | Royalties: Interested Party (M$) | Royalties: Third Party (M$) | Royalties: Total (M$) | Net Capital Costs (M$) | Net Abandonment Costs (M$) | Net Operating Expenses[1] (M$) | Future Net Cash Flow Before Levy and Corporate Income Taxes Discounted at 0% (M$) |
|---|---|---|---|---|---|---|---|---|---|
| 12-31-2019 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 12-31-2020 | 530,630.3 | 61,022.5 | 14,340.3 | 7,627.8 | 82,990.6 | 0.0 | 0.0 | 4,963.1 | 442,676.6 |
| 12-31-2021 | 597,779.7 | 68,744.7 | 16,155.0 | 8,593.1 | 93,492.7 | 0.0 | 0.0 | 5,453.9 | 498,833.0 |
| 12-31-2022 | 377,233.6 | 43,381.9 | 10,194.7 | 5,422.7 | 58,999.3 | 0.0 | 0.0 | 3,329.4 | 314,904.9 |
| 12-31-2023 | 537,012.0 | 61,756.4 | 39,376.8 | 7,719.5 | 108,852.8 | 0.0 | 0.0 | 4,719.4 | 423,439.8 |
| 12-31-2024 | 563,901.0 | 64,848.6 | 70,384.5 | 8,106.1 | 143,339.2 | 174,014.9 | 0.0 | 4,928.6 | 241,618.4 |
| 12-31-2025 | 567,549.1 | 65,268.2 | 70,797.2 | 8,158.5 | 144,223.9 | 0.0 | 0.0 | 4,945.0 | 418,380.3 |
| 12-31-2026 | 573,097.1 | 65,906.2 | 71,542.5 | 8,238.3 | 145,687.0 | 0.0 | 0.0 | 4,976.5 | 422,433.7 |
| 12-31-2027 | 583,341.6 | 67,084.3 | 46,271.1 | 8,385.5 | 121,740.9 | 0.0 | 0.0 | 5,036.0 | 456,564.7 |
| 12-31-2028 | 594,749.9 | 68,396.2 | 43,431.6 | 8,549.5 | 120,377.4 | 0.0 | 0.0 | 5,106.3 | 469,266.2 |
| 12-31-2029 | 601,266.9 | 69,145.7 | 43,907.5 | 8,643.2 | 121,696.4 | 0.0 | 0.0 | 5,139.2 | 474,431.3 |
| 12-31-2030 | 608,919.1 | 70,025.7 | 44,466.3 | 8,753.2 | 123,245.2 | 0.0 | 0.0 | 5,181.6 | 480,492.3 |
| 12-31-2031 | 621,425.2 | 71,463.9 | 45,379.6 | 8,933.0 | 125,776.5 | 0.0 | 0.0 | 5,255.3 | 490,393.4 |
| 12-31-2032 | 636,330.8 | 73,178.0 | 46,468.1 | 9,147.3 | 128,793.4 | 0.0 | 0.0 | 5,345.8 | 502,191.7 |
| 12-31-2033 | 647,689.3 | 74,484.3 | 47,297.5 | 9,310.5 | 131,092.3 | 0.0 | 0.0 | 5,406.6 | 511,190.4 |
| Subtotal | 8,040,925.5 | 924,706.4 | 610,012.8 | 115,588.3 | 1,650,307.5 | 174,014.9 | 0.0 | 69,786.5 | 6,146,816.6 |
| Remaining | 16,326,518.3 | 1,877,549.6 | 1,192,244.0 | 234,693.7 | 3,304,487.3 | 1,268,477.2 | 99,702.7 | 133,509.3 | 11,520,341.8 |
| Total | 24,367,443.9 | 2,802,256.0 | 1,802,256.8 | 350,282.0 | 4,954,794.8 | 1,442,492.1 | 99,702.7 | 203,295.9 | 17,667,158.4 |

| Period Ending | Levy Rate (%) | Levy (M$) | Future Net Cash Flow After Levy and Before Corporate Income Taxes Discounted at 0% (M$) | Corporate Income Tax Rate[2] (%) | Corporate Income Taxes[2] (M$) | Future Net Cash Flow After Levy and Corporate Income Taxes: Discounted at 0% (M$) | Discounted at 5% (M$) | Discounted at 10% (M$) | Discounted at 15% (M$) | Discounted at 20% (M$) |
|---|---|---|---|---|---|---|---|---|---|---|
| 12-31-2019 | - | 0.0 | 0.0 | 23.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 12-31-2020 | - | 0.0 | 442,676.6 | 23.0 | 81,484.6 | 361,192.0 | 335,702.1 | 313,075.5 | 292,881.1 | 274,768.0 |
| 12-31-2021 | - | 0.0 | 498,833.0 | 23.0 | 135,062.6 | 363,770.4 | 321,998.7 | 286,645.9 | 256,497.3 | 230,608.0 |
| 12-31-2022 | - | 0.0 | 314,904.9 | 23.0 | 72,428.1 | 242,476.7 | 204,412.5 | 173,698.3 | 148,671.5 | 128,096.0 |
| 12-31-2023 | - | 0.0 | 423,439.8 | 23.0 | 97,391.2 | 326,048.6 | 261,776.4 | 212,331.9 | 173,837.0 | 143,538.0 |
| 12-31-2024 | 3.5 | 24,542.4 | 217,076.0 | 23.0 | 87,949.7 | 129,126.2 | 98,735.5 | 76,446.0 | 59,865.5 | 47,371.6 |
| 12-31-2025 | 27.7 | 246,401.1 | 171,979.2 | 23.0 | 35,552.9 | 136,426.3 | 99,350.0 | 73,425.3 | 54,999.9 | 41,708.1 |
| 12-31-2026 | 38.0 | 342,229.5 | 80,204.2 | 23.0 | 14,444.6 | 65,759.5 | 45,607.8 | 32,174.6 | 23,052.9 | 16,753.3 |
| 12-31-2027 | 45.5 | 417,799.1 | 38,765.6 | 23.0 | 4,913.7 | 33,851.9 | 22,360.1 | 15,057.2 | 10,319.3 | 7,186.9 |
| 12-31-2028 | 46.8 | 439,210.7 | 30,055.5 | 23.0 | 2,910.4 | 27,145.1 | 17,076.3 | 10,976.4 | 7,195.5 | 4,802.5 |
| 12-31-2029 | 46.8 | 368,083.9 | 106,347.5 | 23.0 | 20,457.6 | 85,889.9 | 51,458.2 | 31,573.2 | 19,797.7 | 12,663.1 |
| 12-31-2030 | 46.8 | 322,247.6 | 158,244.7 | 23.0 | 32,393.9 | 125,850.8 | 71,809.0 | 42,057.2 | 25,225.0 | 15,462.2 |
| 12-31-2031 | 46.8 | 304,798.7 | 185,594.7 | 23.0 | 38,684.4 | 146,910.3 | 79,833.6 | 44,631.7 | 25,605.3 | 15,041.3 |
| 12-31-2032 | 46.8 | 290,139.9 | 212,051.8 | 23.0 | 44,769.6 | 167,282.2 | 86,575.4 | 46,200.7 | 25,353.0 | 14,272.6 |
| 12-31-2033 | 46.8 | 274,359.8 | 236,830.6 | 23.0 | 50,468.7 | 186,361.9 | 91,857.0 | 46,791.1 | 24,560.6 | 13,250.4 |
| Subtotal | | 3,029,812.5 | 3,117,004.0 | | 718,912.1 | 2,398,091.9 | 1,788,552.7 | 1,405,085.1 | 1,147,861.4 | 965,521.9 |
| Remaining | | 5,452,291.2 | 6,068,050.6 | | 1,402,085.5 | 4,665,965.2 | 1,307,795.3 | 430,257.8 | 160,541.1 | 66,006.5 |
| Total | | 8,482,103.8 | 9,185,054.6 | | 2,120,997.6 | 7,064,057.1 | 3,096,347.9 | 1,835,342.9 | 1,308,402.4 | 1,031,528.4 |

Notes: Remaining represents estimates after December 31, 2033, through the end of production in 2064.
Totals may not add because of rounding.

[1] Operating costs are intended to include Delek Drilling's estimates of direct project-level costs, indirect headquarters general and administrative overhead expenses, and the portion of the operator's headquarters general and administrative overhead expenses that can be directly attributed to this project.

[2] Corporate income tax rates and estimates of corporate income taxes are provided by Delek Drilling and are its expected corporate income taxes per year.



*All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.*

NETHERLAND, SEWELL & ASSOCIATES, INC.

CASH FLOW, COSTS, AND TAXES
PHASE 1 - FIRST STAGE
BEST ESTIMATE (2C) CONTINGENT RESOURCES
DELEK DRILLING LIMITED PARTNERSHIP
LEVIATHAN FIELD, LEASES I/14 AND I/15, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2018

| Period Ending | Working Interest Revenue (M$) | Royalties: State (M$) | Royalties: Interested Party (M$) | Royalties: Third Party (M$) | Royalties: Total (M$) | Net Capital Costs (M$) | Net Abandonment Costs (M$) | Net Operating Expenses[1] (M$) | Future Net Cash Flow Before Levy and Corporate Income Taxes Discounted at 0% (M$) |
|---|---|---|---|---|---|---|---|---|---|
| 12-31-2019 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 12-31-2020 | 109,210.9 | 12,559.3 | 2,951.4 | 1,569.9 | 17,080.6 | 0.0 | 0.0 | 1,043.1 | 91,087.2 |
| 12-31-2021 | 130,769.0 | 15,038.4 | 3,534.0 | 1,879.8 | 20,452.3 | 0.0 | 0.0 | 1,218.4 | 109,098.3 |
| 12-31-2022 | 70,923.6 | 8,156.2 | 1,916.7 | 1,019.5 | 11,092.5 | 0.0 | 0.0 | 669.7 | 59,161.5 |
| 12-31-2023 | 127,569.1 | 14,670.5 | 26,712.5 | 1,833.8 | 43,216.7 | 0.0 | 0.0 | 1,137.8 | 83,214.6 |
| 12-31-2024 | 39,975.5 | 4,597.2 | 2,919.2 | 574.6 | 8,091.0 | 174,014.9 | 0.0 | 343.9 | -142,474.3 |
| 12-31-2025 | 111,405.4 | 12,811.6 | 8,135.4 | 1,601.5 | 22,548.5 | 0.0 | 0.0 | 965.2 | 87,891.7 |
| 12-31-2026 | 156,268.7 | 17,970.9 | 11,411.5 | 2,246.4 | 31,628.8 | 0.0 | 0.0 | 1,386.7 | 123,253.2 |
| 12-31-2027 | 187,966.1 | 21,616.1 | 13,726.2 | 2,702.0 | 38,044.3 | 0.0 | 0.0 | 1,672.2 | 148,249.6 |
| 12-31-2028 | 204,679.8 | 23,538.2 | 14,946.7 | 2,942.3 | 41,427.2 | 0.0 | 0.0 | 1,814.0 | 161,438.7 |
| 12-31-2029 | 220,515.6 | 25,359.3 | 16,103.1 | 3,169.9 | 44,632.3 | 0.0 | 0.0 | 1,938.6 | 173,944.6 |
| 12-31-2030 | 236,684.2 | 27,218.7 | 17,283.9 | 3,402.3 | 47,904.9 | 0.0 | 0.0 | 2,069.8 | 186,709.5 |
| 12-31-2031 | 258,527.5 | 29,730.7 | 18,879.0 | 3,716.3 | 52,326.0 | 0.0 | 0.0 | 2,241.4 | 203,960.1 |
| 12-31-2032 | 287,711.9 | 33,086.9 | 21,010.2 | 4,135.9 | 58,232.9 | 0.0 | 0.0 | 2,470.9 | 227,008.2 |
| 12-31-2033 | 318,529.8 | 36,630.9 | 23,260.6 | 4,578.9 | 64,470.4 | 0.0 | 0.0 | 2,714.9 | 251,340.2 |
| Subtotal | 2,460,737.2 | 282,984.8 | 182,790.5 | 35,373.1 | 501,148.4 | 174,014.9 | 0.0 | 21,686.6 | 1,763,883.0 |
| Remaining | 13,983,458.1 | 1,608,097.7 | 1,021,142.0 | 201,012.2 | 2,830,251.9 | 1,268,477.2 | 99,702.7 | 113,165.6 | 9,671,865.0 |
| Total | 16,444,195.3 | 1,891,082.5 | 1,203,932.5 | 236,385.3 | 3,331,400.3 | 1,442,492.1 | 99,702.7 | 134,852.2 | 11,435,748.0 |

| Period Ending | Levy Rate (%) | Levy (M$) | Future Net Cash Flow After Levy and Before Corporate Income Taxes Discounted at 0% (M$) | Corporate Income Tax Rate[2] (%) | Corporate Income Taxes[2] (M$) | Future Net Cash Flow After Levy and Corporate Income Taxes: Discounted at 0% (M$) | Discounted at 5% (M$) | Discounted at 10% (M$) | Discounted at 15% (M$) | Discounted at 20% (M$) |
|---|---|---|---|---|---|---|---|---|---|---|
| 12-31-2019 | - | 0.0 | 0.0 | 23.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 12-31-2020 | - | 0.0 | 91,087.2 | 23.0 | 20,950.1 | 70,137.2 | 65,187.5 | 60,793.8 | 56,872.4 | 53,355.2 |
| 12-31-2021 | - | 0.0 | 109,098.3 | 23.0 | 25,092.6 | 84,005.7 | 74,359.3 | 66,195.3 | 59,233.0 | 53,254.4 |
| 12-31-2022 | - | 0.0 | 59,161.5 | 23.0 | 13,607.1 | 45,554.3 | 38,403.2 | 32,632.9 | 27,931.1 | 24,065.5 |
| 12-31-2023 | - | 0.0 | 83,214.6 | 23.0 | 19,139.4 | 64,075.3 | 51,444.5 | 41,727.6 | 34,162.5 | 28,208.2 |
| 12-31-2024 | 3.5 | 24,520.7 | -166,995.0 | 23.0 | -386.6 | -166,608.4 | -127,396.0 | -98,636.4 | -77,242.9 | -61,122.4 |
| 12-31-2025 | 27.7 | 80,688.8 | 7,202.9 | 23.0 | -2,345.7 | 9,548.6 | 6,953.6 | 5,139.1 | 3,849.5 | 2,919.2 |
| 12-31-2026 | 38.0 | 82,000.6 | 41,252.7 | 23.0 | 5,485.8 | 35,766.9 | 24,806.3 | 17,499.9 | 12,538.6 | 9,112.2 |
| 12-31-2027 | 45.5 | 102,602.0 | 45,647.6 | 23.0 | 6,496.6 | 39,151.0 | 25,860.3 | 17,414.3 | 11,934.7 | 8,311.9 |
| 12-31-2028 | 46.8 | 79,564.2 | 81,874.4 | 23.0 | 14,828.8 | 67,045.7 | 42,176.7 | 27,110.7 | 17,772.2 | 11,861.8 |
| 12-31-2029 | 46.8 | 81,406.1 | 92,538.5 | 23.0 | 17,281.5 | 75,257.0 | 45,087.8 | 27,664.6 | 17,346.8 | 11,095.4 |
| 12-31-2030 | 46.8 | 87,380.0 | 99,329.4 | 23.0 | 18,843.4 | 80,486.0 | 45,924.4 | 26,897.0 | 16,132.3 | 9,888.6 |
| 12-31-2031 | 46.8 | 95,453.3 | 108,506.8 | 23.0 | 20,954.2 | 87,552.6 | 47,577.6 | 26,598.7 | 15,259.7 | 8,964.0 |
| 12-31-2032 | 46.8 | 106,239.8 | 120,768.3 | 23.0 | 23,774.4 | 96,994.0 | 50,198.3 | 26,788.2 | 14,700.2 | 8,275.6 |
| 12-31-2033 | 46.8 | 117,629.2 | 133,715.2 | 23.0 | 26,752.2 | 106,963.1 | 52,721.7 | 26,855.9 | 14,096.6 | 7,605.1 |
| Subtotal | | 857,484.7 | 906,402.5 | | 210,473.7 | 695,928.8 | 443,305.1 | 304,681.5 | 224,586.6 | 175,794.7 |
| Remaining | | 4,554,262.1 | 5,117,598.6 | | 1,173,436.5 | 3,944,162.1 | 951,334.8 | 285,268.5 | 100,979.9 | 40,294.8 |
| Total | | 5,411,746.9 | 6,024,001.1 | | 1,383,910.3 | 4,640,090.8 | 1,394,639.9 | 589,949.9 | 325,566.5 | 216,089.5 |

Notes: Remaining represents estimates after December 31, 2033, through the end of production in 2064.
Totals may not add because of rounding.

[1] Operating costs are intended to include Delek Drilling's estimates of direct project-level costs, indirect headquarters general and administrative overhead expenses, and the portion of the operator's headquarters general and administrative overhead expenses that can be directly attributed to this project.

[2] Corporate income tax rates and estimates of corporate income taxes are provided by Delek Drilling and are its expected corporate income taxes per year.

Table VII

*All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.*

CASH FLOW, COSTS, AND TAXES
PHASE 1 - FIRST STAGE
HIGH ESTIMATE (3C) CONTINGENT RESOURCES
DELEK DRILLING LIMITED PARTNERSHIP
LEVIATHAN FIELD, LEASES I/14 AND I/15, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2018

| Period Ending | Working Interest Revenue (M$) | Royalties: State (M$) | Royalties: Interested Party (M$) | Royalties: Third Party (M$) | Royalties: Total (M$) | Net Capital Costs (M$) | Net Abandonment Costs (M$) | Net Operating Expenses[1] (M$) | Future Net Cash Flow Before Levy and Corporate Income Taxes Discounted at 0% (M$) |
|---|---|---|---|---|---|---|---|---|---|
| 12-31-2019 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 12-31-2020 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 12-31-2021 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 12-31-2022 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 12-31-2023 | 0.0 | 0.0 | -672.4 | 0.0 | -672.4 | 0.0 | 0.0 | 0.0 | 672.4 |
| 12-31-2024 | 13,067.0 | 1,502.7 | 954.2 | 187.8 | 2,644.8 | 174,014.9 | 0.0 | 112.4 | -163,705.1 |
| 12-31-2025 | 19,695.5 | 2,265.0 | 1,438.3 | 283.1 | 3,986.4 | 0.0 | 0.0 | 168.9 | 15,540.2 |
| 12-31-2026 | 51,385.2 | 5,909.3 | 3,752.4 | 738.7 | 10,400.4 | 0.0 | 0.0 | 439.0 | 40,545.8 |
| 12-31-2027 | 84,442.2 | 9,710.9 | 6,166.4 | 1,213.9 | 17,091.1 | 0.0 | 0.0 | 717.3 | 66,633.9 |
| 12-31-2028 | 112,268.8 | 12,910.9 | 8,198.4 | 1,613.9 | 22,723.2 | 0.0 | 0.0 | 960.7 | 88,584.9 |
| 12-31-2029 | 138,912.1 | 15,974.9 | 10,144.1 | 1,996.9 | 28,115.8 | 0.0 | 0.0 | 1,202.7 | 109,593.6 |
| 12-31-2030 | 152,723.3 | 17,563.2 | 11,152.6 | 2,195.4 | 30,911.2 | 0.0 | 0.0 | 1,326.3 | 120,485.8 |
| 12-31-2031 | 170,446.1 | 19,601.3 | 12,446.8 | 2,450.2 | 34,498.3 | 0.0 | 0.0 | 1,477.8 | 134,470.0 |
| 12-31-2032 | 183,781.2 | 21,134.8 | 13,420.6 | 2,641.9 | 37,197.3 | 0.0 | 0.0 | 1,584.0 | 144,999.9 |
| 12-31-2033 | 199,098.1 | 22,896.3 | 14,539.1 | 2,862.0 | 40,297.4 | 0.0 | 0.0 | 1,707.1 | 156,655.0 |
| Subtotal | 1,125,819.4 | 129,469.2 | 81,540.6 | 16,183.7 | 227,193.5 | 174,014.9 | 0.0 | 9,696.1 | 714,476.4 |
| Remaining | 15,785,149.7 | 1,815,292.2 | 1,152,710.6 | 226,911.5 | 3,194,914.3 | 1,268,477.2 | 99,702.7 | 125,842.6 | 11,096,651.6 |
| Total | 16,910,969.2 | 1,944,761.5 | 1,234,251.1 | 243,095.2 | 3,422,107.8 | 1,442,492.1 | 99,702.7 | 135,538.7 | 11,811,127.9 |

| Period Ending | Levy Rate (%) | Levy (M$) | Future Net Cash Flow After Levy and Before Corporate Income Taxes Discounted at 0% (M$) | Corporate Income Tax Rate[2] (%) | Corporate Income Taxes[2] (M$) | Future Net Cash Flow After Levy and Corporate Income Taxes: Discounted at 0% (M$) | Discounted at 5% (M$) | Discounted at 10% (M$) | Discounted at 15% (M$) | Discounted at 20% (M$) |
|---|---|---|---|---|---|---|---|---|---|---|
| 12-31-2019 | - | 0.0 | 0.0 | 23.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 12-31-2020 | - | 0.0 | 0.0 | 23.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 12-31-2021 | - | 0.0 | 0.0 | 23.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 12-31-2022 | - | 0.0 | 0.0 | 23.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 12-31-2023 | - | 0.0 | 672.4 | 23.0 | 154.7 | 517.7 | 415.7 | 337.2 | 276.0 | 227.9 |
| 12-31-2024 | 3.5 | -38,863.0 | -124,842.1 | 23.0 | 9,308.6 | -134,150.7 | -102,577.4 | -79,420.6 | -62,194.9 | -49,214.8 |
| 12-31-2025 | 27.8 | -10,161.6 | 25,701.8 | 23.0 | 1,909.1 | 23,792.7 | 17,326.6 | 12,805.4 | 9,592.0 | 7,273.9 |
| 12-31-2026 | 38.2 | 7,444.4 | 33,101.4 | 23.0 | 3,611.0 | 29,490.5 | 20,453.2 | 14,429.0 | 10,338.3 | 7,513.2 |
| 12-31-2027 | 45.6 | 28,640.7 | 37,993.2 | 23.0 | 4,736.1 | 33,257.1 | 21,967.2 | 14,792.7 | 10,138.0 | 7,060.6 |
| 12-31-2028 | 46.8 | 41,457.7 | 47,127.2 | 23.0 | 6,836.9 | 40,290.3 | 25,345.6 | 16,291.8 | 10,680.0 | 7,128.2 |
| 12-31-2029 | 46.8 | 51,289.8 | 58,303.8 | 23.0 | 9,407.5 | 48,896.2 | 29,294.6 | 17,974.3 | 11,270.6 | 7,209.0 |
| 12-31-2030 | 46.8 | 56,387.3 | 64,098.4 | 23.0 | 10,740.3 | 53,358.1 | 30,445.5 | 17,831.4 | 10,694.9 | 6,555.7 |
| 12-31-2031 | 46.8 | 62,932.0 | 71,538.1 | 23.0 | 12,451.4 | 59,086.6 | 32,108.7 | 17,950.7 | 10,298.3 | 6,049.6 |
| 12-31-2032 | 46.8 | 67,860.0 | 77,140.0 | 23.0 | 13,739.8 | 63,400.1 | 32,812.1 | 17,510.1 | 9,608.8 | 5,409.3 |
| 12-31-2033 | 46.8 | 73,517.7 | 83,571.3 | 23.0 | 15,219.1 | 68,352.3 | 33,690.6 | 17,161.7 | 9,008.1 | 4,859.9 |
| Subtotal | | 340,504.9 | 374,405.5 | | 88,114.4 | 286,291.0 | 141,282.5 | 67,663.6 | 29,710.1 | 10,072.3 |
| Remaining | | 5,195,257.5 | 5,900,960.0 | | 1,395,585.0 | 4,505,375.1 | 967,043.3 | 263,354.8 | 87,201.9 | 33,384.3 |
| Total | | 5,535,762.4 | 6,275,365.5 | | 1,483,699.4 | 4,791,666.1 | 1,108,325.8 | 331,018.3 | 116,912.0 | 43,456.6 |

Notes: Remaining represents estimates after December 31, 2033, through the end of production in 2064.
Totals may not add because of rounding.

[1] Operating costs are intended to include Delek Drilling's estimates of direct project-level costs, indirect headquarters general and administrative overhead expenses, and the portion of the operator's headquarters general and administrative overhead expenses that can be directly attributed to this project.

[2] Corporate income tax rates and estimates of corporate income taxes are provided by Delek Drilling and are its expected corporate income taxes per year.

Table VIII

*All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.*

NETHERLAND, SEWELL & ASSOCIATES, INC.

VOLUMETRIC INPUT SUMMARY
ORIGINAL GAS-IN-PLACE
LEVIATHAN FIELD, LEASES I/14 AND I/15, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2018

| | Gross Rock Volume (acre-feet) | | | Area (acres) | | | Average Gross Thickness[1] (feet) | | | Net-to-Gross Ratio (decimal) | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Reservoir | Low Estimate | Best Estimate | High Estimate | Low Estimate | Best Estimate | High Estimate | Low Estimate | Best Estimate | High Estimate | Low Estimate | Best Estimate | High Estimate |
| A Sand | 10,743,043 | 10,858,904 | 10,858,904 | 82,537 | 83,135 | 83,135 | 130 | 131 | 131 | 0.71 | 0.81 | 0.87 |
| B Sand | 4,674,890 | 4,777,327 | 4,777,327 | 41,177 | 41,840 | 41,840 | 114 | 114 | 114 | 0.30 | 0.34 | 0.39 |
| C Sand | 1,930,119 | 2,011,165 | 2,058,811 | 19,413 | 19,799 | 20,020 | 99 | 102 | 103 | 0.66 | 0.73 | 0.74 |

| | Porosity[2] (decimal) | | | Gas Saturation (decimal) | | | Gas Formation Volume Factor (SCF/RCF)[3] | | | Gas Recovery Factor (decimal) | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Reservoir | Low Estimate | Best Estimate | High Estimate | Low Estimate | Best Estimate | High Estimate | Low Estimate | Best Estimate | High Estimate | Low Estimate | Best Estimate | High Estimate |
| A Sand | 0.23 | 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, well test data, and property ownership interests.

(1) Average gross thickness is calculated by dividing the gross rock volume by the area.
(2) The increasing net-to-gross ratio between cases includes lower porosity rock which results in a lower porosity in the best and high estimate cases relative to the low estimate case.
(3) The abbreviation SCF/RCF represents standard cubic feet per reservoir cubic foot.



*All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.*

CASH FLOW, COSTS, AND TAXES
PHASE 1 - FIRST STAGE LOW ESTIMATE (1C) CONTINGENT RESOURCES (INCLUDING 1P RESERVES)
DELEK DRILLING LIMITED PARTNERSHIP
LEVIATHAN FIELD, LEASES I/14 AND I/15, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2018

| Period Ending | Working Interest Revenue (M$) | Royalties: State (M$) | Royalties: Interested Party (M$) | Royalties: Third Party (M$) | Royalties: Total (M$) | Net Capital Costs (M$) | Net Abandonment Costs (M$) | Net Operating Expenses[1] (M$) | Future Net Cash Flow Before Levy and Corporate Income Taxes Discounted at 0% (M$) |
|---|---|---|---|---|---|---|---|---|---|
| 12-31-2019 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 707,614.1 | 0.0 | 0.0 | -707,614.1 |
| 12-31-2020 | 1,012,388.1 | 116,424.6 | 27,359.8 | 14,553.1 | 158,337.5 | 37,458.1 | 0.0 | 75,618.2 | 740,974.3 |
| 12-31-2021 | 1,121,501.3 | 128,972.7 | 30,308.6 | 16,121.6 | 175,402.8 | 0.0 | 0.0 | 76,441.1 | 869,657.4 |
| 12-31-2022 | 998,361.8 | 114,811.6 | 26,980.7 | 14,351.5 | 156,143.8 | 0.0 | 0.0 | 75,217.7 | 767,000.3 |
| 12-31-2023 | 1,165,922.6 | 134,081.1 | 56,373.1 | 16,760.1 | 207,214.4 | 0.0 | 0.0 | 71,507.5 | 887,200.7 |
| 12-31-2024 | 1,198,805.6 | 137,862.6 | 87,542.8 | 17,232.8 | 242,638.2 | 174,014.9 | 0.0 | 71,756.5 | 710,395.9 |
| 12-31-2025 | 1,205,634.9 | 138,648.0 | 88,041.5 | 17,331.0 | 244,020.5 | 0.0 | 0.0 | 71,785.9 | 889,828.5 |
| 12-31-2026 | 1,218,578.2 | 140,136.5 | 88,986.7 | 17,517.1 | 246,640.2 | 0.0 | 0.0 | 71,860.0 | 900,077.9 |
| 12-31-2027 | 1,240,661.0 | 142,676.0 | 90,599.3 | 17,834.5 | 251,109.8 | 0.0 | 0.0 | 71,987.7 | 917,563.5 |
| 12-31-2028 | 1,267,094.2 | 145,715.8 | 92,529.6 | 18,214.5 | 256,459.9 | 0.0 | 0.0 | 72,149.9 | 938,484.5 |
| 12-31-2029 | 1,282,216.6 | 147,454.9 | 93,633.9 | 18,431.9 | 259,520.6 | 0.0 | 0.0 | 92,834.1 | 929,861.8 |
| 12-31-2030 | 1,300,117.5 | 149,513.5 | 94,941.1 | 18,689.2 | 263,143.8 | 0.0 | 0.0 | 72,330.2 | 964,643.6 |
| 12-31-2031 | 1,324,618.6 | 152,331.1 | 96,730.3 | 19,041.4 | 268,102.8 | 0.0 | 0.0 | 72,471.3 | 984,044.5 |
| 12-31-2032 | 1,355,153.0 | 155,842.6 | 98,960.0 | 19,480.3 | 274,283.0 | 0.0 | 0.0 | 72,657.1 | 1,008,212.9 |
| 12-31-2033 | 1,379,117.0 | 158,598.5 | 100,710.0 | 19,824.8 | 279,133.3 | 0.0 | 0.0 | 72,785.2 | 1,027,198.5 |
| Subtotal | 17,070,170.4 | 1,963,069.6 | 1,073,697.3 | 245,383.7 | 3,282,150.6 | 919,087.1 | 0.0 | 1,041,402.5 | 11,827,530.3 |
| Remaining | 41,622,901.3 | 4,786,633.6 | 3,039,512.4 | 598,329.2 | 8,424,475.2 | 1,268,477.2 | 160,295.0 | 2,354,390.7 | 29,415,263.2 |
| Total | 58,693,071.7 | 6,749,703.2 | 4,113,209.6 | 843,712.9 | 11,706,625.8 | 2,187,564.3 | 160,295.0 | 3,395,793.1 | 41,242,793.4 |

| Period Ending | Levy Rate (%) | Levy (M$) | Future Net Cash Flow After Levy and Before Corporate Income Taxes Discounted at 0% (M$) | Corporate Income Tax Rate[2] (%) | Corporate Income Taxes[2] (M$) | Future Net Cash Flow After Levy and Corporate Income Taxes: Discounted at 0% (M$) | Discounted at 5% (M$) | Discounted at 10% (M$) | Discounted at 15% (M$) | Discounted at 20% (M$) |
|---|---|---|---|---|---|---|---|---|---|---|
| 12-31-2019 | - | 0.0 | -707,614.1 | 23.0 | 0.0 | -707,614.1 | -690,560.7 | -674,683.6 | -659,853.6 | -645,960.3 |
| 12-31-2020 | - | 0.0 | 740,974.3 | 23.0 | 81,484.6 | 659,489.7 | 612,948.6 | 571,635.2 | 534,762.9 | 501,690.8 |
| 12-31-2021 | - | 0.0 | 869,657.4 | 23.0 | 155,327.1 | 714,330.3 | 632,303.9 | 562,882.0 | 503,679.8 | 452,841.3 |
| 12-31-2022 | - | 0.0 | 767,000.3 | 23.0 | 131,716.0 | 635,284.4 | 535,556.9 | 455,086.3 | 389,516.4 | 335,609.2 |
| 12-31-2023 | - | 0.0 | 887,200.7 | 23.0 | 159,362.0 | 727,838.7 | 584,363.8 | 473,988.8 | 388,056.4 | 320,419.9 |
| 12-31-2024 | 3.5 | 24,542.4 | 685,853.5 | 23.0 | 151,074.4 | 534,779.0 | 408,915.2 | 316,602.7 | 247,934.1 | 196,190.3 |
| 12-31-2025 | 27.7 | 246,401.1 | 643,427.4 | 23.0 | 99,291.8 | 544,135.6 | 396,256.7 | 292,856.4 | 219,366.9 | 166,352.4 |
| 12-31-2026 | 38.0 | 342,229.5 | 557,848.5 | 23.0 | 79,608.7 | 478,239.8 | 331,685.1 | 233,991.8 | 167,653.2 | 121,839.0 |
| 12-31-2027 | 45.5 | 417,799.1 | 499,764.4 | 23.0 | 66,249.3 | 433,515.1 | 286,348.6 | 192,826.3 | 132,151.6 | 92,037.2 |
| 12-31-2028 | 46.8 | 439,210.7 | 499,273.7 | 23.0 | 66,136.5 | 433,137.2 | 272,475.3 | 175,143.9 | 114,814.3 | 76,630.9 |
| 12-31-2029 | 46.8 | 435,175.3 | 494,686.5 | 23.0 | 65,081.4 | 429,605.1 | 257,384.1 | 157,923.3 | 99,024.4 | 63,338.3 |
| 12-31-2030 | 46.8 | 451,453.2 | 513,190.4 | 23.0 | 113,600.7 | 399,589.7 | 228,001.3 | 133,536.0 | 80,092.0 | 49,094.2 |
| 12-31-2031 | 46.8 | 460,532.8 | 523,511.7 | 23.0 | 116,405.3 | 407,106.3 | 221,228.8 | 123,679.9 | 70,955.3 | 41,681.4 |
| 12-31-2032 | 46.8 | 471,843.6 | 536,369.3 | 23.0 | 119,362.6 | 417,006.7 | 215,817.9 | 115,170.6 | 63,200.7 | 35,579.2 |
| 12-31-2033 | 46.8 | 480,728.9 | 546,469.6 | 23.0 | 121,685.7 | 424,784.0 | 209,374.2 | 106,653.3 | 55,982.1 | 30,202.3 |
| Subtotal | | 3,769,916.7 | 8,057,613.6 | | 1,526,386.2 | 6,531,227.4 | 4,502,099.9 | 3,237,293.0 | 2,407,336.6 | 1,837,546.0 |
| Remaining | | 13,831,921.0 | 15,583,342.1 | | 3,592,081.9 | 11,991,260.3 | 3,142,954.6 | 995,529.3 | 364,155.0 | 148,229.5 |
| Total | | 17,601,837.7 | 23,640,955.7 | | 5,118,468.1 | 18,522,487.7 | 7,645,054.5 | 4,232,822.2 | 2,771,491.6 | 1,985,775.5 |

Notes As requested, cash flows presented in this table include revenue and costs from 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, 2033, through the end of production in 2064.

Totals may not add because of rounding.

(1) Operating costs are intended to include Delek Drilling's estimates of direct project-level costs, indirect headquarters general and administrative overhead expenses, and the portion of the operator's headquarters general and administrative overhead expenses that can be directly attributed to this project.

(2) Corporate income tax rates and estimates of corporate income taxes are provided by Delek Drilling and are its expected corporate income taxes per year.

NETHERLAND, SEWELL & ASSOCIATES, INC.

CASH FLOW, COSTS, AND TAXES
PHASE 1 - FIRST STAGE BEST ESTIMATE (2C) CONTINGENT RESOURCES (INCLUDING 2P RESERVES)
DELEK DRILLING LIMITED PARTNERSHIP
LEVIATHAN FIELD, LEASES I/14 AND I/15, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2018

| Period Ending | Working Interest Revenue (M$) | Royalties: State (M$) | Royalties: Interested Party (M$) | Royalties: Third Party (M$) | Royalties: Total (M$) | Net Capital Costs (M$) | Net Abandonment Costs (M$) | Net Operating Expenses[1] (M$) | Future Net Cash Flow Before Levy and Corporate Income Taxes Discounted at 0% (M$) |
|---|---|---|---|---|---|---|---|---|---|
| 12-31-2019 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 707,614.1 | 0.0 | 0.0 | -707,614.1 |
| 12-31-2020 | 1,012,388.1 | 116,424.6 | 27,359.8 | 14,553.1 | 158,337.5 | 37,458.1 | 0.0 | 75,618.2 | 740,974.3 |
| 12-31-2021 | 1,121,267.7 | 128,945.8 | 30,302.3 | 16,118.2 | 175,366.3 | 0.0 | 0.0 | 76,439.1 | 869,462.4 |
| 12-31-2022 | 998,361.7 | 114,811.6 | 26,980.7 | 14,351.4 | 156,143.8 | 0.0 | 0.0 | 75,217.7 | 767,000.2 |
| 12-31-2023 | 1,164,316.6 | 133,896.4 | 56,235.6 | 16,737.1 | 206,869.0 | 0.0 | 0.0 | 71,493.7 | 885,953.9 |
| 12-31-2024 | 1,198,884.8 | 137,871.8 | 87,548.6 | 17,234.0 | 242,654.3 | 174,014.9 | 0.0 | 71,757.2 | 710,458.4 |
| 12-31-2025 | 1,205,733.9 | 138,659.4 | 88,048.7 | 17,332.4 | 244,040.5 | 0.0 | 0.0 | 71,786.8 | 889,906.6 |
| 12-31-2026 | 1,218,757.3 | 140,157.1 | 88,999.7 | 17,519.6 | 246,676.5 | 0.0 | 0.0 | 71,861.6 | 900,219.2 |
| 12-31-2027 | 1,240,689.0 | 142,679.2 | 90,601.3 | 17,834.9 | 251,115.4 | 0.0 | 0.0 | 71,987.9 | 917,585.6 |
| 12-31-2028 | 1,267,119.4 | 145,718.7 | 92,531.4 | 18,214.8 | 256,465.0 | 0.0 | 0.0 | 72,150.1 | 938,504.3 |
| 12-31-2029 | 1,282,236.3 | 147,457.2 | 93,635.3 | 18,432.1 | 259,524.6 | 0.0 | 0.0 | 92,834.2 | 929,877.4 |
| 12-31-2030 | 1,300,125.9 | 149,514.5 | 94,941.7 | 18,689.3 | 263,145.5 | 0.0 | 0.0 | 72,330.2 | 964,650.2 |
| 12-31-2031 | 1,324,616.9 | 152,330.9 | 96,730.1 | 19,041.4 | 268,102.5 | 0.0 | 0.0 | 72,471.3 | 984,043.1 |
| 12-31-2032 | 1,355,156.4 | 155,843.0 | 98,960.3 | 19,480.4 | 274,283.7 | 0.0 | 0.0 | 72,657.1 | 1,008,215.6 |
| 12-31-2033 | 1,379,122.3 | 158,599.1 | 100,710.4 | 19,824.9 | 279,134.4 | 0.0 | 0.0 | 72,785.2 | 1,027,198.5 |
| Subtotal | 17,068,776.3 | 1,962,909.3 | 1,073,585.9 | 245,363.7 | 3,281,858.9 | 919,087.1 | 0.0 | 1,041,390.3 | 11,826,435.8 |
| Remaining | 47,069,387.9 | 5,412,979.6 | 3,437,242.1 | 676,622.5 | 9,526,844.1 | 1,268,477.2 | 160,295.0 | 2,396,770.3 | 33,717,005.5 |
| Total | 64,138,164.2 | 7,375,888.9 | 4,510,828.0 | 921,986.1 | 12,808,703.0 | 2,187,564.3 | 160,295.0 | 3,438,160.6 | 45,543,441.3 |

| Period Ending | Levy Rate (%) | Levy (M$) | Future Net Cash Flow After Levy and Before Corporate Income Taxes Discounted at 0% (M$) | Corporate Income Tax Rate[2] (%) | Corporate Income Taxes[2] (M$) | Future Net Cash Flow After Levy and Corporate Income Taxes: Discounted at 0% (M$) | Discounted at 5% (M$) | Discounted at 10% (M$) | Discounted at 15% (M$) | Discounted at 20% (M$) |
|---|---|---|---|---|---|---|---|---|---|---|
| 12-31-2019 | - | 0.0 | -707,614.1 | 23.0 | 0.0 | -707,614.1 | -690,560.7 | -674,683.6 | -659,853.6 | -645,960.3 |
| 12-31-2020 | - | 0.0 | 740,974.3 | 23.0 | 81,484.6 | 659,489.7 | 612,948.6 | 571,635.2 | 534,762.9 | 501,690.8 |
| 12-31-2021 | - | 0.0 | 869,462.4 | 23.0 | 155,282.2 | 714,180.2 | 632,171.0 | 562,763.7 | 503,573.9 | 452,746.1 |
| 12-31-2022 | - | 0.0 | 767,000.2 | 23.0 | 131,715.9 | 635,284.3 | 535,556.8 | 455,086.2 | 389,516.3 | 335,609.1 |
| 12-31-2023 | - | 0.0 | 885,953.9 | 23.0 | 159,075.3 | 726,878.7 | 583,593.0 | 473,363.6 | 387,544.6 | 319,997.3 |
| 12-31-2024 | 3.5 | 24,520.7 | 685,937.7 | 23.0 | 151,093.8 | 534,843.9 | 408,964.8 | 316,641.1 | 247,964.2 | 196,214.1 |
| 12-31-2025 | 27.7 | 246,250.1 | 643,656.4 | 23.0 | 99,344.5 | 544,311.9 | 396,385.2 | 292,951.3 | 219,438.0 | 166,406.3 |
| 12-31-2026 | 38.0 | 342,134.1 | 558,085.1 | 23.0 | 79,663.1 | 478,422.0 | 331,811.5 | 234,080.9 | 167,717.1 | 121,885.4 |
| 12-31-2027 | 45.5 | 417,733.2 | 499,852.4 | 23.0 | 66,269.6 | 433,582.8 | 286,393.4 | 192,856.5 | 132,172.3 | 92,051.6 |
| 12-31-2028 | 46.8 | 439,220.0 | 499,284.3 | 23.0 | 66,138.9 | 433,145.4 | 272,480.4 | 175,147.2 | 114,816.5 | 76,632.3 |
| 12-31-2029 | 46.8 | 435,182.6 | 494,694.8 | 23.0 | 65,083.3 | 429,611.5 | 257,388.0 | 157,925.6 | 99,025.8 | 63,339.2 |
| 12-31-2030 | 46.8 | 451,456.3 | 513,193.9 | 23.0 | 113,601.5 | 399,592.4 | 228,002.9 | 133,536.9 | 80,092.5 | 49,094.5 |
| 12-31-2031 | 46.8 | 460,532.2 | 523,510.9 | 23.0 | 116,405.2 | 407,105.8 | 221,228.5 | 123,679.8 | 70,955.2 | 41,681.3 |
| 12-31-2032 | 46.8 | 471,844.9 | 536,370.7 | 23.0 | 119,362.9 | 417,007.8 | 215,818.5 | 115,170.9 | 63,200.9 | 35,579.3 |
| 12-31-2033 | 46.8 | 480,730.9 | 546,471.9 | 23.0 | 121,686.2 | 424,785.7 | 209,375.1 | 106,653.7 | 55,982.4 | 30,202.4 |
| Subtotal | | 3,769,605.0 | 8,056,834.9 | | 1,526,207.1 | 6,530,627.8 | 4,501,556.9 | 3,236,809.1 | 2,406,909.0 | 1,837,169.5 |
| Remaining | | 15,814,514.9 | 17,902,486.4 | | 4,108,172.5 | 13,794,314.0 | 3,392,660.9 | 1,036,405.5 | 372,864.3 | 150,887.6 |
| Total | | 19,584,119.9 | 25,959,321.4 | | 5,634,379.6 | 20,324,941.8 | 7,894,217.8 | 4,273,214.6 | 2,779,773.3 | 1,988,057.1 |

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, 2033, through the end of production in 2064.

Totals may not add because of rounding.

[1] Operating costs are intended to include Delek Drilling's estimates of direct project-level costs, indirect headquarters general and administrative overhead expenses, and the portion of the operator's headquarters general and administrative overhead expenses that can be directly attributed to this project.

[2] Corporate income tax rates and estimates of corporate income taxes are provided by Delek Drilling and are its expected corporate income taxes per year.



*All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.*

CASH FLOW, COSTS, AND TAXES
PHASE 1 - FIRST STAGE HIGH ESTIMATE (3C) CONTINGENT RESOURCES (INCLUDING 3P RESERVES)
DELEK DRILLING LIMITED PARTNERSHIP
LEVIATHAN FIELD, LEASES I/14 AND I/15, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2018

| Period Ending | Working Interest Revenue (M$) | Royalties: State (M$) | Royalties: Interested Party (M$) | Royalties: Third Party (M$) | Royalties: Total (M$) | Net Capital Costs (M$) | Net Abandonment Costs (M$) | Net Operating Expenses[1] (M$) | Future Net Cash Flow Before Levy and Corporate Income Taxes Discounted at 0% (M$) |
|---|---|---|---|---|---|---|---|---|---|
| 12-31-2019 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 707,614.1 | 0.0 | 0.0 | -707,614.1 |
| 12-31-2020 | 1,012,388.1 | 116,424.6 | 27,359.8 | 14,553.1 | 158,337.5 | 37,458.1 | 0.0 | 75,618.2 | 740,974.3 |
| 12-31-2021 | 1,122,575.0 | 129,096.1 | 30,337.6 | 16,137.0 | 175,570.7 | 0.0 | 0.0 | 76,450.5 | 870,553.7 |
| 12-31-2022 | 998,361.8 | 114,811.6 | 26,980.7 | 14,351.5 | 156,143.8 | 0.0 | 0.0 | 75,217.7 | 767,000.3 |
| 12-31-2023 | 1,177,743.5 | 135,440.5 | 57,349.5 | 16,930.1 | 209,720.1 | 0.0 | 0.0 | 71,609.7 | 896,413.8 |
| 12-31-2024 | 1,198,805.6 | 137,862.6 | 87,542.8 | 17,232.8 | 242,638.2 | 174,014.9 | 0.0 | 71,756.5 | 710,395.9 |
| 12-31-2025 | 1,205,634.5 | 138,648.0 | 88,041.5 | 17,331.0 | 244,020.4 | 0.0 | 0.0 | 71,785.9 | 889,828.2 |
| 12-31-2026 | 1,218,866.4 | 140,169.6 | 89,007.7 | 17,521.2 | 246,698.6 | 0.0 | 0.0 | 71,862.5 | 900,305.4 |
| 12-31-2027 | 1,240,764.9 | 142,688.0 | 90,606.9 | 17,836.0 | 251,130.8 | 0.0 | 0.0 | 71,988.6 | 917,645.5 |
| 12-31-2028 | 1,267,083.6 | 145,714.6 | 92,528.8 | 18,214.3 | 256,457.7 | 0.0 | 0.0 | 72,149.8 | 938,476.1 |
| 12-31-2029 | 1,282,254.4 | 147,459.3 | 93,636.6 | 18,432.4 | 259,528.3 | 0.0 | 0.0 | 92,834.4 | 929,891.7 |
| 12-31-2030 | 1,300,123.4 | 149,514.2 | 94,941.5 | 18,689.3 | 263,145.0 | 0.0 | 0.0 | 72,330.2 | 964,648.2 |
| 12-31-2031 | 1,324,775.2 | 152,349.1 | 96,741.7 | 19,043.6 | 268,134.5 | 0.0 | 0.0 | 72,472.6 | 984,168.1 |
| 12-31-2032 | 1,355,352.6 | 155,865.6 | 98,974.6 | 19,483.2 | 274,323.4 | 0.0 | 0.0 | 72,658.8 | 1,008,370.5 |
| 12-31-2033 | 1,379,666.8 | 158,661.7 | 100,750.2 | 19,832.7 | 279,244.6 | 0.0 | 0.0 | 72,785.2 | 1,027,198.5 |
| Subtotal | 17,084,395.9 | 1,964,705.5 | 1,074,799.8 | 245,588.2 | 3,285,093.6 | 919,087.1 | 0.0 | 1,041,520.6 | 11,838,256.1 |
| Remaining | 49,599,935.3 | 5,703,992.6 | 3,622,035.3 | 712,999.1 | 10,039,026.9 | 1,268,477.2 | 160,295.0 | 2,416,298.6 | 35,716,276.1 |
| Total | 66,684,331.2 | 7,668,698.1 | 4,696,835.1 | 958,587.3 | 13,324,120.5 | 2,187,564.3 | 160,295.0 | 3,457,819.2 | 47,554,532.2 |

| Period Ending | Levy Rate (%) | Levy (M$) | Future Net Cash Flow After Levy and Before Corporate Income Taxes Discounted at 0% (M$) | Corporate Income Tax Rate[2] (%) | Corporate Income Taxes[2] (M$) | Future Net Cash Flow After Levy and Corporate Income Taxes: Discounted at 0% (M$) | Discounted at 5% (M$) | Discounted at 10% (M$) | Discounted at 15% (M$) | Discounted at 20% (M$) |
|---|---|---|---|---|---|---|---|---|---|---|
| 12-31-2019 | - | 0.0 | -707,614.1 | 23.0 | 0.0 | -707,614.1 | -690,560.7 | -674,683.6 | -659,853.6 | -645,960.3 |
| 12-31-2020 | - | 0.0 | 740,974.3 | 23.0 | 81,484.6 | 659,489.7 | 612,948.6 | 571,635.2 | 534,762.9 | 501,690.8 |
| 12-31-2021 | - | 0.0 | 870,553.7 | 23.0 | 155,533.2 | 715,020.5 | 632,914.8 | 563,425.9 | 504,166.4 | 453,278.8 |
| 12-31-2022 | - | 0.0 | 767,000.3 | 23.0 | 131,716.0 | 635,284.4 | 535,556.9 | 455,086.3 | 389,516.4 | 335,609.2 |
| 12-31-2023 | - | 0.0 | 896,413.8 | 23.0 | 161,481.0 | 734,932.7 | 590,059.4 | 478,608.6 | 391,838.7 | 323,543.0 |
| 12-31-2024 | 3.5 | 24,716.6 | 685,679.2 | 23.0 | 151,034.4 | 534,644.9 | 408,812.6 | 316,523.3 | 247,871.9 | 196,141.1 |
| 12-31-2025 | 27.8 | 247,698.0 | 642,130.1 | 23.0 | 98,993.5 | 543,136.7 | 395,529.3 | 292,318.8 | 218,964.2 | 166,047.0 |
| 12-31-2026 | 38.2 | 343,544.6 | 556,760.8 | 23.0 | 79,358.5 | 477,402.3 | 331,104.2 | 233,582.0 | 167,359.6 | 121,625.6 |
| 12-31-2027 | 45.6 | 418,500.0 | 499,145.5 | 23.0 | 66,107.0 | 433,038.5 | 286,033.9 | 192,614.4 | 132,006.4 | 91,936.1 |
| 12-31-2028 | 46.8 | 439,206.8 | 499,269.3 | 23.0 | 66,135.5 | 433,133.8 | 272,473.2 | 175,142.5 | 114,813.4 | 76,630.3 |
| 12-31-2029 | 46.8 | 435,189.3 | 494,702.4 | 23.0 | 65,085.1 | 429,617.3 | 257,391.5 | 157,927.8 | 99,027.2 | 63,340.1 |
| 12-31-2030 | 46.8 | 451,455.4 | 513,192.8 | 23.0 | 113,601.2 | 399,591.6 | 228,002.4 | 133,536.6 | 80,092.4 | 49,094.4 |
| 12-31-2031 | 46.8 | 460,590.7 | 523,577.4 | 23.0 | 116,420.5 | 407,157.0 | 221,256.3 | 123,695.3 | 70,964.1 | 41,686.6 |
| 12-31-2032 | 46.8 | 471,917.4 | 536,453.1 | 23.0 | 119,381.9 | 417,071.2 | 215,851.3 | 115,188.5 | 63,210.5 | 35,584.7 |
| 12-31-2033 | 46.8 | 480,932.0 | 546,700.5 | 23.0 | 121,738.8 | 424,961.7 | 209,461.9 | 106,697.9 | 56,005.6 | 30,214.9 |
| Subtotal | | 3,773,750.8 | 8,064,939.3 | | 1,528,071.1 | 6,536,868.2 | 4,506,835.6 | 3,241,299.5 | 2,410,746.1 | 1,840,462.1 |
| Remaining | | 16,729,813.8 | 18,986,028.3 | | 4,402,038.4 | 14,583,989.9 | 3,555,458.4 | 1,079,450.9 | 387,046.0 | 156,420.9 |
| Total | | 20,503,564.6 | 27,050,967.5 | | 5,930,109.5 | 21,120,858.1 | 8,062,294.0 | 4,320,750.4 | 2,797,792.1 | 1,996,883.1 |

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, 2033, through the end of production in 2064.

Totals may not add because of rounding.

(1) Operating costs are intended to include Delek Drilling's estimates of direct project-level costs, indirect headquarters general and administrative overhead expenses, and the portion of the operator's headquarters general and administrative overhead expenses that can be directly attributed to this project.

(2) Corporate income tax rates and estimates of corporate income taxes are provided by Delek Drilling and are its expected corporate income taxes per year.

*All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.*

# Annex E

# Glossary of Terms Used in Resources 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.<br>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. |

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| 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.) |

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| 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<br>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. |

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| 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. |

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| 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 commercial 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. |

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| 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 | 2.1.1 | 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). |

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| 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. |

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| 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). |

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| 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<br>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.) |

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| On Production | 2.1.3.5<br>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<br>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. |

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| 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<br>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<br>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. |

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| Proved Reserves | 2.2.2<br>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.). |

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| Recoverable Resources | 1.1<br>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<br>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<br>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<br>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. |

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| 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<br>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. |

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| 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.) |

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| Unconventional Resources | 2.4 | Unconventional resources exist in petroleum accumulations that are pervasive throughout a large area and lack well-defined OWC or GWC (also called "continuous-type deposits"). Such resources cannot be recovered using traditional recovery projects owing to fluid viscosity (e.g., oil sands) and/or reservoir permeability (e.g., tight gas/oil/CBM) that impede natural mobility. Moreover, the extracted petroleum may require significant processing before sale (e.g., bitumen upgraders). |
| Undeveloped Reserves | 2.1.3.5 Table 2 | Those quantities expected to be recovered through future investments: (1) from new wells on undrilled acreage in known accumulations, (2) from deepening existing wells to a different (but known) reservoir, (3) from infill wells that will increase recovery, or (4) where a relatively large expenditure (e.g., when compared to the cost of drilling and completing a new well) is required to recomplete an existing well. |
| Undiscovered Petroleum Initially-in-Place | 1.1 | That quantity of petroleum estimated, as of a given date, to be contained within accumulations yet to be discovered. |
| Unrecoverable Resources | 1.1 | Those quantities of discovered or undiscovered PIIP that are assessed, as of a given date, to be unrecoverable by the currently defined project(s). A portion of these quantities may become recoverable in the future as commercial circumstances change, technology is developed, or additional data are acquired. The remaining portion may never be recovered owing to physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks. |
| Upgrader | 2.4 | A general term applied to processing plants that convert extra-heavy crude oil and natural bitumen into lighter crude and less viscous synthetic crude oil. While the detailed process varies, the underlying concept is to remove carbon through coking or to increase hydrogen by hydrogenation processes using catalysts. |
| Wet Gas | 3.2.3 | Natural gas from which no liquids have been removed before the reference point. The wet gas is accounted for in resources assessments, and there is no separate accounting for contained liquids. It should be recognized that this is a resources assessment definition and not a phase behavior definition. |
| Working Interest | 3.3 | An entity's equity interest in a project before reduction for royalties or production share owed to others under the applicable fiscal terms. |

Delek Drilling

# Board of Directors Report on the State of the Partnership's Affairs

# 2018

# Delek Drilling – Limited Partnership

# Chapter B

## The Board of Directors' Report
## on the State of the Partnership's Affairs

## for the Year Ended December 31, 2018

**March 21, 2019**

# Delek Drilling – Limited Partnership

## Report of the Board of Directors' of the General Partner for the Year Ended on December 31, 2018

The board of directors of Delek Drilling Management (1993) Ltd. (the "**General Partner**") hereby respectfully files the board of directors' report for the year ended on December 31, 2018 (the "**Report Year**").

## Part One – Explanations of the Board of Directors on the State of the Partnership's Business

### 1. Main figures from the description of the Partnership's business

For a description of the Partnership's business and the developments that occurred in the Report Year – see Chapter A (Description of the Partnership's Business).

### 2. Results of operations

#### a. General

As of the date of approval of the financial statements, the Partnership's primary business is exploration, development and production of natural gas, condensate and oil, as well as the promotion of the use of infrastructures for the export of natural gas, with the purpose of increasing the volume of natural gas sales. The Partnership is further promoting several alternatives for the sale of its remaining holdings in the Tamar and Dalit reservoirs, in accordance with the provisions of the Gas Framework (see Section G below and Note 12J1 below), including by way of establishing an SPV which would conduct offerings of equity and debt securities, which would be listed on a foreign stock exchange and/or on the Tel Aviv Stock Exchange Ltd., and/or a sale to a third party and/or through split of the Partnership's assets, such that all of the Partnership's assets and liabilities, other than the assets and liabilities attributed to the Tamar and Dalit leases, shall be transferred to a foreign SPV whose shares will be distributed by the Partnership as a distribution in kind to the Partnership's participation unit holders. For further details, see Note 23A to the financial statements attached below.

The "investment recovery date" in the Tamar project, as defined in the Right Transfer Agreement of 1993, fell in January 2018, and from this date the Partnership is paying overriding royalties (wellhead) at the rate of 9.92% *in lieu* of 4.92%. For further details, see Notes 12I(5) and 15D to the financial statements attached below.

In 2018, the Partnership's profits amounted to approx. $276.8 million, compared with approx. $817.2 million last year. The decrease in profit chiefly derives from a profit of approx. $567 million in 2017, which derived from the sale of 9.25% (out of 31.25% which were held by the Partnership) of the Tamar and Dalit leases (the "**Leases**") to Tamar Petroleum Ltd. For further details, see Note 7C1F to the financial statements attached below.

The Partnership's profits in Q4/2018 amounted to approx. $50.9 million versus approx. $62.7 million in the same quarter last year. The decrease in profit primarily derives from a decrease in the financial income which derives from the revaluation of receivables, in respect of the sale of the Partnership's interests in the Karish and Tanin leases which was offset by the net increase in revenues which derive from the increase in the quantities of gas that were sold during the quarter.

b. **Analysis of statements of comprehensive income**

Below are main figures with regard to the Partnership's statements of comprehensive income (Dollars in thousands):

| | **1-3/18** | **4-6/18** | **7-9/18** | **10-12/18** | **2018** | **10-12/17** | 2017 |
|---|---|---|---|---|---|---|---|
| **Revenues** | | | | | | | |
| From natural gas and condensate sales | 106,606 | 113,463 | 124,579 | 113,334 | 457,982 | 100,683 | 501,926 |
| Net of royalties | 21,278 | 20,789 | 25,087 | 24,179 | 91,333 | 16,857 | 80,256 |
| Revenues, net | **85,328** | **92,674** | **99,492** | **89,155** | **366,649** | **83,826** | **421,670** |
| **Expenses and costs** | | | | | | | |
| Cost of production of the gas and condensate | 8,502 | 7,406 | 6,745 | 10,067 | 32,720 | 7,857 | 35,188 |
| Expenses of depreciation, depletion and amortization | 10,309 | 11,262 | 12,955 | 10,532 | 45,058 | 13,390 | 94,898 |
| Expenses of oil and gas exploration and other direct expenses | 1,375 | 2,210 | 2,684 | 3,451 | 9,720 | 2,490 | 7,840 |
| G&A expenses | 2,299 | 2,984 | 2,348 | 2,180 | 9,811 | 2,210 | 10,629 |
| **Total expenses and costs** | **22,485** | **23,862** | **24,732** | **26,230** | **97,309** | **25,947** | **148,555** |
| Other revenues (expenses), net | (988) | 474 | - | (47) | (561) | (392) | 566,542 |
| Partnership's share of earnings (loss) of a company accounted for at equity, net | (5,360) | 4,388 | 6,352 | 5,162 | 10,542 | 4,549 | 10,042 |
| **Operating profit** | **56,495** | **73,674** | **81,112** | **68,040** | **279,321** | **62,036** | **849,699** |
| Financial expenses | (15,804) | (15,296) | (13,905) | (12,427) | (57,432) | (19,589) | (75,044) |
| Financial income | 48,360 | 6,302 | 7,577 | (3,090) | 59,149 | 21,274 | 46,872 |
| Financial income (expenses), net | 32,556 | (8,994) | (6,328) | (15,517) | 1,717 | 1,685 | (28,172) |
| **Profit before levy** | **89,051** | **64,680** | **74,784** | **52,523** | **281,038** | **63,721** | **821,527** |
| Petroleum and gas profit levy | (757) | (1,224) | (641) | (1,583) | (4,205) | (999) | (4,305) |
| **Net profit** | **88,294** | **63,456** | **74,143** | **50,940** | **276,833** | **62,722** | **817,222** |
| **Other comprehensive income (loss) in respect of items that may be subsequently reclassified as profit or loss:** | | | | | | | |
| Loss from cash flow hedging transactions | - | - | - | - | - | - | (3,957) |
| Profit from financial assets available for sale | - | - | - | - | - | 2,100 | 2,237 |
| Carrying to profit or loss for disposition of financial assets available for sale and cash flow hedging transactions | (621) | (567) | (678) | (855) | (2,721) | (420) | (1,599) |
| **Total other comprehensive income (loss) for the period** | (621) | (567) | (678) | (855) | (2,721) | 1,680 | (3,319) |
| **Total Comprehensive income** | **87,673** | **62,889** | **73,465** | **50,085** | **274,112** | **64,402** | **813,903** |
| **Gas sales in BCM**[1] | **2.4** | **2.6** | **2.8** | **2.7** | **10.5** | **2.4** | **9.9** |
| **Condensate sales in Israel in thousands of barrels**[2] | **109** | **118** | **133** | **117** | **477** | **110** | **455** |

[1] The figures refer to sales of (100%) natural gas from the Tamar and Yam Tethys projects, rounded off to one tenth of a BCM.

**Net revenues** in the Report Year amounted to approx. $366.6 million compared with approx. $421.7 million last year, a decrease of approx. 13%. The decrease mainly derives from the decrease in the Partnership's holdings in the Tamar reservoir and an increase in the rate of the overriding royalty, as aforesaid, which was partially offset by an increase in the quantity of natural gas sold from the Tamar reservoir.

In Q4/2018, net revenues amounted to approx. $89.2 million compared with approx. $83.8 million last year, an increase of approx. 6.4% which mainly derives from an increase in the quantity of natural gas and condensate sold from the Tamar reservoir, which was, conversely, partially offset against the increase in the rate of overriding royalties as aforesaid.

**The cost of gas and condensate production** mainly includes the expenses of management and operation in the Tamar project, which include, *inter alia*, salaries, management, maintenance, insurance and shipping and transportation expenses. The cost of gas and condensate production amounted, in the Report Year, to approx. $32.7 million compared with approx. $35.2 million last year, a decrease of approx. 7%. The decrease in the cost of gas and condensate production mainly derives from the decrease in the Partnership's holdings in the Tamar reservoir.

In Q4/2018 the cost of production of the gas and condensate amounted to approx. $10.1 million compared with approx. $7.9 million in the same period last year, an increase of approx. 28%. The increase mainly derives from maintenance and repair works which were carried out in the Tamar rig in the course of Q4/2018.

**Expenses of depreciation, depletion and amortization** amounted in the Report Year to approx. $45.1 million compared with approx. $94.9 million last year. The depreciation expenses include depletion depreciation in the Tamar and Yam Tethys projects. Most of the decrease in expenses of depreciation, depletion and amortization compared with the parallel period last year derives, *inter alia*, from impairment of the cost of the Dolphin well in the Hanna License and from an update of petroleum and gas asset retirement obligations in the sum total of approx. $40 million that were recorded last year.

[2] The figures refer to condensate sales (100%) from the Tamar project, rounded off to thousands of barrels.

In Q4/2018, the depreciation and amortization expenses amounted to approx. $10.5 million compared with approx. $13.4 million last year. The decrease mainly derives from the write-off of surplus drilling equipment in the parallel quarter last year, which was partially offset by an increase in the quantity of proven and developed reserves which serves for amortization of petroleum and gas assets in the Tamar project.

**Oil and gas exploration expenses** include, *inter alia*, expenses of geologists, engineers and consulting as well as G&A expenses of various projects. Oil and gas exploration expenses amounted to approx. $9.7 million and include, *inter alia*, expenses in the Leviathan project in the sum of approx. $7.5 million, and expenses in the Cyprus project in the sum of approx. $1.5 million. Last year, the exploration expenses totaled approx. $7.8 million and included, *inter alia*, expenses in the Leviathan project in the sum of approx. $4.4 million, as well as expenses in the Cyprus project in the sum of approx. $1.6 million. The increase in the expenses of the Leviathan project chiefly derives from an increase in the scope of activity in the project as well as seismic surveys that were performed in the areas of the Leviathan leases.

**G&A expenses** in the Report Year amounted to approx. $9.8 million compared with approx. $10.6 million last year, and include, *inter alia*, expenses in respect of professional services, payroll expenses and expenses of management fees of the General Partner. In addition, G&A expenses include approx. $1.8 million (approx. $2.4 million last year) recorded against a capital reserve for transactions between a corporation and a controlling interest holder thereof and which mainly derive from costs which are financed by the General Partner and affiliates, which, according to the Partnership Agreement, are not loaded on the Partnership. The decrease in capital reserve compared with last year derives mainly from a decrease in expenses due to a share-based payment that was granted to the CEO of the General Partner.
G&A expenses in Q4/2018 amounted to approx. $2.0 million compared with approx. $2.2 million in the same period last year. The decrease primarily derives from a decrease in professional services expenses compared with Q4/2017.

**Other revenues (expenses), net** of approx. $0.6 million (expense) mainly derive from the update of other long-term assets. In the same period last year, other income was recorded in the sum of approx. $566.5 million which primarily derived from the sale of 9.25% of the Partnership’s interests in the Tamar and Dalit leases.

**The Partnership’s share of earnings of a company accounted for at equity, net**, amounted in the Report Year to profit of approx. $10.5 million compared with a profit of approx. $10 million last year. The Partnership’s share of earnings of a company accounted for at equity, net, include the Partnership’s share in the results of a company accounted for at equity and net of the impact of the decrease in the holding rate in the company accounted for at equity, net, as specified in Note 6 to the financial statements attached below. The net increase in the profits of the company accounted for at equity, compared to the previous year primarily derives from the fact that during the Report Year revenues were recorded throughout the entire year, whereas in 2017 revenues were recorded from July 2017, the holding commencement date in the company accounted for at equity. Conversely, revenues were offset this year by approx. $9.1 million due to the impact of the aforesaid decrease in the holding rate.

The Partnership’s share of earnings of company accounted for at equity, net for Q4/2018 amounted to approx. $5.1 million, compared with approx. $4.5 million in the same period last year. The increase in the profits of the company accounted for at equity derives primarily from the increase in the gas sales compared with the same period last year.

**Financial expenses** amounted, in the Report Year, to approx. $57.4 million compared with approx. $75 million last year. The decrease derives mainly from prepayment of the bonds of Tamar Bond in the sum of approx. $320 million which the Company performed upon the sale of a part of its holdings in the Tamar project, last year.
The financial expenses primarily derived from interest in respect of bonds in the sum of approx. $79.1 million, of which the Partnership capitalized approx. $28.4 million, which were attributed to development costs of the Leviathan project. In addition, in the Report Period, the Partnership capitalized direct credit costs of the Leviathan project in the sum of approx. $80.5 million, which derived from a designated loan for financing the share of the Partnership in the development of the Leviathan project.
Last year, financial expenses in respect of bonds totaled approx. $93.8 million, of which the Partnership capitalized approx. $26.8 million, which were attributed mainly to the Leviathan project. In addition, the Partnership capitalized last year direct credit costs of the Leviathan project in the sum of approx. $31 million, which derived from a designated loan for financing the share of the Partnership in the development of the Leviathan project as aforesaid.

In Q4/2018, the financial expenses amounted to approx. $12.4 million, compared with approx. $19.6 million in the same quarter last year. The decrease in financial expenses in Q4/2018 primarily derives from prepayment of the bonds as aforesaid and from a decrease in expenses resulting from the revaluation of short-term investments.

**Financial income** in the Report Year amounted to approx. $59.1 million compared with approx. $46.9 million last year. Financial income mainly derives from the revaluation of royalty receivables from the Karish and Tanin leases and annual receivables deriving from the sale of the Partnership's rights in the Karish and Tanin leases (jointly: "**Receivables**") of approx. $48.3 million. The said update derives mainly from a change in the cap rates, the bringing forward of the date of the decision regarding investment in the development of the leases and an update of the quantity of contingent resources and hydrocarbon liquids (condensate and natural gas liquids). For details, see Note 8B to the financial statements attached below, Regulation 8B of Chapter D (Additional Details on the Partnership) and the royalties and debt component valuations attached below.

Financial income in Q4/2018 amounted to an expense of approx. $3.1 million, deriving from the revaluation of royalty receivables from the Karish and Tanin leases, compared with revenues of approx. $21.4 million in the same quarter last year.

**The petroleum profit levy** amounted, in the Report Year, to approx. $4.2 million, compared with approx. $4.3 million last year. The amount of the levy in the Report Year comprises a levy in respect of the Partnership's revenues from the Yam Tethys project.

## 3. Financial position, liquidity and financing sources

### a. Financial position

Following is a specification of the main changes in the items of the statement of financial position as of December 31, 2018, compared with the statement of financial position as of December 31, 2017:

**Total Assets** as of December 31, 2018 total approx. $3,771.4 million compared with approx. $3,055.5 million as of December 31, 2017.

**Current assets** decreased from approx. $511 million as of December 31, 2017 to approx. $474.7 million as of December 31, 2018. The change mainly derived from the factors specified below:

**(1)** **Cash and cash equivalents** decreased from approx. $154.8 million as of December 31, 2017 to approx. $143.9 million as of December 31, 2018. The change mainly derived from the distribution of profits participation unit holders and advance tax payments and conversely, the Partnership withdrew cash surpluses generated from designated accounts of the bonds of Tamar Bond and repaid short-term investments.

**(2)** **Short-term investments** decreased from approx. $278.8 million as of December 31, 2017 to approx. $186.2 million as of December 31, 2018, and include, *inter alia*, corporate bonds, short-term deposits, a deposit that serves as a safety cushion for the bonds of Tamar Bond and ETFs.

**(3)** **Trade receivables** totaled approx. $45.5 million as of December 31, 2018, compared with approx. $46.5 million as of December 31, 2017.

(4) **Trade and other receivables** increased from approx. $30.9 million as of December 31, 2017 to approx. $99.2 million as of December 31, 2018. The increase mainly derives from the increase in trade and other receivables as part of the joint ventures, and the classification of annual receivables deriving from the sale of all of the Partnership's rights in Karish and Tanin leases in the sum of approx. $15 million.

**Non-current assets** increased from approx. $2,544.5 million as of December 31, 2017 to approx. $3,296.7 million as of December 31, 2018. The change mainly derived from the factors specified below:

(1) **Investments in petroleum and gas assets** increased from approx. $2,023.7 million as of December 31, 2017 to approx. $2,805.4 million as of December 31, 2018. The increase mainly derives from investment of approx. $816 million in the development of the Leviathan project. On the other hand, the Partnership recorded depreciation, depletion and amortization expenses in the Tamar and Yam Tethys projects in the amount of approx. $45.1 million.

(2) **Investment in a company accounted for at equity** decreased from approx. $129.8 million as of December 31, 2017 to approx. $124.3 million as of December 31, 2018. The decrease in investment derived from dividend distributions of approx. $16.1 million and an expense due to the decrease in the holding rate of approx. $9.1 million which was offset by the recording of equity profits, net of approx. $19.7 million.

(3) **Long-term deposits** decreased from approx. $101.5 million as of December 31, 2017 to approx. $60.3 million as of December 31, 2018. The said deposits serve as a safety cushion for the bonds of Tamar Bond. The decrease mainly derives from the use of the deposits for the purpose of prepayment of bonds, as specified below.

(4) **Other long-term assets** increased from approx. $289.5 million as of December 31, 2017 to approx. $306.8 million as of December 31, 2018. The assets include mainly receivables in respect of the sale of the Karish and Tanin leases in the sum of approx. $189.5 million, other receivables in respect of the construction of infrastructures to export gas to Jordan in the sum of approx. $48 million and advance payments on account of royalties paid to the State, to related parties and to third parties in the sum of approx. $36.4 million (see Note 15 to the financial statements attached below).

**Current liabilities** decreased from approx. $502.2 million as of December 31, 2017 to approx. $196.5 million as of December 31, 2018. The change mainly derived from the factors specified below:

(1) **Bonds –** Current liabilities in 2017 included current maturities in the sum of approx. $319.4 million (net of issue expenses) of bonds of Tamar Bond which were repaid throughout the year.

(2) **Declared profit for distribution** - in December 2018, the Partnership declared a distribution of profit in the sum of approx. ILS 130 million (approx. $34.7 million), which was performed in January 2019, compared with profit for distribution in the amount of ILS 209.3 million (approx. $60.4 million), declared in December 2017 and distributed in January 2018.

(3) **Trade and other payables** as of December 31, 2018 amounted to approx. $161.8 million, compared with approx. $122.4 million last year. The increase in this item primarily resulted from an increase in the other payables item in the context of the Joint Venture related to the development of the Leviathan project and from interest to be paid in respect of a bank loan.

**Non-current liabilities** increased from the sum of approx. $1,934.9 million as of December 31, 2017 to approx. $2,719.8 million as of December 31, 2018. The change mainly derived from the factors specified below:

(1) **Bonds –** in the sum of approx. $1,347.6 million as of December 31, 2018, compared with approx. $1,344.3 million last year, including Series A Bonds in the sum of approx. $395.7 million (net of issue expenses) (see Paragraph B below) and bonds of Tamar Bond in the sum of approx. $951.9 million (net of issue expenses) (see Part Four below).

(2) **Long-term liabilities to banks** include a loan (net of debt-raising costs) in the sum of approx. $1,238.1 million as of December 31, 2018, compared with approx. $469 million last year, taken by the Partnership in connection with the financing of the Leviathan project (as stated in Note 10C to the financial statements attached below).

(3) **Other long-term liabilities** as of December 31, 2018 total approx. $134 million, compared with approx. $121.6 million as of December 31, 2017, and include mainly gas and petroleum asset retirement obligations in the Yam Tethys, Tamar and Leviathan projects, in the amount of approx. $112.2 million and tax payment liabilities on account of the tax owed by the holders of the Partnership's participation units in the sum of approx. $21.1 million.

**The capital of the Limited Partnership** as of December 31, 2018 amounts to approx. $855.1 million, compared with approx. $618.5 million as of December 31, 2017. The change in the capital mainly derives from comprehensive income recorded in the Report Year in the amount of approx. $274.1 million, as well as from an increase in a capital reserve for benefits from a control holder of approx. $1.8 million, which was offset by distributed profits and declared profits for distribution in the sum total of approx. $34.7 million and advance income tax payments on account of the tax owed by the holders of participation units in the Partnership in the sum, net, of approx. $4.6 million.

**b.** **Cash flow**

The net cash flow deriving from operating activities amounted in the Report Year to approx. $258.1 million, compared with a net cash flow deriving from operating activities of approx. $329.3 million last year. The decrease derives mainly from the disposal of a part of the Partnership's interests in the Tamar reservoir.

The net cash flow used for investment activity amounted in the Report Year to approx. $654.6 million, compared with the net cash flow deriving from investment activity last year in the sum of approx. $236.2 million. Generated cash flow from investment activity in the same period last year included proceeds in the sum of approx. $830 million from the disposal of a part of the Partnership's interests in the Tamar reservoir. Furthermore, in the Report Year, the Partnership invested approx. $740 million, mainly in the development of the Leviathan project, compared with investments in the sum of approx. $443 million last year.

The net cash flow derived from financing activity amounted, in the Report Year, to approx. $385.5 million, compared with a net cash flow used for financing activity in the sum of approx. $891.5 million last year. This year's cash flow mainly includes the partial repayment of the bonds of Tamar Bond in the sum of approx. $320 million, and a distribution of profit in the sum of approx. $61 million. On the other hand, the Partnership borrowed credit from banks in the sum of approx. $775 million for the purpose of financing the development of the Leviathan project. Last year's cash flow mainly includes the repayment of the bonds of Tamar Bond in the sum of approx. $320 million, a distribution of profit in the sum of approx. $781.1 million, and tax advances paid for participation unit holders in the sum of approx. $207 million, conversely, the Partnership borrowed credit from banks in the sum of approx. $420 million for the purpose of financing the development of the Leviathan project.

The balance of cash and cash equivalents as of December 31, 2018, amounted to approx. $143.9 million, compared with approx. $154.8 million as of December 31, 2017.

**c.** **Financing**

On August 31, 2018, Delek & Avner (Tamar Bond) Ltd. prepaid the second bond series of Tamar Bond, *in lieu* of the original maturity date that is December 30, 2018. The amount of the prepayment included the bonds’ principal in the sum of $320 million, interest accrued as of the prepayment date in the sum of approx. $2.1 million and prepayment fees of approx. $1.3 million.

# Part Two – Exposure to and Management of Market Risks

## Report on exposure to and management of market risks

### 1. The person in charge of market risk management in the Partnership

The person in charge of market risk management in the Partnership is the Deputy CEO, Mr. Yossi Gvura.

### 2. A description of the main market risks to which the Partnership is exposed

**a. The exchange rate risk**

The changes in the dollar exchange rate may influence the Partnership's results as follows:

1. As aforesaid, the Partnership’s functional currency is the U.S. dollar, but since some of the Partnership's expenses and income are stated in Shekels or influenced by the ILS/Dollar exchange rate, a strengthening of the ILS against the Dollar increases the expenses and reduces the income.

2. Since the Partnership reports its taxable income in ILS, changes in the ILS/Dollar exchange rate influence the amount of its taxable income.

**b. The interest rate risk**

In February 2017, the Partnership signed financing documents in connection with a loan that would be used for the financing of its share in the costs of development of the Leviathan project. The loan bears variable LIBOR interest plus a staggered margin. Consequently, the Partnership is exposed to possible changes in the cash flow which may derive from changes in the LIBOR interest. See Section 4 below with respect to hedging transactions performed by the Partnership.
In addition, the liquid financial assets of the Partnership are mainly invested in Dollar deposits, investment grade bonds and ETFs. Such investments are affected by changes in the LIBOR interest rates, which may affect both the current return of the short-term deposits, and the market price of the bonds and the ETFs that are presented in the statement of financial position according to their quoted price as of the report date.

c. **<u>The natural gas and condensate price risk</u>**

The prices paid by consumers for the natural gas in the reservoirs in which the Partnership is a partner, derive, *inter alia*, from the electricity production tariff, to which the gas agreements for private electricity customers are linked, from the U.S. CPI, and from the Brent barrel price (the "**Indices**"). For details on the various linkages in the natural gas price formulas, see Notes 12C1 and 12C2 to the financial statements attached below. It is noted with respect to the electricity production tariff that the frequent methodological changes made by the Electricity Authority (PUA-E) to the manner of calculation thereof, hinder the ability to predict it, and may lead to disagreements on the manner of calculation thereof between gas suppliers and customers.

A decline in the electricity production tariff (resulting, *inter alia*, from a price adjustment to be sought by the IEC, if any, according to the mechanism that was determined in the agreement that was signed therewith as stated in Note 12C1B to the financial statements attached below) and/or in the Brent prices and/or in the U.S. CPI may adversely affect the Partnership's revenues from the existing and future gas sale agreements. Furthermore, a significant change in the prices of other energy sources (including coal and other gas substitutes), the reforms and decisions related to the electricity market, including changes in environment protection laws, may lead to a change in the consumption model of IEC and other large customers, which may reduce the demand for natural gas and lead to a decrease in the prices of natural gas in the economy.

## 3. <u>The Partnership’s policy on exchange rate market risk management</u>

**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 gas and petroleum 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, ETFs and corporate bonds.

**c.** When the Partnership is aware of material payments in foreign currency or ILS it aspires to protect the payment and hedge against currency rate changes.

d. No events have been determined regarding which there is an obligation to adopt a special resolution at the board of directors with regard to market risks.

## 4. The Partnership's policy on LIBOR interest market risk management

Further to Section 2B in respect of the financing of the development of the Leviathan project, each period the Partnership examines its exposure to changes in the LIBOR interest rate and hedges accordingly.

In the framework of the Partnership's risk management policy, the Partnership decided, prior to signing the said financing documents, to perform IRS cash flow hedging transactions which hedge the changes in the LIBOR interest. The Partnership performed, in 2017, cash flow hedging transactions in the sum of $1.1 billion. The hedging transactions were exercised by the Partnership during September 2017, in proximity to their original expiration date, in consideration for payment by the Partnership of approx. $4 million. In accordance with the risk management policy, the Partnership is continuing to examine hedges against market risk exposures.

In February and March 2019, the Partnership performed IRS cash flow hedging transactions, which hedge the changes in the LIBOR interest, in the sum of approx. $400 million.

## 5. Means of supervision and implementation of the policy

The General Partner's investment policy is set forth in the Partnership Agreement. The investment committee discusses the Partnership's investments portfolio on a bi-annual basis, in order to verify, *inter alia*, the compliance of the method of investment of the Partnership's available cash with the investment policy. Furthermore, the audit committee determines the mix and structure of the Partnership's investment portfolio according to the management's recommendation. Insofar as the investment committee believes that amendment is required in the investment policy, it will recommend such amendment to the board of directors of the General Partner. The members of the investment committee, as of the date of this report are: Mr. Roni Bar-On (Chairman of the Investment Committee, independent director), Mr. Assi Bartfeld (Chairman of the Board), and Mr. Amos Yaron (outside director).

The handling of currency and interest risk exposure, formulation of hedging strategies and supervision of the performance thereof is entrusted to the General Partner's board of directors.

## 6. <u>Sensitivity tests</u>

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".

<u>Description of parameters, assumptions and models</u>

Parameters:

| Parameter | Source/Manner of Treatment |
|---|---|
| ILS/Dollar exchange rate | Representative rate as of December 31, 2018 |
| Dollar interest | According to the LIBOR curve |

**<u>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 ($ in thousands):</u>**

| Sensitive instrument | Profit/(loss) from the changes | | Fair value | Profit/(loss) from the changes | |
|---|---|---|---|---|---|
| | 2% | 1% | | -1% | -2% |
| Royalty receivables from the Karish and Tanin leases | (14,368) | (7,534) | 113,100 | 8,327 | 17,557 |
| Loan to Energean as part of the sale of Karish and Tanin leases (**see Note 8B to the financial statements**) | (5,666) | (2,915) | 91,500 | 3,092 | 6,373 |
| **Total** | **(20,034)** | **(10,449)** | **204,600** | **11,419** | **23,930** |

**<u>Analysis of the sensitivity of the value of contingent proceeds in respect of royalty receivables from the Karish and Tanin leases to changes in the natural gas price ($ in thousands):</u>**

| Sensitive instrument | Profit/(loss) from the changes | | Fair value | Profit/(loss) from the changes | |
|---|---|---|---|---|---|
| | 10% | 5% | | -5% | -10% |
| Royalty receivables from the Karish and Tanin leases | **4,557** | **3,603** | **113,100** | **(3,539)** | **(4,494)** |

**Tests of sensitivity to changes in Dollar/ILS exchange rate ($ in thousands):**

| Sensitive instrument | Profit/(Loss) from the changes | | Fair value | Profit/(Loss) from the changes | |
|---|---|---|---|---|---|
| | **10%** | **5%** | | **-5%** | **-10%** |
| | **4.123** | **3.935** | **3.748** | **3.561** | **3.737** |
| Cash and cash equivalents | **(3,852)** | **(1,926)** | **38,515** | **1,926** | **3,852** |
| Bank deposits | **(17)** | **(9)** | **174** | **9** | **17** |
| Other Payables | **8** | **4** | **(78)** | **(4)** | **(8)** |
| **Total** | **(3,861)** | **(1,931)** | **38,611** | **1,931** | **3,861** |

**Tests of sensitivity to changes in the LIBOR curve (Dollars in thousands):**

| Dollar interest | Profit/(Loss) from the changes | | Fair value | Profit/(Loss) from the changes | |
|---|---|---|---|---|---|
| | 10% | 5% | | -5% | -10% |
| Bonds | (430) | (215) | 73,648 | 215 | 430 |
| Liabilities to banks | (7,382) | (3,686) | (1,314,992) | 3,677 | 7,345 |
| Total | **(7,812)** | **(3,901)** | **(1,241,344)** | **3,892** | **7,775** |

## 7. **<u>Report on linkage bases in Dollars, in thousands, as of December 31, 2018</u>:**

| | Financial balances | | | |
|---|---|---|---|---|
| | **In Dollars or Dollar linked** | **In non-linked ILS** | **Non-financial balances** | **Total** |
| **<u>Property</u>** | | | | |
| Cash and cash equivalents | 105,370 | 38,515 | - | 143,885 |
| Short-term investments and deposits | 185,979 | 174 | - | 186,153 |
| Trade receivables | 45,481 | - | - | 45,481 |
| Trade and other receivables | 96,487 | - | 2,684 | 99,171 |
| Investments in gas and petroleum assets | - | - | 2,805,352 | 2,805,352 |
| Long-term deposits | 60,281 | - | - | 60,281 |
| Investment in a company accounted for at equity | - | - | 124,250 | 124,250 |
| Other long-term assets | 201,560 | - | 105,242 | 306,802 |
| **Total property** | **695,198** | **38,689** | **3,037,528** | **3,771,375** |
| **<u>Liabilities</u>** | | | | |
| Trade and other payables | 142,383 | 78 | 19,366 | 161,827 |
| Declared profits for distribution | - | - | 34,685 | 34,685 |
| Bonds | 1,347,575 | - | - | 1,347,575 |
| Long-term liabilities to banks | 1,238,143 | - | - | 1,238,143 |
| Other long-term liabilities | - | - | 134,041 | 134,041 |
| **Total liabilities** | **2,728,101** | **78** | **188,092** | **2,916,271** |
| **Net asset balance** | **(2,032,943)** | **38,611** | **2,849,436** | **855,104** |

## 8. Report on linkage bases in Dollars, in thousands, as of December 31, 2017:

| | Financial balances | | | |
|---|---|---|---|---|
| | In Dollars or Dollar linked | In non-linked ILS | Non-financial balances | Total |
| **Property** | | | | |
| Cash and cash equivalents | 140,842 | 13,993 | - | 154,835 |
| Short-term investments and deposits | 278,632 | 194 | - | 278,826 |
| Trade receivables | 46,506 | - | - | 46,506 |
| Trade and other receivables | 29,462 | - | 1,416 | 30,878 |
| Investments in gas and petroleum assets | - | - | 2,023,671 | 2,023,671 |
| Long-term deposits | 101,482 | - | - | 101,482 |
| Investment in a company accounted for at equity | - | - | 129,833 | 129,833 |
| Other long-term assets | 179,885 | - | 109,587 | 289,472 |
| **Total property** | **776,809** | **14,187** | **2,264,507** | **3,055,503** |
| **Liabilities** | | | | |
| Trade and other payables | 96,344 | 62 | 25,823 | 122,355 |
| Declared profits for distribution | - | - | 60,381 | 60,381 |
| Bonds | 1,663,740 | - | - | 1,663,740 |
| Long-term liabilities to banks | 468,967 | - | - | 468,967 |
| Other long-term liabilities | - | - | 121,582 | 121,582 |
| **Total liabilities** | **2,229,177** | **62** | **207,786** | **2,437,025** |
| **Net asset balance** | **(1,452,368)** | **14,125** | **2,056,721** | **618,478** |

# Part Three – Aspects of Corporate Governance

## 1. The Partnership's donation policy

The Partnership has not yet set out a donation policy, and accordingly made no monetary contributions in the Report Year, due to restrictions applicable thereto under the Partnership Agreement.

## 2. Directors having accounting and financial expertise

The board of directors of the General Partner has determined, pursuant to Section 92(a)(12) of the Companies Law, 5759-1999, that the minimum appropriate number of directors having accounting and financial expertise shall be one. The board of directors of the General Partner believes that considering the type of business of the company, which is the General Partner in the Partnership that operates mainly in the field of natural gas, condensate and oil exploration, and the vast business experience of the directors (also those who do not fulfill the definition of "having accounting and financial expertise"), the aforesaid minimum number allows the board of directors to fulfill the obligations imposed thereon pursuant to the law and the documents of incorporation of the Partnership, in respect of the examination of the Partnership's financial position and the preparation and approval of the financial statements. The aforesaid reasons are accompanied by the fact that pursuant to the Partnership's work procedure, the auditors of the financial statements are invited to every board meeting at which the financial statements are discussed, and are available to give the members of the board of directors any explanation required in relation to the financial statements and the financial position of the Partnership, both in and outside of the meetings in which they participate. In addition, it is noted that under the law any director who so wishes is entitled, in circumstances that so justify and under the conditions set forth in the law, to receive professional advice, at the expense of the General Partner, in order to perform his work, including accounting and financial advice.

As of the Report Release Date, four directors with accounting and financial expertise serve on the board of directors of the General Partner (Messrs. Assi Bartfeld, Barak Mashraki, Jacob Zack and Ronnie Bar-On). It is noted that upon the commencement of office of Mr. Efraim Sadka as an outside director in the board of directors of the General Partner, on April 1, 2019, five directors with accounting and financial expertise will serve on the board of directors of the General Partner. For details regarding the education, experience and qualifications of these directors, see Section 26 of Chapter D (Additional Details on the Partnership), which is attached below.

## 3. Independent directors

The Partnership did not adopt a provision in the Trust and Partnership Agreements with regards to the number of independent directors, as they are defined by the Companies Law, 5759-1999. Although not required, on January 4, 2016, Mr. Ronnie Bar-On was appointed as an independent director in the board of directors of the General Partner (in addition to the two outside directors who serve, as of the Report Date, on the board of directors of the General Partner, and the three outside directors from April 1, 2019, upon the commencement of office of Mr. Efraim Sadka). For details on directors' independence, see Regulation 26 of Chapter D (Additional Details on the Partnership) which is attached below.

## 4. Disclosure on the internal auditor at the Partnership

### a. Details of the internal auditor

(1) Internal auditor’s name: CPA Gali Gana.

Date of commencement of office: February 1, 2016.

(2) His qualifications for the position:

The internal auditor fulfills the terms and conditions set forth in Sections 3(a) and 8 of the Internal Audit Law, 5752-1992 (the “**Internal Audit Law**”) and Section 146(b) of the Companies Law, 5759-1999 (the “**Companies Law**”).

A CPA with a degree in Business Administration majoring in accounting, and an M.A. in Public Administration and Internal Audit, Certified Information Systems Auditor (CISA), Certified Internal Auditor (CIA), Certified in Risk Management Assurance (CRMA), Certified in Risk and Information Systems Control (CRISC).

(3) The internal auditor is not an employee of the Partnership, but rather provides internal audit services thereto as an outside provider. 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, of Delek Group Ltd. and of companies held thereby (Delek Energy Systems Ltd. and Cohen Development and Industrial Buildings Ltd.). His service as the internal auditor of the aforesaid corporations does not create a

conflict of interests with his function as the internal auditor at the Partnership.

(6) The internal auditor is not an interested party of the Partnership or a relative of an interested party of the Partnership and is also not the auditor or another on his behalf.

(7) The internal auditor does not hold securities of the Partnership or of a body affiliated therewith.

**b. Appointment procedure**

The appointment of Mr. Gana as the internal auditor was approved by the board of directors of the General Partner on January 27, 2016. The board of directors of the General Partner approved the internal auditor's appointment after receipt of the recommendation of the audit committee, and after it found him to have the appropriate qualifications for the position, *inter alia* in view of his specialization and vast experience in the field of internal audit, and after Mr. Gana declared that he meets all of the eligibility requirements needed to fulfill his position as internal auditor pursuant to law, considering, *inter alia*, the Partnership's type, size and the scope and complexity of its operations.

**c. 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 auditor of the Partnership operates according to an annual work plan as part of a multi-year plan. The internal auditor recommended an annual and multi-annual audit plan which is based on a risk survey for the determination of the internal audit targets. The annual plan was approved by the audit committee. The multi-annual plan is based on the performance of audits in connection with central processes at the Partnership at an audit frequency that was determined in accordance with the level of prioritization that was weighted based on the exposure to fraud and evaluation of the probability of a failure event and the extent of the damage.

The plan is prepared by the Partnership's internal auditor in coordination with the Chairman of the Board and management of the General Partner, is presented to the audit committee and the board of directors of the General Partner and approved by the audit committee.

The work plan leaves the internal auditor discretion to deviate therefrom, subject to the formal approval of the audit committee.

Transactions as provided in Section 270 of the Companies Law which were performed in the Report Year, including their approval processes, are examined by the internal auditor as part of his annual work plan.

It is noted, that in addition to the internal auditor's work, and pursuant to the joint operating agreement (JOA), the Partnership performs, through external companies, a joint audit with its partners in the Tamar, Leviathan and Cyprus projects, over the work of the operator in such projects. The internal auditor participates in the preparation, monitoring and supervision meetings of the aforesaid audit and reports to the audit committee and the board of directors of the General Partner on its findings and results.

Further to the aforesaid, in 2018 the Partnership carried out an audit of the books of the operator of the joint venture in Cyprus, in cooperation with the transaction audit department of Royal Dutch Shell Plc., the indirect parent company of the other partner in the project. The audit was approx. 130 hours long and at the conclusion thereof the findings were delivered to the operator, which accepted the majority thereof.

In addition, a periodic audit for the years 2017-2018 of the books of the operator of the joint ventures in the Tamar and Leviathan projects is currently being performed through an international outside consultant who specializes in audits in the oil and gas industry. The audit, with an approved budget of approx. 1,700 hours. The said audit is due to be completed by the end of 2019. It is noted that the audit is carried out in cooperation with all of the partners in the projects other than the operator, in accordance with the audit rules set forth in the joint operation agreements, applicable to the above projects.

**e. <u>Scope of engagement</u>**

The number of hours is determined according to the needs of the approved annual audit, in the budget determined upon commencement of the internal auditor's term of office. The scope of the internal auditor's engagement in the reporting year amounted to approx. 600 hours.

The scope of the internal auditor's engagement was determined, *inter alia*, based on the size and complexity of the Partnership's business activity. The General Partner's management, the audit committee and the board of directors of the General Partner have the option to expand the scope of the plan according to the circumstances.

The management, the audit committee and the Chairman of the Board have the option to change the scope of the plan, upon the request of the internal auditor and according to his recommendations or according to the instructions of the audit committee.

**f. <u>Conducting the audit</u>**

The internal audit is conducted according to the internal audit standards that are accepted in Israel and worldwide, and in accordance with professional directives in the field of internal auditing, as set forth in Section 4(b) of the Internal Audit Law.

The board of directors of the General Partner is satisfied that the auditor has fulfilled all of the requirements and the conditions that were stated above, considering the internal auditor's notice, as was delivered to the board of directors of the General Partner.

**g.** **<u>Access to information</u>**

The internal auditor has full, unlimited, constant and direct access to the Partnership's information systems, including financial figures for the purpose of the audit pursuant to Section 9 of the Internal Audit Law.

**h.** **<u>The internal auditor's report</u>**

The internal auditor's report was submitted in writing.

After submission of the audit reports to the General Partner's management and receipt of its position, audit reports were submitted to the chairman of the board, to the members of the audit committee and to the members of the General Partner's board, and were discussed at length at the audit committee. Below are dates on which the audit committee discussed reports of the internal auditor: March 7, 2018, August 2, 2018, November 18, 2018, March 5, 2019 and March 14, 2019.

**i.** **<u>Board of directors' assessment of the internal auditor's activity</u>**

The board of directors of the General Partner estimates 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.** **<u>Compensation</u>**

In 2018, the Partnership recorded a total annual amount of ILS 120 thousand in respect of the internal audit services. The General Partner's board of directors estimates that the compensation is reasonable and does not affect the exercise of the internal auditor's independent professional discretion.

## 5. Auditors' fee

The Partnership has joint auditors: BDO Ziv Haft and EY – Kost Forer Gabbay & Kasierer. Below are details regarding the auditors' fee.

Following is a specification of the amounts of the fee of the auditors at the Partnership, and the Partnership's share of the auditors' fee in joint ventures:

| | 2018 | | | | 2017 | | | |
|---|---|---|---|---|---|---|---|---|
| | For audit, audit-related and tax services | Hours | For other services* | Hours | For audit, audit-related and tax services | Hours | For other services* | Hours |
| | ILS in thousands | | ILS in thousands | | ILS in thousands | | ILS in thousands | |
| Kost Forer Gabbay & Kasierer and Ziv Haft, the auditors | 2,625 | 9,748 | 1,261 | 3,218 | 2,546 | 10,266 | 1,413 | 1,837 |
| Somekh Chaikin CPAs** | 49 | 227 | - | - | 66 | 293 | - | - |
| Total | 2,674 | 9,975 | 1,261 | 3,218 | 2,612 | 10,559 | 1,413 | 1,837 |

*** Other services, including offerings.**

**** Joint accountants in the Michal and Matan joint venture.**

The auditor's fee is a consequence of the number of audit hours invested by him. The function authorizing the auditor's fee is the board of directors of the General Partner, following a discussion by the financial statements review committee of the auditor's scope of work and fee and his qualification to perform an audit of the Partnership.

## 6. The Partnership's policy on negligible transactions

On March 11, 2009, the board of directors of the General Partner adopted, for the first time, guidelines and rules for the classification of a transaction of the Partnership with an interested party therein as a negligible transaction, as stated in Regulation 41(a3) of the Securities Regulations (Annual Financial Statements), 5710-2010 (the "**Negligibility Procedure**" and "**Reporting Regulations**", respectively). The Negligibility Procedure has been updated over the years and most recently updated by the audit committee and the board of the General Partner on March 14, 2019 and March 17, 2019, respectively.

**The audit committee and board of directors of the General Partner (within the approval of the annual report) determined that a transaction shall be considered a negligible transaction if it fulfills all of the following conditions:**

a. It is not an irregular transaction (as this term is defined in the Companies Law).

b. In any transaction for which the negligibility threshold is examined, the criterion that is relevant to the contemplated transaction shall be examined before the event as specified below, and insofar as each of the criteria that are relevant to the transaction (as specified below in sub-sections 1-5) is at a rate of no more than 0.8% and the scope of the transaction does not exceed U.S. $1,000,000 (the "**Negligibility Threshold**"), the transaction shall be considered as negligible:

1) In a purchase/sale of a fixed asset – the scope of the asset contemplated in the transaction divided by the total assets of the Partnership according the last reviewed or audited financial statements, as the case may be.

2) A sale of products or services – the sale volume contemplated in the transaction divided by the total annual sales, calculated based on the last four quarters regarding which reviewed or audited financial statements were released.

3) A purchase of products or services – the scope of the expenses contemplated in the transaction divided by the total annual operating expenses that are relevant to the transaction calculated based on the last four quarters regarding which reviewed or audited financial statements were released.

4) An assumption of a financial liability – the undertaking contemplated in the transaction divided by the total liabilities according to the latest reviewed or audited financial statements, as the case may be.

5) Insurance transactions – the premium shall be examined as the transaction amount, as distinguished from the scope of the insurance coverage that is given.

The aforesaid notwithstanding, in transactions in which the Partnership will enter into joint agreements with an interested party therein and/or the control holder for the receipt of consultation and/or management services from employees or third parties in various fields – the transaction shall be considered negligible if it meets all of the rules of the Negligibility Procedure (other than the Negligibility Threshold), provided that the scope of the annual expenses for the services contemplated in the transaction does not exceed ILS 1.5 million and that the terms of the engagement in joint agreements in respect of the Partnership do not differ from the terms with respect to the interested party and/or control holder, considering their relative share.

c. In cases where, according to the discretion of the audit committee, all of the aforesaid criteria are irrelevant to the contemplated transaction, the audit committee shall determine other criteria, provided that the scope of the transaction shall not exceed the rules that have been set forth above.

d. The transaction is negligible also from the qualitative aspect. Thus, one of the criteria for such examination is that the transaction is not classified by the Partnership as an event which is required to be reported according to the provisions of Regulation 36 to the Reporting Regulations.

e. In multi annual transactions (such as a lease of a property for several years) the negligibility of the transaction shall be examined on an annual basis (by calendar year) (in other words, in the aforesaid example, the annual rent shall be examined).

f. The negligibility of each transaction shall be examined separately, although the negligibility of integrated or contingent transactions shall be examined in the aggregate. Transactions that are performed frequently during the year and in close time proximity to one another shall be deemed as integrated transactions.

g. For the purpose of disclosure in the periodic report the negligibility of each transaction shall be examined on an annual basis while combining all of the same-kind transactions that were performed with the interested party or controlling interest holder, as the case may be, in the Report Year.

h. In cases where questions arise with regard to the implementation of the aforesaid criteria, the Partnership shall exercise discretion and examine the negligibility of the transaction based on the purpose of the Reporting Regulations and the rules and guidelines above.

i. Each year, the Partnership's management shall present to the audit committee transactions with interested parties to which the Partnership is a party and which were classified as negligible transactions under the procedure, and the audit committee will review the implementation of the provisions of the said procedure by the Partnership.

## 7. <u>Internal enforcement program</u>

The board of directors of the General Partner has determined that the audit committee will be in charge of the adoption of an updated internal enforcement program in respect of securities, for the management of the program and for the ongoing follow-up and supervision on the performance thereof. Accordingly, in August 2018, the audit committee approved an updated internal enforcement program in respect of securities, according to the criteria published by the ISA and based on the results of a compliance survey that was conducted in the Partnership. In this context, the procedures were updated according to the changes in the law since the adoption of the enforcement program existing in the Partnership until that date and the results of the said survey, and an officer responsible for internal enforcement was appointed.

# Part Four – Disclosure in Connection with the Partnership's Financial Reporting

## Subsequent events

See Note 23 to the financial statements attached below.

## Part Five – Details regarding bonds that were issued by Delek & Avner (Tamar Bond) Ltd.[3] (Dollars in thousands) and the issue of Series A bonds by the Partnership (ILS in thousands)

| **Bond Series**[4] [5] | **2018** | **2020** | **2023** | **2025** |
|---|---|---|---|---|
| **Par value on issue date** | | 400,000 | 400,000 | 400,000 |
| **Issue date** | | May 19, 2014 | May 19, 2014 | May 19, 2014 |
| **Par value as of December 31, 2018** | | 320,000 | 320,000 | 320,000 |
| **Linked par value as of December 31, 2018** | | 320,000 | 320,000 | 320,000 |
| **Value in the Partnership's books as of December 31, 2018** | | 318,841 | 317,100 | 315,938 |
| **Market cap as of December 31, 2018**[6] | | 319,830 | 320,176 | 320,282 |
| **Fixed annual interest rate** | | 4.435% | 5.082% | 5.412% |
| **Principal payment date** | | December 30, 2020 | December 30, 2023 | December 30, 2025 |
| **Interest payment dates** | | Semiannual interest payable on every June 30th and every December 30th from the date of the issue in 2014-2020 | Semiannual interest payable on every June 30th and every December 30th from the date of the issue in 2014-2023 | Semiannual interest payable on every June 30th and every December 30th from the date of the issue in 2014-2025 |
| **Linkage base: base index**[7] | None | | | |

[3] A company wholly owned by the Partnership (the "**Bond Company**").
[4] $80 million were repaid in each series in the context of the sale of 9.25% (out of 100%) of the interests in the Tamar lease.
[5] On August 31, 2018, the Partnership prepaid the 2018 Bond Series.
[6] The bonds are traded in Israel on the "TACT-Institutional" system of the Tel Aviv Stock Exchange.
[7] The bond principal and interest are in dollars.

| | |
|---|---|
| **Conversion right** | None |
| **Right to prepayment or mandatory conversion**[8] | Right to prepayment |
| **Guarantee for payment of the liability** | See Note 10B to the financial statements attached below. |
| **Name of the trustee** | HSBC BANK USA, NATIONAL ASSOCIATION |
| **Name of person in charge at the trust company** | Susie Mox |
| **Trustee's address and e-mail** | HSBC Bank USA, National Association, as TRUSTEE<br>452 5th Avenue, 8E6<br>New York, NY 10018<br>CTLANYDealManagement@us.hsbc.com |
| **Rating as of the issue date**[9] | Moody's: Baa3<br>S&P: BBB-<br>Midroog Ltd: Aa2<br>Standard & Poor's Maalot: ilAA |
| **Rating as of the report date**[10] | Moody's: Baa3<br>S&P: BBB-<br>Midroog Ltd: Aa2<br>Standard & Poor's Maalot: ilAA |
| **Has the company fulfilled, by December 31, 2018 and during the Report Year, all of the conditions and obligations under the indenture** | Yes |

[8] The Partnership has the right to prepay the bonds at any time, in whole or in part, subject to a prepayment fee. Prepayment following events set forth in the bonds may be performed without a prepayment fee.

[9] See the Partnership's immediate reports of May 29, 2014 (Ref. No. 2014-01-077676), June 8, 2014 (Ref. No. 2014-01-084870) and June 17, 2014 (Ref. No. 2014-01-093135 and 2014-01-093132), the information appearing in which is hereby included by way of reference.

[10] From the date of issue of the bonds, no change has occurred in the rating with respect to the initial rating report. See the report of November 15, 2018 (Ref. No. 2018-01-103804), the information included in which is incorporated herein by reference.

| | |
|---|---|
| **Is the bond series material**[11] | 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 attached below. |

[11] A series of bond certificates shall be deemed material if the sum of the corporation's liabilities thereunder as of the end of the Report Year, as presented in the financial statements, constitutes five percent or more of the corporation's total liabilities.

| | |
|---|---|
| **Bond Series** | **Series A** |
| **Par value on issue date in ILS in thousands** | 1,528,533[12] |
| **Issue date** | December 26, 2016 |
| **Par value as of December 31, 2018 in ILS** | 1,528,533 |
| **Linked par value as of December 31, 2018 in ILS in thousands** | 1,500,116 |
| **Value on the Partnership's books as of December 31, 2018 in ILS in thousands** | 1,490,067 |
| **Market cap as of December 31, 2018 in ILS in thousands** | 1,482,524 |
| **Fixed annual interest rate** | 4.5% |
| **Principal payment date** | December 31, 2021 |
| **Interest payment dates** | Semiannual interest payable on every June 30th and every December 31st from the date of the issue in 2017-2021 |
| **Linkage base: base index** | The bond is stated in ILS. The principal and interest are linked to a dollar rate of 3.819 |
| **Conversion right** | None |
| **Right to prepayment or mandatory conversion[13]** | Right to prepayment |
| **Guarantee for payment of the liability** | See Note 10D to the financial statements attached below. |
| **Name of the trustee** | Reznik Paz Nevo Trusts Ltd. |
| **Name of person in charge at the trust company** | Adv. Michal Avtalion-Rishony |
| **Trustee's address and e-mail** | 14 Yad Harutzim St., Tel Aviv |
| **Rating as of the issue date[14]** | Midroog Ltd.: A1 stable |
| **Rating as of the report date[15]** | Midroog Ltd.: A1 stable |
| **Has the partnership fulfilled, by December 31, 2018 and during the Report Year, all of the conditions and obligations under the indenture** | Yes |
| **Have any conditions establishing cause for acceleration of the bonds been fulfilled** | No |
| **Pledges to secure the bonds** | See Note 10D to the financial statements attached below. |
| **The Partnership's financial equity as of December 31, 2018, as defined in the indenture[16]** | $4,539 thousand |
| **The financial equity to debt ratio as of December 31, 2018, as defined in the indenture[16]** | Approx. 11 |
| **Is it material[17]** | Yes |

[12] The bonds include ILS 767,847 thousand in bonds issued by the Partnership and of ILS 760,686 thousand in bonds issued by Avner prior to the partnerships' merger.
[13] The Partnership has the right to fully or partially prepay the bonds, at any time, all in accordance with the indenture.
[14] See the Partnership's immediate report of December 22, 2016 (Ref. No. 2016-01-090873), the information appearing in which is hereby included by way of reference.
[15] From the issue date of the bonds, no change has occurred in the bond rating. For the updated rating report see the Partnership's immediate report of January 1, 2019 (Ref. No. 2019-01-000193), the information appearing in which is hereby included by way of reference.
[16] In accordance with the Partnership's undertaking on the date of the issue of the bonds – for further details, see Note 10D to the financial statements attached below. The ratio was calculated, *inter alia*, based on the discounted cash flows of the Tamar project and the Leviathan project as of December 31, 2018 included in Chapter A (Description of the Partnership's Business).
[17] A series of bond certificates shall be deemed material if the sum of the corporation's liabilities thereunder as of the end of the Report Year, as presented in the financial statements, constitutes five percent or more of the corporation's total liabilities.

## Additional information

The board of directors of the General Partner expresses its appreciation of the management of the General Partner of the Partnership, the officers and the entire team of employees for their dedicated work and their significant contribution to the promotion of the Partnership’s business.

Sincerely,

| | |
|---|---|
| **Assi Bartfeld** | **Yossi Abu** |
| Chairman of the Board of Directors | CEO |

**Delek Drilling Management (1993) Ltd.**
On behalf of: Delek Drilling – Limited Partnership

# Annex A to the Board of Directors' Report

# Figures regarding Delek & Avner (Tamar Bond) Ltd.

Further to the provisions of Note 10B to the financial statements attached below and to the provisions of Part Five of the Board of Directors' Report and following a tax ruling received by the Partnership immediately prior to the bond issuance, below are financial figures which will be disclosed to the holders of bonds of Delek & Avner (Tamar Bond) Ltd.

**Statements of Financial Position (Expressed in US$ Thousands)**

| | 31.12.2018 | 31.12.2017 |
|---|---|---|
| | Audited | Audited |
| **Assets**: | | |
| Current Assets: | | |
| Short-term deposits | 37,158 | 94,127 |
| Related parties | 2,561 | - |
| Loans to Shareholders | - | 320,000 |
| | 39,719 | 414,127 |
| **Noncurrent Assets**: | | |
| Loans to shareholders | 958,822 | 960,000 |
| Long-term bank deposits | 60,281 | 101,482 |
| | 1,019,103 | 1,061,482 |
| | 1,058,822 | 1,475,609 |
| **Liabilities and Equity**: | | |
| Current Liabilities: | | |
| Related parties | - | 95,609 |
| Bonds | - | 320,000 |
| | - | 415,609 |
| **Noncurrent Liabilities**: | | |
| Bonds | 960,000 | 960,000 |
| Loans from shareholders | 100,000 | 100,000 |
| | 1,060,000 | 1,060,000 |
| **Equity** | (1,178)** | * |
| | 1,058,822 | 1,475,609 |

* Less than $1,000.
** The deficit stems from the initial implementation of IFRS 9, approx. 419 thousand USD$ (Income) for the current period and approx. 1,596 USD$ (Expense) for past periods.

**Statements of Comprehensive Income (Expressed in US$ Thousands)**

| | For the Year Ended 31.12.2018 Audited | For the Year Ended 31.12.2017 Audited |
|---|---|---|
| Financial expenses | 60,570 | 70,584 |
| Financial income | (60,989) | (70,584) |
| Total comprehensive income | (419) | - |

**SPONSOR FINANCIAL DATA REPORT[18]**
**Cash flow for the period from January 1, 2018 to December 31, 2018**

| | | |
|---|---|---|
| | Item | Quantity/Actual Amount (in thousands) |
| A. | Total Offtake (BCM) (100%)[19] | 10.3 |
| B. | Tamar Revenues (100%) | 2,027,733 |
| C. | Loss Proceeds, if any, paid to Revenue Accounts | - |
| D. | Sponsor Deposits, if any, into Revenue Accounts | - |
| E. | Gross Revenues (before Royalties) | 447,986 |
| F. | Overriding Royalties | |
| | (a) Statutory Royalties | (51,682) |
| | (b) Third Party Royalties | (41,532) |
| G. | Net Revenues | 354,772 |
| H. | Costs and Expenses (Income): | |
| | (a) Fees Under the Financing Documents (Interest Income) | 1,535 |
| | (b) Taxes | - |
| | (c) Operation and Maintenance Expenses | (33,821) |
| | (d) Capital Expenditures | (7,547) |
| | (e) Payments under the Tamar FUA | - |
| | (f) Insurance – income | (4,600) |
| I. | Total Costs and Expenses (sum of Items H(a), (b), (c), (d), (e) and (f) | (44,433) |
| J. | Total Cash Flows Available for Debt Service (Item G minus Item H) | 310,339 |
| K. | Total Debt Service[20] | 377,335 |

[18] The aforesaid report is delivered to the trustee for the bonds on a quarterly and annual basis, and represents the cash flow deriving for the Partnership from the Tamar project relative to the amounts required for the debt service in such period.

[19] Sections A and B are based on 100% of Tamar partners, whereas in Section C all data refers to movements in the Sponsor Accounts.

[20] Includes early prepayment of the 2018 bonds.

Delek Drilling

# Financial Statements

2018

**Date: March 21, 2019**

**The board of directors of the general partner of Delek Drilling – Limited Partnership (the "Partnership")**
**19 Abba Even, Herzliya**

**Dear Sir/Madam,**

**Re: Letter of Consent Given Concurrently with the Publication of a Periodic Report in Connection with a Shelf Prospectus of the Partnership (the "Offering Document")**

We hereby notify you that we agree to the inclusion (including by way of reference), in the above-referenced Offering Document, of our reports specified below:

1. The auditor's report of March 21, 2019 on the Partnership's financial statements as of December 31, 2018 and 2017 and for each one of the three years in the period ended December 31, 2018.

2. The auditor's report of March 21, 2019 on an audit of components of internal control of financial reporting of the Partnership as of December 31, 2018.

| | |
|---|---|
| Kost Forer Gabbay & Kasierer | Ziv Haft |
| Certified Public Accountants | Certified Public Accountants |

**<u>Delek Drilling – Limited Partnership</u>**

**<u>Financial Statements as of December 31, 2018</u>**

**<u>in U.S. Dollars in Thousands</u>**

***This report is a translation of Delek Drilling - Limited Partnership's Hebrew-language financial statements, prepared solely for convenience purposes. Please note that the Hebrew version is the binding version, and in any event of discrepancy, the Hebrew version shall prevail.***

**Delek Drilling – Limited Partnership**

**Financial Statements as of December 31, 2018**

**in U.S. Dollars in Thousands**

## Contents

**Independent Auditors' Report to the Partners of Delek Drilling – Limited Partnership regarding Audit of Components of Internal Control over Financial Reporting pursuant to Section 9B(c) of the Securities Regulations (Periodic and Immediate Reports), 5730-1970**

We have audited components of internal control over financial reporting of Delek Drilling – Limited Partnership **(**the "**Partnership**") as of December 31, 2018. These components of control were determined as explained in the following paragraph. The Board of Directors (the "**Board**") and Management of the Partnership's general partner are responsible for maintaining effective internal control over financial reporting and for their assessment of the effectiveness of the components of internal control over financial reporting, attached to the periodic report as of the above date. Our responsibility is to express an opinion on the components of internal control over financial reporting of the Partnership, based on our audit.

The components of the internal control over financial reporting that were audited were determined pursuant to Audit Standard 104 of the Institute of Certified Public Accountants in Israel "Audit of Components of Internal Control over Financial Reporting", including the amendments thereto ("**Audit Standard 104**"). 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 104. This Standard requires that we plan and perform the audit with the purpose of identifying the Audited Components of Control, and to obtain reasonable assurance about whether these components of control were effectively maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, identifying the Audited Components of Control, assessing the risk that a material weakness exists in the Audited Components of Control, and testing and evaluating the design and operating effectiveness of such components of control, based on the assessed risk. Our audit of such components of control also included performing such other procedures as we considered necessary in the circumstances. Our audit only referred to the Audited Components of Control, as opposed to internal control over all of the material processes in connection with the financial reporting, and therefore our opinion refers only to the Audited Components of Control. In addition, our audit did not address mutual effects between the Audited Components of Control and non-audited controls, and therefore, our opinion does not take into consideration such possible effects. We believe that our audit provides a reasonable basis for our opinion in the context described above.

Because of its inherent limitations, internal control over financial reporting in general and components thereof in particular, may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Partnership effectively maintained, in all material respects, the Audited Components of Control as of December 31, 2018.

We have also audited, based on Generally Accepted Auditing Standards in Israel, the financial statements of the Partnership as of December 31, 2018 and 2017, and for each of the three years in the period ended December 31, 2018, and our report as of March 21, 2019, included an unqualified opinion on such financial statements.

Tel Aviv, March 21, 2019

| | |
|---|---|
| **Kost Forer Gabbay & Kasierer** | **Ziv Haft** |
| **Certified Public Accountants** | **Certified Public Accountants** |

## Independent Auditors' Report to the Partners of Delek Drilling – Limited Partnership

We have audited the accompanying statements of financial position of Delek Drilling – Limited Partnership (the "**Partnership**") as of December 31, 2018 and 2017 and the statements of comprehensive income, the statements of changes in the Partnership's equity, and the statements of cash flows for each of the years in the three-year period ended December 31, 2018. The Board and Management of the Partnership's general partner are responsible for these financial statements. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Generally Accepted Auditing Standards in Israel, including standards set in the Accountants Regulations (Mode of Operation of Accountants) 5733-1973. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by the Board and Management of the Partnership's general partner, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the Partnership as of December 31, 2018 and 2017 and the results of its operations, the changes in its capital and cash flows for each of the years in the three-year period ended December 31, 2018 in accordance with International Financial Reporting Standards (IFRS) and the provisions of the Securities Regulations (Annual Financial Statements), 5770-2010.

We have also audited, pursuant to Audit Standard 104 of the Institute of Certified Public Accountants in Israel "Audit of Components of Internal Control over Financial Reporting", and its amendments, components of the Partnership's internal control over financial reporting as of December 31, 2018 and our report as of March 21, 2019 included an unqualified opinion on the effective maintenance of such components.

Tel Aviv, March 21, 2019

| | |
|---|---|
| **Kost Forer Gabbay & Kasierer** | **Ziv Haft** |
| **Certified Public Accountants** | **Certified Public Accountants** |

**Delek Drilling – Limited Partnership**

**Statements of Financial Position (U.S. Dollars in thousands)**

| | Note | 31.12.2018 | 31.12.2017 |
|---|---|---|---|
| **Assets:** | | | |
| **Current assets:** | | | |
| Cash and cash equivalents | 3 | 143,885 | 154,835 |
| Short-term investments | 4 | 186,153 | 278,826 |
| Trade receivables | | 45,481 | 46,506 |
| Trade and other receivables | 5 | 99,171 | 30,878 |
| | | 474,690 | 511,045 |
| **Non-current assets:** | | | |
| Investments in petroleum and gas assets | 7 | 2,805,352 | 2,023,671 |
| Investments in a company accounted for at equity | 6 | 124,250 | 129,833 |
| Long-term deposits | 4 | 60,281 | 101,482 |
| Other long-term assets | 8 | 306,802 | 289,472 |
| | | 3,296,685 | 2,544,458 |
| | | 3,771,375 | 3,055,503 |
| **Liabilities and equity:** | | | |
| **Current liabilities:** | | | |
| Bonds | 10 | - | 319,421 |
| Declared distributable profits | 13C | 34,685 | 60,381 |
| Trade and other payables | 9 | 161,827 | 122,355 |
| | | 196,512 | 502,157 |
| **Non-current liabilities:** | | | |
| Bonds | 10 | 1,347,575 | 1,344,319 |
| Long-term liabilities to banking corporations | 10 | 1,238,143 | 468,967 |
| Other long-term liabilities | 11 | 134,041 | 121,582 |
| | | 2,719,759 | 1,934,868 |
| **Equity:** | 13 | | |
| Partners' equity | | 154,791 | 154,791 |
| Capital reserves | | 21,010 | 23,995 |
| Retained earnings | | 679,303 | 439,692 |
| | | 855,104 | 618,478 |
| | | 3,771,375 | 3,055,503 |

**The attached notes constitute an integral part of the financial statements.**

| March 21, 2019 | | | |
|---|---|---|---|
| Date of approval of the Financial Statements | Assi Bartfeld<br>Chairman of the Board<br>Delek Drilling<br>Management (1993) Ltd.<br>General Partner | Yossi Abu<br>CEO<br>Delek Drilling<br>Management (1993) Ltd.<br>General Partner | Yossi Gvura<br>Deputy CEO<br>Delek Drilling<br>Management (1993) Ltd.<br>General Partner |

## Delek Drilling – Limited Partnership

## Statements of Comprehensive Income (U.S. Dollars in thousands)

| | Note | For the year ended 31.12.2018 | 31.12.2017 | 31.12.2016[1] |
|---|---|---|---|---|
| **Revenues:** | | | | |
| From natural gas and condensate sales | 14 | 457,982 | 501,926 | 542,025 |
| Net of royalties | 15 | 91,333 | 80,256 | 85,181 |
| **Revenues, net** | | 366,649 | 421,670 | 456,844 |
| **Expenses and costs:** | | | | |
| Cost of production of natural gas and condensate | 16 | 32,720 | 35,188 | 39,625 |
| Depreciation, depletion and amortization expenses | 7 | 45,058 | 94,898 | 55,784 |
| Oil and gas exploration and other direct expenses | 17 | 9,720 | 7,840 | 5,917 |
| G&A | 18 | 9,811 | 10,629 | 9,442 |
| **Total expenses and costs** | | 97,309 | 148,555 | 110,768 |
| Other revenues (expenses), net[2] | | (561) | 566,542 | 42,276 |
| The Partnership's share in the profits of a company accounted for at equity, net | 6 | 10,542 | 10,042 | - |
| **Operating profit** | | 279,321 | 849,699 | 388,352 |
| Financial expenses | 19 | (57,432) | (75,044) | (71,450) |
| Financial income | 19 | 59,149 | 46,872 | 10,985 |
| Financial income (expenses), net | | 1,717 | (28,172) | (60,465) |
| **Income before levy** | | 281,038 | 821,527 | 327,887 |
| Petroleum and gas profit levy | 20 | (4,205) | (4,305) | (1,019) |
| **Net income** | | 276,833 | 817,222 | 326,868 |
| **Other comprehensive income (loss) for items which may subsequently be reclassified to profit or loss:** | | | | |
| Profit (loss) in respect of cash flow hedging transactions | 22F2 | - | (3,957) | 11,960 |
| Profit in respect of financial assets available for sale | | - | 2,237 | 1,532 |
| Carried to profit or loss in respect of cash flow hedging transactions | | (2,721) | (904) | - |
| Carried to profit or loss in respect of financial assets available for sale | | - | (695) | (48) |
| **Total other comprehensive income (loss)** | | (2,721) | (3,319) | 13,444 |
| **Total comprehensive income** | | 274,112 | 813,903 | 340,312 |
| Basic and diluted profit per participation unit (in U.S. Dollars) | | 0.236 | 0.696 | 0.278 |
| Weighted number of participation units for the purpose of the said calculation (in thousands) | | 1,173,815 | 1,173,815 | 1,173,815 |

**The attached notes constitute an integral part of the financial statements.**

[1] Retroactive classification due to the merger (including the notes attached to the financial statements), see Note 2F below.
[2]With respect to other revenues generated in 2017 from the sale of the Tamar and Dalit leases, see Note 7C1F.

**Delek Drilling – Limited Partnership**

**Statements of Changes in the Partnership's Equity (U.S. Dollars in thousands)**

| | The Partnership's equity | Capital reserve for redemption of participation units | Capital reserve for transactions between the corporation and a control holder thereof | Capital reserve for financial assets available for sale and cash flow hedging transactions | Retained earnings | Total |
|---|---|---|---|---|---|---|
| **Balance as of January 1, 2016[3]** | 154,791 | 1,631 | 8,257 | (927) | 490,592 | 654,344 |
| **Changes in the year ended December 31, 2016[2]:** | | | | | | |
| Net income | - | - | - | - | 326,868 | 326,868 |
| Other comprehensive income | - | - | - | 13,444 | - | 13,444 |
| Total comprehensive income | - | - | - | 13,444 | 326,868 | 340,312 |
| Profits distributed (Note 13C) | - | - | - | - | (50,017) | (50,017) |
| Profits for distribution, declared (Note 13C) | - | - | - | - | (100,004) | (100,004) |
| Advance tax payments on the account of the tax owed by the participation unit holders (Note 13C) | - | - | - | - | (58,211) | (58,211) |
| Capital reserve for benefits from a control holder (Note 13F) | - | - | 2,491 | - | - | 2,491 |
| **Balance as of December 31, 2016[3]** | 154,791 | 1,631 | 10,748 | 12,517 | 609,228 | 788,915 |
| **Changes in the year ended December 31, 2017:** | | | | | | |
| Net income | - | - | - | - | 817,222 | 817,222 |
| Other comprehensive loss | - | - | - | (3,319) | - | (3,319) |
| Total comprehensive income (loss) | - | - | - | (3,319) | 817,222 | 813,903 |
| Profits distributed (Note 13C) | - | - | - | - | (680,710) | (680,710) |
| Profits for distribution, declared (Note 13C) | - | - | - | - | (60,000) | (60,000) |
| Advance tax payments on the account of the tax owed by the participation unit holders (Note 13C) | - | - | - | - | (246,048) | (246,048) |
| Capital reserve for benefits from a control holder (Note 13F) | - | - | 2,418 | - | - | 2,418 |
| **Balance as of December 31, 2017** | 154,791 | 1,631 | 13,166 | 9,198 | 439,692 | 618,478 |
| Effect of first application of IFRS 9 (see Note 2C) | - | - | - | (2,100) | 2,114 | 14 |
| **Balance as of January 1, 2018 after implementation of the said change** | 154,791 | 1,631 | 13,166 | 7,098 | 441,806 | 618,492 |
| **Changes in the year ended December 31, 2018:** | | | | | | |
| Net income | - | - | - | - | 276,833 | 276,833 |
| Other comprehensive loss | - | - | - | (2,721) | - | (2,721) |
| Total comprehensive income (loss) | | | | (2,721) | 276,833 | 274,112 |
| Profits distributed (Note 13C) | - | - | - | - | (274) | (274) |
| Declared distributable profits (Note 13C) | - | - | - | - | (34,446) | (34,446) |
| Advance tax payments on the account of the tax owed by the participation unit holders (Note 13C) | - | - | - | - | (4,616) | (4,616) |
| Capital reserve for benefits from a control holder (Note 13F) | - | - | 1,836 | - | - | 1,836 |
| **Balance as of December 31, 2018** | 154,791 | 1,631 | 15,002 | 4,377 | 679,303 | 855,104 |

**The attached notes constitute an integral part of the financial statements.**

[3] Retroactive classification due to the merger (including the notes attached to the financial statements), see Note 2F below.

**Delek Drilling – Limited Partnership**

**Statements of Cash Flows (U.S. Dollars in thousands)**

| | For the year ended | | |
|---|---|---|---|
| | **31.12.2018** | **31.12.2017** | **31.12.2016[4]** |
| **Cash Flows - Current Operations:** | | | |
| Income for the year | 276,833 | 817,222 | 326,868 |
| Adjustments for: | | | |
| Depreciation, depletion and amortization | 47,518 | 100,179 | 59,982 |
| Change in fair value of financial derivatives, net | - | 558 | 64 |
| Update of asset retirement obligation | 5,070 | 3,704 | 2,851 |
| Revaluation of short-term and long-term investments and deposits | 2,603 | (826) | (579) |
| Expenses (income) due to revaluation of share-based payment | (221) | 52 | 338 |
| Benefit from a control holder included in expenses against a capital reserve | 1,836 | 2,418 | 2,491 |
| Loss from the disposition of financial assets available for sale | - | - | (48) |
| Profit from the sale of petroleum and gas assets | - | (572,454) | (42,276) |
| Revaluation of other long-term assets | (48,804) | (25,724) | - |
| The Partnership's share in the profits of a company accounted for at equity, net | (10,542) | (10,042) | - |
| **Changes in assets and liabilities items:** | | | |
| Decrease (increase) in trade receivables | 1,025 | 11,667 | (8,488) |
| Decrease (increase) in trade and other receivables | 446 | (182) | (4,002) |
| Decrease (increase) in other long-term assets | (2,114) | 4,711 | (8,488) |
| Increase (decrease)in trade and other payables | (15,503) | (1,901) | 3,966 |
| Increase (decrease) in another long-term liability | (1) | (110) | 24 |
| | (18,687) | (487,950) | 5,835 |
| **Net cash deriving from current operations** | 258,146 | 329,272 | 332,703 |
| **Cash Flows - Investment Activity:** | | | |
| Investment in petroleum and gas assets | (744,186) | (443,329) | (159,999) |
| Decrease (increase) in other long-term assets | (15,930) | (31,412) | 1,846 |
| Proceeds from the sale of petroleum and gas assets | - | 829,898 | 40,000 |
| Loan given to a company accounted for at equity | - | (34,000) | - |
| Repayment of loans given | 10,850 | 34,000 | - |
| Decrease (increase) in short-term investment, net | 91,159 | (150,819) | 264,773 |
| Long-term deposit in bank deposits | (60,000) | (17,676) | (82,884) |
| Repayment of long-term bank deposits | 100,000 | 51,307 | 102,905 |
| Dividend received from a company accounted for at equity | 16,125 | - | - |
| Disposition of financial assets available for sale | - | 4,251 | 14,450 |
| Decrease (increase) in other receivables – operator of the joint ventures | (52,590) | (6,001) | 15,830 |
| **Net cash deriving from (used for) investment activity** | (654,572) | 236,219 | 196,921 |
| **Cash Flows - Financing Activity:** | | | |
| Bond issue (net of issue costs) | - | - | 392,563 |
| Receipt of long-term loans from banks (net of financial expenses) | 775,384 | 420,534 | - |
| Profits distributed | (61,359) | (781,116) | (50,171) |
| Payments on account of the tax liable by participation unit holders | (33,310) | (206,993) | (51,483) |
| Reimbursement received from income tax for previous years, net | 24,761 | - | - |
| Repurchase of issued bonds | (10,103) | - | (15,234) |
| Repayment of bonds | (309,897) | (320,000) | (368,753) |
| Proceeds (payments) from the exercise of hedging transactions | - | (3,957) | 11,960 |
| **Net cash used in (generated by) financing activity** | 385,476 | (891,532) | (81,118) |
| **Increase (decrease) in cash and cash equivalents** | (10,950) | (326,041) | 448,506 |
| **Cash and cash equivalents balance at the beginning of the year** | 154,835 | 480,876 | 32,370 |
| **Cash and cash equivalents balance at the end of the year** | 143,885 | 154,835 | 480,876 |
| **Annex A - Finance and investment activity not involving cash flows:** | | | |
| Investments in petroleum and gas assets against liabilities | 127,110 | 94,166 | 33,237 |
| Proceeds from the disposition of oil and gas assets against investment in a company accounted for at equity and against long-term assets | - | 119,790 | 140,300 |
| Declared distributable profits and payable advance tax payments on account of the unit holders | 34,446 | 98,653 | 106,732 |
| **Annex B - Additional information on cash flows:** | | | |
| Interest paid (including capitalized interest) | 129,117 | 109,015 | 84,484 |
| Interest received | 10,205 | 7,832 | 7,265 |
| Dividend received | 16,125 | 80 | 353 |
| Petroleum and gas levy paid | - | - | 1,019 |

**The attached notes constitute an integral part of the financial statements.**

[4] Retroactive classification due to the merger (including the notes attached to the financial statements), see Note 2F below.

**Note 1 – General:**

**A.** Delek Drilling – Limited Partnership (the "**Partnership**") was founded according to a limited partnership agreement of July 1, 1993 between Delek Drilling Management (1993) Ltd. as general partner (the "**General Partner**") of the first part, and Delek Drilling Trusts Ltd. as a limited partner (the "**Trustee**") of the second part.

The Trustee serves as trustee for the holders of the participation units, under the supervision of the supervisors, CPA Micha Blumenthal, together with Fahn Kanne & Co., CPAs and Gissin & Keidar (the "**Supervisor**"). The Supervisor was granted certain supervision powers in the partnership agreement and in the Partnerships Ordinance.

The parent company of the General Partner is Delek Energy Systems Ltd. (the "**Parent Company**") and the Partnership's ultimate parent company is Delek Group Ltd. ("**Delek Group**").

The participation units of the Partnership were listed for trade on the Tel Aviv Stock Exchange (TASE) and started being traded thereon commencing in 1993.

The address of the Partnership's registered office is 19 Abba Eban Boulevard, Herzliya.

**B.** As of the date of approval of the financial statements, the Partnership's primary business is exploration, development and production of natural gas, condensate and petroleum, as well as the promotion of the use of infrastructures for the export of natural gas, aiming to increase the sales volume of natural gas. The Partnership is also promoting several alternatives for the sale of its remaining direct holdings in the Tamar I/12 and Dalit I/13 leases (jointly: "**Tamar and Dalit**"), in accordance with the provisions of the Gas Framework (see Section G below and Note 12J1 below), including by way of establishing an SPV which will offer debt and equity, to be listed on a foreign stock exchange and/or on the TASE and/or sale to a third party and/or through split of the Partnership's assets, such that all of the Partnership's assets and liabilities, other than the assets and liabilities attributed to the Tamar and Dalit leases, shall be transferred to a foreign SPV whose shares will be distributed by the Partnership as a distribution in kind to the Partnership's participation unit holders. For further details, see Note 23A below.

**C.** The Partnership's revenues from the sale of natural gas are affected mainly from the scope of natural gas consumption by the Israel Electric Corp. Ltd. ("**IEC**"). (See Notes 12C1B and 14B below).

**D.** The financial figures in the financial statements of the joint ventures used by the Partnership in the preparation of its financial statements are based, *inter alia*, on documents and accounting data provided by the operator of the joint ventures in Israel, Noble Energy Mediterranean Ltd. and the operator of the joint venture in Cyprus, Noble Energy International Ltd. (jointly: "**Noble**" and/or the "**Operator**"). Also see Note 12E.

**E. Restructuring by way of merger**:

On May 17, 2017, Avner Oil Exploration – Limited Partnership[5] (the "**Avner Partnership**") merged with and into the Partnership such that all of the assets and liabilities of Avner Partnership were transferred As Is to the Partnership. The exchange ratio determined in the merger transaction was set at 1:5.32, such that in lieu of 3,334,830,842 participation units of Avner Trusts Ltd. (the limited partner in the Avner Partnership), 626,847,820 participation units of the Trustee were allotted.

[5] On May 17, 2017, upon merger thereof into the Partnership, the Avner Partnership was wound up without liquidation and written off from the registrations of the Registrar of Partnerships.

**Note 1 – General (Cont.)**

After the closing of the merger, the amount of participation units in the Partnership's authorized capital is 1,173,814,691. In addition, the Avner Partnership's Series A bond series, which includes ILS 760,686,000 par value of bonds of ILS 1 each, was consolidated with the Partnership's Series A bond series, which includes ILS 767,847,000 par value of bonds of ILS 1 each, such that the two series, all of the terms and conditions of which are identical, constitute one expanded series of Series A Bonds of the Partnership, which includes ILS 1,528,533,000 par value of bonds of ILS 1 each.

It is noted that in view of the said merger, the trust agreement and the partnership agreement were amended accordingly. See Note 12I3 below regarding a motion for class certification in connection with the merger transaction.

**F.** In July 2017, the Partnership sold 9.25% (out of 100%) of the interests in the Tamar and Dalit Leases to Tamar Petroleum Ltd. (the "**Company Accounted for at Equity**" or "**Tamar Petroleum**") against consideration in cash and allotment of shares of Tamar Petroleum, for further details, see Notes 6 and 7C1F below.

**G.** On August 16, 2015 a Government resolution was adopted concerning a framework for the regulation of the natural gas sector in Israel, including in relation to the Partnership's rights in the natural gas reservoirs "Tamar", "Leviathan", "Karish" and "Tanin", which resolution came into effect on December 17, 2015, upon the grant of an exemption from several provisions of the Restrictive Trade Practices Law, 5748-1988 (the "**Restrictive Trade Practices Law**") to the Partnership jointly with Noble by the Prime Minister, in his capacity as the Minister of Economic Affairs, under Section 52 of the Restrictive Trade Practices Law (the Government resolution and the provisions of the exemption shall hereinafter be jointly referred to as the: "**Gas Framework**"). Following a judgment rendered by the High Court of Justice on petitions related to the Gas Framework filed by various entities against the Government, the Prime Minister and others, including the Partnership, on May 22, 2016 the Government readopted its resolution of August 16, 2015 in respect of the Gas Framework, while setting an alternative arrangement for the clause in the Framework concerning a "stable regulatory environment", to ensure a regulatory environment that encourages investments in the natural gas exploration and production segment. For further details with respect to the Gas Framework see Note 12J1 below. For details regarding the sale of rights in the Karish and Tanin leases see Note 8B below, for details regarding the sale of interests in Tamar and Dalit leases (9.25% out of 100%) see Note 7C1F below.

## Note 2 - Significant Accounting Policies:

The accounting policy specified below was consistently applied in the financial statements of the Partnership, throughout the presented periods, unless stated otherwise.

**A. Declaration regarding compliance with the International Financial Reporting Standards (IFRS):**

The financial statements comply with the provisions of the International Financial Reporting Standards.

**B. Principles of preparation of the financial statements:**

The annual financial statements include the additional disclosure required pursuant to the Securities Regulations (Annual Financial Statements), 5770-2010.
The financial statements were prepared applying the cost principle, except in relation to financial assets and liabilities which are measured at fair value.

The Partnership has elected to present the profit or loss items using the function of expense method.

**C. Functional currency and presentation currency:**

1. Functional currency: The functional currency which best and most faithfully represents the economic effects of transactions, events and circumstances on the Partnership's business is the U.S. Dollar. Any transaction that is not in the Partnership's functional currency is a foreign currency transaction, with all values rounded off to the nearest thousand, unless stated otherwise. See Paragraph D below.
2. Presentation currency: The Partnership's financial statements are presented in the U.S. Dollar.

**D. Transactions in foreign currency:**

A transaction denoted in foreign currency is recorded, upon initial recognition, in the functional currency, using the immediate exchange rate between the functional currency and the foreign currency on the date of the transaction.

At the end of each report period:

- Financial items in foreign currency are translated using the exchange rate as of the end of the report period;
- Non-financial items measured at historic cost in foreign currency are translated using the exchange rate on the date of the transaction;
- Rate differentials deriving from the settlement of financial items or deriving from the translation of financial items according to different exchange rates to those used for translation upon initial recognition during the period, or to those used for translation in previous financial statements, shall be recognized at profit or loss in the period in which they derived.

**E. The operating cycle period:**

The Partnership's operating cycle period is one year.

**Note 2 - Significant Accounting Policies (Cont.):**

**F.** Further to Note 1E above concerning the merger with the Avner Partnership, the data of the period up to the merger were presented, including the comparison figures in the Partnership's financial statements, subject to the following:

1) The statements of financial position, the statements of changes in the Partnership's equity, the statements of comprehensive income and the statements of cash flows were presented to reflect the financial position, business results and cash flows of the Partnership had the merger transaction ever been closed.
2) The financial statements were prepared based on the "as pooling" method, as the Partnership and the Avner Partnership were under the same control before and after the merger. The "as pooling" method was applied in these financial statements such that all of the assets and liabilities are reflected according to their book value including the assets and liabilities of the Avner Partnership. In addition, in applying such method, the sum of retained earnings was determined according to an aggregation of the retained earnings of the Partnership and the Avner Partnership and the difference between the issued units of the Partnership and the net assets (capital) of the Avner Partnership was recorded to the Partnership's capital.
3) The net income per participation unit was calculated by dividing the net income attributed to the participation unit holders by the number of participation units in circulation following the closing of the merger transaction as aforesaid, totaling approx. 1,173,815 thousand participation units.

**G. 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.

It appears that 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. Any 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.

**Note 2 - Significant Accounting Policies (Cont.):**

**G. Joint ventures and SPCs (Cont.):**

**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'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.

**H. Cash equivalents:**

Highly liquid short-term investments, which include, *inter alia*, short-term deposits deposited in bank which are unlimited in use and unpledged, are deemed as cash equivalents. Such investments may easily be converted into known amounts of cash and are exposed to an insignificant risk of changes in value, with the period until repayment being up to three months from the date of the investment.

**I. Short-term deposits:**

Short-term deposits in banks whose original term exceeds three months but is shorter than one year on the date of the investment. The deposits are presented in accordance with the terms of their deposit.

**J. Financial instruments:**

As specified in Section CC2 regarding the first-time application of International Financial Reporting Standard No. 9 – Financial Instruments (in this section: "**IFRS 9**"), the Partnership chose to retroactively apply the provisions of IFRS 9 without restatement of comparison figures. The accounting policy that was applied until December 31, 2017 with respect to financial instruments, is as follows:

**1. Financial assets:**

A financial asset is recognized when the Partnership becomes a party to the contractual provisions of the instrument. Financial assets covered by IAS 39 are recognized on the initial recognition date at fair value, plus direct transaction costs, 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.

After the initial recognition, the accounting treatment of financial assets is based on their classification as specified below:

**a) Financial assets measured at fair value through profit or loss:**

This group includes financial assets held for trading and financial assets designated, upon the initial recognition thereof, to be presented at fair value through profit or loss.
Embedded derivatives are separated from the host contract and treated separately if:

1) There is no close connection between the financial characteristics and the risks of the host contract and of the embedded derivate;

2) A separate instrument with the same conditions as the embedded derivative would have met the definition of a derivative, and

3) The combined instrument is not measured at fair value through profit or loss.

**Note 2 - Significant Accounting Policies (Cont.):**

**J. Financial instruments (Cont.):**

**1. Financial assets (Contd.):**

**a) Financial assets measured at fair value through profit or loss (Contd.):**

The Partnership examines the existence of an embedded derivative and the need to separate it on the date of fulfillment, *inter alia*, of all of the conditions precedent to its being a party to the engagement. The need to separate an embedded derivative is reassessed only when there is a change in the terms of the engagement which significantly affects the cash flows from the engagement.

**b) Financial assets available for sale**:

Non-derivative financial assets which are designated as available for sale or which are not classified to any other group of financial assets are presented as available-for-sale financial assets, while after the initial recognition fair value changes are usually recognized as a separate component in other comprehensive income and accrued in equity, with the exception of fair value changes that are attributed to dividends in respect of an equity instrument and which are attributed to the accrual of effective interest and to rate differences due to debt instruments, which are recognized in profit or loss.

**c) Loans and other receivables:**

Loans and other receivables are investments repaid in fixed or determinable instalments, which are not traded on an active market. After the initial recognition, loans and other receivables are presented according to their terms and conditions, using the effective interest method, net of a provision for impairment.

**2. Financial liabilities:**

Financial liabilities are initially recognized at fair value when the Partnership becomes a party to the contractual provisions of the instrument.

The financial liabilities are recognized net of transaction costs which may be directly attributed to the taking or issue of a financial liability.

After the initial recognition, the accounting treatment of financial liabilities is based on their classification as specified below:

**Financial liabilities at amortized cost:**

After the initial recognition, these liabilities, such as bonds, are measured at their amortized cost in accordance with the effective interest method.

**3. Setoff of financial instruments:**

Financial assets and financial liabilities are offset and the net amount presented in the statement of financial position if there is a legally enforceable right to offset the amounts recognized, and there is an intention to retire the asset and the liability on a net basis or to dispose of the asset and settle the liability simultaneously.

**Note 2 - Significant Accounting Policies (Cont.):**
**J. Financial Instruments (Cont.):**

4. **Write-off of financial instruments:**

   a) **Financial assets:**

   A financial asset is written off when the contractual rights to receive the cash flows from the financial asset expire or when the Partnership transfers the contractual rights to receive the cash flows from the financial asset or when it assumes a liability to pay the cash flows received in full to the third party, without significant delay.

   In addition, when it substantially transfers all of the risks and the benefits relating to the asset or does not transfer and also does not substantially retain all of the risks and benefits relating to the asset but transfers the control of the asset.
   Upon the writing off of a financial asset available for sale, the capital reserve for the same asset that was recognized prior thereto in other comprehensive income is classified as profit or loss as an adjustment due to reclassification.

   b) **Financial liabilities:**

   A financial liability is written off when it is settled, i.e. the liability is paid, cancelled or expires. A financial liability is settled when the debtor (the Partnership) pays the liability by a cash payment, other financial assets, or is legally released from the liability.

5. **Impairment of financial assets:**

   The Partnership examines, on each report date, whether there is objective evidence of impairment of a financial asset or a group of financial assets which are presented at amortized cost. Objective evidence of impairment exists when one or more events negatively affect the estimate of the future cash flows from the asset after the recognition date. For an investment in an equity instrument, objective evidence of impairment includes also a significant (considering the standard deviation of the specific instrument) or continuous decline in the fair value of the investment below its original cost.

   If objective evidence exists as aforesaid, the treatment is as follows:

   <u>Impairment of financial assets presented at amortized cost</u>

   The amount of the loss that is carried to profit or loss is measured as the difference between the balance of the asset in the financial statements and the present value of the estimate of the future cash flows from the asset (which do not include future credit losses that have not yet formed), which are discounted according to the financial asset's original effective interest rate.

   The amount of the loss is recognized in the statement of comprehensive income. If the financial asset bears variable interest, the discounting is done according to the current effective interest rate. In subsequent periods, a loss from impairment is cancelled when it is possible to objectively ascribe the recovery of the value of the asset to an event that occurred after the recognition of the loss.

   Such cancelation is carried to profit or loss up to the amount of the loss recognized.

**Note 2 - Significant Accounting Policies (Cont.):**

**J. Financial Instruments (Cont.):**

**5. Impairment of financial assets (Contd.):**

Impairment of financial assets available for sale

The difference between the purchase cost (net of principal repayments and any impairments) and the fair value of the asset, which was recognized in the past in other comprehensive income and accrued in the equity, net of any loss from impairment in respect of such financial asset that was recognized prior thereto in profit or loss, is reclassified from the equity to profit or loss as an adjustment due to reclassification. Losses from impairment that were recognized in profit or loss in respect of investments in an equity instrument are not cancelled through profit or loss.

**K. Derivative financial instruments:**

The Partnership sometimes performs engagements in derivative financial instruments such as foreign currency forward contracts and interest rate swap (IRS) transactions in order to protect itself against the risks entailed by fluctuations in the exchange rates of foreign currency and in the interest rates. These financial derivatives are initially recognized according to the fair value.

After the initial recognition, the financial derivatives are measured at fair value. Profits or losses deriving from changes in the fair value of derivatives that are not used for hedging purposes are immediately carried to profit or loss.

**L. Derivative financial instruments for hedging purposes (protection):**

The Partnership designates certain financial instruments, generally derivatives, as hedging instruments. At the time of creation of the hedge, the Partnership records the hedge ratios and the purpose of the risk management and the Partnership's strategy for performing the hedge. The documentation includes, at least, the identification of the hedging instrument, the identification of the hedged item or transaction, the nature of the hedged risk and the manner in which the Partnership examines the effectiveness of the hedging instrument in offsetting the exposure to changes in the fair value or cash flow of the hedged item, which are attributable to the hedged risk when entering the hedging transaction and on an ongoing basis. The Partnership examines in each period that the hedge is expected to be highly effective in achieving offsetting changes in fair value or cash flow, and that the effectiveness of the hedging is reliably measurable.

The Partnership performs cash flow hedges:

The effective part of the changes in the fair value of derivatives designated for cash flow hedge is recognized as other comprehensive income and is accrued under equity.

The non-effective part of the change in the aforesaid fair value is recognized as profit or loss. Amounts recognized as other comprehensive income are reclassified as profit or loss in periods during which the projected cash flow that was hedged affects the profit or loss, excluding a loss amount which is not expected to be recovered in a future period.

The Partnership discontinues hedge accounting when the hedging instrument expires, is sold, is cancelled, or is exercised, when the hedging is no longer qualified to be recognized as account hedging or the company decides to cancel the designation as account hedging. Cumulative changes at the time of cessation of the hedging that were recognized as other comprehensive income and accrued as equity, remain under equity, unless they derived from a projected transaction which is no longer expected to occur or until the defined projected cash flows affect the profit or loss.

**Note 2 – Significant Accounting Policies (Cont.):**

**L. Derivative financial instruments for hedging purposes (protection) (Cont.):**

The accounting policy which is applied from January 1, 2018 with respect to financial instruments is as follows:

1) **Financial assets:**

Financial instruments that are subject to IFRS 9 are measured on the date of first-time recognition at fair value plus transaction costs that can be directly attributed to the purchase of the financial asset, except in the case of a financial asset that is measured at fair value through profit or loss, with respect to 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.

<u>The Partnership measures debt instruments at amortized cost, when</u>:

The Partnership's business model is holding the financial assets in order to collect contractual cash flows; and the contractual terms and conditions of the financial asset provide entitlement on set dates to cash flows that are only interest and principal payments for the outstanding principal amount.

Subsequently to the initial recognition, instruments in this group will be presented according to their terms according to cost plus direct transaction costs, using the amortized cost method.

In addition, on the date of first-time recognition an entity may designate, irrevocably, a debt instrument as measured at fair value through profit or loss if such designation significantly reduces or cancels inconsistent measurement or recognition, for example in the event that the relevant financial liabilities are also measured at fair value through profit or loss.

<u>The Partnership measures debt instruments at fair value through other comprehensive income, when</u>:

The Partnership's business model is both holding the financial assets in order to collect contractual cash flows and sale of the financial assets; and the contractual terms and conditions of the financial asset provide entitlement on set dates to cash flows that are only interest and principal payments for the outstanding principal amount. Subsequently to the initial recognition, instruments in this group are measured according to fair value. Profit or loss as a result of fair value adjustments, other than interest, rate differentials and impairment, are recognized in other comprehensive income.

**Note 2 – Significant Accounting Policies (Cont.):**

**L. Derivative financial instruments for hedging purposes (protection) (Cont.):**

**1) Financial assets (Cont.):**

**Equity instruments:**

Financial instruments that constitute investments in equity instruments do not meet the aforesaid criteria and are therefore measured at fair value through profit or loss.

In relation to equity instruments that are not held for trade, on the date of first-time recognition, the Partnership may make an irrevocable choice, to present in other comprehensive income subsequent changes to the fair value that would have otherwise been recognized through profit or loss. Such fair value changes will not be carried to profit or loss in the future even upon write-off of the investment.

**2) Impairment of financial assets:**

On each report date the Partnership examines the provision for loss due to financial debt instruments that are not measured at fair value through profit or loss.

The Partnership distinguishes between two situations of recognition of a provision for loss;

a) Debt instruments whose credit quality did not significantly deteriorate since the date of first-time recognition or cases in which the credit risk is low – the provision to loss that will be recognized with respect to such debt instrument will take into account anticipated credit loss in the 12-month period after the report date, or;

b) Debt instruments whose credit quality did significantly deteriorate since the date of first-time recognition and with respect to which the credit risk is not low, the provision to loss that will be recognized will take into account anticipated credit loss – for the remainder of the instrument's life. The Partnership applies the relief set forth in IFRS 9 according to which it assumes that the credit risk of a debt instrument did not significantly increase since the date of first-time recognition if it was determined on the report date that the instrument has low credit risk, for example when the instrument has an external "investment grade" rating.

The decrease in value with respect to debt instruments measured according to a depreciated cost shall be carried to profit or loss against a provision while the decrease in value with respect to debt instruments measured at fair value through other comprehensive income will be attributed against a capital reserve and will not reduce the book value of the financial asset in the statement of financial position.

**Note 2 – Significant Accounting Policies (Cont.):**
**L. Derivative financial instruments for hedging purposes (protection) (Cont.):**

3) **Write-off of financial assets:**

The Partnership writes-off a financial asset when, and only when:

(a) The contractual rights to the cash flows from the financial asset expired, or

(b) The Partnership materially transfers all of the risks and benefits that derive from the contractual rights to receive the cash flows from the financial asset or when part of the risks and benefits upon transfer of the financial asset remain in the hands of the entity but it can be said that it transferred control over the asset, or

(c) The Partnership retains the contractual rights to receive the cash flows that derive from the financial asset, but assumes a contractual obligation to pay such cash flows in full to a third party, without substantial delay.

4) **Financial liabilities:**

On the date of first-time recognition, the Partnership measures the financial liabilities that are subject to IFRS 9 at fair value, less transaction costs that can be directly attributed to the issuance of the financial liability.

Subsequently to the date of first-time recognition, the Partnership measures all of the financial liabilities according to the amortized cost method.

5) **Write-off of financial liabilities**:

The Partnership writes-off a financial liability when, and only when it is retired – i.e., when the liability that was defined in the contract is paid or cancelled or expires.

A financial liability is retired when the debtor pays the liability by payment in cash, with other financial assets or is legally released from the liability.

In the event of a change of conditions with respect to an existing financial liability, the Partnership examines whether the terms and conditions of the liability are materially different than the existing conditions.

When a material change is made in the conditions of an existing financial liability, the change is treated as a write-off of the original liability and a recognition of a new liability. The difference between the balance of the two aforesaid liabilities in the financial statements is carried to profit or loss.

If the change is immaterial, the Partnership is required to update the liability amount, i.e., capitalize the new cash flows at the original effective interest rate, with the differences carried to profit or loss.

Upon examining whether the change to the conditions of an existing liability is material, the Partnership takes qualitative and quantitative considerations into account.

**Note 2 – Significant Accounting Policies (Cont.):**
**L. Derivative financial instruments for hedging purposes (protection) (Cont.):**

**6) Setoff of financial instruments:**

Financial assets and financial liabilities are offset and the net amount presented in the statement of financial position if there is a legally enforceable right to offset the amounts recognized, and there is an intention to retire the asset and the liability on a net basis or to dispose of the asset and settle the liability simultaneously. The setoff right must be legally enforceable, not only in the ordinary course of business of the parties to the contract but also in the event of bankruptcy or insolvency of one of the parties. For the setoff right to be available immediately, it cannot be contingent on a future event or, occasionally inapplicable or, expire pursuant to certain events.

**7) Embedded derivatives:**

Pursuant to the provisions of IFRS 9, derivatives embedded in financial assets shall not be separated from a host contract. Such hybrid contracts shall be measured in their entirety at a depreciated cost or at fair value, according to the criteria of the business model and contractual cash flows.

When a host contract does not fulfill the definition of a financial asset, an embedded derivative is separated from the host contract and treated as a derivative when the economic risks and characteristics of the embedded derivative are not tightly connected to the economic risks and characteristics of the host contract, the embedded derivative fulfills the definition of a derivative and the hybrid instrument is not measured at fair value when the differences are carried to profit or loss.

The need to separate an embedded derivative is reassessed only when there is a change in the engagement which significantly affects the cash flows from the engagement.

**8) Derivative financial instruments for hedging (protection) purposes:**

The Partnership occasionally performs engagements in derivative financial instruments such as foreign currency forward contracts and interest rate swap (IRS) transactions in order to protect itself against the risks entailed by interest rate and foreign currency exchange rate fluctuations.

Profits or losses deriving from changes in the fair value of derivatives that are not used for hedging purposes are immediately carried to profit or loss.

Hedging transactions qualify for hedging accounting, *inter alia*, when on the hedging creation date there is formal documentation and designation of the hedging relations and of the purpose of the risk management and the Partnership's strategy to perform hedging. The hedging is examined on an ongoing basis and it is determined in practice to be highly effective in the financial reporting period for which the hedging is designated. The Partnership applies the hedge accounting policies set forth in IFRS 9.

**Note 2 – Significant Accounting Policies (Cont.):**
**L. Derivative financial instruments for hedging purposes (protection) (Cont.):**

**8) Derivative financial instruments for hedging (protection) purposes (Contd.):**

Hedging (protection) transactions are treated as follows:

**Cash flow hedging:**

The effective part of the changes in the fair value of the hedging instrument is recognized in other comprehensive profit (loss) while the ineffective part is immediately carried to profit or loss.

Other comprehensive profit (loss) is carried to profit or loss when the hedging transaction results are carried to profit or loss. For example, in periods when interest revenues or expenses are recognized or when an anticipated sale occurs.

When the hedged item is a non-financial asset or liability, their cost also includes the amount of profit (loss) from the hedging instrument.

The Partnership is stopping to apply hedge accounting henceforth only when all or part of the hedge ratios cease to fulfill the entitling criteria (after taking into account a rebalance of the hedge ratios, if applicable), including cases where the hedging instrument expires, is sold, cancelled or settled. When the Partnership discontinues the application of hedge accounting, the amount that accrued in the hedge fund remains in the hedge fund until the cash flow materializes or is carried to profit or loss if the hedged future cash flows are no longer expected to materialize.

**M. Provisions:**

A provision according to IAS 37 is recognized when the Partnership has a liability in the present (legal or implicit) as a result of an event that occurred in the past, use of economic resources is expected to be required in order to settle the liability, and it may be reliably estimated. When the Partnership expects to recover the expenditure, in whole or in part, the recovery will be recognized as a separate asset, only on the date on which receipt of the asset is in fact certain. An asset retirement obligation was recorded on the Partnership's books – see Section N2 below regarding costs in respect of asset retirement obligations.

**Legal claims:**

A provision for claims is recognized when the Partnership has a present legal liability or an implicit liability as a result of an event that occurred in the past, where it is more likely than not that the Partnership will require its economic resources to settle the liability, and it may be reliably estimated.

**Levies**:

Levies imposed on the Partnership by government institutions through legislation are treated in accordance with the interpretation 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 X below).

**Note 2 – Significant Accounting Policies (Cont.):**

**N. Expenses of oil and gas exploration and development of proved reservoirs:**

**1.** The Partnership's accounting policy in respect of the treatment of investments in oil and gas exploration is the "successful efforts" method, whereby:

**a)** The expenses of participation in the performance of geological and seismic surveys and tests which occur at the preliminary stages of the exploration are carried to profit or loss upon the forming thereof, until the date on which, following the performance of these surveys and tests, a specific drilling plan is formulated.

**b)** Investments in reservoirs before they are proven uncommercial, were classified as "exploration and appraisal assets", and are presented at cost (see Note 7 below).

**c)** Investments in reservoirs that have been proven dry and were abandoned or determined to be uncommercial, are fully amortized from the "exploration and appraisal assets" item to expenses in profit or loss.

**d)** Investments in reservoirs with regards to which it has been determined that there is technical feasibility and commercial viability of gas or oil production, which are examined in a gamut of events and circumstances, are classified, subject to the performance of an examination of impairment, from the "exploration and appraisal assets" item to the "petroleum and gas assets" item, and are presented in the statement of financial position at cost (see Note 7 below). Such petroleum and gas assets, which include, *inter alia*, reservoir development planning costs, development wells, purchase and construction of production facilities, gas transmission pipelines, drilling equipment, construction of a terminal and asset retirement costs (see also Paragraph 2 below), are amortized to profit or loss as specified in Section R below.

**e)** Investments in petroleum and gas assets are amortized in the depletion method (i.e., based on the production amount) as follows: the drilling cost is amortized according to the quantity of the proved and developed reserves, and the cost of the additional components (such as: platform, pipeline and terminals) is amortized according to the quantity of the proved reserves (developed and to be developed).

**f)** Impairment of exploration and appraisal assets and petroleum and gas assets is examined when facts and circumstances indicate that the value on the books of an exploration and appraisal asset and petroleum and gas assets may exceed its recoverable amount in accordance with IAS 36 and IFRS 6 (see Paragraph Q below).

**g)** If, at the time of farm-in agreements, at the exploration and appraisal stages, a holder of a petroleum and/or gas right transfers part of the right, in consideration for the transferee's consent to bear future investments which the transferor would otherwise have had to bear, these agreements will be treated as follows:

In agreements in which the Partnership is the transferee: at the stage of creation of the costs, the Partnership shall recognize an expense in respect of the costs which it bore and which are attributed to the rights retained by the transferor.

In agreements in which the Partnership is the transferor: The Partnership shall not record any expense that was incurred by the transferee and shall recognize a profit or loss from the farm-in agreement in the amount of the difference between the consideration received or which it is entitled to receive and the value on the books of the rights that were written off.

**Note 2 - Significant Accounting Policies (Cont.):**
**N. Expenses of oil and gas exploration and development of proved reservoirs (Cont.):**

2. **Asset retirement obligation costs:**

   The Partnership recognizes a liability in respect of its share in the obligation to retire assets 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 its present value and is amortized to profit or loss as stated in Section 1 above.

   Changes deriving from timing, cap rates and the amount of the financial resources required to discharge the liability, are added to or subtracted from the asset (if not fully amortized) in the current period concurrently with the change in the liability. The items of the statement of financial position record the balance of the liability (under "other long-term liabilities" item) and the asset balance after amortization (under "investments in petroleum and gas assets" item).

**O. Credit costs:**

The Partnership capitalizes credit costs related to the purchase, construction or production of qualified assets, the preparation, designated use or sale of which require a significant period of time. Capitalization of the credit costs begins on the date on which costs in respect of the asset itself are incurred, the actions for preparation of the asset begin and credit costs are caused, and it ends when all of the actions for preparation of the qualified asset for the designated use or for sale thereof have been substantially completed. The amount of the credit costs, discounted in the report period, includes general credit costs according to a weighted cap rate as well as specific credit costs.

**P. Recognition of income:**

The accounting policy that was applied until December 31, 2017 to recognition of income is as follows:
Income is recognized in profit or loss when it may be reliably measured and the Partnership is expected to gain the economic benefits related to the transaction, and the costs incurred or to be incurred in respect of the transaction can be reliably measured. The income is measured according to the fair value of the consideration in the transaction, net of commercial discounts and quantity discounts.
Set forth below are the specific criteria regarding recognition of income that are required to be fulfilled before the recognition of the income:
Income from the sale of oil and gas – income from the sale of oil and gas is recognized upon the transfer of the oil and/or gas to the customer. The Partnership's income includes only economic benefits that the Partnership receives and/or is entitled to receive for itself.
Interest income – interest income in respect of financial assets, which are measured at amortized cost, are recognized on accrual basis using the effective interest method.
Dividend income – income from a dividend from investments, treated as financial assets available for sale, is recognized on the effective date for entitlement to the dividend.
The accounting policy applied to recognition of income as of January 1, 2018 is as follows:

**Note 2 - Significant Accounting Policies (Cont.):**

**P. Recognition of income (Cont.):**

Revenues from contracts with customers are recognized in profit or loss when control of the asset or service is obtained by the customer. Revenue is measured and recognized according to fair value of the consideration expected to be received pursuant to the terms and conditions of the contract, net of the amounts collected in favor of third parties (such as taxes). Revenue is recognized in profit or loss up to the extent the Partnership expects to receive the economic benefits, and the revenue and costs, if applicable, may be reliably measured. Also see Section CC(1) below.

**Q. Impairment of non-financial assets:**

The Partnership examines, in accordance with the rules set forth in IAS 36 and IFRS 6, the need to recognize the impairment of non-financial assets when there are indications, as a result of events or changes in circumstances, that the balance in the financial statements is not recoverable.

In cases in which the balance in the financial statements of the non-financial assets exceeds their recoverable amount, the assets are amortized to their recoverable amount. The recoverable amount is the higher of the fair value net of sale costs and usage value. In the assessment of the usage value, the expected cash flows are discounted according to a discount rate before tax which reflects the risks specific to each asset. In respect of an asset that does not generate independent cash flows, the recoverable amount is determined for the cash-producing unit to which the asset belongs.

For the purpose of examination of impairment, a cash-producing unit is comprised of all of the Partnership's investments in the single reservoir, except in cases in which two or more reservoirs are grouped into a single cash-producing unit, inter alia in view of the existence of dependency on the positive cash flows deriving from the reservoirs and the joint use of infrastructures. Losses from impairment are carried to profit or loss.

A loss from impairment of an asset is cancelled only when changes occur in the estimates used to determine the recoverable amount of the asset from the date on which the loss from the impairment was last recognized. Cancelation of the loss as aforesaid is limited to the lower of the amount of the impairment of the asset that was recognized in the past (net of depreciation or amortization) and the total appreciation.

The unique criteria below are applied in the examination of impairment of petroleum and gas assets:

Petroleum and gas assets (including exploration and appraisal assets) are examined for impairment when facts and circumstances may attest that their books value exceeds the recoverable amount attributed thereto. The recoverable value of petroleum and gas assets, in accordance with economic valuations which include use of appraisal techniques and assumptions in respect of estimates of future cash flows expected from the asset and an estimate of an appropriate cap rate for these cash flows.

**Note 2 - Significant Accounting Policies (Cont.):**

**Q. Impairment of non-financial assets (Cont.):**

In the measurement of the recoverable value of petroleum and gas assets, the management of the Partnership's General Partner is required to use certain assumptions with respect to expected investments and costs, the likelihood of the existence of development plans, quantities of the resources in the reservoir, the expected sale prices, repercussions of the Petroleum Profits Levy Law, determination of the cap rates etc., in order to estimate the future cash flows from the assets. If possible, the fair value is determined in relation to transactions made recently in assets with a similar character and location to the subject of the assessment.

At the end of every report period, the Partnership examines whether there are signs indicating impairment of assets.

**R. Critical accounting estimates and judgements:**

Preparation of the Partnership's financial statements in accordance with IFRS requires the management of the Partnership's General Partner to make estimates and assumptions that affect the amounts presented in the financial statements. These estimates occasionally require judgment in an environment of uncertainty and have a material effect on the presentation of the data in the financial statements.

Below is a description of the critical judgements and key sources of estimation uncertainty used in the preparation of the Partnership's financial statements, in the preparation of which the management of the Partnership's General Partner was required to make assumptions as to circumstances and events that involve significant uncertainty. In exercising its judgment when making the estimates, the management of the Partnership's General Partner relies on past experience, various facts, external factors and reasonable assumptions according to the circumstances relevant to each estimate. Actual results differ from the estimates of the management of the Partnership's General Partner.

**Estimate of gas and condensate reserves** (jointly: the "**Gas Reserves**") **–** the estimate of the Gas Reserves is used in determining the rate of amortization of the producing assets serving the operations during the reported period. Investments related to the discovery and production of proved Gas Reserves are amortized according to the depletion method as stated in Section N1D above.

The estimated gas quantity in the proven reservoirs in the reported period is determined on an annual basis, according to the opinions of external experts on the evaluation of reserves in oil and gas reservoirs.

Evaluation of the proved gas reserves according to the above principles is a subjective process and the evaluations of different experts may occasionally be materially different. In light of the materiality of the amortization expenses, the abovementioned changes may have a material effect on the results of the operations and the financial condition of the Partnership.

**Asset retirement obligation –** the Partnership recognizes the asset concurrently with a liability in respect of its obligation to retire petroleum and gas assets at the end of the period of use thereof. The timing and amount of the economic resources required to discharge the obligation are based on estimation by the management of the General Partner of the Partnership, which relies, *inter alia*, on a professional consultant's evaluation, and are examined periodically to ensure the fairness of such estimations.

**Note 2 - Significant Accounting Policies (Cont.):**

**R. Key assumptions in using estimation uncertainty (Cont.):**

**The investment recovery date for the payment of overriding royalty in the Tamar Project** – in the preparation of a report for the determination of the date of recovery of the investment in the Tamar Project, the Partnership relied, *inter alia*, on the ruling of an expert from 2002, who was appointed by agreement between the Partnership and the royalty interest owners and who provided his opinion on the method of calculation of the investment recovery date as well as on the various components which must be taken into account for the purpose of determining the investment recovery date. (See also Notes 15D and 12I5 below).

**Claims** – In the assessment of the chances of the results of the legal claims filed against the Partnership, the Partnership relied on opinions of its legal counsel. This assessment of the legal counsel is based on their best professional judgment, considering the stage of the proceedings, and on the legal experience accrued on the various issues. Since the outcome of the claims shall be determined in court, this outcome may be different to this assessment.

**Determination of the fair value of a non-negotiable financial asset** – The fair value of a non-negotiable financial asset classified at level 3 of the fair value scale is determined according to valuation methods, generally according to the evaluation of the discounted future cash flow according to current cap rates for items with similar conditions and risk characteristics. Changes in the estimate of future cash flow 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.

**S. Fair value:**

**1. Measurement of fair value:**

The Partnership measures fair value as the price that would have been received in the sale of an asset or the price that would have been paid for the transfer of a liability in a regular transaction between market participants on the measurement date.

When the price of an identical asset or identical liability is not observable (i.e. there is no price that is quoted in an active market), the Partnership measures fair value using a different appraisal technique that is suited to the circumstances and for which there are sufficient obtainable data to measure fair value, while making maximum use of relevant observable data and minimum use of non-observable data.

The Partnership measures fair value under the assumption that the transaction for the sale of the asset or for the transfer of the liability occurs in the main market of the asset or the liability to which the Partnership has access; or in the absence of a main market, in the best market for the asset or the liability to which the Partnership has access.

In the measurement of fair value of a non-financial asset, the Partnership takes into account the ability of a market participant to generate economic benefits through the asset in its optimal use or through the sale thereof to another market participant that will make optimal use of the asset.

**Note 2 - Significant Accounting Policies (Cont.):**

**S. Fair value (Cont.):**

The fair value of a financial liability with an on-call feature (for example an on-call deposit) is no lower than the amount payable on call, discounted from the first date on which the amount may be called.

**2. Fair value hierarchy:**

For disclosure purposes, the Partnership classifies fair value measurements under one of the levels in the fair value hierarchy that reflects the significance of the data used when making the measurements. The fair value hierarchy is:

| | |
|---|---|
| Level 1 | - Quoted prices (unadjusted) in active markets for identical assets or identical liabilities. |
| Level 2 | - Inputs other than quoted prices included within Level 1, which are observable directly or indirectly. |
| Level 3 | - Inputs that are not based on observable market data (valuation techniques that use inputs which are not based on observable market data). |

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.

**T. Profit per participation unit:**

Profit per participation unit is calculated in accordance with the provisions of IAS 33, which prescribes, *inter alia*, that the Partnership shall calculate the amounts of the basic profit per participation unit in respect of profit or loss, which is attributed to the holders of participation units of the Partnership, and shall calculate the amounts of the basic profit per participation unit in respect of profit or loss from continued operations, which is attributed to the holders of participation units of the Partnership, in the event that such profit is presented. See also Section F3 above.

**U. Employee benefits:**

**1. Short-term employee benefits:**

Short-term employee benefits, which include salaries, recuperation pay, sick days and national insurance employer deposits, are recognized as expenses upon provision of the services. When the Partnership has an established legal or implied reliably estimable liability for the granting of bonuses to employees, the Partnership recognizes this liability on the date of establishment of the liability.

The Partnership classifies a benefit as a short-term employee benefit when the benefit is expected to be fully settled within 12 months from the end of the annual report period in which the employees provide the relevant service.

**2. Post-employment employee benefits:**

In accordance with employment law and employment agreements in Israel and in accordance with the Partnership's custom, the Partnership is liable for the payment of severance pay to employees who are terminated and under certain conditions to employees who resign or retire.

**Note 2 - Significant Accounting Policies (Cont.):**

**U. Employee benefits (Cont.):**

**2. Post-employment employee benefits: (Cont.)**

The Partnership's liabilities for the payment of severance pay to the Partnership's employees pursuant to Section 14 of the Severance Pay Law (the Partnership pays fixed payments without having any legal or implicit liability to make additional payments, even if sufficient amounts have not accrued in the plan to pay all of the benefits to employees relating to the employee's employment in the current period and in the previous periods) are treated as a defined deposit plan. The Partnership recognizes as an expense, apart from exceptions, the amount that is required to be deposited concurrently with receipt of the work services from the employee.

**V. Share-based payment:**

**1.** The Partnership recognizes share-based payment transactions in accordance with the provisions of IFRS 2. These transactions include transactions with employees which are settled in equity instruments or in cash.

**2.** Loans provided to employees for the purchase of participation units of the Partnership, with the participation units themselves serving as sole security for the repayment thereof, are treated as the granting of options to employees. With respect to share-based payment transactions that are settled in cash, the value of the benefit is presented as a liability that is measured at fair value on every report date and on the settlement date. The value of the benefit of share-based payment transactions is recognized on a current basis in the statement of comprehensive income. When the Partnership receives services in consideration for a payment based on its equity instruments which is granted by the Partnership's Parent Company or by the General Partner, it is a share-based payment transaction such that the expense is recognized in the comprehensive income over the period of the employees' entitlement to the equity instruments against the entry of a corresponding amount in the capital in respect of a capital injection received from the Parent Company or from the General Partner.

**W. Benefit from control holders:**

The Partnership records expenses in the statements of comprehensive income against a capital reserve for benefits it received from the control holder.

**X. Taxes on Income and Petroleum and Gas Profit Levy:**

**1.** The financial statements do not include taxes on income, since the tax liability on the Partnership's profits applies to the partners in the Partnership. Payments paid by the Partnership to income tax are on account of the tax for which the holders of the units in the Partnership are liable and they are amortized from the retained earnings item in the Partnership's equity.

**2.** The Partnership includes in the financial statements expenses in respect of its levy payment liability under the Taxation of Profits and Natural Resources Law, 5771-2011 (the "**Levy**"). The Levy is calculated for each project separately. The classification and presentation of the Levy in the financial statements is similar to the manner in which taxes on income are classified and presented.

**Note 2 - Significant Accounting Policies (Cont.):**

**X. Taxes on Income and Petroleum and Gas Profit Levy (Cont.):**

**3.** During 2017, the Partnership's management, together with the Israeli partners (which are reporting corporations) in the Tamar project (the "**Reporting Entities**"), revisited the matter, including reconsideration of whether the Levy is indeed governed by IAS 12 or possibly governed by IFRIC No. 21 by the International Financial Reporting Interpretations Committee – "Levies" ("**IFRIC 21**"), as well as the timing at which recognition of the Levy within the financial statements would be required. In the beginning of August 2017, the Reporting Entities expressed their position on the matter before the Israel Securities Authority (ISA) Staff. After the Reporting Entities had examined the treatment of the Levy and particularly the question of whether, in this case, in view of the unique characteristics of a Levy as aforesaid, the provisions of IFRIC 21 or the provisions of IAS 12 ought to be implemented, the Reporting Entities reached the conclusion that in the case at bar it would be more reliable and relevant to implement the provisions of IFRIC 21 with regard to such Levy, and the ISA Staff decided not to intervene in their position. Therefore, *de facto*, the Reporting Entities shall recognize the expense due to the Levy according to the "obligating event" approach, i.e., only on the date on which the obligation of payment thereof arises (i.e., only as of the date of commencement of actual payment thereof). The accounting treatment of the Levy as aforesaid has no effect on these financial statements, since the obligation of payment of the Levy has not yet arisen.

**Y. Finance lease:**

A lease is an agreement according to which the lessor transfers to the lessee, in consideration for a payment or a series of payments, the usage rights in the asset for an agreed period of time. Assets in respect of which all of the risks and benefits relating to the ownership of the asset were transferred from the Partnership to others, in the lease agreement, are classified as a finance lease. Upon initial recognition of a finance lease, the leased asset is written off and a financial asset is recognized in the other receivables item (in current assets and non-current assets) in the amount of the present value of the lease income. After the initial recognition, in any subsequent period, the Partnership recognizes finance income in accordance with the cap rate used for calculation of the present value as aforesaid. See Also Section DD below.

**Z. Assets held for sale**:

A non-current asset or group of assets are classified as held for sale when settlement thereof is made primarily through a sale transaction rather than through ongoing use. The aforesaid is applicable when the assets are available for immediate sale, in their present condition, the Partnership has an obligation to sell, there is a plan to identify a buyer, and the disposition is highly likely to be consummated within one year from the date of the classification. These assets are not amortized from the date of their first classification as such and are separately presented as current assets, at the lower of their book value or fair value net of sale costs.

## Note 2 - Significant Accounting Policies (Cont.):

### AA. Loss of control:

When the Partnership loses control over a subsidiary, it writes off the assets and liabilities of such subsidiary, according to the book value as of the date of loss of control. The consideration received and any remaining investment in such subsidiary are recognized according to the fair value thereof as of the date of loss of control. Any difference created is recognized as a profit or loss in the statement of comprehensive income.

### BB. An investment treated according to the equity method:

The Partnership's investment in a company accounted for at equity is treated according to the equity method.

According to the equity method, the investment in a company accounted for at equity is presented according to cost plus changes that occurred subsequent to the purchase in the Partnership's share of the assets, net, including other comprehensive income of the company accounted for at equity. Profits and losses deriving from transactions between the Partnership and the company accounted for at equity are cancelled in accordance with the holding rate.

The financial statements of the Partnership and the company accounted for at equity are prepared as of identical dates and periods. The accounting policy in the financial statements of the company accounted for at equity was implemented uniformly and consistently with that which was implemented in the Partnership's financial statements.

The equity method is implemented until the date of loss of the significant influence in the company accounted for at equity or the classification thereof as an investment held for sale.

The Partnership is examining an amount recoverable from a company accounted for at equity, together with other assets of the Partnership, the cash flows from which are dependent on the same factors on which the cash flows from the company accounted for at equity are dependent.

On the date of loss of significant influence over the company accounted for at equity, the Partnership recognizes a profit or loss, according to the difference between the balance of the investment in the company accounted for at equity on the Partnership's books, and its fair value.

**Note 2 - Significant Accounting Policies (Cont.):**

**CC. Changes in the accounting policy – Initial application of new financial reporting standards and amendments to existing accounting standards**:

1. Initial application of IFRS 15 – Revenue from Contracts with Customers

In May 2014, the IASB published IFRS 15 – Revenue from Contracts with Customers (the "**New Standard**"), which supersedes, *inter alia*, IAS 18 – Revenues.
The New Standard introduces a five-step model to be applied to revenues arising from contracts with customers:

Step 1 - Identification of the contract with the customer, including provisions with respect to a combination of contracts and accounting for contract modifications.

Step 2 - Identification of several distinct performance obligations in the contract.

Step 3 - Determination of the transaction price, including provisions with respect to variable consideration, a significant financing component, non-cash consideration and consideration paid to the customer.

Step 4 - Allocation of the transaction price to each distinct performance obligation based on the relative stand-alone selling price while using expected prices, if available, or estimates and assessments.

Step 5 - Recognition of revenues when or as a performance obligation is satisfied, while distinguishing between fulfillment of an obligation at a specific point in time and fulfillment of an obligation over time.

The application of IFRS 15 had no effect on the Partnership's condensed interim financial statements.

**Notes to the Financial Statements for December 31, 2018 (U.S. Dollars in thousands)**

**Note 2 - Significant Accounting Policies (Cont.):**

**CC. Changes in the accounting policy – Initial application of new financial reporting standards and amendments to existing accounting standards (Cont.):**

2. Initial application of IFRS 9 – Financial Instruments

In July 2014, the IASB published the full and final version of IFRS 9 – Financial Instruments, which supersedes IAS 39 – Financial Instruments: Recognition and Measurement. IFRS 9 (in this section: the "**New Standard**"), primarily changes the provisions of classification and measurement of financial assets and it applies to all of the financial assets governed by IAS 39.
The New Standard is applied for the first time in these financial statements.
The Partnership chose to apply the provisions of the New Standard retroactively, without restatement of comparison figures.
The Partnership recognizes any difference between the book value prior to application of the standard and the book value on the date of initial application in the opening balance of retained earnings.

The following table presents the effect of the initial application of IFRS 9:

| As of January 1, 2018 | As previously reported | Change | Under IFRS 9 |
|---|---|---|---|
| Retained earnings | 439,692 | 2,114 | 441,806 |
| Capital reserve for financial assets available for sale and cash flow hedging transactions | 9,198 | [6](2,100) | 7,098 |
| Short term investments | 278,826 | (112) | 278,714 |
| Trade and other payables | (122,355) | 126 | (122,229) |
| Total equity | 618,478 | 14 | 618,492 |

[6] Under the New Standard, the right to receive royalties in connection with the sale of the Karish and Tanin leases (see Note 8B below) is now presented according to fair value through profit or loss.

**Note 2 - Significant Accounting Policies (Cont.):**

**DD. The effect of new International Financial Reporting Standards and amendments to standards in the period prior to their application which may affect the financial statements in the period of initial application:**

**International Financial Reporting Standard 16 – "Leases" ("IFRS 16"):**

In January 2016, the IASB published IFRS 16 – Leases (in this section: the "**New Standard**").

According to the New Standard, a lease is defined as a contract, or part of a contract, which transfers, in consideration for payment, the right to use the asset for a defined period of time.

The main effects of the New Standard are as follows:

- The New Standard requires lessees to recognize all leases in the statement of financial position (apart from certain exceptions – see below). Lessees will recognize a liability in respect of the lease payments on the one hand, and a right-of-use asset on the other hand, similarly to the accounting treatment of finance leases according to the present standard IAS 17 – Leases. Furthermore, lessees will recognize interest expenses and depreciation expenses separately.

- Variable lease payments that do not depend on an index or interest, which are based on performance or use, will be recognized as an expense on the lessee's side or revenue on the lessor's side on the date of creation thereof.
- In the event of change in index-linked variable lease payments, the lessee is required to reassess the lease liability, with the effect of the change being attributed to the right-of-use asset.
- The accounting treatment on the lessor's side remains with no material change compared with the present standard, i.e., classification as finance lease or operating lease.
- The New Standard includes two exceptions with respect to which the lessees are permitted to account for the leases according to the present accounting treatment of operating leases, which exceptions concern leases of low value assets or leases for a term of up to one year.

The New Standard will be applied as of the annual periods commencing on or after January 1, 2019.

The New Standard allows lessees to choose one of the following application approaches:

1. The full retrospective application approach – According to this approach, the right-of-use asset and the liability will be presented in the statement of financial position as if they have always been measured according to the provisions of the New Standard. In such a case, the effect of application of the New Standard as of the beginning of the earliest period presented will be attributed to equity. The company shall also restate its financial statements that are presented as comparative figures. The balance of the liability as of the date of the initial application of the New Standard according to this approach, shall be calculated using the interest rate implicit in the lease, unless such rate cannot be readily determined, in which case use shall be made of the lessee's incremental borrowing rate as of the date of engagement in the lease.

**Notes to the Financial Statements for December 31, 2018 (U.S. Dollars in thousands)**

**Note 2 - Significant Accounting Policies (Cont.):**

**DD. The effect of new International Financial Reporting Standards and amendments to standards in the period prior to their application which may affect the financial statements in the period of initial application (Cont.):**

**International Financial Reporting Standard 16 – Leases ("IFRS 16") (Cont.):**

2. The modified retrospective application approach – According to this approach, no restatement of the comparison numbers will be required. The balance of the liability as of the date of initial application of the New Standard will be calculated while using the lessee's incremental borrowing rate existing on the date of initial application of the New Standard. As to the balance of the right-of-use asset, the Company may decide, with respect to every lease separately, to apply either of the following alternatives:
   - Recognition of an asset in the amount of the recognized liability, with certain adjustments.
   - Recognition of the asset as if it has always been measured according to the provisions of the New Standard

Any difference created on the date of initial application of the New Standard due to modified retrospective application, if created, will be attributed to equity.

The Partnership continued to examine the implications of IFRS 16 on its financial statements, at this stage, according to the information held thereby. In the Partnership's estimation, the application thereof is not expected to have a material effect on its financial statements and it continues to examine the implications of the Standard.

**Note 3 – Cash and cash equivalents:**

**Composition**:

| | **31.12.2018** | **31.12.2017** |
|---|---|---|
| **In Dollars:** | | |
| Cash in banks | 15,150 | 7,722 |
| Deposits in banks[7] | 90,220 | 133,120 |
| | 105,370 | 140,842 |
| **In ILS:** | | |
| Cash in banks | 130 | 11,743 |
| Deposits in banks[8] | 38,385 | 2,250 |
| | 38,515 | 13,993 |
| **Total** | 143,885 | 154,835 |

[7] The interest rate as of December 31, 2018 is approx. 2.43% to approx. 2.58%.

[8] The interest rate as of December 31, 2018 is approx. 0.15%-0.20%.

**Notes to the Financial Statements for December 31, 2018 (U.S. Dollars in thousands)**

## Note 4 – Short-term investments[9]:

**Composition:**

| | Interest rate as of 31.12.2018 | 31.12.2018 | 31.12.2017 |
|---|---|---|---|
| | % | | |
| **Under current assets:** | | | |
| Corporate bonds[10] | 3.3 | 78,720 | 95,070 |
| ETFs | | 28,136 | 14,093 |
| Deposits in banks: | | | |
| in dollars | 2.58-3.3 | 79,123 | 169,479 |
| in ILS | | 174 | 184 |
| | | 186,153 | 278,826 |
| **Under non-current assets:** | | | |
| Deposits in banks: | | | |
| in dollars | 2.73 | 60,281 | 101,482 |

## Note 5 – Trade and other receivables:

**Composition:**

| | 31.12.2018 | 31.12.2017 |
|---|---|---|
| Trade and other receivables within joint ventures[11] | 79,990 | 27,782 |
| Related parties (See Note 21 below) | 87 | 178 |
| Receivables in connection with a loan given (see Note 8B below) | 15,100 | - |
| Prepaid expenses and other receivables | 3,994 | 2,918 |
| **Total** | 99,171 | 30,878 |

## Note 6 – Investment in a company accounted for at equity

**a.** See Note 7C1 regarding the sale of interests in the Tamar and Dalit leases to Tamar Petroleum.

**b.** As of December 31, 2018, the Partnership holds 22.6% (December 31, 2017: 40%) of the issued and paid-up capital and approx. 13.42% (December 31, 2017: 16.67%) of the voting rights of the Company Accounted for at Equity. In March 2018) Tamar Petroleum purchased from Noble 7.5% of the rights in the Tamar and Dalit leases, *inter alia*, in consideration for a private allotment of 43.5% of the Tamar Petroleum shares (post allotment). Following the aforesaid, the Partnership's rate of holding in Tamar Petroleum dropped to approx. 22.6% of the equity rights. The Partnership's share in the results of Tamar Petroleum in the report period, and the effect of the decrease in holding rate were included under the item of the Partnership's share of earnings of a company accounted for at equity, net.

[9] With respect to pledges and guarantees, see Note 12H.
[10] Weighted interest rate.
[11] Including monetary balances with the operator.

**Notes to the Financial Statements for December 31, 2018 (U.S. Dollars in thousands)**

## Note 6 – Investment in a company accounted for at equity (Cont.):

**c.** In the Report Year, Tamar Petroleum declared and distributed dividends of approx. U.S. $71.3 million. The Partnership's share approx. U.S. $16.1 million.

**d.** Following is condensed financial information regarding the investment of the Partnership in the Company Accounted for at Equity, treated according to the equity method:

| | 31.12.2018 | 31.12.2017 |
|---|---|---|
| Cost of investment | 110,641 | 119,791 |
| Accrued profits (net of dividends) | 13,609 | 10,042 |
| Total | 124,250 | 129,833 |

**e.** Following are condensed figures from the financial statements of the Company Accounted for at Equity (100%):

| | 31.12.2018 | 31.12.2017 |
|---|---|---|
| Assets | 1,316,704 | 575,312 |
| Liabilities | 1,177,312 | 678,448 |
| | | |
| Income before tax | 136,097 | 98,695 |
| Comprehensive income | 98,818 | 88,226 |

**f.** Following is the market value of the Company Accounted for at Equity according to the price on TASE (100%):

| | 31.12.2018 | 31.12.2017 |
|---|---|---|
| As of the date of the financial statements | 359,838 | 287,136 |
| Close to the date of approval of the financial statements | 378,706 | 496,320 |

**g.** On March 6, 2019 (after the date of the statement of financial position), the CEO of the General Partner of the Partnership (the "**CEO**") gave notice to the board of directors of the Company Accounted for at Equity of his resignation from his position as a director of the Company Accounted for at Equity, effective as of the date of delivery of the notice.

The Partnership is examining the possible accounting implications of the CEO's resignation from the board of directors of the Company Accounted for at Equity, *inter alia* on the manner of classification of the investment in the shares of Tamar Petroleum in the Partnership's books. Insofar as, upon conclusion of the examination, it is indicated that following his aforesaid resignation, the classification of the investment in the Company Accounted for at Equity should be changed in the Partnership's books and measured as a financial asset measured at fair value, the difference, if any, between the balance of the investment in the Company Accounted for at Equity (as recorded in the books) and the market value of the Company Accounted for at Equity on March 31, 2019, will then be recorded as a profit or loss in the Partnership's financial statements as of March 31, 2019. It is noted that, according to the closing price of the shares of the Company Accounted for at Equity on TASE close to the date of approval of the financial statements and based on the balance of the investment in the books as of December 31, 2018, the expected loss will amount to approx. U.S. $39 million. Since as of the date of the statement of financial position, the investment in the Company Accounted for at Equity forms part of a larger cash-producing unit, no impairment recognition was required.

**Notes to the Financial Statements for December 31, 2018 (U.S. Dollars in thousands)**

## Note 7 – Investments in petroleum and gas assets:

### A. Composition:

#### 1. Composition by assets:

| | Exploration and appraisal assets | Petroleum and gas assets[12] | Total |
|---|---|---|---|
| **Cost**[13] | | | |
| **Balance as of January 1, 2017** | 138,563 | 2,310,930 | 2,449,493 |
| Changes during 2017: | | | |
| Investments | 755 | 508,645 | 509,400 |
| Write-offs | [14](25,132) | (448,384) | (473,516) |
| **Balance as of December 31, 2017** | 114,186 | 2,371,191 | 2,485,377 |
| Changes during 2018: | | | |
| Investments | 766 | 827,252 | 828,018 |
| Amortization | - | (4,407) | (4,407) |
| Write-offs | - | (978) | (978) |
| **Balance as of December 31, 2018** | 114,952 | 3,193,058 | 3,308,010 |
| **Accumulated Depreciation** [15] | | | |
| **Balance as of January 1, 2017** | - | 472,166 | 472,166 |
| Changes during 2017: | | | |
| Depreciation and amortization[16] | - | 51,324 | 51,324 |
| Write-offs | - | (61,784) | (61,784) |
| **Balance as of December 31, 2017** | - | 461,706 | 461,706 |
| Changes during 2018: | | | |
| Depreciation and amortization | - | 41,034 | 41,034 |
| Write-offs | - | (82) | (82) |
| **Balance as of December 31, 2018** | - | 502,658 | 502,658 |
| **Amortized cost as of December 31, 2017** | 114,186 | 1,909,485 | 2,023,671 |
| **Amortized cost as of December 31, 2018** | 114,952 | 2,690,400 | 2,805,352 |

[12] Including the balance of asset retirement amortized cost as of the date of the statement of financial position in the sum of approx. $66.3 million (December 31, 2017: $24.7 million).
[13] For details regarding capitalized credit costs, see Note 19B below.
[14] Mainly with respect to the amortization of Dolphin well (see Section C9B below).
[15] The amortization rate of the producing assets is approx. 7.8% in the Tamar project and approx. 7.4% in the Yam Tethys project according to the amortized component (2017: approx. 7.9% in the Tamar project; approx. 37% in the Yam Tethys project).
[16] The balance excludes an update in the amount of approx. $17 million regarding an asset retirement obligation in respect of the Yam Tethys project Noa and Pinnacles reservoirs).

**Notes to the Financial Statements for December 31, 2018 (Dollars in thousands)**

**Note 7 – Investments in petroleum and gas assets (Cont.):**

**A. Composition (Cont.):**

2. **Composition by joint ventures:**

| | 31.12.2018 | 31.12.2017 |
|---|---|---|
| **Petroleum and gas assets:** | | |
| Michal-Matan joint venture (Section C1 and Note 12J1) | 869,944 | 903,144 |
| Ratio-Yam joint venture (Section C2 and Note 12J1) | 1,819,714 | 1,003,950 |
| Yam Tethys joint venture (Section C5) | 742 | 2,391 |
| | 2,690,400 | 1,909,485 |
| **Exploration and appraisal assets:** | | |
| Block 12 Cyprus (Section C4) | 114,952 | 114,186 |
| | 114,952 | 114,186 |
| **Total** | 2,805,352 | 2,023,671 |

**B. Details on the Partnership's rights in petroleum and gas assets (as of December 31, 2018)[17]:**

| | Type of right | Name of right | Right valid through | Partnership's share |
|---|---|---|---|---|
| Yam Tethys | Lease | I/10 Ashkelon | 10.6.2032 | 48.5% |
| Yam Tethys | Lease | I/7 Noa | 31.1.2030 | 48.5% |
| Michal-Matan | Lease | I/12 Tamar | 1.12.2038 | 22%[18] |
| Michal-Matan | Lease | I/13 Dalit | 1.12.2038 | 22%[19] |
| Ratio-Yam | Lease | I/15 Leviathan North | 13.2.2044 | 45.34% |
| Ratio-Yam | Lease | I/14 Leviathan South | 13.2.2044 | 45.34% |
| Block 12 in Cyprus | Production sharing under a PSC | Block 12 | 23.5.2016[20] | 30% |
| Alon D | License | 367/Alon D | 20.4.2020 | 52.941%[21] |

The validity of the petroleum rights is extended from time to time and is contingent upon the fulfillment of certain undertakings on the dates set forth in the terms and conditions of the petroleum assets. In the event of non-fulfillment of the conditions, the petroleum right may be invalidated. For information regarding a benefit in respect of the right to receive royalties from the sale of the rights in the Karish and Tanin leases, see Section Note 8B below. For further information, see Section C9 below.

[17] For details with respect to engagement in an agreement for the purchase of rights in onshore petroleum assets after the date of the statement of financial position, see Note 23M below.

[18] Excluding the Partnership's indirect holding in Tamar lease through the Partnership's holding of shares of Tamar Petroleum at a rate of 3.7855% (out of 100%).

[19] See Footnote 17 above.

[20] For details with respect to the validity of the PSC, see Section C4 below.

[21] For details regarding the transfer of Noble's rights in the license to the Partnership at a rate of 22.059%, see Section C6 below.

**Note 7 – Investments in petroleum and gas assets (Cont.):**

**A. The Partnership's oil and gas exploration business:**

**1. The Michal-Matan joint venture (the Tamar and Dalit leases):**

**a)** The Michal-Matan joint venture is a venture for exploration, development and production of oil and gas in the area of the Tamar and Dalit leases. The production from the Tamar reservoir commenced in the end of March, 2013.

**b) Further details with respect to the Michal-Matan joint venture operations**:

**1) The development plan for the Tamar project:**

The development plan of the Tamar project includes 6 subsea production wells, each of which is able to produce approx. 250 MMCF per day. The gas is piped from the wells in Tamar field through two 16-inch pipes to a processing platform which has been set up off the Ashkelon shores (the "**Tamar Platform**"), approx. 2 km north of the platform of the Yam Tethys project. The natural gas and condensate are piped from the Tamar Platform in 30-inch and 6-inch pipes, respectively. Furthermore, in August 2016, the Minister of Energy granted the Tamar partners a license to operate a 10-inch pipe which was originally designated for the transmission of condensate from the Tamar Platform, for the transmission of natural gas, in order to increase the gas supply capacity, to the terminal for the completion of treatment of the natural gas and condensate, and from there the natural gas is piped to the national transmission system of Israel Natural Gas Lines Ltd. ("**INGL**") and the condensate is piped to Paz Ashdod Refinery Ltd. which is nearby. The capacity of gas supply from the Tamar project (which includes the Tamar project's facilities, the compressor systems and the transmission and treatment systems of the Yam Tethys project that were upgraded and adjusted for use in the Tamar project) to the INGL transmission system is approx. 1.1 BCF per day at maximum production.

**2) Examination of possible expansion of the Tamar project's supply capacity:**

The total supply capacity of the Tamar facilities is currently limited to the piping capacity of two 16-inch pipes. As of the date of approval of the financial statements, the Tamar partners are examining options for expanding the supply capacity from the Tamar Project, insofar as it shall be required, according to the scope of demands expected in the domestic market and for export.

**c) The Tamar South West reservoir ("Tamar SW") and the development thereof:**

According to the development plan of the Tamar SW Reservoir, which was approved by the Petroleum Commissioner (the "**Commissioner**") in January 2019 (after the date of the statement of financial position), considering the provisions of the Gas Framework specified in Note 12J1 below. The Tamar SW Reservoir is planned to be developed by converting the discovery well into a production well and connecting it to the subsea facilities of the Tamar project. The estimated cost of development of the Tamar SW reservoir, is expected to amount to approx. $450 million[22] (100%, the Partnership's share being approx. $99 million), of which approx. $202 million have been invested to date (100%, the Partnership's share being approx. $44 million). It is clarified that some of the reserves in the Tamar SW well extend into the area of the 353/Eran license (see Section C9C below).

In the Partnership's estimation, the completion of the Tamar SW reservoir and connection thereof to the production system are expected to occur in 2021.

[22] The development cost as aforesaid, has not yet been approved by the Tamar partners.

**Note 7 – Investments in petroleum and gas assets (Cont.):**

**C. The Partnership's oil and gas exploration business (Cont.):**

**1. The Michal-Matan joint venture (the Tamar and Dalit leases) (Cont.):**

**d) Appraisal of the condensate and natural gas reserves in the Tamar gas field:**

According to a report prepared in February 2018 by Netherland Sewell & Associates Inc. ("NSAI", which is a qualified, expert an independent reserve and resource appraiser) according to the SPE-PRMS, the natural gas reserves in the Tamar project (consisting of the Tamar and Tamar SW reservoirs), classified as reserves under production as of December 31, 2018, and which are classified as proved reserves are approx. 229.6 BCM (of which approx. 9.8% attributed to Tamar SW), and the amount of reserves classified as proved + probable reserves is approx. 315.5 BCM (of which approx. 8.6% attributed to Tamar SW).

According to the said report, the condensate reserves in the Tamar and Tamar SW reservoirs, which are classified as reserves under production as of December 31, 2018, which are classified as proved reserves, are approx. 10.5 million barrels (of which approx. 9.5% attributed to Tamar SW), and the amount of reserves classified as proved + probable reserves is approx. 14.5 million barrels (of which approx. 8.3% attributed to Tamar SW). Such reserves do not include the reserves that overflow into the Eran license. See Section 7 below regarding uncertainty in the evaluation of reserves.

**e) Dalit 1 well:**

In 2009, the Dalit 1 offshore well was drilled, at a distance of around 50 km off the shores of Israel, following which a finding was announced. According to a report prepared in March 2018 by NSAI according to PRE-PRMS, the amount of the contingent resources at the Dalit lease, classified at the Development Pending stage, as of December 31, 2017, ranges between approx. 6.1 BCM (low estimate) and approx. 9.5 BCM (high estimate). In the resource report, it is indicated that the contingent resources are contingent upon the approval of a project which includes an approved development plan and a reasonable projection for sales of natural gas. As of December 31, 2018, no change occurred in the details provided in such report. See Section 7 below regarding uncertainty in the appraisal of reserves.

The Partnership, jointly with its partners in the Dalit and Tamar project, submitted to the Commissioner in 2010 a development plan of the Tamar reservoir, which includes, *inter alia*, reference to the development of the Dalit lease. In addition, the Partnership, together with the partners in the Dalit and Tamar leases, are updating the mapping of the Dalit reservoir and performing an analysis of the reservoir, based on a seismic survey that has been conducted.

**f) Sale of working interests at the rate of 9.25% (out of 100%) of the interests in the Tamar and Dalit reservoirs:**

On July 2, 2017, the Partnership signed a sale agreement (the "**Sale Agreement**" or the "**Agreement**") with Tamar Petroleum for the transfer of 9.25% (out of 100%) of the interests in the Tamar and Dalit leases, in consideration for approx. ILS 3 billion. The transaction was closed on July 20, 2017.

**Note 7 – Investments in petroleum and gas assets (Cont.):**

**C. The Partnership's oil and gas exploration business (Cont.):**

**1. The Michal-Matan joint venture (the Tamar and Dalit leases) (Cont.):**

**f) Sale of working interests at the rate of 9.25% (out of 100%) of the interests in the Tamar and Dalit reservoirs (Cont.):**

The principal provisions of the Sale Agreement are as follows:

1) The Partnership undertook to sell and transfer to Tamar Petroleum working interests at a rate of 9.25% (out of 100%) in the Tamar and Dalit leases, subject to the existing obligations for payment of overriding royalties to related parties and to third parties, as well as the relative share (9.25%) of the rights and obligations under the Joint Operating Agreement, the agreements for the sale of gas from the Tamar lease, the agreement for use of the Yam Tethys facilities, the shares of Tamar 10 Inch Ltd., the Tamar platform operation permit and the permits for export from Tamar (the "**Object of Sale**").

2) In consideration for the Object of Sale the Partnership was paid a sum of approx. ILS 3 billion (approx. $837 million) in cash and shares at a rate of 40% of the Company's capital that are presented under the item "investment in a company accounted for at equity" (see Note 6 above).

3) The Company undertook that it would act to enable the Partnership to carry out a shelf (sale) offering for the shares allotted thereto, subject to certain restrictions and qualifications, including a lockout period that would apply to the shares, as specified below.

4) The effective date for the purpose of calculation of the amount of the consideration and transfer of the rights and obligations in respect of the Object of Sale to Tamar Petroleum is July 1, 2017 (the "**Effective Date**"). The Agreement provides that the Partnership[23] will continue to bear the liability in respect of the following matters, also after the transaction closing date: The arbitration in respect of the production component tariff (see Note 12C1A8 below), the claim concerning the royalties relating to the sale of gas from the Tamar Project to the customers of the Yam Tethys Project, including with respect to any liability related to such proceedings incurred in the period subsequent to the Effective Date; the motion for class certification filed by a consumer of the Israel Electric Corp. (IEC) against the Tamar partners (see Note 12I2 below), with respect to sums received by the Partnership in the period preceding the Effective Date; liability for taxes and royalties to the State relating to the period preceding the Effective Date, or in relation to any profits, revenues or proceeds of the Partnership in connection with the Object of Sale (including if such tax assessment was made after the Effective Date), with the exception of taxes relating to reports filed with the Tax Authorities prior to the Effective Date in connection with the Taxation of Profits from Natural Resources Law, 5771-2011);

[23] On the basis of the Partnership's share before the sale of the said rights.

**Note 7 – Investments in petroleum and gas assets (Cont.):**

**C. The Partnership's oil and gas exploration business (Cont.):**

**1. The Michal-Matan joint venture (the Tamar and Dalit leases) (Cont.):**

**f) Sale of working interests at the rate of 9.25% (out of 100%) of the interests in the Tamar and Dalit reservoirs (Cont.):**

5) The Partnership made various representations in the Sale Agreement, as is standard in transactions of this type, including an undertaking of indemnification for breach of representations. Furthermore, additional provisions were stipulated, as is standard in agreements of this type, including with respect to a dispute resolution mechanism, interpretation and the delivery of notices.

6) The Sale Agreement further provides that, insofar as the Partnership holds shares of the Company after the closing of the share offering, the Partnership unilaterally waives all of the voting rights attached to all of the shares held thereby in excess of shares in a quantity equal to 12% of the Company's shares after the closing of the offering. For the avoidance of doubt, it was clarified that all equity rights attached to the shares held by the Partnership shall remain in full force and effect, including: the right to receive dividends, bonus shares, interests, and the right to receive surplus assets upon liquidation of the Company. The shares in excess of 12% as aforesaid (the "**Surplus Shares**") shall be deposited thereby with a trustee, which shall act according to an irrevocable letter of instructions that will provide, *inter alia*, as follows: the Surplus Shares will also include bonus shares or rights, or shares deriving from such rights, which shall be allotted to the Partnership in respect of the Surplus Shares as part of an issuance of bonus shares and/or rights to all of the Company's shareholders. With respect to a future right offering, if any, the trustee will receive instruction from the Partnership whether to exercise or sell the right. The Partnership undertook to first sell the Surplus Shares (which, after their sale, will confer upon the purchaser all of the rights attached thereto, including voting and equity rights as aforesaid) and also undertook not to purchase additional shares of the Company for as long as it has not sold the Surplus Shares. It is clarified in this respect that shares to be allotted to the Partnership in the context of an issuance of bonus shares and/or an offering of rights shall not be deemed a purchase for the purpose of this undertaking. It is noted that shares of the Company allotted to the Partnership shall be subject to TASE lockout regulations.

On July 20, 2017, all of the conditions of the Sale Agreement were satisfied, following which rights at a rate of 9.25% (out of 100%) in the Tamar and Dalit leases were transferred against cash consideration and against the allotment of 19,990,000 ordinary shares of par value ILS 0.1 each of the Company (the "**Consideration in Stock**").

Out of the total cash consideration, the Partnership made a partial prepayment of $320 million of four bond series (Series 2018, 2020, 2023 and 2025), representing a rate of 20% of the total outstanding balance of each of the bond series (i.e., $80 million in each of the series). The profit derived from the sale of the rights as aforesaid amounted to a sum of approx. $572 million and was included in the statement of comprehensive income in the "other revenues, net" item for the year ended on December 31, 2017. The shares that were allotted to the Partnership in the context of the consideration that was received were measured according to the fair value thereof on the date of recognition for the first time and the difference between the value as aforesaid and the Partnership's share of the book value of the Company's net assets as of such date is attributed to petroleum and gas assets and is amortized according to the amortization rate of such assets.

**Note 7 – Investments in petroleum and gas assets (Cont.):**
**C. The Partnership's oil and gas exploration business (Cont.):**
**1. The Michal-Matan joint venture (the Tamar and Dalit leases) (Cont.):**
**f) Sale of working interests at the rate of 9.25% (out of 100%) of the interests in the Tamar and Dalit reservoirs (Cont.):**

On July 20, 2017, a tax ruling was received from the Tax Authority, determining, *inter alia*, the date of payment of the tax in respect of the Consideration in Stock, whereby, subject to the conditions and provisions listed therein:

1) For the capital gain the Partnership generated from the Consideration in Cash, the Partnership shall pay advance tax payments in accordance with the law.

2) The date of payment of the tax in respect of the capital gain deriving from the Consideration in Stock shall be deferred until the occurrence of one of the following (the "**Deferred Tax**"):

   a) On the date of disposition of the Company's shares, including a decrease in the rate of holdings following a dilution, the Deferred Tax will be paid in respect of the part of the shares disposed out of all of the shares held prior to the disposition; on the date on which the Partnership's holding rate in the Company's shares drops to 5% or lower, the full Deferred Tax balance will be paid.

   b) If a profit distribution is declared in the Partnership after August 1, 2017, in a sum exceeding the amount of the capital gain from the sold rights, net of the tax paid in respect thereof, payment will be made out of the Deferred Tax of an amount equal to 25% of the sum of the distribution declared with respect thereto as aforesaid and no more than the Deferred Tax balance (a distribution of profits declared prior to such date will not lead to acceleration of the payment of the Deferred Tax).

   c) When the Company distributes a dividend to its shareholders, payment will be made of Deferred Tax in a sum equal to 25% of the dividend to be received by the Partnership and no more than the balance of the Deferred Tax yet unpaid,

3) The Partnership may bring forward the date of payment of the Deferred Tax, according to its sole discretion.

4) In order to enable the participation unit holders to benefit from the tax deferral arrangement specified in the tax ruling, it has been provided that the tax certificates to be issued to the entitled holders in respect of the tax year will only report the capital gain whose payment date occurs in such tax year according to the provisions of the tax ruling. It has also been agreed that such capital gain, including the capital gain to be reported in the subsequent years as a result of the sale of the Company's shares, will be subject to the tax rates applicable in 2017. A holder will be able to offset such gain only from a loss incurred by him up to and including the tax year of 2017.

In August 2017 the Partnership paid advance tax on account of the capital gain of approx. ILS 557.5 million (approx. $160 million). It is noted that in 2018, reimbursements from income tax were received in connection with the said advance tax, see Note 20A14 below.

**Note 7 – Investments in petroleum and gas assets (Cont.):**

**C. The Partnership's oil and gas exploration business (Cont.):**

**1. The Michal-Matan joint venture (the Tamar and Dalit leases) (Cont.):**

**f) Sale of working interests at the rate of 9.25% (out of 100%) of the interests in the Tamar and Dalit reservoirs (Cont.):**

For the deferred tax and according to the aforesaid tax arrangement, the Partnership recorded taxes payable on account of the unit owners in a sum of approx. $21 million, net, which are presented under the item "other long-term liabilities".

**2. The Ratio-Yam joint venture:**

**a)** The "Ratio-Yam" joint venture is a venture for exploration, development and production of oil and gas in the area of the I/15 Leviathan North and I/14 Leviathan South leases (the "**Leases**" or "**Leviathan Leases**").

**b) Development plan for the Leviathan reservoir:**

In June 2016, the Development Plan was approved by the Commissioner, as submitted by Noble.

On February 23, 2017, the Leviathan Partners adopted a final investment decision (FID) for the development of Phase 1A of the Development Plan for the Leviathan reservoir, at a capacity of approx. 12 BCM per year, with a budget of approx. $3.75 billion (100%, the Partnership's share approx. $1.7 billion. It is noted that the cost of drilling included in the budget of Phase 1A of the development of the Leviathan reservoir amounted to a sum which is approx. $50 million below the drilling budget, as estimated at the time of approval of such Phase 1A budget.

As of the date of the statement of financial position, a sum of approx. $3.4 billion (100%, the Partnership's share – approx. $1.5 billion) has been invested in the project (including exploration wells), aiming to enable commencement of the piping of natural gas from the Leviathan reservoir during Q4/2019.

The plan for the full development (Phase 1A and Phase 1B) of the Leviathan project consists of natural gas and condensate supply to the domestic market and for export as well as condensate supply to the domestic market (in this section: the "**Development Plan**" or the "**Plan**"), the principles of which are as follows:

**Note 7 – Investments in petroleum and gas assets (Cont.):**

**C. The Partnership's oil and gas exploration business (Cont.):**

**2. The Ratio-Yam joint venture (Cont.):**

**b) Development plan for the Leviathan reservoir (Cont.):**

1) 8 production wells (four of which have been drilled and completed for production in Phase 1A) will be connected by a subsea pipeline to a permanent platform (in this section: the "**Platform**"), which shall be constructed offshore in accordance with the provisions of National Outline Plan 37/H and on which all gas and condensate treatment systems will be installed. The gas will flow from the Platform to the northern onshore entry point of the national transmission system of INGL as defined in National Outline Plan 37/H[24] (the "**INGL Connection Point**"). On April 5, 2016, the National Zoning Council approved the aforesaid principles of the Development Plan, in accordance with the provisions of the National Outline Plan. The condensate will also be piped to the shore in a separate pipe, adjacent to the gas pipeline.
2) The production capacity, treatment and transportation of the wells, the Platform, the pipeline leading thereto from the field and the related facilities including the pipeline from the Platform to the INGL Connection Point, the condensate pipeline and the related onshore facilities (in this section jointly: the "**Production System**") will amount to approx. 21 BCM per year. The gas to be supplied at the INGL Connection Point will be designated for the domestic market and for supply through the national transportation system to neighboring countries.
   Furthermore, the Platform will include an additional exit point, which is designated for connection to a subsea pipeline with a capacity of up to approx. 12 BCM per year, which will be chiefly designated for export.
3) The Development Plan will be implemented in two phases, according to the maturity of the relevant markets, as specified below:
   Phase 1A – includes four development wells, related subsea systems, subsea pipeline to the Platform, and a platform that has treatment facilities with a capacity of approx. 12 BCM per year, pipeline to the shore and all of the required pipeline and onshore facilities, with a budget of approx. $3.75 billion (100%), as aforesaid;
   Phase 1B[25] – will include four additional wells, related subsea systems, subsea pipeline to the Platform, and expansion of the treatment facilities at the Platform to increase the total treatment capacity of the Platform by approx. 9 additional BCM per year (approx. 21 BCM per year in total), with an estimated budget of approx. $1.5-2 billion (100%, the Partnership's share approx. $0.68-0.91 billion).
4) Furthermore, in order to allow for production in the required scope, additional production wells will be required during the life of the project.

[24] Over the past year, several petitions were filed with the Haifa District Court seated as the Court of Administrative Affairs and with the High Court of Justice, the shared purpose of which is to challenge various aspects pertaining to the Development Plan of the Leviathan Project, both in relation to the offshore segment and in relation to the onshore segment, including regulatory approvals granted to the Operator in relation to the Development Plan as well as additional issues. It is noted that thus far all petitions on which a hearing was held have been denied, either by dismissal with prejudice or dismissal without prejudice, and various motions filed by the petitioners in the various petitions for the issuance of interim orders in relation to the various petitions that were filed have also been denied. It is noted that, according to the estimation of the Operator's counsel (the Partnership is not a respondent in the petitions filed thus far), the probability that the legal proceedings not yet denied will have an adverse effect on the ability to produce gas from Leviathan on schedule is lower than 50%.

[25] As of the date of approval of the financial statements, the Leviathan partners have not yet adopted a Final Investment Decision for the development of Phase 1B.

**Note 7 – Investments in petroleum and gas assets (Cont.):**

**C. The Partnership's oil and gas exploration business (Cont.):**

**2. The Ratio-Yam joint venture (Cont.):**

**c) Examination of different alternatives for increase of the production capacity from the Leviathan reservoir:**

As of the date of approval of the financial statements, the Partnership, together with its partners in the Leviathan project, are examining various alternatives to increase the production scope from the Leviathan reservoir beyond Phase 1A and concurrently with the examination of Phase 1B, based on the existing facilities, and acting to update the development plan accordingly, so as to enable an increase of the capacity up to 24 BCM per year, all according to the current and expected demand in the local market and regional and global target markets, including:

1) Increasing the production capacity from 12 BCM per year to 16 BCM per year through the addition of wells and related infrastructures, including the addition of a third 20" pipe from the Leviathan field to the Leviathan platform.

2) Increasing the production capacity from 16 BCM per year to 24 BCM per year (subject to implementation of the first alternative as described above), *inter alia* through the addition of wells, subsea pipeline and related infrastructures (beyond those specified above). This alternative would enable the supply of additional quantities of gas for export, as required, including to the liquefaction facilities located in Egypt and/or for the supply of gas to a floating liquefaction facility (FLNG).

In order to examine various expansion alternatives, the Leviathan's partners approved a budget for a detailed engineering plan in 2019 in the scope of approx. $25 million (100%, the Partnership's share approx. $11.3 million).

**d) Evaluation of reserves and contingent resources in the Leviathan Leases[26]:**

In March 2019, a reserves and contingent and prospective resources in the leases report was received from NSAI, updated as of December 31, 2018. According to the report, the overall quantity of resources is estimated at approx. 608.7 BCM and is divided into categories of resources classified as reserves and resources classified as contingent. The quantity of reserves Approved for Development, classified as Proved Undeveloped is approx. 266.9 BCM and the quantity of reserves classified as Proved + Probable Reserves is approx. 379.1 BCM.

Additionally, there are approx. 16.9 million barrels of condensate reserves in the leases, in the sub-class of Approved for Development, in the sub-category of Proved Undeveloped, and there are approx. 24 million barrels of reserves classified as Proved + Probable Reserves.

In the contingent resource report, the contingent resources were divided into two categories, which relate to each of the development stages of the reservoir, as follows:

[26] In the opinion of the Commissioner, according to an opinion provided to his office by an international firm, the estimated amount of natural gas to be produced from the Leviathan reservoir is 17.6 TCF, according to the production plan submitted in the context of the application for approval of the development plan.

**Note 7 – Investments in petroleum and gas assets (Cont.):**

**C. The Partnership's oil and gas exploration business (Cont.):**

**2. The Ratio-Yam joint venture (Cont.):**

**d) Evaluation of reserves and contingent resources in the Leviathan Leases (Cont.):**

Phase 1A (Phase I - First Stage) – contingent resources which are classified at the Development Pending stage, these resources are contingent on the decisions to perform additional drillings and on the execution of additional agreements for the sale of natural gas. Future Development – resources contingent on the adoption of another investment decision, in accordance with Phase 1 - Second Stage in the development plan and with an additional stage (insofar as the development plan is updated) and on the execution of additional agreements for the sale of natural gas range between approx. 329.6 BCM (the high estimate) and approx. 214 BCM (the low estimate) and condensate contingent resources range between approx. 20.9 million barrels (the high estimate) and approx. 13.6 million barrels (the low estimate). See Section 7 below regarding uncertainty in the appraisal of reserves.

**e) Deep Target Drilling:**

As of the date of approval of the financial statements, the Partnership is formulating deep-target prospects for its petroleum assets, including the formulation of a plan for deep target exploration drilling in the Leviathan Leases, for the purpose of submission thereof to the Petroleum Commissioner. It is clarified a decision on the execution and budget for such deep drilling is expected to be presented for approval by the Leviathan Partners in 2019.

**3. Engagement in agreements for the purchase of EMG shares and for the purchase of rights in the EMG pipeline:**

On September 27, 2018, the Partnership announced that, with the aim of realizing the Dolphinus agreements (as stated in Notes 12C1C and 12C2D above), on September 26, 2018, EMED Pipeline B.V. ("**EMED**")[27] signed agreements for the purchase of 39% of the share capital of Eastern Mediterranean Gas Company S.A.E ("**EMG**") for the flow of natural gas from Israel to Egypt through the EMG pipeline (the "**EMG Transaction**" or the "**Transaction**" or the "**EMG Pipeline**"). The closing of the Transaction is contingent, *inter alia*, on the signing of a Capacity, Lease & Operatorship Agreement – CLOA, between EMED and EMG, in which EMG shall grant EMED the exclusive right to lease and operate the EMG Pipeline for the flow of natural gas from Israel to Egypt (the "**CLOA**"), all as specified below:

EMG is a private company registered in Egypt which owns a 26-inch submarine pipeline which is 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 (jointly: the "**EMG Pipeline**").

[27] EMED is an SPV which was established for the purpose of the transaction and is registered in the Netherlands, whose shares are held as follows: a wholly-owned subsidiary of the Partnership registered in Cyprus – 25%, Noble Cyprus – 25% and Sphinx EG BV, a wholly-owned subsidiary of East Gas Company, which holds, *inter alia*, a gas pipeline and infrastructures in Egypt (the "**Egyptian Partner**") – 50%.

**Note 7 – Investments in petroleum and gas assets (Cont.):**

**C. The Partnership's oil and gas exploration business (Cont.):**

**3. Engagement in agreements for the purchase of EMG shares and for the purchase of rights in the EMG pipeline (Cont.):**

The EMG Pipeline was planned for a capacity of approx. 7 BCM per year, with an option to increase the capacity to approx. 9 BCM per year through the installation of additional systems. The flow of gas in the EMG Pipeline from Egypt to Israel was stopped several years ago, and to the best of the Partnership's knowledge, EMG has no commercial activity, and it remained exposed to lawsuits and debts on the part of authorities, finance providers, suppliers and customers in significant amounts. It is noted that in the framework of the Transaction, the Partnership is not required to provide collateral or guarantees in relation to the existing debts of EMG.

As of the date of approval of the financial statements, the shareholders of EMG are:

(1) EGI-EMG LP – 12%;
(2) Merhav MNF Ltd. – 8.2%;
(3) Merhav Ampal Energy Holdings, Limited Partnership – 8.6%;
(4) Merhav Ampal Group Ltd. – 8.2% (the "**Merhav Ampal Group**");
(5) PTT Energy Resources Company Limited ("**PTT**")[28] – 25%;
(6) Mediterranean Gas Pipeline Ltd. ("**MGPC**)[29] – 28%;
(7) Egyptian General Petroleum Corporation ("**EGPC**")[30] – 10%;
(Shareholders (1)-(4) above shall be referred to hereinafter collectively as: the "**Sellers**").

It is noted that some of the Sellers, the shareholders of the Sellers and companies affiliated with the Sellers are conducting several arbitration proceedings at international arbitration institutes against the Egyptian Government and companies owned thereby in connection with the cessation of the flow of the gas from Egypt to Israel (collectively: the "**Arbitration Proceedings**"). In addition, EMG is a party to arbitration proceedings against companies owned by the Egyptian Government.

**1) <u>Agreements for the purchase of 39% of EMG's share capital</u>**

On September 26, 2018, EMED signed four separate, mainly similar, agreements with the Sellers for the purchase of EMG shares held by the Sellers, at a total rate of 37% of the share capital of EMG (collectively: the "**Share Purchase Agreements**"), as well as another agreement for the purchase of shares at a rate of 2% from MGPC (the "**MGPC Agreement**").

**a) <u>The principles of the Share Purchase Agreements</u>**

1) Subject to fulfillment of the conditions precedent, the main ones of which are mentioned in Paragraph 4 below, and the conditions to the closing of the transaction, the Sellers shall sell and transfer to EMED the EMG shares held thereby, at a total rate of 37% of EMG's share capital (the "**Purchased Shares**"), including all of the rights attached to the Purchased Shares.

[28] A public energy company partially owned by the Thai Government.
[29] A private company which, to the best of the Partnership's knowledge, is controlled by the Evsen Group, a company headed by Dr. Ali Evsen.
[30] An Egyptian government-owned corporation.

**Note 7 – Investments in petroleum and gas assets (Cont.):**

**C. The Partnership's oil and gas exploration business (Cont.):**

**3. Engagement in agreements for the purchase of EMG shares and for the purchase of rights in the EMG pipeline (Cont.):**

**1. Agreements for the purchase of 39% of EMG's share capital (Cont.):**

**a) The principles of the Share Purchase Agreements (Contd.):**

2) The Sellers, the shareholders of the Sellers and the companies affiliated with the Sellers shall waive any claim, lawsuit, award, decision, order or remedy that are available to them against the Egyptian Government and companies owned thereby in the framework of the Arbitration Proceedings.

3) In consideration for the Purchased Shares, for waiver of their rights in the framework of the Arbitration Proceedings, and other rights in accordance with the Share Purchase Agreements, as aforesaid, EMED shall pay the Sellers, on the date of the closing of the transaction, the sum total of U.S. $518 million (the "**Consideration**"), out of which each one of the Partnership and Noble shall pay a sum of approx. U.S. $185 million, and the balance will be paid by the Egyptian Partner.

4) Performance of the transaction contemplated in the Share Purchase Agreements is contingent on fulfillment of standard conditions precedent, including: receipt of all of the approvals and the consents required for the transfer of the Purchased Shares from the Sellers and registration thereof in EMED's name; receipt of the approvals and the consents required pursuant to any law in Egypt and Israel for fulfillment of the transactions contemplated in the Share Purchase Agreements and for the flow of the gas in the EMG Pipeline from Israel to Egypt; signing of the CLOA and lifting of any material impediment to performance thereof; completion of the engineering due diligence process in relation to the EMG Pipeline[31], including the performance of continuous gas flow tests from Israel to Egypt via the EMG Pipeline, in accordance with the quantities and the period determined; modification of the existing debt structure of EMG in favor of an Egyptian bank and rescheduling thereof to EMED's satisfaction; receipt of all of the formal approvals required by the Sellers, including in relation to the controlling shareholder of the Merhav Ampal Group, which is in dissolution proceedings, court approvals, and the closing of all of the Share Purchase Agreements.

5) In October 2018, the Partnership and Noble contacted the Ministry of Energy in an application to approve the use of the EMG Pipeline for the transmission of natural gas from Israel to Egypt.

6) The deadline for fulfillment of the conditions precedent and for the closing of the transaction is June 30, 2019. In the Partnership's estimation, the piping of natural gas from Israel to Egypt through the EMG Pipeline will commence during Q2/2019.

[31] To the best of the Partnership's knowledge, as of the date of approval of the financial statements, Noble completed the external examination of the EMG Pipeline, by means of a subsea robot (ROV), without any irregular findings, and is acting to complete the engineering due diligence of the EMG Pipeline.

**Note 7 – Investments in petroleum and gas assets (Cont.):**

**C. The Partnership's oil and gas exploration business (Cont.):**

**3. Engagement in agreements for the purchase of EMG shares and for the purchase of rights in the EMG pipeline (Cont.):**

**1. Agreements for the purchase of 39% of EMG's share capital (Cont.)**

**b) The principles of the MGPC Agreement**

Concurrently with the signing of the Share Purchase Agreements, an agreement was signed between EMED and MGPC whereby MGPC shall transfer to EMED, without consideration, subject to and concurrently with the closing of the Share Purchase Agreements, 2% of EMG's shares which are held thereby, against the conclusion of disputes between some of the Sellers and MGPC.

Subject to and after the closing of the EMG Transaction, EMG's shareholders will be:

(1) EMED – 39%;
(2) PTT – 25%;
(3) MGPC – 17;
(4) The Egyptian Partner – 9%[32];
(5) EGPC – 10%.

**2) The Capacity Lease & Operatorship Agreement**

As aforesaid, the closing of the EMG Transaction is contingent, *inter alia*, on the signing of the CLOA between EMED and EMG, in which EMG shall grant EMED the exclusive right to lease and operate the EMG Pipeline for the entire term of the Dolphinus agreements (see Notes 12C1C and 12C2D below), with an option to extend the agreement. According to this agreement, the costs required for refurbishment of the EMG Pipeline, up to the sum of $30 million (which reflects an initial estimate of these costs), and the current operation costs of the pipeline, shall be borne by EMED (collectively: the "**Operation Costs**"), while EMG will be entitled to receive the current transmission fees which Dolphinus shall pay for use of the pipeline (the "**Transmission Fees**"), net of the Operation Costs.

**3) EMED's shareholders' agreement**

In proximity to the date of the signing of the Share Purchase Agreements, EMED's shareholders signed a shareholders' agreement which regulates the relationship between them as shareholders of EMED, including provisions regarding material resolutions that shall be adopted unanimously. In addition, arrangements were put in place for a right of first refusal for transfers of shares of EMED.

[32] To the best of the Partnership's knowledge, MGPC is expected to transfer the said shares to the Egyptian Partner.

**Note 7 – Investments in petroleum and gas assets (Cont.):**

**C. The Partnership's oil and gas exploration business (Cont.):**

**3. Engagement in agreements for the purchase of EMG shares and for the purchase of rights in the EMG pipeline (Cont.):**

**4) Term sheet for use of additional infrastructures**

Concurrently with the signing of the Share Purchase Agreements, as described above, a term sheet was signed between the Partnership and Noble and the Egyptian Partner (which holds the Arab Gas Pipeline) in the segment from el Arīsh to Aqaba, and an affiliate of Dolphinus, whereby the parties agreed that the Partnership and Noble would receive access to additional capacity in the Egyptian transmission system through the Arab Gas Pipeline, at the entry point to the Egyptian transmission system in the Aqaba area, allowing the flow of gas in additional quantities over and above the gas quantities that would flow via the EMG Pipeline (the "**Additional Infrastructure**"), for the purpose of implementation of the Dolphinus agreement and other agreements for the sale of natural gas to Egypt. In addition, the parties agreed to look into other projects for the transmission of natural gas from Israel to potential customers and facilities in Egypt.

Note that as of the date of approval of the financial statements, the Partnership and Noble are negotiating with the holders of the Additional Infrastructure for the signing of a binding agreement.

**5) MOUs with the Tamar partners and the Leviathan partners**

In proximity to the date of the signing of the EMG Transaction, Noble and the Partnership signed a non-binding MOU with the Tamar partners and a non-binding MOU with the Leviathan partners in connection with the allocation of the capacity and other arrangements in connection with the flow of natural gas in the EMG Pipeline and in the Additional Infrastructure (as defined above).

The MOU with the Leviathan partners determined that subject, *inter alia*, to the signing of a binding agreement by June 30, 2019 and to the closing of the EMG Transaction, the partners in the Leviathan project would pay, on the date of the closing of the EMG Transaction, the sum of $250 million in consideration for EMED's undertaking to allow the flow of natural gas from the Leviathan reservoir for the purpose of realization of the Leviathan-Dolphinus agreement and securing a capacity of 350,000 MMbtu per day in the EMG Pipeline and in the Additional Infrastructure, such that further to Section 1A3 above, on the date of the closing of the Transaction, out of the sum of the consideration that shall be paid by the Partnership and Noble, the sum of approx. $250 million will be paid by the Leviathan partners, such that the sum of the consideration that shall be paid by the Partnership on the date of the closing of the Transaction will be approx. $170 million, in accordance with all of the conditions of the approval by the participation unit holders meeting with respect to the avoidance of distribution of profit for the purpose of their investment in the purchase of EMG rights.

**Note 7 – Investments in petroleum and gas assets (Cont.):**

**C. The Partnership's oil and gas exploration business (Cont.):**

**3. Engagement in agreements for the purchase of EMG shares and for the purchase of rights in the EMG pipeline (Cont.):**

**5. MOUs with the Tamar partners and the Leviathan partners (Cont.)**

Concurrently, Noble and the Partnership signed a non-binding MOU with partners in the Tamar project, whereby subject, *inter alia*, to the signing of a binding agreement by June 30, 2019 and the closing of the EMG Transaction, the Tamar partners would pay the Leviathan partners, by June 30, 2020, the sum of $125 million (which constitutes a reimbursement of 50% of the amount due to be paid by the Leviathan partners on the date of the closing of the EMG Transaction), in consideration for EMED's undertaking to allow the transfer of gas from the Tamar reservoir for the purpose of realization of the Tamar-Dolphinus agreement, including sale on an interruptible basis during 2019, or a proportionately reduced amount, if the amount of the capacity of the EMG Pipeline and the Additional Infrastructure, as is approved by a competent technical entity, is lower than a capacity of 700,000 MMbtu per day. In addition, the MOUs determined mechanisms that allow the Leviathan partners to use the capacity available above 350,000 MMbtu per day, insofar as the Tamar partners do not use the capacity in full.

Note that as of the date of approval of the financial statements, Noble and the Partnership are holding advanced negotiations with the Tamar partners and the Leviathan partners regarding the allotment of capacity in the EMG Pipeline and in the Additional Infrastructure (as defined herein), based on the update of the Tamar-Dolphinus Agreement (see Note 12c1c below) and on the increase of quantities of natural gas on a firm basis in the Leviathan-Dolphinus agreement (see Note 12c2d below)

It is emphasized that the binding agreements with the Tamar partners and the Leviathan partners, if and insofar as signed, are expected to include specific arrangements with respect to regulation of the use of the EMG Pipeline and the Additional Infrastructure, including arrangements with respect to distribution of the capacity in different cases, investments in the Additional Infrastructure and other arrangements. The binding agreements, if and insofar as signed, will be subject to receipt of the relevant regulatory approvals, including the approval of the Competition Authority and the approval of the Ministry of Energy, insofar as required.

In this context it is noted that transmission of the natural gas to Egypt, may be done by using the existing transmission infrastructures (such as the existing transmission infrastructure of INGL and/or by using the Arab Gas Pipeline) and/or by establishing new gas transmission infrastructures from Israel to Egypt.

**Note 7 – Investments in petroleum and gas assets (Cont.):**

**C. The Partnership's oil and gas exploration business (Cont.):**

3. **Engagement in agreements for the purchase of EMG shares and for the purchase of rights in the EMG pipeline (Cont.):**

   **5. MOUs with the Tamar partners and the Leviathan partners (Cont.)**

   It is clarified that the information presented above, including with respect to the possibility of the flow of gas in the EMG Pipeline in the framework of the engineering due diligence, the terms and conditions of the CLOA, if and insofar as signed, the possibilities for financing the Transaction, the costs of refurbishing the EMG Pipeline, the possibility of fulfillment of the transaction closing conditions and the possible date for fulfillment thereof, and the possibility of the signing of binding agreements with the Leviathan and/or Tamar partners, may not materialize, in whole or in part, or may materialize in a materially different manner, due to various factors over which the Partnership has no control.

4. **Block 12 in Cyprus**:

   **a)** The Partnership has a production sharing contract (PSC), whereby the Partnership holds 30% of the rights in the Aphrodite reservoir in Block 12, which is situated in the exclusive economic zone of Cyprus. Noble Energy International Ltd. is the operator of the joint venture ("**Noble Cyprus**").

   **b)** In June 2015, the Partnership, together with its partners in the Aphrodite reservoir, notified the Government of Cyprus of a commerciality announcement and a proposed framework for the development of the Aphrodite reservoir.

   **c)** On April 20, 2016, the partners in the PSC, submitted an updated plan for development of the reservoir, concurrently with the submission of an application for a production license and on September 21, 2017 the partners in the license submitted updated chapters on engineering and technical issues out of the reservoir development plan. Upon the expiration date of the exploration license, the exploration areas not included in the area of the Aphrodite reservoir were returned to the Government of Cyprus. To the best of the Partnership's understanding, based on a legal opinion of its legal advisors, during the interim period after expiration of the exploration license and before receipt of the production license, as aforesaid, the partners in the PSC have the right to receive a production license for the area of the Aphrodite reservoir, upon the approval of the development plan (if and to the extent approved).

   As of the date of approval of the financial statements, the updated Development Plan submitted by the partners in the Aphrodite reservoir to the Cypriot Government has not yet been approved (see paragraph E below). Although, ostensibly, according to the Production Sharing Contract of October 24, 2008 (the "**Production Sharing Contract**"), the Cypriot Government has the option, in the absence of an approved development plan, to claim for termination of the Production Sharing Contract, the partners in the Aphrodite reservoir are continuing to act, in cooperation with the Cypriot Government, for the update and approval of the Development Plan and the update of the Production Sharing Contract. In this context, the Cypriot Government decided to invite the partners to a series of discussions on the issue of the update of the Production Sharing Contract, including updating the mechanism of the fiscal conditions. As of the date of approval of the financial statements, and following such invitation, the parties are holding continuous discussions on the said issue.

**Note 7 – Investments in petroleum and gas assets (Cont.):**

**C. The Partnership's oil and gas exploration business (Cont.):**

**4. Block 12 in Cyprus (Cont.):**

**d)** The right holders are obligated to commence development actions within 6 months from the receipt of the approval of the Republic of Cyprus for the Development Plan.

**e) Plan for Development of the Aphrodite reservoir:**

1) As of the date of approval of the financial statements, the plan for development of the Aphrodite reservoir, which has been submitted for approval by the Government of Cyprus[33], includes the export of natural gas through a pipeline to export markets, by means of constructing a floating independent production facility in the area of the Aphrodite reservoir, with the estimated production capacity of approx. 800 MMCF per day (the "**Floating Facility**" and the "**Development Plan**", respectively).

2) According to an updated estimate of Noble Cyprus, which has been provided to the Partnership and to the Government of Cyprus, and prior to the completion of techno-economic feasibility studies, including the performance of full engineering design (FEED), the estimated cost of the Development Plan, excluding the cost of construction of the pipelines to the target markets, is estimated at the amount of approx. $2.5 to 3.5 billion (in terms of 100%).

3) The formulation of the Development Plan and arrival at the stage of making a final investment decision (FID) for the development of the Aphrodite reservoir, are subject, *inter alia*, to the approval of the aforesaid plan by the Government of Cyprus and the partners in Block 12, receipt of a production license under the Production Sharing Contract, performance of full engineering design (FEED), commercial arrangements for development of the pipelines, signing of natural gas supply agreements and fulfillment of the conditions precedent in such agreements, regulatory approvals and execution of financing arrangements. It is noted that agreements for supply to the target markets may be contingent, *inter alia*, upon the signing of intergovernmental framework agreements between Cyprus and Egypt.

4) The updated Development Plan is subject, *inter alia*, to the Cypriot Government's approval. Insofar as such approval shall be received during 2019, and insofar as the aforesaid conditions precedent shall be fulfilled, the scheduled date for the commencement of natural gas supply from the Aphrodite reservoir is, at the earliest, during 2025.

5) It is emphasized that the aforementioned Development Plan, including the budget estimate and the timetable, are merely preliminary, since the techno-economic studies, the full engineering design (FEED) and the formulation of the project's financing and commercial arrangements are yet to be completed.

[33] It is noted that the Aphrodite reservoir is mostly in the Cypriot EEZ, and a small part thereof is in the area of the Yishai /370 license, which is in the EEZ of Israel. As of the date of the approval of the financial statements, the governments of Israel and Cyprus are conducting negotiations for the regulation of the rights of the parties in the Aphrodite reservoir.

**Note 7 – Investments in petroleum and gas assets (Cont.):**

**C. The Partnership's oil and gas exploration business (Cont.):**

**4. Block 12 in Cyprus (Cont.):**

**e) Plan for Development of the Aphrodite reservoir (Cont.):**

6) Furthermore, the partners in Block 12 are simultaneously examining additional possibilities for the development of the Aphrodite reservoir, including the possibility of integrating the development thereof with the development plans of adjacent reservoirs located in the Israeli Exclusive Economic Zone, including the Leviathan reservoir and/or sharing transportation of gas infrastructures and are also considering the possibility of using existing infrastructures in the area.

**f)** The Production Sharing Contract between the Partnership and the Republic of Cyprus defines, *inter alia*, the right of the Republic of Cyprus to some of the produced oil and/or gas, to the extent produced, in accordance with the arrangements provided in the Production Sharing Contract.

**g)** According to a report prepared in March 2018 by NSAI according to the rules of SPE-PRMS, the amount of contingent resources of natural gas classified under the "Development Pending" stage at the Aphrodite reservoir, as of December 31, 2017 (as of December 31, 2018 there is no change), ranges between approx. 132.5 BCM (the high estimate) and approx. 53.4 BCM (the low estimate).

According to the aforesaid report, the condensate reserves in the Aphrodite reservoir, which are classified as "Development Pending" as of December 31, 2017 (as of December 31, 2018 there is no change), range between approx. 10.3 million barrels (the high estimate) and approx. 3.1 million barrels (the low estimate). See section 7 below with respect to uncertainty in the evaluation of reserves.

**Note 7 – Investments in petroleum and gas assets (Cont.):**

**C. The Partnership's oil and gas exploration business (Cont.):**

5. **The Yam Tethys joint venture**:

The Yam Tethys joint venture is a venture for the exploration, development and production of oil and gas in the areas of the Ashkelon and Noa leases. Production from the Yam Tethys reservoir commenced in 2004.

a) **Commercial arrangement of the operation and production from the Yam Tethys project and the Tamar project ("Commercial Arrangement"):**

Commencing from May 2013 until and including September 2017, natural gas was supplied from the Tamar reservoir[34] (*in lieu* of the Yam Tethys reservoir) by virtue of agreements for gas supply between the Yam Tethys partners and their customers (the "**Ultimate Customers**" and the "**Early Agreements**", respectively).

Such gas supply was performed both by the Tamar partners who are partners in the Yam Tethys project and who have obligations under such agreements and by Tamar partners who are not partners in the Yam Tethys project (and who are not obligated by such agreements).

The consideration which was obtained from the Ultimate Customers, together with the consideration reflecting the share of the Delek Group, which is a right holder Yam Tethys and is not a holder of direct rights in Tamar, was divided such that the partners in the Tamar project which are not partners in the Yam Tethys project, received a natural gas price equal to the monthly average price of natural gas supplied during that month by virtue of agreements executed between the Tamar partners and their customers, and the remaining monetary balance was divided among the Yam Tethys partners that have rights in the Tamar Project, according to their share in the Tamar Project. This division allowed for the maintaining of a balance of the gas quantities in the Tamar Project among the partners therein pro rata.

For details with respect to a claim filed by the Partnership and Noble, which also hold rights in the Yam Tethys Project, as to the royalty rate to which the State is entitled in respect of revenues deriving from the supply of natural gas within the framework of the sale as aforesaid, see Note 12I1 below.

Commencing from October 2017, upon the expiration of some of the agreements for the sale of natural gas from the Yam Tethys reservoir, the Yam Tethys partners are supplying natural gas to customers of the Yam Tethys project as well customers of the Tamar Project.

In May 2018, the Yam Tethys partners engaged with the Tamar partners in an agreement on an interruptible basis (which was updated in September 2018), for the sale of (immaterial) surplus of production from the Yam Tethys reservoir to the Tamar partners, for the sale thereof to the Tamar Project customers, for a period of 24 months from October 1, 2017.

[34] As of December 31, 2018, the balance for supply to the Yam Tethys customer is approx. 0.5 BCM. The agreement for gas supply is scheduled to end during 2022.

**Note 7 – Investments in petroleum and gas assets (Cont.):**

**C. The Partnership's oil and gas exploration business (Cont.):**

**5. The Yam Tethys Joint Venture (Cont.):**

**b) Agreement for the grant of usage rights in the facilities of the Yam Tethys Project:**

In July 2012, the Partnership announced that an engagement agreement was signed (the "**Usage Agreement**") between the partners in the Yam Tethys Project and the partners in the Tamar Project, whereby the Yam Tethys partners would grant the Tamar partners usage rights in the existing facilities of the Yam Tethys project, including the wells, the Mari-B platform, the compression system, the pipeline and the terminal, and the Tamar partners were also granted the right to upgrade and/or construct facilities for the purpose of transportation and storage of natural gas from the Tamar Project (the "**Yam Tethys Facilities**". The usage rights in the Yam Tethys Facilities will be granted subject to the reservation of capacity for natural gas produced from the Yam Tethys project in the pipeline and in the terminal.

The term of the Usage Agreement will end upon the earlier of: (1) the expiration or termination of the Tamar lease, and in the event that the Dalit field is developed, in a manner that makes use of the Yam Tethys Facilities, the expiration or termination of the Dalit lease; (2) the giving of a notice by the Tamar partners of the permanent cessation of commercial gas production from the Tamar project; (3) the abandonment of the Tamar Project.

The Agreement includes, *inter alia*, provisions that regulate the relationship between the Tamar partners and the Yam Tethys partners throughout the entire term of use of the Yam Tethys Facilities, including with respect to the management of the Yam Tethys Facilities, the mechanism for the distribution of the operating expenses of the Yam Tethys Facilities and the distribution of the capital expenses of the Yam Tethys Facilities in connection with the preparation and upgrade of the Yam Tethys Facilities for the receipt of natural gas from the Tamar Project based on the gas capacity scope ratios between the Yam Tethys project and the Tamar Project, restrictions on the transfer and/or pledge of the rights of the parties of the Usage Agreement, and an arbitration mechanism for the resolution of disputes between the parties.

It is noted that ownership of the Yam Tethys Facilities and the cost of abandonment of the facilities will remain with the Yam Tethys partners and the Usage Agreement will provide a settlement of accounts mechanism relating to the value of such facilities at the end of the term of production from the Tamar Project.

**Note 7 – Investments in petroleum and gas assets (Cont.):**

**C. The Partnership's oil and gas exploration business (Cont.):**

**6. The Alon D License (in this section: the "License"):**

On August 21, 2017, the Minister of Energy notified the partners in the License of his decision whereby the License would continue to be in effect for 32 months from the date of the Minister of Energy's decision as aforesaid, subject to conditions determined by the Minister of Energy in such decision.

In April 2018 the Operator delivered an application to the Commissioner for instructions on the performance of the said environmental survey. In January 2019 (after the date of the statement of financial position), the Commissioner approached the partners in the license with a request for additional details on the location at which the drilling is intended to take place within the area of the license, in order to provide detailed instructions on the performance of the environmental survey. In February 2019 (after the date of the statement of financial position), the Partnership provided the Commissioner with the information he asked to receive as aforesaid, and as of the date of approval of the financial statements his response to the information provided to him as aforesaid has not yet been received.

Furthermore, in March 2019 (after the date of the statement of financial position) the operator in the license notified the Partnership that it wishes to withdraw from the exploration activity in the petroleum asset and waive its rights therein. In view of the aforesaid, the Partnership reached an agreement with the operator whereby the operator shall transfer rights at the rate of 25% (out of 100%) in the license to another operator that shall step into its shoes, as the Partnership shall decide, for no consideration (the "**Operator's Rights**"). The operator shall transfer its remaining rights at the rate of 22.059% (out of 100%), to the Partnership, also for no consideration.

On March 5, 2019 and March 17, 2019 and after several potential operators, which the Partnership contacted, expressed no interest in the proposal to act as operator in the license, the audit committee and the board of the General Partner, respectively, approved the engagement of the Partnership with Ithaca Energy Inc. ("**Ithaca**"), a company wholly-owned by Delek Group, in a transaction whereby Ithaca shall be appointed as the operator of the petroleum asset and shall receive from the operator, by transfer, the Operator's Rights, and all subject to the receipt of any and all required approvals, including the approval of the Commissioner, approval of the Competition Authority (if required) and approval of the General Meeting of the Partnership unit holders, in accordance with the provisions of the Partnerships Ordinance, as an irregular transaction of the Partnership with its control holder.

**Note 7 – Investments in petroleum and gas assets (Cont.):**

**C. The Partnership's oil and gas exploration business (Cont.):**

7. **Appraisals of reserves of natural gas, condensate and contingent resources:**

   The above appraisals regarding the reserves of natural gas, condensate and contingent resources in the rights of the Partnership in the oil and gas exploration leases, licenses and the franchise 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.

8. **Exercise of option to purchase working interests in the 399/Roy License:**

   As of the date of the statement of financial position, the Partnership has an option to acquire from Edison International S.P.A ("**Edison**"), an option granted thereto by Ratio Oil Exploration Limited Partnership ("**Ratio**") for the purchase of working interests at an overall rate of 20% (out of 100%) in the 399/Roy License (the **"Roy License**").

   On September 25, 2018, Ratio notified that the Commissioner announced the extension of the Roy license until April 14, 2020, subject to changes to the work plan of the Roy license.

   On March 19, 2019 (after the date of the statement of financial position), the Partnership notified Ratio and Edison, which serves as the operator of the Roy License, of the exercise of the Option (the "**Exercise Notice**").

   According to the Exercise Notice, and in accordance with certain changes in the terms and conditions of the option agreed upon between Ratio and the Partnership, as specified below, the Partnership shall purchase from Ratio interests at the rate of 24.99% (*in lieu* of an option at the rate of 20% as aforesaid) in the Roy License (the "**Transaction**"). The closing of the Transaction and the transfer of the interests in the Roy License to the Partnership are subject to the fulfillment of conditions precedent and the receipt of required approvals.

   The principal terms and conditions of the Transaction are as follows:

   **a)** Against the transfer of the purchased interests, the Partnership shall bear past costs that were borne by Ratio in connection with the purchased interests in the sum total of approx. $4 million (the "**Past Costs**") and additional costs, if any, until the date of completion of the process of transfer of the purchased interests (the "**Interim Costs**").

   **b)** The Past Costs shall be paid by the Partnership to Ratio on the date on which final approval of the partners in the Roy License is received, in accordance with the provisions of the Joint Operating Agreement (if received) for a work plan and a budget for development of the reservoir in the area of the Roy License (FID). The Interim Costs shall be paid by the Partnership to Ratio on the date of completion of the transfer of the purchased interests.

**Note 7 – Investments in petroleum and gas assets (Cont.):**
**C. The Partnership's oil and gas exploration business (Cont.):**
**8. Exercise of option to purchase working interests in the 399/Roy License (Cont.):**

**c)** The parties have agreed that they will perform the binding work plan in the Roy License for 2019-2020 (as shall be approved by the partners in the Roy License), in the framework of which an exploration well will be drilled, with the Partnership bearing its proportionate share in the costs of such well.

**d)** The Partnership has undertaken to grant Eitan Aizenberg Ltd. an overriding royalty at the rate of 2% out of a 14.99% interest (i.e. an overriding royalty at the rate of approx. 0.2998% out of 100%) in petroleum and/or gas that is produced from the area of the Roy License, according to the market value at the wellhead. It is clarified that the remainder of the purchased interests (at the rate of 10%) is not subject to the said overriding royalty.

**e)** The purchased interests shall be transferred to the Partnership without any pledge, lawsuit, liability, right to receive a royalty (with the exception of the State's right to royalties and the provisions of Paragraph d. above) or any other third party right. It is clarified that the purchased interests will be subject to the Partnership's obligation to pay overriding royalties to interest parties of the Partnership and to third parties.

The closing of the Transaction and the transfer of the purchased interests to the Partnership is subject to the fulfillment of conditions precedent and the receipt of approvals, including approval by the Commissioner, approval by the Competition Commissioner (insofar as required) and receipt of the necessary consents from the other partners in the License, Edison and Israel Opportunity Energy Resources – Limited Partnership, which hold 20% and 10% of the interests in the Roy License, respectively. In addition, the approval of the meeting of the holders of the Partnership's units is required for amendment of the limited partnership agreement, in order to allow the Partnership to participate in oil and/or gas exploration and production in the Roy License.

If not all of the necessary conditions and approvals are received up to seven days before commencement of the first exploration drilling in the area of the Roy License, the Option shall expire and terminate without any liability of any of the parties. The aforesaid notwithstanding, if the Partnership pays the Interim Costs in respect of the purchased interests and continues to bear any and all costs of the joint actions in the Roy License in respect of the purchased interests (and such payments are without recourse), the exercise of the option shall not be revoked.

**Note 7 – Investments in petroleum and gas assets (Cont.):**

**C. The Partnership's oil and gas exploration business (Cont.):**

**9. Additional information**:

**a)** The lease deeds were granted subject to the Petroleum Law and grant the partners in the leases an exclusive right to produce oil and natural gas in the areas of the leases for a 30-year period, with the right of extension thereof by 20 additional years, in accordance with and subject to the provisions of the Petroleum Law.

**b)** In June 2017 the Minister of Energy dismissed the appeal filed by the partners in the Hanna license. As a result, the Partnership recorded in 2017 impairment of approx. $24.5 million for the costs of the Dolphin well in the depreciation and amortization item in the statements of comprehensive income.

**c)** In June 2013, the 353/Eran license expired. In November 2014, the Partnership, jointly with its partners in the aforesaid license, filed a petition with the High Court of Justice with respect to the decision of the Minister of Energy to deny the appeal filed by the partners in the license from the decision of the Commissioner not to extend the term of the license. On June 2, 2016, the High Court of Justice sanctioned as a decision the parties' agreement to seek a mediation proceeding. On March 13, 2019, the respondents filed a motion stating that the parties have reached a proposed version for the conclusion of the mediation; however, several approvals were still required for the proposed version. Upon conclusion of the mediation proceeding, the parties reached understandings that were established in a mediation settlement. Such mediation settlement was filed on March 20, 2019 with the Court, which was requested to sanction it as a judgment. In the mediation settlement, the parties agreed to mediation (with the knowledge and 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 right in the area of the Eran license would be divided at a ratio of 76% to the State and 24% to the holders of the rights in the Eran License prior to the expiration thereof. As of the date of approval of the financial statements, such approval by the Court has not yet been received.

**d)** With respect to the engagement in an agreement for the acquisition of onshore petroleum assets after the date of the statement of financial position, see Note 23M.

**Notes to the Financial Statements for December 31, 2018 (Dollars in thousands)**

## Note 8 – Other long-term assets:

**a. Composition:**

| | 31.12.2018 | 31.12.2017 |
|---|---|---|
| Royalties receivable and loan given (see Paragraph B Below) | 189,500 | 167,100 |
| Prepaid expenses for raising a liability to banks (see Note 10C) | 17,080 | 43,783 |
| Ministry of Energy for royalties (see Note 15) | 29,745 | 28,130 |
| Interested parties for overriding royalties (see Notes 15 and 12B) | 4,395 | 4,044 |
| Third party for overriding royalties (see Note 12B) | 2,229 | 2,045 |
| Long-term receivables in joint ventures[35] | 63,853 | 44,370 |
| **Total** | 306,802 | 289,472 |

**b. Agreement for the sale of rights in the Karish I/17 and Tanin I/16 leases (in this section "Leases"):**

On August 16, 2016[36], an agreement was signed between the Partnership and Ocean Energean Oil and Gas Ltd. (the "**Buyer**" or "**Energean**"), for the sale of all of the rights of the Partnership and Noble[37] 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) The Buyer shall pay the Partnership the sum total of U.S. $148.5 million which constitutes a reimbursement for past expenses invested in the Leases by the Partnership and Noble, plus royalties in connection with natural gas and condensate to be produced from the Leases as follows:

[35] The balance mainly includes the cost for construction of the natural gas transmission systems from Israel to Jordan in the Leviathan and Tamar projects in the sum total of approx. $48 million (2017: approx. $33 million). With respect to the construction of a transmission system from the Leviathan project to Jordan, see Note 12C2B below.

[36] According to the Gas Framework, the Partnership and Noble should have sold their entire interests in the leases.

[37] In November 2015, the Partnership entered into a right conferral agreement with Noble, whereby Noble conferred upon the Partnership the right to sell its interests in the leases.

**Note 8 – Other long-term assets (Cont.):**

**b. Agreement for the sale of rights in the Karish I/17 and Tanin I/16 leases (Cont.):**

a) As part of the closing of the transaction, the Buyer paid a sum total of $40 million;

b) The balance of the consideration, in the sum total of $108.5 million, will be paid to the Partnership in ten annual equal installments (in the financial statements: the "**Annual Installments**" or "**Loan**"), plus interest, in the mechanism and at the rate determined in the Agreement, commencing on the date of a final investment decision (FID) in connection with development of the Leases (it is noted that in March 2018 Energean received a Final Investment Decision regarding the development of the Leases and paid the first installment to the Partnership);

c) The Sold Rights were transferred to the Buyer together with the obligation to pay overriding royalties existing in the Leases, which the Seller had undertaken with respect to its share (the "**Existing Royalties**"), and accordingly, the duty to pay the same to the royalty holders shall be imposed on the Buyer as of the transaction closing date;

d) The Buyer shall pay royalties to the Seller in connection with natural gas and condensate to be produced from the Leases at the rate of 7.5% – prior to the payment of the petroleum profit levy under the Taxation of Profits from Natural Resources Law, 5771-2011 (the "**Levy**") in connection with the Leases, and at the rate of 8.25%% - from the date of commencement of payment of the Levy, net of the amount of the Existing Royalties .

e) 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.

2) The Partnership engaged with an external independent appraiser in order to assess the fair value of the royalties and Annual Installments (see Note 22 below).

The financial income item in the report period includes a sum of approx. $48.4 million deriving from revaluation of the value of the Royalty from the Leases and from revaluation of the Annual Installments. Such update derives mainly from changes in the cap rates, bringing forward of the date of the investment decision on the development of the Leases, updating of the contingent resources and hydrocarbon liquids (condensate and natural gas liquids) and a production rate forecast.

Below are main parameters out of the valuations that were used to measure the Royalties and the Receivables: cap rate for the Receivables is estimated at 7.5% (2017: 10%); the cap rate estimated for the Royalties component is estimated at 11.5% (2017: 12%); the sum total of the contingent resources of natural gas and hydrocarbon liquids that were used for the valuation to measure the Royalties were estimated at approx. 67 BCM and approx. 33 MMBBL, respectively.

## Note 9 – Trade and other payables:

**Composition:**

| | 31.12.2018 | 31.12.2017 |
|---|---|---|
| Related parties (see Note 21) | 4,647 | 2,545 |
| Interest payable for liability to banks | 15,761 | 6,869 |
| Institutions (see Note 20) | 1,834 | 15,167 |
| Petroleum and Gas Profit levy (see Note 20) | 7,978 | 3,773 |
| Ministry of Energy in respect of royalties | 6,538 | 4,838 |
| Payables in joint ventures[38] | 123,145 | 86,275 |
| Financial derivative | - | 126 |
| Share-based payment (see Note 13G) | 159 | 104 |
| Other payables and expenses due | 1,765 | 2,658 |
| **Total** | 161,827 | 122,355 |

## Note 10 – Bonds and Liabilities to Banks:

**A. Composition and maturities by years after the date of the statement of financial position:**

**1. Composition of bonds and liabilities to banks:**

| | 31.12.2018 | 31.12.2017 |
|---|---|---|
| Tamar Bond (see Section B below) | 951,879 | 1,269,560 |
| Liability to Banks (see Section C below) | 1,238,143 | 468,967 |
| Series A Bonds (See Section D below) | 395,696 | 394,180 |
| | 2,585,718 | 2,132,707 |
| Net of current maturities of Tamar Bond (See Section B below) | - | 319,421 |
| **Total (net of current maturities)** | 2,585,718 | 1,813,286 |

**2. Maturities by years after the date of statement of financial position:**

| | Amount ($ in millions) | Amortized Cost ($ in millions) | Interest | Stated Maturity |
|---|---|---|---|---|
| Tamar Bond – 12/2020 | 320 | 318.8 | 4.435% | December 2020 |
| Liability to banks (financing of the Leviathan Project) | 1,254 | 1,238 | LIBOR plus margin | February 2021 |
| Series A Bonds | 400.2 | 395.7 | 4.5% | December 2021 |
| Tamar Bond – Series 12/2023 | 320 | 317.2 | 5.082% | December 2023 |
| Tamar Bond – Series 12/2025 | 320 | 315.9 | 5.412% | December 2025 |

[38] Expenses incurred by the operator of the joint transactions and not yet paid.

**Note 10 – Bonds and Liabilities to Banks (Cont.):**

**B. Tamar Bond**

In May 2014, the process of issuing bonds offered by Delek & Avner (Tamar Bond) Ltd. (the "**Issuer**"), a special purpose company (SPC) fully owned by the Partnership, was completed, whereby 5 series of bonds in the total sum of $ 2 billion were issued.

On May 15, 2014, the bonds were listed on TACT-Institutional on Tel Aviv Stock Exchange Ltd. In the framework of the transaction, the Issuer and the Partnership undertook, *inter alia*, that if a duty to withhold tax is imposed on the payments they are required to make under the terms and conditions of the bonds to foreign residents, then subject to certain defined exceptions, the Issuer and/or the Partnership, as applicable, will pay additional amounts as required in order for the net amounts received by the foreign resident to be equal to the amounts such foreign resident would receive if no tax withholding were required. In this context, it is noted that on March 27, 2014, the Partnership received confirmation from the Tax Authority that the bonds to be traded on TACT-Institutional on TASE are bonds listed on a stock exchange in Israel for the purpose of Section 9(15D) of the Income Tax Ordinance (concerning an exemption from tax on interest paid to foreign residents on bonds listed on a stock exchange) and Section 97(B2) of the Ordinance (concerning an exemption from tax for foreign residents on capital gains in the sale of bonds listed on a stock exchange), all subject to the conditions specified in the Tax Authority's confirmation and the provisions of the Income Tax Ordinance and the regulations promulgated thereunder.

To secure the repayment of the bonds, the Partnership pledged its rights in the Tamar project, and mainly its rights in the Tamar lease, in agreements for the sale of gas and condensate, in the joint operating agreement between all of the partners in the Tamar project and the parties' rights in the joint equipment thereunder (including the platform, wells, production system facilities and additional equipment), in the agreement for the grant of usage rights in the Yam Tethys facilities, in bank accounts, including, *inter alia*, the accounts into which the Partnership's revenues from the sale of gas and condensate from the Tamar project are deposited), in insurance policies (with the exception of D&O liability insurance) for insurance of the assets of the Tamar project, in the Issuer's shares etc. (collectively: the "**Collateral**" or the "**Pledged Assets**"). The Collateral for repayment of the bonds are from the Tamar project, without there being any guarantees or collateral external to the Tamar project. However, for as long as certain conditions are not fulfilled and at least until the expiration of 4 years from the date of the issue of the bonds, the bondholders shall have a right of recourse to other assets of the Partnership in respect of 50% of the monies the Partnership has withdrawn and will withdraw from the pledged accounts until such time. The bondholders' right of recourse is limited in amount and also solely limited to assets that have not been pledged by the Partnership by means of a security interest (limited recourse), and without the bondholders being entitled to initiate bankruptcy proceedings against the Partnership. It is noted that the foregoing pledges are subject to the State's royalty rights and to the rights of other royalty holders who are entitled to receive royalties from the Partnership (including interested parties), and that pledges are registered in favor of such royalty holders on the Partnership's rights in the Tamar lease to secure the royalty payment obligation, which will be valid until the repayment of the Bonds. In the framework of the transaction, the Issuer and the Partnership assumed several covenants vis-à-vis the bondholders, including, *inter alia*, the following covenants: restrictions on the creation of additional pledges on the Pledged Assets and the sale thereof;

**Note 10 – Bonds and Liabilities to Banks (Cont.):**

**B. Tamar Bond (Cont.):**

restrictions on the performance of a merger or restructuring as specified in the issue documents, restrictions on amendment or modification of the joint operating agreement, the agreement for use of the facilities or the gas sale agreements, as specified in the issue documents; limitations on expansion of the bond series or the taking of additional debt secured by the Pledged Assets, subject to compliance with several conditions; undertaking to monitor the bonds' rating by the international rating agencies that rated the debt. In addition, restrictions on and conditions were defined for a withdrawal of the surplus cash flow from the Tamar project. The Issuer and the Partnership undertook to indemnify, in certain cases, the representatives that committed to purchase the bonds following the pricing process, if it transpires that representations given by the Issuer and/or the Partnership were breached.

In addition, events of default were defined, upon the occurrence of which the trustee for the bonds will be entitled (and in the case of a demand of 25% of the bondholders - will be obligated) to accelerate the unpaid balance of the bonds, the principal events of which are: (1) principal or interest payment failure; (2) breach of representations; (3) breach of covenants; (4) events of insolvency of the IEC or of the operator of the Tamar project or of the Partnership, if constituting a significant adverse change (as defined) and subject to certain conditions and qualifications; (5) early termination of the gas supply agreement with the IEC, the joint operating agreement or the agreement for usage of the facilities of the Yam Tethys project with the Partnership, if constituting a significant adverse change, subject to certain conditions and qualifications; (6) an event of default by the IEC under the gas supply agreement with the IEC which constitutes a significant adverse change, subject to certain conditions and qualifications; (7) abandonment or discontinuation of the operation of the Tamar project for a consecutive period of 15 days, which is expected to constitute a significant adverse change; (8) damage to the Tamar project (including physical damage, revocation of a license or transfer of the Partnership's rights therein by the State of Israel) which constitutes a significant adverse change and which is not remedied, in certain cases; (9) revocation of an approval related to the Tamar project by the State of Israel which is expected to constitute a significant adverse change and subject to a remedy period of 30 days; (10) discontinuance of the bonds' rating for a certain period; (11) cross default of another financial liability in an amount exceeding $50 million; (12) if any of the issue documents ceases to be valid, or collateral whose aggregate value exceeds $50 million cease to be valid; and (13) a non-appealable judgment for payment of an amount exceeding $50 million, which is not discharged at the elapse of 90 days. In the case of an event of insolvency (as defined in the indenture), the bonds shall automatically be accelerated (in certain cases, only if not removed within 90 days).

The Partnership has the right to prepay the Loan, in whole or in part, at any time, subject to a prepayment fee. Prepayment resulting from various events specified in the bonds (and *inter alia*, as aforesaid, the sale of rights in Tamar) may be made without a prepayment fee. It is further noted that a certain period before any payment due date of the principal of a bond series, the Issuer is required to accrue money in the pledged account in preparation for the upcoming principal payment date. As of the date of the statements of financial position, the Issuer complied with the conditions and undertakings under the indenture.

Further to Note 7C1F above, on the sale of 9.25% (out of 100%) of the Partnership's rights in the Tamar and Dalit leases, the Partnership paid a sum of $320 million from Tamar Bond as partial prepayment of four bond series (Series 2018, 2020, 2023 and 2025) i.e., $80 million from each of the series. Note that if and when the Partnership sells other rights regarding Tamar and Dalit leases, the net expected consideration will first serve for payment of the Tamar Bond.

**Note 10 – Bonds and Liabilities to Banks (Cont.):**

**B. Tamar Bond (Cont.):**

On August 31, 2018, the Partnership fully prepaid the second bond series of Tamar Bond in the total sum of $320 million (the "**Principal Amount**"), originally maturing on December 30, 2018. The prepayment amount includes the Principal Amount plus accrued interest in the sum total of approx. $2.1 million, plus a prepayment fee of approx. $1.2 million (the "**Prepayment Fee**"). It is noted that the amount of the Prepayment Fee is lower than the interest balance which would have been paid by the bond issuer, Delek and Avner (Tamar Bond) Ltd., had the second bond series of Tamar Bond been paid at its original maturity.

**C. Execution of an agreement for the financing of the Partnership's share in the costs of development of the Leviathan Project:**

On February 20, 2017, financing agreements (as amended) (the "**Financing Agreement**" or the "**Agreement**") were signed between the Partnership and a consortium of local and foreign finance providers headed by HSBC Bank Plc. and J.P. Morgan Limited (collectively: the "**Lenders**"), whereby a limited recourse loan was provided to the Partnership in the sum of approx. $1.75 billion (the "**Loan**"), for the purpose of financing its share in the balance of the investment in the development of the Leviathan project (the "**Leviathan Project**").

The Loan is divided into facilities, as follows:

Facility A in the sum of $750 million is available for withdrawal after fulfillment of the preconditions, including the adoption of a Final Investment Decision (FID) by the partners in the Leviathan Project for development of Phase 1A of the development plan, and the registration of pledges in favor of the Lenders by the Commissioner.

Facility B in the sum of $375 million, which will be available for withdrawal upon fulfillment of several preconditions as specified in the loan agreement, the main one being engagement in construction agreements which were defined in the Agreement.

Facility C in the sum of $375 million.

Facility D in the maximum sum of $250 million. Withdrawal of Facility D is contingent upon the infusion of money from a source other than the Financing Agreement monies (the "**Capital**"), such that the ratio between the withdrawals from Facility D and the Capital shall be at least 30% Equity/70% withdrawals.

Provision of Facilities B, C and D by the Lenders is contingent also upon the execution of agreements for the supply of gas at a minimum total annual quantity that was defined in the Agreement, which varies according to the amount of each facility (if the minimum threshold is not met, the facility may be used against the injection of Capital from the Partnership in the same amount as the amount of the facility used).

In addition, provision of each one of the facilities will be contingent upon meeting a ratio for debt coverage of no less than 2:1 between the value of the resources in the reservoir (which will be calculated based on the last discounted cash flow figures published by the Partnership for the project, prior to the calculation, calculated according to 2P and discounted according to 10%) plus the value determined in the Agreement for each gas unit that was not taken into account for the purpose of the discounted cash flow and the balance of the Loan.

**Note 10 – Bonds and Liabilities to Banks (Cont.):**

**C. Execution of an agreement for the financing of the Partnership's share in the costs of development of the Leviathan Project (Cont.):**

The loan agreement includes another facility of $750 million (totaling $2.5 billion), which is contingent upon the signing of agreements for the supply of gas at a minimum total annual volume defined in the Agreement, and a decision to increase the capacity of the production and transmission system to Phase 1B of the development plan or alternatives thereto, which may be given by the Lenders, in whole or in part, or by other lenders, although there is no undertaking of the Lenders to provide this facility and in such case the borrower may approach potential new lenders.

The loan principal will be repaid in a single installment upon the lapse of 48 months from the date of execution of the Financing Agreement. The Loan is a dollar loan and bears variable interest to be paid every period, which is calculated according to LIBOR plus a graded margin. In addition, the Partnership has undertaken to pay a commitment fee at the rate of 35% of the margin that shall apply to the Loan in respect of any amount not withdrawn. The Loan amounts are transferred to Delek Drilling (Leviathan Financing) Ltd., a wholly owned subsidiary of the Partnership, in accordance with calls made by the operator to the partners in the Leviathan Project and for the purpose of financing part of the costs of the Loan and other costs as specified in the loan agreement and are transferred as a loan to the Partnership under the same conditions (back-to-back). The Financing Agreement specifies events, upon the occurrence of any of which the Loan must be paid through prepayment, which include, *inter alia*: unlawfulness, falling below a minimal holding rate (as specified in the Agreement) in the General Partner and/or in the participation units of the Partnership and partial repayment in the case of a partial sale of the Partnership's rights in the Leviathan Project. The Partnership is entitled to prepay the Loan at any time, in whole or in part, subject to the terms and conditions set forth in the Agreement. To secure repayment of the Loan, the Partnership pledged its rights in the assets relating to the Leviathan Project, including, *inter alia*, the Leviathan leases, the joint operating agreement, the project equipment and the insurance policies, gas sale agreements (including agreements that shall be signed in the future, if any) and the project accounts. The Loan is a limited recourse loan and the Lenders will have no recourse to the Partnership's assets that were not pledged in their favor.

It is noted that the foregoing pledges are subject to royalty rights of the State and to rights of other royalty holders who are entitled to receive royalties from the Partnership (including interested parties), and that the pledges that the Partnership has registered on the Leviathan leases in favor of the said royalty holders in the framework of the interim financing transaction to secure their royalty rights will continue to be in effect also throughout the term of the Financing Agreement.

As is customary in financing transactions of this type, the Partnership has assumed covenants which include, *inter alia*, the following main covenants: restrictions on the taking of additional credit (these restrictions shall not apply to non-recourse credit, inferior loans from affiliates and credit in the sum total of up to $800 million (the "**Additional Credit**")); Meeting of liquidity criteria, whereby on dates for review that were determined in the Financing Agreement, the Partnership will be required to prove, according to the liquidity criteria set forth in the Agreement, that it holds sufficient financing sources to meet its liabilities in the coming 12 months and/or until commencement of the production from the Leviathan reservoir; meeting of the required ratio for debt coverage, which ratio will be measured upon each withdrawal (as aforesaid), on the date of provision of a resource report and on the date of sale of rights in Leviathan, if any; restrictions on a change in the field of business; restrictions on the performance of actions that may have a material adverse effect;

**Note 10 – Bonds and Liabilities to Banks (Cont.):**

**C. Execution of an agreement for the financing of the Partnership's share in the costs of development of the Leviathan Project (Cont.):**

the exercise of certain rights by virtue of the joint operating agreement with the consent of the Lenders only, etc.

Withdrawal of surpluses from the accounts pledged in favor of the Lenders will be subject to the terms and conditions set forth in the Financing Agreement and subject to partial prepayment of the Loan at the same time in accordance with the withdrawal amount defined in the Agreement (or were deposited in an account designated for this purpose).

As is customary in financing transactions of this type, the Financing Agreement defines events of default, upon the occurrence of which the finance providers will be entitled to accelerate the Loan, which include, *inter alia*, the following main events: cross default of another financial liability which is not a limited recourse liability; an event having a material adverse effect on the Partnership's ability to fulfill its material liabilities in connection with the Financing Agreement or the project documents (as defined in the Financing Agreement) or on its assets, business or financial position, in a manner which impairs its ability to pay its debts as they become due, or on the project in a manner which jeopardizes or is highly likely to jeopardize the ability to refinance the Loan; termination of agreements for the supply of gas and other project documents if such termination shall or may have a material adverse effect on the ability to refinance the Loan; noncompliance with the liquidity criteria that were defined in the Agreement; noncompliance with the Additional Credit conditions as specified above; engagement in hedging transactions, except as agreed according to the Agreement; transfer of control of the General Partner, as defined in the Agreement, and a decline in the control holder's holdings of units of the Limited Partner to 45% and under; abandonment of the project; insolvency events; an ongoing *force majeure* event in connection with the project which has or may have a material adverse effect; all subject to the conditions and qualifications and/or remediation periods set forth in the Agreement. As of the date of the statement of financial position, the Partnership is in compliance with the financial covenants set forth in the Financing Agreement. As of the date of approval of the financial statements, the Partnership withdrew approx. $1.3 billion from the Loan monies. Note, that in December 2017, the Tax Authority's approval was received regarding tax gross-up for foreign lenders at a rate of 5%. According to the above-specified terms and conditions of the Financing Agreement, the Partnership is exposed to possible cash flow changes that may derive from changes in the LIBOR interest rate. With respect to hedging transactions performed during Q1/2019, see Note 22F2.

**D. Series A Bonds:**

In December 2016, the Partnership issued to the public ILS 1,528,533,000 par value of Series A Bonds (see Note 1E above regarding the Partnerships' merger), which were listed on the TASE (the "**Bonds**"). The Bonds were issued in consideration for their par value, and they bear fixed annual interest of 4.50%. The Bonds and the Partnership's undertakings under the indenture for the Bonds (the "**Indenture**") are not secured by any collateral.

The consideration received net of issue expenses totaled approx. $392.6 million.

The principal of the Bonds will be paid in a single payment on December 31, 2021, together with the last interest payment therefor. The interest on the unpaid balance of the principal of the Bonds will be paid in semi-annual payments, on June 30 and December 31 of each of the years 2017 to 2021. The principal and the interest of the Bonds are linked to the US dollar rate. The basic dollar rate is ILS 3.819.

**Note 10 – Bonds and Liabilities to Banks (Cont.):**

**D. Series A Bonds (Cont.):**

The Partnership has a right to perform at any time, at its own initiative, full or partial pre-payment of the Bonds, in accordance with the conditions determined in the Indenture. The Indenture includes provisions with respect to the acceleration of the Bonds, in the event of a decrease in the full indirect holding rate of the Partnership in the Tamar lease, to under 10% (out of 100% of the holdings of all of the partners in the Tamar Project) and/or a decrease in the full indirect holding rate of the Partnership in the Leviathan lease to under 18% (out of 100% of the holdings of all of the partners in the Leviathan Project), in accordance with the conditions and the definitions specified in the Indenture.

The Indenture includes the Partnership's undertaking for the payment of the Bonds, according to the conditions thereof, and additional standard undertakings in indentures, including an undertaking to act for the rating of the Bonds until full repayment thereof, by at least one rating agency and an undertaking not to create a floating charge on all of its assets in favor of any third party, to secure any debt or undertaking, without receipt of advance approval from the holders of the Bonds. The aforesaid does not limit corporations controlled by the Partnership from creating such a floating charge on all of their assets, and the Partnership may pledge any and/or all of its assets in various fixed charges including the creation of floating charges on one or more specific assets of the Partnership, and it may further take non-recourse or limited recourse loans without any limitation and without the need to obtain any consent from the Series A Bond holders and/or the trustee, as the case may be.

The Indenture specifies grounds for the acceleration of the Bonds in specific cases, as is standard in indentures, which mainly include (a) in the event that the financial equity of the Partnership (as defined in the Indenture) drops below $400 million (the "Minimum Financial Equity") during two consecutive quarters; (b) in the event the Partnership's financial equity to debt ratio on a standalone basis (as defined in the Indenture) drops below 300% (times 3) during two consecutive quarters; and (c) in the event that the Partnership performed a distribution as defined in the Indenture or announced an intention of performing a distribution, following which the Partnership's financial equity to debt ratio on a standalone basis will drop below 450% (times 4.5). As of the date of statement of financial position, the Partnership is in compliance with the financial covenants set forth in the Indenture.

In addition, the Indenture includes a mechanism for adjusting the annual interest rate to be borne by the unpaid balance of the Bond principal (the "**Interest Rate of the Bonds**"), whereby:

- In the event that the rating of the Bonds is updated to be lower than their basic rating which is A1 (on the rating scale of Midroog), the Interest Rate of the Bonds will increase by 0.25% for every notch downgrade, up to a maximum interest equal to the basic interest rate of the Bonds plus 1.25% (the "**Maximum Interest**"). Notwithstanding the aforesaid, the Interest Rate of the Bonds shall not increase due to a single notch downgrade below the basic rating (it is clarified that upon a two-notch downgrade below the basic rating, the Interest Rate of the Bonds will rise by 0.50%).
- In the event that the Partnership's financial equity drops below the Minimum Financial Equity, or in the event that the Partnership's financial equity to debt ratio on a standalone basis drops below 350% (times 3.5), the interest rate of the Bonds will increase by a rate of 0.5% above the interest rate prior to the change, but in any event no higher than the Maximum Interest.

**Delek Drilling – Limited Partnership**

**Notes to the Financial Statements for December 31, 2018 (Dollars in thousands)**

## Note 11 – Other long-term liabilities:

### A. Composition

| | 31.12.2018 | 31.12.2017 |
|---|---|---|
| Obligations to retire petroleum and gas assets (see Note 2N2 and Section B below) | 112,195 | 95,725 |
| Taxes payable on account of the unit holders (see Note 7C1F) | 21,068 | 25,000 |
| Share-based payment (see Note 13G) | 19 | 97 |
| Others | 759 | 760 |
| **Total** | 134,041 | 121,582 |

### B. Transactions in obligations to retire petroleum and gas assets

| | 31.12.2018 | 31.12.2017 |
|---|---|---|
| Balance as of January 1 | 95,725 | 79,439 |
| Additions | ,10288 | ,21842 |
| Effect of the passing of time | 5,070 | 3,795 |
| Effect of update of the cap rate | 1,112 | - |
| Decrease due to sale | - | (9,351) |
| Balance as of December 31 | 112,195 | 95,725 |

The cap rates used for the measurement of the petroleum and gas assets retirement obligation as of December 31, 2018 are 4%-5.1% (December 31, 2017: 4.75%-6.9%).

## Note 12 – Contingent liabilities, engagements and pledges:

**A.** Under the Partnership agreement, the General Partner will be entitled to 0.01% of the revenues and shall bear 0.01% of the expenses and losses of the Partnership.
The General Partner will be entitled to management fees as specified below:

1. Regular management fees in an amount in Shekels equal to US$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 US$120,000 per quarter.

The General Partner will be entitled to reimbursement of certain direct expenses involved in the management of the Partnership, as specified in the agreement. According to the Partnership agreement, the limited partner (the Trustee) will be entitled to 99.99% of the revenues and will bear 99.99% of the expenses and losses of the Partnership.

**B. Engagements for the payment of royalties:**

1. Following the closing of the merger of the partnerships (as specified in Note 1E above), all of the liabilities related to royalties apply with respect to all of the (current and future) gas and petroleum assets of the Partnership, however, the rate of royalties in respect thereof, was reduced by 50% compared with the rate of royalties prior to the merger (since the Partnership and Avner Partnership held equal parts in those petroleum assets, excluding the Ashkelon and Noa leases, in which the Partnership held 25.5% and Avner Partnership 23%, and in their respect the rate of royalties was reduced by 47.42% with respect to the royalties paid by the Partnership to Delek Group and Delek Energy ("**DES** "), as defined below, and by 52.58% with respect to the royalties paid by Avner Partnership before the merger, as specified below).

2. In the context of a right transfer agreement signed in 1993, the Partnership undertook to pay DES 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".
It is further noted that in June 2018, the rights to receive royalties in respect of the Tamar Project were transferred from Delek Energy to Delek Royalties (2012) Ltd. ("**Delek Royalties**"), and therefore, as of such date, the Partnership has been paying Delek Royalties overriding royalties from the Tamar Project.
With respect to the dispute regarding the investment recovery date in the Tamar Project, see Notes 15D and 12I5 below.

**Note 12 – Contingent liabilities, engagements and pledges (Cont.):**

**B. Engagements for the payment of royalties (Cont.):**

3. In addition, the Partnership will pay, by virtue of the Avner Partnership Agreement, royalties at a rate of 3% of all of the share of the limited partnership in petroleum and/or gas and/or other valuable substances which will be produced and utilized out of the petroleum assets in which the limited partnership has a present or will have a future interest (before deduction of royalties of any type, but after the reduction of the oil to be used for the purpose of the production itself).

   In an agreement signed on September 2, 1991, it was determined that the said right of the royalties is held by the General Partner in trust, and it is paid to those entitled to royalties under the Limited Partnership Agreement. Out of the total royalties as aforesaid, Cohen Development and Industrial Buildings Ltd. (an affiliate) will receive 1.375% in the Noa and Ashkelon lease and 1.4375% of any future petroleum right of the Partnership. The remaining entitlement to royalties is paid to third parties.

4. In addition, the Partnership undertook to pay R&B Energy Mediterranean Ltd. ("**R&B**") an overriding royalty at the rate of 0.7% of all oil, gas and other hydrocarbons that will be produced from New Discoveries (as defined in the agreement executed in September 2000 between R&B and Delek Group), in the Noa and Ashkelon leases for rights at a rate of 3.5% (which the Partnership purchased from Delek Group) out of 15% of the rights (purchased by Delek Group from R&B) in the said leases.

5. On January 21, 2007, the Partnership and Avner Partnership entered an agreement with Dor Chemicals for the purchase of 2.5% (out of 100%) of rights in the Tamar and Dalit leases (the "**Sold Rights**"). In consideration for the Sold Rights, Dor Chemicals is entitled to an overriding royalty at a rate of 6% of the quantity of gas and/or other valuable substances that will be produced from the Sold Rights, on the basis of a calculation formula that was determined.

6. It is noted that following the transaction of the sale of rights to Tamar Petroleum, a proportional share of the overriding royalties (9.25% out of 31.25%) will be paid by Tamar Petroleum (see note 7C1F above).

7. Royalty to the State:

   The Petroleum Law, 5712-1952 (the "**Petroleum Law**") and the Petroleum Regulations, 5713-1953, prescribe that a lease holder, within the meaning of such term in the Petroleum Law, owes the State Treasury royalty at the rate of one-eighth of the petroleum quantity produced and utilized from the area of the lease, according to the market value at the wellhead, excluding the quantity of petroleum used by the lease holder for operating the area of the lease, but royalties will in no event fall below the minimum royalties prescribed by the law (see Note 15 below).

8. In the context of the exercise of an option to purchase working interests in the Roy License, the Partnership has undertaken to grant Eitan Aizenberg Ltd. an overriding royalty at the rate of 2% out of a 14.99% interest (see Note 7C8 above).

**Note 12 – Contingent liabilities, engagements and pledges (Cont.):**

**C. Engagements for the supply of natural gas to the domestic market and for export:**

**1. Following is a table presenting the summary of agreements for the sale of natural gas of the Tamar partners (the data described refers to 100% of the rights in the petroleum assets):**

| | Supply Commencement Year | Basic Gas Supply Period[39] | Is there an Extension Option? | Total Maximum Amount for Supply (100%) (BCM)[40] | Total Amount Supplied by December 31, 2018 (100%) (BCM) | Primary Gas Price Linkage Basis |
|---|---|---|---|---|---|---|
| IEC[41] | 2013 | 15 years | Option for extension by two additional years. | Approx. 87 | Approx. 25.8 | The U.S. Consumer Price Index (U.S. CPI) |
| Dalia Power Energies Ltd. | 2015 | 17 years | Option for extension by two additional years. | Approx. 23.3 | Approx. 4.1 | The linkage formula is mostly based on linkage to the electricity production tariff and includes a "floor price". |
| Other private electricity producers[42] | 2013-2020 | 15-18 years except for one agreement for a shorter period. | Some of the agreements include an option for extension thereof by a period of between one to three additional years[43] . | Approx. 57.5 | Approx. 12.2 | In most of the agreements the linkage formula is based on linkage to the electricity production tariff, with a small part linked to the U.S. CPI. In several agreements, the linkage formula is mostly based on linkage to the electricity production tariff with a small part linked to the Brent prices. In all of the agreements the gas price is determined according to a formula that includes a base price and linkage and includes a "floor price" |

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

[40] Such quantity is the maximum quantity the Tamar partners have undertaken to supply to the customer for the term of the agreements. The quantity they have undertaken to purchase is lower than this quantity.

[41] For details regarding the agreement with the IEC and amendment of the agreement in connection with the gas price, see Paragraph B below.

[42] It is clarified that in some of the agreements not all of the conditions precedent to the agreement were met.

[43] Except for the extension period set forth in the agreement executed between the Tamar partners and Israel Chemical Corporation Ltd. ("**ICL**") on February 21, 2018 (the "**ICL from Tamar Agreement**"). Under this supply agreement, in the event of a delay in the date of commencement of commercial production from the Tanin and Karish reservoirs, the term of the agreement will be automatically extended by additional terms of six months each, up to the date of commencement of the commercial production from the Tanin and Karish reservoirs or up to December 31, 2025, whichever is earlier. It was also determined that ICL will be entitled to notify the Tamar partners of the termination of the supply agreement upon the lapse of each of the said extension periods. Should the Tanin Karish Agreement be terminated, the term of the supply agreement will be automatically extended until December 31, 2025.

| | Supply Commencement Year | Basic Gas Supply Period[44] | Is there an Extension Option? | Total Maximum Amount for Supply (100%) (BCM)[45] | Total Amount Supplied by December 31, 2018 (100%) (BCM) | Primary Gas Price Linkage Basis |
|---|---|---|---|---|---|---|
| Industrial customers | 2013-2017 | 5-7 years | One of the agreements includes an option for an additional two-year extension. | Approx. 7.6 | Approx. 5 | In most of the agreements the linkage formula is based on linkage to the Brent prices and includes a "floor price" (where with one agreement, in addition to the foregoing, the linkage formula is also based, in a small part, on the rate of electricity production). In one of the agreements, the linkage formula is based on the prices of liquid fuels, and it includes a "floor price" and in another agreement, the price formula is based on the base price set forth in the Gas Framework. |
| Natural gas marketing companies | 2013-2018 | 5-7 years | Some of the agreements include an option for extension thereof by a period of up to one additional year. | Approx. 1.5 | Approx. 0.2 | The linkage formula is based on linkage to the Brent prices and includes a "floor price". |
| Export Agreement – NBL | 2017 | 15 years | There is an option for an additional two-year extension. | Approx. 3[46] | Approx. 0.2 | The linkage formula is based mostly on linkage to the Brent prices and includes a "floor price". |
| Export Agreement – Dolphinus | For details see Paragraph C1C below | Commencing from the completion of the relevant transmission systems to Egypt up to December 31, 2030. | - | Approx. 32 | - | The linkage formula is based mostly on linkage to the Brent prices and includes a "floor price". |
| **Total** | | | | **Approx. 211.9** | **Approx. 47.5** | |

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

[45] Such quantity is the maximum quantity the Tamar partners have undertaken to supply to the customer for the term of the agreements. The quantity they have undertaken to purchase is lower than this quantity.

[46] It is noted that the latest agreement with NBL, signed in October 2018 is on an interruptible basis for the supply of an overall quantity of up to approx. 1 BCM. Note that within a tax ruling regarding the agreements for supply to Jordan, given to Tamar partners by the Tax Authority, the Tamar partners undertook to offer new potential consumers to engage in agreements for the sale of natural gas, at a price which be calculated according to the optimal formula, based on the Brent price, as specified in the Gas Framework, with an undertaking for such offer to apply for a period of 3 years from the date of the government decision (i.e., until August 16, 2018) and from the date of execution of the last agreement with NBL (i.e., until October 14, 2021), respectively. The offer will be carried out according to the provisions of the Gas Framework, including with respect to the date of supply which may apply at any time commencing from the commencement of supply under the agreements for supply from Jordan up to six years from their execution date.

**Note 12 – Contingent liabilities, engagements and pledges (Cont.):**

**C. Engagements for the supply of natural gas (Cont.):**

**1. Tamar Project (Cont.):**

**a. Further details with respect to all of the agreements for natural gas sale in the Tamar project:**

**1)** In the natural gas sale agreements, the aforesaid purchasers undertook, insofar as supply is on a fixed basis, to "Take or Pay" for a minimal annual quantity of natural gas at a scope and according to the mechanism specified in the supply agreement (the "**Minimum Quantity**"). If such purchasers do not purchase the Minimum Quantity in any year, they shall be liable to pay the sellers for the difference between the Minimum Quantity defined and the quantity actually bought by the purchaser. The supply agreements further specify a balance accumulation mechanism for surplus quantities used by the purchaser in a given year and the utilization thereof to reduce the purchaser's obligation to buy the Minimum Quantity as aforesaid for several years thereafter ("**Carry Forward**"). Furthermore, provisions and mechanisms are determined, which allow such purchasers, after using the Minimum Quantity billable for a given year, to receive gas in the same year for no additional payment up to the balance of the gas quantity not used in previous years and for which they paid the sellers under their billable Minimum Quantity commitment as aforesaid.

**2)** Following the decisions of the Competition Commissioner regarding the grant of restrictive arrangement exemption in respect of agreements wherein the basic supply period is longer than 7 years, except for the agreement with the IEC (the "**Long-Term Agreements**"), in some of the agreements signed with customers, each of the purchasers was granted the option to reduce the Minimum Quantity to approx. 50% of the average annual amount consumed thereby in the three years preceding the notice of exercise of the option, subject to adjustments as specified in the supply agreement (in this section: the "**Option**"). Upon the reduction of the Minimum Quantity, the other amounts specified in the supply agreement will be reduced accordingly. As of the report release date, the Tamar partners are acting to amend the rest of the purchase agreements with the relevant consumers in accordance with the decision of the Commissioner.

As of the date of approval of the financial statements, the Tamar partners are acting to amend the rest of the purchase agreements with the relevant consumers according to the decision of the Competition Commissioner.

In this context it is noted that at the beginning of 2019 (after the date of the statement of financial position), the Tamar partners signed an amendment to the agreement with Dalia Energies, in which Dalia Energies undertook to purchase from the Tamar project the full quantities of natural gas it shall use in its facilities in the period commencing from the date of flow of gas from the Leviathan reservoir until such time as Dalia Energies exercise the Option (in this section: the "**Period**"), if exercised. In the same amendment, the parties further agreed that for the purpose of calculation of the average annual quantity used by Dalia Energies under the agreement in the three years preceding the notice of exercise of the Option relative to the Period, the calculation shall be made based on the Minimum Quantity billable (in accordance with the mechanism set forth in the amendment to the agreement therewith), and not based on the quantity actually taken by Dalia Energies. The amendment to the agreement with Dalia Energies is subject, *inter alia*, to the approval of the Competition Authority.

**Note 12 – Contingent liabilities, engagements and pledges (Cont.):**

**C. Engagements for the supply of natural gas (Cont.):**

**1. Tamar Project (Cont.):**

**a. Further details with respect to all of the agreements for natural gas sale in the Tamar project (Cont.):**

**3)** Following the Gas Framework, in the agreements for the supply of natural gas signed commencing from August 16, 2015 for a period exceeding 8 years, the consumer received a unilateral right to shorten the term of the agreement. Such right will also be granted in agreements signed up to December 13, 2020 for a period exceeding 8 years.

**4)** The supply agreements stipulate further provisions, *inter alia*, on the following issues: the right to terminate the agreement in the event of breach of a material undertaking, the right of the Tamar partners to supply gas to the aforesaid purchasers from other natural gas sources, compensation mechanisms in the event of delays in the gas supply from the Tamar project or in the event of failure to supply the amounts specified in the agreement, limitations on the liability of the parties to the agreement, and with respect to the relations among the sellers themselves in matters related to the gas supply to the such purchasers.

**5) Engagement in a condensate supply agreement with Paz Ashdod Oil Refineries Ltd. ("Paz Refineries"):**

In November 2012, Paz Refineries and the Tamar partners (in this section, the "**Sellers**"), signed a condensate supply agreement (in this section: the "**Agreement**"), whereby the Sellers undertook to supply Paz Refineries condensate for a five-year period as of the date of commencement of condensate flow from the Tamar project, in a non-material scope (quantities and price). In November 2016, the parties agreed to extend the agreement for 5 additional years. The condensate price is determined according to the Brent prices net of a margin, as specified in the supply agreement.

**6) Agreement for natural gas supply to Delek, the Israel Fuel Corporation Ltd. ("Delek Israel"):**

In December 2013, an agreement for the supply of natural gas was signed with Delek Israel, a company wholly controlled by Delek Group, the controlling shareholder of the General Partner.

According to the supply agreement, the sellers undertook to supply the purchaser natural gas in a total quantity of up to approx. 0.46 BCM (the "**TCQ**") according to the terms specified in the supply agreement.

The term of the supply agreement commenced in H1/2015 and will expire at the elapse of approx. 7 years or when the purchaser shall have consumed the TCQ, whichever is earlier.

**7) Agreement for natural gas supply with I.P.P. Delek Sorek Ltd. ("Delek Sorek"):**

May 2015 saw the amendment of the natural gas supply agreement signed in March 2014 with Delek Sorek, a company indirectly controlled by Delek Group, the (indirect) controlling shareholder of the General Partner.

**Note 12 – Contingent liabilities, engagements and pledges (Cont.):**

**C. Engagements for the supply of natural gas (Cont.):**

**1. Tamar Project (Cont.):**

**a. Further details with respect to all of the agreements for natural gas sale in the Tamar project (Cont.):**

The sellers undertook to supply the purchaser natural gas in a total quantity of up to approx. 3.3 BCM (the "**TCQ**") according to the terms specified in the supply agreement.

The term of the supply agreement is approx. 15 years, with an option to extend the agreement by two additional years, or on the date that the purchaser shall have consumed the Total Contractual Amount, whichever is earlier.

**8)** The Electricity Authority's (the “**PUA-E**") decision of July 22, 2013 to split the uniform electricity production tariff that existed until that time into several different tariffs, has led to a disagreement with all customers linked to the electricity production tariff as to the gas price linkage for quantities supplied in the period between May 2013 and February 2015. It is noted that on January 21, 2015 and September 7, 2015, the PUA-E’s decisions on the update of the production tariffs were published, which decisions considerably reduced the disparities between the various production tariffs. In September 2015, the PUA-E has returned to a structure containing one electricity production tariff. Commencing in 2015, settlement agreements were signed between the Tamar partners and most of the customers linked to the electricity production tariff, (apart from OPC Mishor Rotem Ltd. (“**OPC**”)). In June 2017 the Partnership filed together with some of the Tamar partners an international arbitration proceeding with OPC. Due to the aforesaid dispute, the Partnership included on the date of the statement of financial position, a long-term trade receivables balance of approx. $8.6 million (based, *inter alia*, on the last agreed tariff practiced prior to the split). It is noted that the disputed amounts carry interest (Base + LIBOR) according to the terms and conditions of the gas agreement signed with this customer. In the estimation of the Partnership, based on assessment by its legal counsel, there is a chance of more than 50% in the OPC arbitration proceeding that the Partnership’s position, according to which the amounts of gas supplied during the period from May 2013 up to February 2015 will be subject to the last electricity production tariff which prevailed prior to the split, will be accepted.

**b. Further details regarding the gas supply agreement between the Tamar partners and the IEC:**

**1)** The gas supply agreement between the Tamar partners and the IEC was signed in March 2012 and amended in July 2012, May 2015 and September 2016 (in this section: the “**Agreement**”), *inter alia*, with respect to the exercise of options for increase of the gas quantities to be consumed by the IEC.

**Note 12 – Contingent liabilities, engagements and pledges (Cont.):**

**C. Engagements for the supply of natural gas (Cont.):**

**1. Tamar Project (Cont.):**

**b. Further details regarding the gas supply agreement between the Tamar partners and the IEC (Cont.):**

**2)** As part of the Agreement the IEC the options were exercised to increase the total contractual quantity from approx. 78 BCM to approx. 87 BCM.

**3)** From January 1, 2019 until the expiration of the term of the Agreement, the minimum quantity to be charged will be approx. 3 BCM per year. The Agreement contains provisions regarding the calculation and adjustment of the minimum quantity to be charged including under circumstances of *force majeure* or the sellers' supply failure.

**4)** The gas price is determined according to a formula which includes a base price and linkage which is based on the U.S. CPI, plus 1% a year until 2019 and less 1% a year from 2020 onwards. The gas price in respect of one unit of MMBTU in 2011 was calculated according to a base price of $5.042. In respect of the natural gas quantities to be consumed by the IEC within the Option stipulated in the Agreement to increase of the contractual quantities, as of 2014, the gas price is linked to only 30% of the U.S. CPI increase rate and the aforesaid addition or reduction of 1% per year does not apply.

**5)** The Agreement stipulates two dates on which each party may request the adjustment of the price (according to a mechanism stipulated in the Agreement), if such party believes that the contractual price is no longer suitable for a long-term contract with an anchor buyer for the consumption of natural gas for use in the Israeli market: upon the lapse of 8 years and 11 years from the commercial operation date (as defined in the Agreement commencing on July 1, 2013) of the Tamar Project (i.e.: July 1, 2021 and July 1, 2024), whichever is earlier. On the first adjustment date (July 1, 2021 - after 8 years) the adjustment applied to the price will be at a range of up to 25% (addition or reduction), and on the second adjustment date (July 1, 2024 – 11 years later), the adjustment applied to the price will be at a range of up to 10% (addition or reduction).

**Note 12 – Contingent liabilities, engagements and pledges (Cont.):**

**C. Engagements for the supply of natural gas (Cont.):**

**1. Tamar Project (Cont.):**

**b. Further details regarding the gas supply agreement between the Tamar partners and the IEC (Cont.):**

**6)** The IEC or any of the Tamar partners will be entitled to terminate the Agreement, in the event that the other party performs an insolvency act (as defined in the Agreement) which is likely to have a material adverse effect on the performance of its undertakings under the Agreement, by providing an advance written notice of at least 120 days. The IEC and the sellers agreed not to exercise any right to terminate the Agreement which they may have according to any law, other than with respect to significant or continuous breaches of material provisions of the Agreement and only after provision of a 120-day period to the breaching party (unless a shorter period is stipulated in the Agreement) to remedy the breach.

**7)** According to the agreement, if the sellers fail to supply the gas amounts ordered by the IEC according to the Agreement's provisions and the supply failure is in a quantity exceeding the deviation rates permitted by the Agreement, the sellers will then compensate the IEC by way of supplying gas in the subsequent month in an unsupplied quantity and at a reduced price. Furthermore, the Agreement specifies special breaches for which compensation at higher rates will be paid. The Agreement stipulates limits to the liability of each of the parties for a breach of some of the provisions of the Agreement at the rates specified in the Agreement.

**8)** The assignment of the obligations and rights of the IEC under the agreement, is contingent upon the transferee being technically and financially able to meet its obligations under the agreement and that the transferee will also be transferred the same proportional share of the power stations of the IEC (i.e., if a proportional part of the rights and obligations are transferred to any transferee, it will also get a proportional part of the power stations of the IEC).

**9)** On February 14, 2019 (after the date of the statement of financial position), the board of the General Partner of the Partnership approved an amendment to the agreement in connection with the gas price which shall apply until the first adjustment date, and in connection with the daily gas quantity which the IEC shall be entitled to order under the agreement (in this Section: the "**Amendment to the Agreement**"). The Amendment to the Agreement provides that from January 2019 until the first adjustment date (in this Section: the "**Interim Period**"), the linkage clause set forth in the agreement shall not be implemented, such that the price to be paid by the IEC shall be the contractual price that was valid during 2018. On the first adjustment date, an adjustment shall be made to the contractual price as set forth in the agreement, in reference to the contractual price that would have been paid but for the Amendment to the Agreement, i.e., the contractual price assuming implementation of the linkage set forth in the agreement, as aforesaid.

If and insofar as it is determined that a price reduction is required on the first adjustment date, the parties shall discuss the manner and scope at which the amount of the savings that will derive for the IEC from the Amendment to the Agreement in the Interim period may be taken into account in such reduction.

**Note 12 – Contingent liabilities, engagements and pledges (Cont.):**

**C. Engagements for the supply of natural gas (Cont.):**

**1. Tamar Project (Cont.):**

**b. Further details regarding the gas supply agreement between the Tamar partners and the IEC (Cont.):**

The Amendment to the Agreement further provides that from the date of flow of gas from the Leviathan project to the Israeli market, the maximum daily gas quantity which the IEC shall be entitled to order under the agreement shall be reduced from 655,200 MMBTU to 500,000 MMBTU, without reducing the minimal annual quantity which the IEC undertook to 'take or pay' under the agreement.

The Amendment to the Agreement shall be subject to the receipt of approval from some of the Tamar partners' lenders, as well as the approval of the Competition Authority, if and insofar as such approval is required by law. The Amendment to the Agreement is expected to be signed upon receipt of the regulatory approvals that are required by the IEC (if and insofar as received). As of the date of approval of the financial statements, the said approvals were not yet received and therefore the Amendment to the Agreement has not been signed yet.

**c. Engagements for natural gas export:**

In February 2018, an agreement for the export of natural gas from the Tamar Project to Egypt as executed between the Partnership and Noble (hereinafter they will be jointly referred to in this Section as the "**Sellers**") and Dolphinus Holdings Limited[47] ("**Dolphinus**") (in this Section: the "**Export from Tamar Agreement**") the scope of which is significantly larger than the agreement for the supply of natural gas executed between the Tamar partners and Dolphinus on March 17, 2015 and which was executed with the intention of replacing it. On September 26, 2018, the Sellers endorsed the Export from Tamar Agreement to the other partners in the Tamar Project.

Note that as of the financial statements' approval date, the parties are conducting negotiations regarding amendments to the Export from Tamar Agreement and the memorandum of understanding with the Tamar partners, as specified in Note 7C3 above, which have not formulated to agreements yet. It is further noted that at the same time, negotiations are held with Dolphinus for increasing the quantity of gas to be supplied to Dolphinus under the agreement for export from Leviathan to Dolphinus as specified in Section C2D below, and with the Leviathan partners regarding the memorandum of understanding as specified in Note 7C3 above.

The Export from Tamar Agreement provides that the gas supply to Dolphinus would initially be on an interruptible basis. The Export from Tamar Agreement grants the Tamar partners an option to notify Dolphinus that the gas supply (in whole or in part) will be converted to firm basis (in this Section: the "**Option**"). The Option may be exercised by the Tamar partners, in whole or in part, during the period commencing in July 2020 and ending at the end of December 2021, or during another period, as shall be agreed between the Tamar partners and Dolphinus.

[47] To the best of the Partnership's knowledge, the buyer is a company which engages in natural gas trade and intends to supply gas to large industrial and commercial consumers in Egypt.

**Note 12 – Contingent liabilities, engagements and pledges (Cont.):**

**C. Engagements for the supply of natural gas (Cont.):**

**1. Tamar Project (Cont.):**

**c. Engagements for natural gas export (Cont.):**

From the Option exercise date, as aforesaid, the Tamar partners will be obligated to supply Dolphinus with an annual quantity of up to approx. 3.5 BCM (according to the quantities for which the Option will be exercised) and Dolphinus will be obligated to take or pay for a minimal annual quantity of natural gas according to a mechanism determined in the Export from Tamar Agreement. The total contractual gas quantity stated in the Export from Tamar Agreement is approx. 32 BCM.

The price of the gas to be supplied to Dolphinus under the Export from Tamar Agreement, will be determined according to a formula based on the price of a Brent oil barrel.

The supply according to the Export from Tamar Agreement is expected to begin during 2019, upon the regulation of the use of the infrastructures necessary for the transmission of natural gas to Egypt. The supply will continue up to the supply of the total contractual quantity set forth in the Export from Tamar Agreement or up to December 2030, whichever is earlier.

Note that within the Export from Tamar Agreement it was agreed that the Tamar partners would bear the costs of gas piping in the INGL transmission system.

The Export from Tamar Agreement includes several conditions precedent, mainly regarding the receipt of regulatory approvals in Israel and Egypt (including the receipt of approvals for the gas export and import as aforesaid), entering agreements which will allow use of the transmission infrastructure, including execution of transmission agreements with INGL (if necessary) receipt of guarantees in favor of the Tamar partners as required in the Export from Tamar Agreement, as well as receipt of approvals from the tax authorities in Israel regarding transactions contemplated in the Export from Tamar Agreement. It is clarified that there is no certainty that the sale of gas to Dolphinus under the Export from Tamar Agreement will materialize, due to the non-fulfillment of the conditions precedent in the Export from Tamar Agreement, in whole or in part, etc. and changes which shall occur following negotiations held for the amendment of the Export from Tamar Agreement as aforesaid.

**2. The Leviathan project:**

**a) Agreements for the sale of natural gas from the Leviathan Project:**

During the years 2016-2018, the Partnership signed, together with the other Leviathan partners, a few agreements for the supply of natural gas from the Leviathan project, the main provisions of which are presented below:

**Notes to the Financial Statements for December 31, 2018 (Dollars in thousands)**

## Note 12 – Contingent liabilities, engagements and pledges (Cont.):
## C. Engagements for the supply of natural gas (Cont.):
### 2. Leviathan Project (Cont.):
#### a) Agreements for the sale of natural gas from the Leviathan Project (Cont.):

| | Year of Commencement of Supply | Basic Gas Supply Period[48] | Is there an extension option? | Total maximum quantity for supply (100%) (BCM)[49] | Main Linkage Basis for the Gas Price |
|---|---|---|---|---|---|
| Private Electricity Producers[50] | The date of gas flow from the Leviathan reservoir in commercial quantities or the date of commencement of the commercial operation of the power station of the purchaser (whichever is later) | 18-20 years from the date of the commencement of supply, excluding one agreement which provides that such period will be counted from the date of commencement of commercial operation of the buyer's power plant or the date of commencement of the commercial operation of the Leviathan project (whichever is earlier) excluding an agreement between ICL and Leviathan Partners[51] which contains a different supply period. | Option to extend by another two years, excluding an agreement between ICL and the Leviathan Partners[52] | Approx. 28.9 | The linkage formula of the Agreements, excluding the ICL Agreement, is based on linkage to the electricity production tariff, and includes a "floor price". |
| Industrial Customer | The date of gas flow from the Leviathan reservoir in commercial quantities | 15 years | Option to extend by one more year. | Approx. 3.1 | The linkage formula is based in part on linkage to the Brent prices, and in part on the electricity production tariff and includes a "floor price". There is also partial linkage to the refining margin index. |
| Nepco Export Agreement | The date of gas flow from the Leviathan reservoir in commercial quantities, the date on which the purchaser's facilities are ready or the date on which the relevant transmission systems will be ready (whichever is later) | 15 years | The agreement is for a period of 15 years, may be extended for a period of up to two more years. | Approx. 45 | The linkage formula is based on linkage to the Brent prices plus a marketing commission, transmission fee and participation in the payments to INGL. |
| Dolphinus Export Agreement | The date of gas flow from the Leviathan reservoir in commercial quantities, the date on which the purchaser's facilities are ready or the date on which the relevant transmission systems will be ready (whichever is later) | 10 years | - | Approx. 32 | The linkage formula is based on linkage to the Brent prices |
| **Total** | | | | **Approx. 109** | |

[48] In most of the agreements the gas supply period, that commences from the piping date with respect to the relevant agreement, is as stated in the table above, or until the buyer consumes the maximum contractual quantity determined in the agreement, whichever is earlier.

[49] This quantity is the maximum quantity the Leviathan partners undertook to supply to the customer during the term of the agreements. The quantity which they undertook to purchase is lower than this quantity. It is noted that there are agreements in which a mechanism is determined whereby the buyer may increase/decrease the quantities purchased (including the total maximum quantity) up to the date determined in the agreement, in accordance with its needs and the provisions determined in the agreement .

[50] As of the date of approval of the financial statements described above, all of the conditions precedent to the agreement were fulfilled.

[51] The supply agreement executed between the Leviathan partners and ICL on February 21, 2018, specified a mechanism similar to the mechanism for extension of the ICL from Tamar Agreement.

[52] See Footnote 51.

**Note 12 – Contingent liabilities, engagements and pledges (Cont.):**

**C. Engagements for the supply of natural gas (Cont.):**

**2. Leviathan Project (Cont.):**

**a) Agreements for the sale of natural gas from the Leviathan Project (Cont.):**

**Further details with respect to natural gas sale agreements signed by the Leviathan partners**:

1) In each of the natural gas sale agreements, the aforesaid purchasers undertook to purchase or pay (“Take or Pay”) for a minimal annual amount of natural gas at a scope and according to the mechanism specified in the supply agreement (the "**Minimum Quantity**"). The supply agreements further specify a mechanism of accumulation of balance in respect of surplus amounts consumed by the purchaser in a specific year and the utilization thereof for reducing the purchaser's obligation to purchase such Minimum Quantity for several years thereafter. Furthermore, provisions and mechanisms are provided, which allow each of such purchasers, after paying for gas not consumed due to the application of the mechanism of Minimum Quantity to be charged as aforesaid, to receive gas with no additional payment up to the amount it had paid for gas it had not consumed.

2) In accordance with the Gas Framework, each of the buyers, in agreements executed by June 13, 2017 and for a period to exceed 8 years, was given an option to reduce the minimum quantity to an amount equal to 50% of the average annual quantity it actually consumed in the three years preceding the date of the notice of exercise of the option, subject to adjustments as determined in the supply agreement (in this section: the “**Option**”). Upon the reduction of the minimum quantity, the other quantities determined in the supply agreement will be reduced accordingly. Each one of the said buyers may exercise the above Option with a notice, to be given to the sellers during a period of 3 years which shall commence 5 years after the date of commencement of the gas flow from the Leviathan project to the buyer or 4 years from the date on which the Commissioner approved the transfer of the rights in the Karish and Tanin leases in accordance with the Gas Framework (i.e. December 13, 2020) (whichever is later). If the buyer gave notice of the exercise of the said Option, the quantity will be decreased 12 months after the date the notice was given.

3) The supply agreements include a number of conditions precedent which include, *inter alia*, the receipt of a license for a gas transmission system from the Leviathan reservoir in accordance with the Natural Gas Sector Law (see paragraph G3 below), the adoption of an FID by the Leviathan partners and the receipt of the required approvals on the part of the buyer with respect to the agreement.

4) In the supply agreements additional provisions were determined, inter alia, on the following subjects: a right to terminate the agreement in the event of the breach of a material undertaking, a right of the Leviathan Partners to supply gas to the said buyers from other natural gas sources, compensation mechanisms in the event of a delay in the gas supply from the Leviathan project or in the event of a failure to supply the contractual quantities, limits to the liability of the parties to the agreement, and with respect to the internal relationship among the sellers with respect to the supply of gas to the said buyers.

**Note 12 – Contingent liabilities, engagements and pledges (Cont.):**

**C. Engagements for the supply of natural gas (Cont.):**

**2. Leviathan Project (Cont.):**

**b) Agreement for the Export of Natural Gas from the Leviathan Project to the Jordanian National Electric Power Company:**

In September 2016, a detailed agreement was signed for the supply of natural gas between NBL Jordan Marketing Limited (the "**Marketing Company**") and the Jordanian National Electric Power Company ("**NEPCO**" and the "**Export Agreemen**t", respectively). The Marketing Company is a subsidiary wholly owned by the partners in the Leviathan project, who hold it relative to their holding rates in the Leviathan project.

According to the Export Agreement, the Marketing Company undertook to supply natural gas to NEPCO for a period of approx. 15 years after the commencement of the commercial supply or when the total supply volume will be approx. 45 BCM. The supply according to the Export Agreement is expected to start with the commencement of the supply from the Leviathan reservoir and the completion of the transmission systems required to carry natural gas to NEPCO in Israel and in Jordan.

The supply of gas is expected to be carried out at the exit from the Israeli transmission system on the border between Israel and Jordan. The cost of the completion of the Israeli transmission system up to the border between Israel and Jordan is estimated at an amount of approx. $119 million (100%, the Partnership's share, approx. $54 million).

NEPCO has undertaken to purchase or pay for ("Take or Pay") a minimum annual quantity of gas, in such amount and in accordance with the mechanism as determined in the Export 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, transmission fee and participation in the payments to INGL.

it is noted that pursuant to a tax ruling regarding the agreement, the Leviathan partners are obligated to offer every new Israeli customer a natural gas price alternative, which will be determined according to a Brent barrel price, as calculated according to the optimal formula for the consumer, prevailing on the date of the government decision on the Tamar partners agreements. The undertaking to such offer by virtue of the tax ruling will apply for a period of three years from the date of execution of the export agreement (i.e., until September 25, 2019).

The supply date under the offer will commence in any period beginning upon the commencement of supply pursuant to the export agreement (expected to apply upon the commencement of gas supply from the Leviathan reservoir, i.e., during Q/4 2019, according to the Partnership's estimation) until six years after the date of execution of the export agreement.

**Note 12 – Contingent liabilities, engagements and pledges (Cont.):**

**C. Engagements for the supply of natural gas (Cont.):**

**2. Leviathan Project (Cont.):**

**b) Agreement for the Export of Natural Gas from the Leviathan Project to the Jordanian National Electric Power Company (Cont.):**

On March 7, 2018, the Partnership announced that all of the conditions precedent set forth in the Agreement were fulfilled.

**c) Execution of a (non-binding) letter of intent by and between the Leviathan partners and BG International Limited for the export of natural gas:**

Following the non-binding LOI of June 2014, which was executed between the Leviathan partners and BG International Limited, which was acquired by Shell the Partnership continues, together with the other Leviathan partners to conduct negotiations with Shell for the supply of natural gas for the purpose of feeding the existing Shell liquefaction plant near the city of Edco, Egypt (in this Section: the "**Liquefaction Plant**").

It is clarified that the aforesaid transaction will be subject to the successful completion of the negotiations between the parties and to the signing of the binding agreement, and that there is no certainty that the parties will agree on the conditions of the binding agreement and that such an agreement will be signed.

Furthermore, the Partnership is reviewing, together with its other partners in the Aphrodite reservoir, the possibility of joint supply of natural gas with the Leviathan Project to the Liquefaction Plant, which will be performed, if at all, from the Aphrodite reservoir in an amount of approx. 6BCM per year for a period of approx. 10-15 years, subject to a plan for the development of Aphrodite reservoir, as specified in Note 7C4 above, and from the production platform of the Leviathan project, as part of additional development phases of the Leviathan reservoir (beyond Phase 1A of the Leviathan reservoir development plan).

It is noted that to the best of the Partnership's knowledge, the maximal annual capacity of the Liquefaction Plants is approx. 12BCM per year.

**d) Agreement for natural gas export from the Leviathan project to Dolphinus:**

In November 2015, a non-binding letter of intent was signed between the Leviathan partners and Dolphinus (in this Section: the "**LOI**"), in which the parties confirmed their intention to negotiate an agreement for the supply of natural gas from the Leviathan project to Dolphinus by means of a Pipeline (in this Section: the "**Binding Agreement**").

In February 2018, an agreement was signed between the Partnership and Noble (jointly hereinafter in this section: the "**Sellers**") and Dolphinus (hereinafter in this Section: the "**Purchaser**") for the export of natural gas from the Leviathan Project to Egypt (in this section: the "**Export from Leviathan Agreement**"), which was executed following the non-binding LOI signed in November 2015.

On September 26, 2018, the Sellers endorsed the Export Agreement to the additional partner in the Leviathan project.

**Note 12 – Contingent liabilities, engagements and pledges (Cont.):**

**C. Engagements for the supply of natural gas (Cont.):**

**2. Leviathan Project (Cont.):**

**d) Agreement for natural gas export from the Leviathan project to Dolphinus (Cont.):**

In the Export from Leviathan Agreement it was determined that the supply of gas to the Purchaser will be on a firm basis. The Sellers undertook to supply the Purchaser with an annual quantity of approx. 3.5 BCM and the Purchaser undertook to take or pay for a minimal quantity according to the mechanism set forth in the agreement. The total contractual gas quantity stated in the Export from Leviathan Agreement is approx. 32 BCM.

It is noted that as of the date of approval of the financial statements, the partners and Noble are conducting negotiations with Dolphinus for an increase of the gas quantity to be supplied to Dolphinus under the Export from Leviathan Agreement. It is further noted that at the same time, negotiations are held regarding amendments to the agreement for export from Tamar to Dolphinus as specified in Section 17C1C above and with respect to the memorandum of understanding with the Tamar partners as specified in Note 7C3 above.

The price of gas to be supplied to the Purchaser pursuant to the Export from Leviathan Agreement will be determined according to a formula based on the price of a Brent oil barrel. The supply pursuant to the Export from Leviathan Agreement is expected to begin with the commencement of production from the Leviathan reservoir. The supply will last until the supply of the total contractual quantity set forth in the Export from Leviathan Agreement or until December 2030, whichever is earlier.

The Export from Leviathan Agreement includes several conditions precedent, mainly the receipt of regulatory approvals in Israel and Egypt (including receipt of approvals for the export and import of the gas as stated), entry into agreements that will enable use of the transmission infrastructure, including the signing of transmission agreements between the Leviathan partners and INGL (if required), the receipt of guarantees in favor of the Leviathan partners as required pursuant to the Export from Leviathan Agreement, and receipt of approvals from the Israeli Tax Authorities in respect of the transactions that are the subject-matter of the Export from Leviathan Agreement.

It is noted that, as part of the Export from Leviathan Agreement, it was agreed that the Leviathan partners would bear the costs of the gas piping in the INGL transmission system.

It is clarified that there is no certainty that the sale of the gas to the Purchaser under the Export from Leviathan Agreement will be realized, due to the non-fulfillment of the conditions precedent in the Export from Leviathan Agreement, in whole or in part, etc.

**e) Agreement for the supply of natural gas from Leviathan project to Israel Chemical Ltd. ("ICL"):**

On February 21, 2018 an agreement was signed between the Leviathan project partners and ICL for the supply of natural gas (the "**ICL from Leviathan Agreement**"). The period of the supply agreement shall begin on the date of piping of the gas in commercial quantities from the Leviathan project and expire on September 1, 2020.

**Note 12 – Contingent liabilities, engagements and pledges (Cont.):**

**C. Engagements for the supply of natural gas (Cont.):**

**2. Leviathan Project (Cont.):**

**e) Agreement for the supply of natural gas from Leviathan project to Israel Chemical Ltd. ("ICL") (Cont.):**

As the Leviathan partners were informed by ICL, ICL engaged in an agreement for the purchase of natural gas from the Tanin and Karish leases (the "Tanin Karish Agreement" and "Tanin and Karish Reservoirs", respectively). Therefore, pursuant to the provisions of the Gas Framework and the orders of the Antitrust Authority, the Leviathan partners and ICL agreed that in the event of a delay in the date of the commencement of commercial production from the Tanin and Karish Reservoirs, the term of the agreement shall be automatically extended by additional periods of six months each, until the date of the commencement of commercial production from the Tanin and Karish Reservoirs or until December 31, 2025, whichever is earlier. It was further determined that ICL shall be entitled to notify the Leviathan partners of the termination of the supply agreement upon the expiration of each of the aforesaid extension periods. The supply agreement further determined that if the Tanin Karish Agreement will be terminated, the period of the supply agreement shall be automatically extended until December 31, 2025.

The Leviathan partners undertook to supply ICL with an annual quantity of natural gas in the scope of approx. 0.38 BCM, pursuant to the terms and conditions set forth in the supply agreement. ICL undertook to take or pay. The supply agreement further determined a mechanism for increasing the gas quantity that will be supplied to the buyer, up to an annual amount in the scope of approx. 0.76 BCM.

The supply agreement set forth that the gas price shall be linked in part to the Brent oil barrel price and in part to the electricity production tariff, as the same will be determined from time to time by the PUA-E, including a "floor price".

**3. A Request for Proposals for the supply of natural gas to the Israel Electric Corporation Ltd.**

On December 2, 2018 a request for proposals was delivered to the Tamar partners and the Leviathan partners by the IEC for the supply of natural gas at an estimated annual quantity of up to 2 BCM, to be supplied from the later of October 2019 or the date of commencement of production of gas from the Leviathan reservoir, until the earlier of June 30, 2021 or the date of commencement of production of gas from the Karish reservoir (in this section: the "**Supply Period**"). During the Supply Period, the IEC shall approach the winner only for the purchase of gas, according to its need, over and above the gas supplied thereto under the agreement therewith described above. On March 7, 2019 (after the date of the statement of financial position), the Tamar and Leviathan partners submitted proposals under the said request.

## Note 12 – Contingent liabilities, engagements and pledges (Cont.):

### D. Estimates regarding gas quantities and supply dates:

The estimates regarding the natural gas quantities which will be purchased by the aforesaid purchasers, 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 purchasers, the gas prices to be determined according to the formulas specified in the supply agreements, the electricity production tariff, the Dollar-Shekel exchange rate (insofar as relevant to the supply agreement), the Brent prices (insofar as relevant to the supply agreement), the U.S. CPI (insofar as relevant to the supply agreement), performance and completion of the expansion of supply from the Tamar Project (insofar as relevant to the supply agreement), construction and operation of the power plants and/or other plants of the purchasers (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.

### E. Dependence on the Operator and the Operator agreements:

The principal part of the Partnership's operations in the joint ventures in Israel Michal-Matan, Ratio-Yam, and Yam Tethys is carried out by Noble. The principal part of the Partnership’s operation in the Block 12 joint venture in Cyprus is carried out by Noble Cyprus.

According to the joint operation agreements in such joint ventures, it was agreed that Noble or Noble Cyprus, according to the aforesaid, would serve as the operator and would be exclusively responsible for the management of the joint operations.

According to the rules of settlement of accounts specified in the agreements, Noble and Noble Cyprus are entitled to reimbursement of indirect expenses calculated as a percentage of the direct expenses, as specified below:

**Michal-Matan joint venture**:

Noble is entitled to reimbursement of all of the expenses it will expend in connection with the performance of its duties as operator, at a rate equal to 1% of all of the direct expenses as of January 1, 2016, other than in respect of marketing activities.

**Ratio-Yam joint venture:**

Noble is entitled to a reimbursement of all the direct expenses it incurs in connection with the fulfillment of its duties as an operator and to a reimbursement of the indirect expenses deriving from a percentage of the expenses of the joint venture at the exploration stage, at a rate of 1% of all the direct development expenses, as defined in the agreement, subject to certain exceptions.

**Yam Tethys joint venture:**

Noble is entitled to reimbursement of all of the direct expenses it will expend in connection with the performance of its duties as operator as well as reimbursement of the indirect expenses deriving from the amount of 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.):**
**E. Dependence on the Operator and the Operator agreements (Cont.):**

**Block 12 Cyprus**:

Noble Cyprus is entitled to reimbursement of all of the direct expenses it will expend in connection with the performance of its duties as operator as well as reimbursement of the indirect expenses deriving from the amount of expenses of the joint venture at a rate of 1% of the expenses up to an expense amount of $20 million per year, and over and above such amount – at a rate of 0.85% of the expenses. It is noted that as of the date of approval of the financial statements, the rate for development and production expenses has not yet been determined.

**F. Dependence on a customer:**

The Partnership has a principal customer with which a binding agreement has been signed for the supply of gas from the Tamar project – the IEC (See Paragraph 1C above).

The Partnership's share in sales to the IEC in 2018 totaled approx. $221.9 million (2017: approx. $263.7 million; 2016: approx. $297.6 million). The IEC's debt balance as of December 31, 2018, included in the trade receivables item, is approx. $17.1 million (December 31, 2017: $15.8 million). Furthermore, the Dalia Power Energies Ltd. is another principal customer – also see Notes 14B and Note 22G below.

**G. Permits and licenses for the projects' facilities:**

**1.** In the context of the development of the Yam Tethys project, the Yam Tethys partners received permits and licenses under the Petroleum Law and the Natural Gas Sector Law, which are required for the purpose of construction and operation of the production system and the transmission system from the production platform to the terminal.

**2.** In the context of the development of the Tamar project, the Tamar partners received approval for the construction of a permanent rig for natural gas and condensate production, as well as approval for the operation of a system for the production of natural gas and condensate from the Tamar project, whereby the Tamar partners are obligated, *inter alia*, to provide a guarantee in the sum total of approx. $25.6 million (100%; the Partnership's share - approx. $5.6 million).

With respect to the license for operation of a 10-inch pipe through an SPC "Tamar 10-inch Ltd." owned by the Tamar partners, see Note 7C1C1 below.

**3.** In February 2017, the Minister of Energy granted an SPC owned by the Leviathan partners, "Leviathan Transmission System Ltd.", a license for the construction and operation of the transmission system.

**H. Pledges and guarantees:**

1. A short-term bank deposit as of December 31, 2018 in the amount of approx. $37.2 million used for debt service and current payments in the context of the issue of the bonds of Tamar Bond (see Note 10B above).
2. A long-term bank deposit as of December 31, 2018 in the amount of approx. $60.3 million serving as a safety cushion in the context of the issue of the bonds of Tamar Bond (see Note 10B above).
3. Also see Notes 10B and 10C as to pledges provided by the Partnership on its assets in the context of the issue of the bonds of Tamar Bond and a liability to banks.

## Note 12 – Contingent liabilities, engagements and pledges (Cont.):

## H. Pledges and guarantees (Cont.):

4. According to the demand of the Republic of Cyprus in the framework of the PSC as stated in Note 7C4 above, in 2013, Delek Group extended a performance guarantee in favor of the Republic of Cyprus. In consideration for extending 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. During April 2018, the Israeli partners at the Leviathan project extended an additional guarantee in favor of the Israeli Tax Authority (Customs) regarding equipment imported by the operator of the transaction for the development of the Leviathan Project. The share of the Partnership in the said guarantee is in a sum total of approx. ILS 188 million. As of the financial statements' approval date, the Partnership's share in the guarantees extended in favor of the Customs with respect to the Tamar and Leviathan Projects, amounts to a total of approx. ILS 375 million (as updated from time to time). During July 2018, the partners of the Leviathan Project extended another guarantee in favor of the Israel Land Authority regarding the construction of development infrastructure for Leviathan Project. The share of the Partnership in the said guarantee is in a total of approx. ILS 2.3 million.

## I. Legal proceedings:

**1.** On March 12, 2015, the Partnership, together with Noble (jointly in this section: the "**Plaintiffs**"), filed a claim with the Jerusalem District Court against the State of Israel by its representatives at the Ministry of Energy (in this Section: the "**Defendant**"), which chiefly consists of restitution of royalties paid by the Plaintiffs to the Defendant, in excess and under protest, in respect of revenues deriving from natural gas supply agreements which were executed between third party customers (in this Section: the "**Ultimate Customers**") and the Yam Tethys partners, whereby some of the gas contemplated in those agreements was supplied from the Tamar Project, all according to the framework of the sale, as specified in Note 7C5A above. The Plaintiffs further moved within the claim to grant a declaratory remedy according to which the royalties to be paid by the Plaintiffs in the future in respect of such revenues will be based on the consideration to be received from the Ultimate Customers (in this Section: the "**Contractual Consideration**"). Together with the share of Delek Group, which is not the holder of rights in Tamar (hereinafter together with the Contractual Consideration: the "**Total Consideration**"). The claim is based on the Plaintiffs' argument whereby, unlike the State's claim, the Plaintiffs, as the holders of rights in both Yam Tethys and in Tamar, take the gas which is in their possession, such that no sale was carried out between the "Tamar Project" and the "Yam Tethys Project" and therefore they must pay royalties based only on the Total Consideration. As a result, the State collects royalties in excess from the Plaintiffs, in respect of amounts that exceed the amounts they receive from the Ultimate Customers, i.e., from the Contractual Consideration, reflecting the market value of the gas, in view of the Ultimate Customers being an unrelated party.

As of December 31, 2018, the restitution remedy due to the main argument of the Plaintiffs as aforesaid is approx. $26.7 million (the Partnership's share is approx. $12.4 million).

**Note 12 – Contingent liabilities, engagements and pledges (Cont.):**

**I. Legal Proceedings (Cont.):**

**1. (Cont.):**

Alternatively, the plaintiffs argued that even if there had been any kind of a sale, the sale that was performed was with respect to the share of the holders of the rights in the Tamar Project that are not the holders of the rights in Yam Tethys (Isramco and Dor – 32.75% and in part of the period after the purchase of the rights in the Tamar Project by Tamar Petroleum and Everest – 45.5%) and the holders of the rights in the Yam Tethys project, with the balance of the gas that is being supplied to the Ultimate Customers by the Plaintiffs (67.25% and in part of the period after the sale of the rights in the Tamar Project to Tamar Petroleum and Everest hold rights – 54.5%) is gas that is in the plaintiffs' possession, which they are entitled to use for the purpose of supplying gas to the Ultimate Customers as aforesaid (in this section: the "**Partial Sale Approach**").

As of December 31, 2018, the remedy of restitution with respect to the Partial Sale Approach as aforesaid is approx. $18.6 million (the Partnership's share is approx. $8.7 million).

In January 2019 (after the date of the statement of financial position) a decision was handed down by the Court, whereby the preliminary proceedings have ended. In addition, in March 2019 trial hearings were scheduled for September 2019.

In the Partnership's estimation, based on the opinion of its legal counsel, the chance that the Partial Sale Approach will be accepted is higher than the chance of it being dismissed.

**2.** On June 18, 2014, a motion for class certification was filed with the Tel Aviv District Court by a consumer of the IEC (who was replaced by his widow in April 2018 (the "**Petitioner**")) against the Tamar partners (the "**Certification Motion**"). Such motion concerns the price at which the Tamar partners sell natural gas to the IEC. The Certification Motion claims that the gas price for the IEC is an unfair price which constitutes abuse of the Tamar Partners' position as holders of a monopoly in the Israeli natural gas supply sector in violation of Section 29A of the Restrictive Trade Practices Law.

The remedies sought in the Certification Motion are: compensation for all of the electricity consumers in the sum of the difference between the price paid by the IEC for natural gas supplied by the Tamar partners and the fair price thereof, which was estimated on the date of filing of the Certification Motion at a total sum of approx. ILS 2.5 billion (in 100% terms), as well as declaratory orders whereby the Tamar partners are required to refrain from selling the natural gas from the Tamar project for a sum exceeding the sum specified in the Certification Motion and sale thereof at a higher price constitutes abuse of their monopolistic power.

On November 23, 2016 a decision was issued, denying a motion filed by the Tamar partners in April 2016, for summary dismissal of the Certification Motion. In December 2016, the Tamar partners filed an appeal on this decision.

## Note 12 – Contingent liabilities, engagements and pledges (Cont.):

### I. Legal Proceedings (Cont.):

**2. (Cont.):**

On September 28, 2017, the Supreme Court decided to deny the appeal motion and remand the case to the district court to hear the Certification Motion on the merits. In May and June 2018 examinations were held of the affiants on behalf of the State, and additional examination days for these affiants and the affiants on behalf of the Tamar partners. According to the Court's decision, the Petitioner filed its closing statements in writing in January 2019 and the date for filing the closing statements on behalf of the Tamar partners was scheduled for April 2019. In the Partnership's estimation, based on the opinion of its legal counsel, chances of the motion for class certification being accepted are lower than 50%.

**3.** On December 25, 2016, a motion for class certification (in this section: the "**Motion**") was filed claiming that the merger transaction between the Partnership and Avner Partnership (as set forth in Note 1E above) had been approved by an unfair procedure and the consideration paid to the holders of the minority units in Avner Partnership, as determined in the merger agreement, was unfair. The motion was filed against Avner Partnership, the general partner in Avner Partnership and the board members thereof, Delek Group as the (indirect) control holder of Avner Partnership, and against Price Waterhouse Coopers Consulting Ltd. PWC, as the economic advisors of an independent board committee set up by Avner Partnership.

Among other claims, the Motion argues that the committee members, the board of directors of Avner Partnership and the company of the general partner in the Avner Partnership had breached the duty of care to Avner Partnership and that Avner Partnership conducted itself in a manner that discriminated the minority. The petitioners estimate the total damage at ILS 320 million.

On February 13, 2017, the court approved a stipulation whereby the class certification motion would be amended by adding a claim of discrimination against the minority by Delek Group. On July 6, 2017, the Court ordered, pursuant to the Partnership's motion, of the joining of the Partnership as a respondent. On October 15, 2018 a pre-trial hearing in the Certification Motion was held, in which the parties agreed to try to reach a stipulation regarding the petitioners' motion for a discovery and document inspection order. In February 2019, the Court granted the motion of the parties to approve a stipulation in relation to the motion for a discovery and document inspection order. Accordingly, the respondents are required to produce documents as agreed by March 28, 2019.

In the estimation of the Partnership's legal counsel, the chances of the certification motion to be granted are lower than 50%.

**Note 12 – Contingent liabilities, engagements and pledges (Cont.):**

**I. Legal Proceedings (Cont.):**

4. On February 5, 2019 (after the date of the statement of financial position) the Partnership learned of the filing of a class action and a motion for class certification thereof (in this section: the "**Certification Motion**"), which 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, officers of theirs and Leader Issues (1993) Ltd. (in this section jointly: the "**Respondents**"), in connection with the issue of the shares of Tamar Petroleum in July 2017 (in this section: the "**IPO**").
   According to the Petitioners, in essence, the Respondents misled the investing public in the IPO with respect to the ability of Tamar Petroleum to distribute a dividend to its shareholders, for the period commencing on the IPO date and ending at the end of 2021 (in this section: the "**Period**"), and breached duties under various laws, *inter alia* a breach of the duty of care of the said officers and breach of the Partnership's duties as shareholder and holder of control of Tamar Petroleum before the IPO.
   The remedies sought in the said class action mainly consist of 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.
   The date for filing a response is scheduled for April 2019. As of the date of approval of the financial statements, pleadings have not yet been filed by the Partnership and the other Respondents.
   In the estimation of the Partnership's legal counsel, the chances of the Certification Motion to be granted are lower than 50%.

5. **Motion for the certification of a derivative suit on the issue of the date of recovery of the investment in the Tamar Project:**

   a) On November 29, 2018, a motion was received at the Partnership's offices for approval of the filing of a derivative suit, which was filed with the Tel Aviv District Court against the Partnership, the General Partner of the Partnership, Delek Group, Delek Energy and Delek Royalties (Delek Group, Delek Energy and Delek Royalties, hereinafter in this section jointly: the "**Royalty Interest Owners**"), the directors of the General Partner of the Partnership, the CEO of the General Partner of the Partnership and the Partnership's auditors, in connection with the payment of royalties to the Royalty Interest Owners at the rate of 6.5% (in lieu of 1.5%) from January 2018, the date of recovery of the investment in the Tamar project (in this section: the "**Certification Motion**"). According to the Petitioner, in essence, faults have occurred in the determination of the approval of the date of recovery of the investment in the Tamar project, including the non-inclusion of a gas and petroleum profits levy under the Taxation of Profits from Natural Resources Law (in this section: the "**Sheshinski Levy**"), in the calculation of the investment recovery date. In addition, according to the Petitioner, the General Partner and the officers breached the duty of care and the fiduciary duty imposed on them to the Partnership, by making a draft calculation of the investment recovery date that is wrong and/or does not include the Sheshinski Levy. The Petitioner further alleges breach of the duty of fairness imposed on the Royalty Interest Owners and breach of the duty of care imposed on the Partnership's auditors.

**Note 12 – Contingent liabilities, engagements and pledges (Cont.):**

**I. Legal Proceedings (Cont.):**

**5. Motion for the certification of a derivative suit on the issue of the date of recovery of the investment in the Tamar Project (Cont.)**:

**a) (Contd.):**

The remedies sought in the Certification Motion include declaratory remedies, including a determination that the calculation of the investment recovery date must include the Sheshinski Levy, and that accordingly the investment recovery date must be calculated as a later date, only after which will the royalty rate be 6.5%, and that until such later date the Royalty Interest Owners shall not be entitled to receive royalties at a rate higher than 1.5%, a monetary remedy in an amount equal to the difference between the royalties amount paid by the Partnership from the investment recovery date at the rate of 6.5% and the royalties amount at the rate of 1.5%.

It is noted that on December 27, 2018 the Partnership filed a motion for summary dismissal of the motion (and for stay of proceedings pending the decision of the motion for summary dismissal), due to the lack of an advance request according to Section 194(b) of the Companies Law, and due to the authorization of the Audit Committee on July 8, 2018 to handle the issue of the investment recovery date and the decision of the general meeting of participation unit holders which was summoned by the Partnership's supervisor as specified above. On December 30, 2018 the Court granted the motion for stay of proceedings and ordered the filing of the Petitioner's response to the motion for summary dismissal, followed by the Partnership's reply, which have been filed. The Royalty Interest Owners have also filed their response. On January 6, 2019, the supervisor filed a complaint and an urgent motion for provisional injunction, as described in Section (b) below. Consequently, the Petitioner moved the Court to consolidate the aforesaid Supervisors' claim and the Certification Motion. A decision has not yet been issued on the matter.

**b)** On January 6, 2019 (after the date of the statement of financial position), the supervisor on behalf of the holders of participation units in the Partnership filed a complaint and an urgent motion for a provisional order with the Tel Aviv District Court (Economic Department) (the "**Complaint**" and the "**Provisional Order Motion**", respectively), according to Section 65-23(b) of the Partnerships Ordinance, against the Partnership, the General Partner of the Partnership, and the Royalty Interest Owners.

In the Complaint, the supervisor moves the Court, *inter alia*: 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.

**Note 12 – Contingent liabilities, engagements and pledges (Cont.):**

**I. Legal Proceedings (Cont.):**

**5. Motion for the certification of a derivative suit on the issue of the date of recovery of the investment in the Tamar Project (Cont.)**:

**b) (Contd.):**

Furthermore, in the Provisional Order Motion the supervisor moves the Court to issue an order preventing an act that may deprive the rights of the participation unit holders, so as to order the Partnership and the General Partner of the Partnership to avoid transferring the overriding royalty at the increased rate to the Royalty Interest Owners, and to transfer the same to an escrow account held by the Partnership, and to order Delek Group and Delek Royalties to return the increased overriding royalty they received to date from the Partnership and deposit the same in the escrow account. All of the Respondents have filed their objections to the motion.

The Complaint states, *inter alia*, that the supervisor acted in an attempt to reach an agreement with the Royalty Interest Owners on the resolution of the dispute on the investment recovery date by way of arbitration before an agreed arbitrator. However, after the filing of the motion for certification of a derivative suit by a participation unit holder on November 29, 2018 (as aforesaid) (in this section: the "**Derivative Motion**"), the Royalty Interest Owners clarified to the supervisor that they were not prepared to conduct the arbitration in parallel to the hearing of the Derivative Motion, and that they would agree to commence the arbitration only if the Derivative Motion was withdrawn and not heard concurrently. The Complaint states that it is the supervisor's position that the Derivative Motion should not have been filed while the meeting of participation unit holders had authorized the supervisor to clarify the matter of the investment recovery date, but once it was filed and in view of the position of the Royalty Interest Owners in reference to the Derivative Motion, as specified above, the supervisor decided to file the Complaint and the Provisional Order Motion with the Court. On January 22, 2019 answers to the Provisional Order Motion were filed with the Court by the Respondents. The answer filed by the Partnership and the General Partner of the Partnership states that the motion should be denied, inter alia, as it does not meet the case law criteria for the granting of a provisional remedy and is tainted by severe laches. The Royalty Interest Owners' answer states that the payments for the "Sheshinski Levy" to be made by the Partnership in the future should not be taken into account in the determination of the investment recovery date. The Royalty Interest Owners further claimed, *inter alia*, that the calculation made by the Partnership whereby the investment recovery date occurred in January 2018 included many expenses that should not be taken into account (including financing, transmission, marketing, removal and clearing of facilities and headquarters expenses), and that according to an alternative calculation carried out by experts on behalf of the Royalty Interest Owners, the investment recovery date occurred already in August 2015, such that they were entitled to receive royalties at an increased rate since then, and they intend to file a claim against the Partnership in connection therewith with the appropriate court.

On February 6, 2019, the Partnership and the General Partner filed a motion for a stay of proceedings in the claim, due to the existence of a binding arbitration clause in the right transfer agreement between the Partnership and the control holders of August 2, 1993. Concurrently with the filing of this motion, a motion was also filed for extension of the timeframe for the filing of pleadings on behalf of the Partnership and the General Partner pending decision of the said motion for a stay of the proceedings, and no decision has yet been issued therein.

**Note 12 – Contingent liabilities, engagements and pledges (Cont.):**

**I. Legal Proceedings (Cont.):**

**5. Motion for the certification of a derivative suit on the issue of the date of recovery of the investment in the Tamar Project (Cont.)**:

**b) (Contd.):**

On February 26, 2019, a hearing was held at the court on the motion for a provisional remedy, at which the court clarified that no provisional remedy will be granted with respect to a date earlier than the date of the hearing of the motion. The court requested that the parties hold talks in an attempt to reach agreements regarding the provisional remedy, and insofar as such agreements are reached, decisions will be issued in the motions of the Partnership and the General Partner. If agreements are not reached, the hearing of the motion for a stay of proceedings and of the motion for a provisional remedy is expected to be held in May or June 2019.

In view of the disputes described above and insofar as the Royalty Interest Owners' argument regarding the earlier occurrence of the investment recovery date in August 2015 is fully accepted, in a claim to be filed thereby, the Partnership will then be required to pay the Royalty Interest Owners a sum of approx. $56 million (excluding interest and linkage, if any). Conversely, according to the estimation of the Supervisor's economic consultant, in a report submitted by him to the Partnership in June 2018, inclusion of the oil and gas profit levy in the investment recovery date report would postpone the investment recovery date by 1 to 1.5 years. Insofar as the Supervisor's argument concerning the postponement of the investment recovery date is fully accepted, the Royalty Interest Owners will be required to pay the Partnership a sum of approx. $35 million (excluding interest and linkage, if any).

In the Partnership's estimation, following an examination of all arguments of both the Royalty Interest Owners and the Supervisor, and based on the opinion of its legal advisors, the provision recorded in the financial statements as of December 31, 2018 is sufficient.

**J. Regulation:**

**1. The Gas Framework**:

**a)** On August 16, 2015, Government Resolution No. 476 (readopted by the Government Resolution of May 22, 2016) was adopted with respect to a framework for the increase of the natural gas quantity produced from the "Tamar" natural gas field and the expeditious development of the "Leviathan", "Karish" and "Tanin" natural gas fields and other natural gas fields (in this section: the "**Government Resolution**"), which took effect on December 17, 2015, upon the grant of an exemption from certain provisions of the Restrictive Trade Practices Law to the Partnership, Ratio and Noble (in this section: the "**Parties**") by the Prime Minister, in his capacity as Minister of Economic Affairs, pursuant to the provisions of Section 52 of the Restrictive Trade Practices Law (in this section: the "**Exemption**" or the "**Exemption pursuant to the Restrictive Trade Practices Law**"), the main principles of which are presented below (see also Note 1G above).

**Note 12 – Contingent liabilities, engagements and pledges (Cont.):**

**J. Regulation (Cont.):**

**1. The Gas Framework (Contd.):**

**b) 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 Antitrust Commissioner's position, as a result of the acquisition of the rights in the Ratio-Yam permit by the Parties; and the restrictive arrangement that was ostensibly created as a result of the Parties' coming together as joint holders of the Ratio-Yam permit and the Leviathan reservoir.

2) The restrictive arrangement that shall ostensibly be created in a case in which the Parties or some of them jointly market the gas that shall be extracted from the Leviathan reservoir to the domestic market until January 1, 2025.

3) The restrictive arrangement 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 arrangement which may be created as a result of a certain agreement for the purchase of natural gas from the Leviathan reservoir, provided that such agreement is signed by January 1, 2025.

5) With respect to their activity in the Tamar and Leviathan reservoirs only, the Partnership and Noble being the holders of a monopoly according to the Antitrust Commissioner's declarations.

**c)** The exemption from the restrictive arrangements detailed in paragraph (b) above is contingent, *inter alia*, on the fulfillment of the following conditions: Sale of the Partnership's full rights in the Karish and Tanin leases, sale of the Partnership's full rights in the Tamar and Dalit leases within 72 months from the date of granting of the exemption under the Restrictive Trade Practices Law, certain stipulations relating to existing and future agreements for the supply of gas from the Tamar and Leviathan reservoirs including price alternatives, linkage and gas quantities. Compliance with instructions in connection with the development of the Tamar SW reservoir, an undertaking to invest in local content. The Gas Framework also regulated issues pertaining to the export of natural gas, the existence of a stable regulatory environment and various taxation issues. And all subject to the conditions and directives set forth in the Gas Framework.

**d)** As of the date of approval of the financial statements, the Partnership has sold its all of its holdings in the Karish and Tanin reservoirs (see Note 8B above), 9.25% (out of 100%) of its rights in the Tamar and Dalit Leases (see Note 7CF1 above), and the Partnership continues to act to ensure its compliance with the conditions and provisions specified in the Gas Framework.

## Note 12 – Contingent liabilities, engagements and pledges (Cont.):

### J. 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.

3. **Directives on the provision of collateral in respect of the petroleum rights:**

   In September 2014, pursuant to Section 57 of the Petroleum Law, the Commissioner published directives for the provision of collateral in connection with petroleum rights.

   As of the date of the statement of financial position, the Partnership has deposited autonomous bank guarantees with the Ministry of Energy, in the amount of approx. $40.6 million in respect of the holding of the Leviathan, Tamar, Dalit, Ashkelon and Noa leases and the Alon D license, against bank credit.

   It is noted that the guarantee in respect of the Tamar lease includes a guarantee that was provided in connection with approval that the Tamar partners received for the operation of a system for natural gas and condensate production from the Tamar project. It is noted that in March 2019 (after the date of the statement of financial position), the Partnership provided another guarantee (in the sum of approx. $1.2 million) in respect of Noble's share in the Alon D license (see Note 7C6 above), such that as of the date of approval of the financial statements, the Partnership has provided a guarantee for 100% of the interests in respect of this license.

## 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.** As of December 31, 2018: 1,173,814,691 units (as of December 31, 2017: 1,173,814,691) of par value ILS 1, which are listed on TASE, are registered in the unit holder register.

**Note 13 – Equity (Cont.):**

**C. Distribution of Profits:**

**1. The partnership agreement and the trust agreement:**

a) The limited partnership agreement, as amended, prescribes rules regarding the profit distribution in the Partnership, and, *inter alia*, entitles the General Partner to refrain from or delay a profit distribution, to the extent required, for the purpose of financing the Partnership's operations, in the manner and on the terms and conditions stipulated by the agreement and by the general meetings.

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. In view of the substantial amounts to be required by the Partnership for compliance with the contemplated work plans, including the expected investments in the development of the Leviathan project and the expansion of the Tamar project, and considering the commitments undertaken by the Partnership in connection with the financing of the Tamar project, development of the Leviathan project and financing of the costs of development thereof, bonds issued by the Partnership, and the distribution of profits made in recent years, as of the date of approval of the financial statements, the Partnership is unable to estimate whether additional profits will be distributable in the coming years, beyond advance payments and payments on account of the tax under the provisions of Section 19 of the Taxation of Profits and Natural Resources Law, 5771-2011 ("**Section 19**" and the "**Taxation of Profits and Natural Resources Law**", respectively).

**2. The profit distribution amounts:**

| Date of declaration of profit distribution | Date of profit distribution | Overall distribution amount in millions | | Distribution amount per participation unit | |
|---|---|---|---|---|---|
| | | The Partnership | Avner partnership | The Partnership | Avner partnership |
| 29.3.2016 | 20.4.2016 | Approx. $25 | Approx. $25 | $0.04571 | $0.00750 |
| 30.11.2016 | 12.1.2017 | Approx. $46.6 | Approx. $53.4 | $0.08519 | $0.01601 |
| 16.1.2017 | 9.2.2017 | Approx. $92.3 | Approx. $107.7 | $0.16866 | $0.03231 |
| 25.5.2017 | 20.6.2017 | $180 | | $0.15335 | |
| 15.8.2017 | 7.9.2017 | $300 | | $0.25558 | |
| 21.12.2017 | 18.1.2018 | Approx. ILS 209 | | ILS 0.1783416 | |
| 24.12.2018 | 14.1.2019 | ILS 130 | | ILS 0.1107500 | |

**Notes to the Financial Statements for December 31, 2018 (Dollars in thousands)**

**Note 13 – Equity (Cont.):**

**C. Distribution of Profits (Cont.):**

**3. Distributions to the limited partner:**

**a)** On January 16, 2017, the board of directors of the General Partner approved a distribution to the Limited Partner in the sum of approx. ILS 450 thousand (approx. $118 thousand). At the same time, the board of directors of the general partner in the Avner Partnership approved a distribution to the limited partner in the Avner Partnership in the sum of approx. ILS 350 thousand (approx. $91 thousand).

**b)** On November 20, 2018, the board of directors of the General Partner approved a distribution to the Limited Partner in the sum of approx. ILS 1 million (approx. $270 thousand).

Such distributions will be used for payment of the fees of the supervisor and trustee, in accordance with the provisions of the trust agreement.

**4. Amounts of Advance Tax Payments:**

**a)** According to the provisions of Section 19, the General Partner paid income tax, on account of the tax to be owed by the participation units holders in the 2016 tax year, advance payments in the aggregate sum of approx. ILS 106.7 million (approx. $28 million), i.e., approx. ILS 0.195 per participation unit in the Partnership pre-merger. Furthermore, the general partner of Avner Partnership paid income tax, on account of the tax that the partners would owe for tax year 2016, advance payments in an aggregate amount of approx. ILS 114 million (approx. $29.9 million), i.e., approx. ILS 0.03424 per participation unit in the Avner Partnership (for further details, see Notes 20A and 20C).

**b)** According to the provisions of Section 19, the General Partner paid income tax, on account of the tax that the partners would be liable for in tax year 2017, advance payments in an aggregate sum of approx. ILS 764.7 million (approx. $220.6 million), i.e., approx. ILS 0.651 per participation unit (for further details, see Notes 20A and 20C).

**c)** According to the provisions of Section 19, the General Partner has paid the income tax authorities, on account of the tax for which the holders of the participation units shall be liable in the tax year 2018, advance payments in the aggregate sum of approx. ILS 110 million (approx. $29.3 million), i.e. approx. ILS 0.0937 per participation unit (for further details, see Notes 20A and 20C).

**D. The composition of equity as of December 31, 2018 is as follows:**

| | The Limited Partner | The General Partner | Total |
|---|---|---|---|
| The Partnership's equity | 154,776 | 15 | 154,791 |
| Capital reserves | 21,008 | 2 | 21,010 |
| Retained earnings | 679,235 | 68 | 679,303 |
| Balance as of December 31, 2018 | 855,019 | 85 | 855,104 |

**Note 13 – Equity (Cont.):**

**D. The composition of equity as of December 31, 2017 is as follows (Cont.):**

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).

**E.** In September 2018, the Partnership released a shelf offering report, under which Delek Group offered, *inter alia*, participation units of the Partnership, within a full exchange tender offer that Delek Group wished to carry out with the shares of Delek Energy. In October 2018, Delek Group and the Partnership announced that the said tender offer had been accepted in full. In addition, it is noted that the period for the offering of securities under the Partnership's shelf prospectus of May 25, 2018 was extended until May 25, 2019.

**F.** Capital reserve for transactions between a corporation and the control holder thereof – The Partnership recorded in the statements of comprehensive income expenses against a capital reserve for transactions between a corporation and a control holder thereof in respect of the costs of employment of officers of the General Partner including the employment terms of the CEO of the General Partner and in respect of the expenses borne, *inter alia*, by the General Partner, the parent company and Delek Group, over and above the payment of the management fees that the Partnership pays the General Partner.

**G. Option plan:**

On July 13, 2016, the Board of Directors of the General Partner resolved to adopt a phantom unit plan (the "**Plan**") for senior officers of the Partnership and the General Partner.
According to the terms and conditions of the Plan 1,600,278 phantom units were granted (out of which the General Partner granted 72,740 phantom units), whose underlying asset is a participation unit conferring a working interest in the rights of the Limited Partner in the Partnership, the cost of which is borne by the Partnership and the General Partner (in this Section: the "**Phantom Units**")[53]. The Phantom Units will vest in three equal installments, the first installment vesting upon the lapse of two years from July 13, 2016 and the second and third installments vesting upon the lapse of 3 years from July 13, 2016 (in this Section: the "**Total Package**"). Each of the installments may be exercised commencing from the vesting date of such installment until the lapse of 90 days after the expiration of the vesting period of the third installment, i.e., on October 10, 2019, subject to adjustments. The exercise price of the Phantom Units issued by the Partnership and the General Partner (in this Section: the "**Delek Options**") was ILS 14.15; the exercise price of the Phantom Units issued by the Avner partnership and the general partner therein (in this Section: the "**Avner Options**") was at ILS 12.66 for the first installment (according to the adjustment mechanism set in the employment agreement) plus 5% per installment from the second installment.

[53] Note that concurrently with the grant of 794,799 phantom units whose underlying asset is a participation unit conferring a working interest in the rights of the Limited Partner in the Partnership, the officers were granted 4,285,158 phantom units, whose underlying asset is a participation unit conferring a working interest in the rights of the limited partner in the Avner Partnership (in this footnote: the "**Phantom Units in Avner**"). Upon the closing of the partnerships' merger, the Phantom Units in Avner were replaced with other phantom units in the Partnership, according to the adjustment mechanism specified in the employment agreement.

**Notes to the Financial Statements for December 31, 2018 (Dollars in thousands)**

## Note 13 – Equity (Cont.):

### G. Option Plan (Cont.):

It is noted that the General Partner will bear part of the costs of the Plan of the officer who is employed both by the General Partner and the Partnership.

According to a valuation received by the Partnership and the General Partner, the financial value of the units, as of December 31, 2018, totaled approx. ILS 0.7 million (out of which units in the value of approx. ILS 0.67 million were granted to officers of the Partnership), and calculated according to the Black-Scholes model for pricing options and based on the following assumptions:

(1) The price of a participation unit as of December 31, 2018 – ILS 9.82; (2) The exercise price of each option (adjusted to profit distribution) is calculated according to ILS 10.63 (Delek Options)/ILS 10.3 (Avner Options) for the first installment, ILS 11.34 (Delek Options)/ ILS 10.99 (Avner Options) for the second installment and ILS 12.08 (Delek Options)/ ILS 11.73 (Avner Options) for the third installment; (3) the rate of standard deviation 24.98%; (4) risk-free interest rate of approx. 0.43%; (5) contractual duration of approx. 0.78 years; (6) Abandonment rate after the vesting period taken into account – 0%; (7) Restriction of the maximal benefit to be generated for the officers from the exercise of each Phantom Unit will not exceed 100% of the exercise price specified for the Phantom Unit included in the exercised installment on the date of grant.

In view of the drop in the value of the options in the report period, revenues were recorded in the statement of comprehensive income in an amount of approx. $11 thousand (2017: income in an amount of approx. $14 thousand, 2016: expense in an amount of approx. $215 thousand).

With respect to the Phantom Units granted to the CEO of the General Partner in the Partnership, see Note 21C.

## Note 14 – Revenues from the sale of natural gas and condensate:

**A.** The Partnership’s revenues originate from natural gas and condensate sales to its various customers, all in accordance with engagement agreements signed therewith as specified in Note 12 above.

**B.** Volume of sales to the Israel Electric Corp. Ltd. in 2018: approx. 48% (2017: approx. 54%; 2016: approx. 55%) of the sales, to Dalia Power Energies Ltd. in 2018: approx. 10% (2017: approx. 11% 2016: approx. 10%) of the sales.

The total quantity of natural gas sold in the account year in the Tamar and Yam Tethys projects amounted to approx. 10.5 BCM (2017: approx. 9.9 BCM; 2016: approx. 9.4 BCM) and the total quantity of condensate sold at the Tamar Project in 2018 amounted to approx. 477 thousand barrels (2017: approx. 454.7 thousand barrels; 2016: approx. 447.6 thousand barrels).

## Note 15 – Royalties:

### A. Composition:

| | For the year ended | | |
|---|---|---|---|
| | **31.12.2018** | **31.12.2017** | **31.12.2016** |
| Royalties to the State (Note 12B above and Paragraph B below) | 51,123 | 56,600 | 61,049 |
| Royalties to interested parties (Note 12B above and Paragraphs C and D below) | 32,123 | 14,703 | 14,425 |
| Royalties to a third party (Note 12B above and Paragraph C below) | 8,087 | 8,953 | 9,707 |
| **Total** | 91,333 | 80,256 | 85,181 |

**Note 15 – Royalties (Cont.):**

**B. Royalties to the State:**

1. Pursuant to the Petroleum Law, the State is entitled to royalties from the quantity of the extracted gas (see Note 12B7 above). The Commissioner notified the operator of the joint ventures (Tamar and Yam Tethys) that the State has decided not to receive in kind the royalties to which it is entitled from the gas discoveries, but rather to receive the market value of the royalties at the wellhead, in dollars.

2. In accordance with the Commissioner's announcement of July 19, 2004 and a summary of a discussion held with the Commissioner, the manner of calculation of the royalties that shall be due to the State from the Yam Tethys reservoirs was agreed. Based on implementation of the English formula principles and considering the gas sale outline between the Tamar partners and the Yam Tethys partners, the actual rate of the State's royalties in the Yam Tethys project on which the Partnership relied in its financial statements for the years 2016, 2017 and 2018 was approx. 9.6%, approx. 11.05% and approx. 11.28%, respectively. The royalties to the royalty interest holders in the Ashkelon lease for those years were also calculated accordingly.

3. As of the date of the approval of the financial statements, the partners in the Tamar project, including the Partnership, are negotiating with the Commissioner on the manner of calculating the market value of the royalties at the wellhead in the Tamar project. Until completion of the said negotiations, the Tamar partners paid the State, from beginning of production in the Tamar Project until the end of 2016, under protest, advance payments on account of the royalties at a rate of 12% in respect of the revenues from the Tamar project. In February 2017, a letter was received from the Ministry of Energy with respect to advance payments of royalties for 2017, whereby it was determined that the effective royalty rate to be paid as advance payments in 2017 will be 11.65% (a similar rate in 2018). It was also clarified that such rate is determined as an advance payment only. It is the position of the Operator and the other Tamar partners that the calculation of the actual rate of the State's royalties in respect of the revenues from the Tamar project should reflect the complexity of the project, the risks involved therein and the amount of the investments in the project, compared with the Yam Tethys project.

   It is noted that, according to a calculation based on the principles of the "English formula", which constitutes the closest estimate to the agreement signed with the State in the Yam Tethys project, the actual rate of the royalties to the State, which the Partnership applied in its financial statements, in the Tamar project in 2016, 2017 and 2018, is approx. 11.15%, approx. 11.22% and approx. 11.16% respectively.

4. In February 2019 (after the date of the statement of financial position) the Yam Tethys partners and the Ministry of Energy signed an agreement on final royalty reports for the years 2011-2013. The agreement provides that the Yam Tethys partners are entitled to the sum of approx. $4.4 million (100%), which was offset against monthly royalty payments in the Yam Tethys project.

   From 2014 to December 2016 the Yam Tethys partners paid, under protest, advance payments on account of royalties to the State at the rate of approx. 11.96% for the income from the Yam Tethys project.

   It is noted that in February 2017, a letter was received from the Ministry of Energy with respect to advance payments of royalties for 2017, whereby it was determined that the rate of royalties for 2017 will be 0%. It is noted that insofar as significant production is carried out, such rate will be updated.

**Note 15 – Royalties (Cont.):**

**B. Royalties to the State (Cont.):**

5. For details regarding a claim for the restitution of royalties paid to the State by the Partnership and Noble in respect of their revenues deriving from the supply of natural gas from their share in the Tamar project to their customers, under the Yam Tethys project agreements, see Note 12I1 above.

6. The gaps between the royalties actually paid to the State and the effective royalty rate which the Partnership applied in its financial statements in the Tamar and Yam Tethys projects amounted to approx. $21.2 million (2017: approx. $19.6 million) which were included in the other long-term assets item – see Note 8A above.

**C.** The manner of calculation of the royalties determined in Paragraph B above 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, according to the limited partnership agreement as specified in Note 12B above. The effective overriding royalty rate from the sale of natural gas and condensate from the Tamar reservoir in 2016-2018 ranges between approx. 4.4% and approx. 8.6% (out of which the rate of royalty paid to affiliates in the said years ranges between approx. 2.6% and 6.9%) of the gross sales for each one of the years. The effective overriding royalty rate in 2016-2018 from natural gas sales in the Ashkelon lease and considering the commercial arrangement (Note 7C5 above) ranges between 7.4% and 8.7% of the gross sales. As of the date of approval of the financial statements, there is a gap between the royalties paid to related parties and to third parties and the effective royalty rate in in the aforesaid projects, in an amount of approx. $6.6 million, which were included in the other long-term assets item - see Note 8A above.

**D.** Further to the provisions of Note 12B2 and in view of the fact that the Royalty Interest Owners include the Partnership’s control holders, the board of directors of the General Partner decided to authorize the audit committee (which comprises external and independent directors only) to handle the issue of the investment recovery date in the Tamar lease, including an examination of issues arising from a report prepared by an external economic advisor (the "**Advisor**" and the "**Advisor's Report**", respectively), who was appointed by the supervisor, clarifying the various issues vis-à-vis the Royalty Interest Owners and taking any other step as the committee deems fit, at its discretion, and all in the best interests of the Partnership.
According to the board’s resolution, the Audit Committee shall be authorized to retain the services of external, independent professional advisors at its discretion and at the Partnership’s expense, to provide legal and economic support to the process, and to determine the terms of compensation of such advisors. The Audit Committee has been asked to form its recommendations on the matter and present the same to the board. On September 4, 2018, the Audit Committee and subsequently the board (without directors who hold office in the control holder) approved a calculation of the investment recovery date, whereby the investment recovery date falls in January 2018 (in lieu of December 2017 according to the Draft Calculation).

**Notes to the Financial Statements for December 31, 2018 (Dollars in thousands)**

**Note 15 – Royalties (Cont.):**
**D. (Cont.):**

Modification of the investment recovery date as aforesaid mainly derives from the correction of a calculation error that was included in the Draft Calculation in respect of the financial expenses. As a result, the Partnership approached the Royalty Interest Owners demanding restitution of approx. $2 million that had been overpaid to them, and which was repaid to the Partnership during September 2018. It is noted that the calculation was approved by the Audit Committee and the board of directors after the receipt of a special report by the auditors upon completion of a special audit by them, in the scope that was determined and based on independent legal advice to the Audit Committee.

With respect to the motion for the certification of a derivative suit, the complaint filed by the Partnership's supervisor and the claims of the Royalty Interest Owners with respect to the investment recovery date, see Note 12I5.

**Note 16 – Cost of natural gas and condensate production[54]:**

| Composition: | For the year ended | | |
|---|---|---|---|
| | 31.12.2018 | 31.12.2017 | 31.12.2016 |
| Salaries and social benefits | 6,737 | 7,155 | 5,134 |
| Guarding and security | 1,976 | 2,392 | 2,574 |
| Insurance | 4,460 | 3,816 | 6,436 |
| Transportation and conveyance costs | 4,346 | 5,856 | 7,903 |
| Operation management and operator fee | 5,416 | 5,782 | 8,046 |
| Maintenance and others | 9,785 | 10,187 | 9,532 |
| **Total** | 32,720 | 35,188 | 39,625 |

**Note 17 – Oil and gas exploration expenses and other direct expenses[55]:**

| Composition: | For the year ended | | |
|---|---|---|---|
| | 31.12.2018 | 31.12.2017 | 31.12.2016 |
| Seismic surveys | 834 | 698 | 142 |
| Direct and other expenses, including professional services[56] | 8,886 | 7,142 | 5,775 |
| **Total** | 9,720 | 7,840 | 5,917 |

[54] Mostly through the Tamar and Yam Tethys joint ventures.
[55] Mostly through the joint ventures.
[56] Mostly G&A expenses of the Leviathan and Cyprus projects.

**Notes to the Financial Statements for December 31, 2018 (Dollars in thousands)**

### Note 18 – G&A expenses:

| Composition: | For the year ended | | |
|---|---|---|---|
| | 31.12.2018 | 31.12.2017 | 31.12.2016 |
| Salaries and social benefits[57] | 2,883 | 2,634 | 2,695 |
| General Partner management fee expenses | 960 | 960 | 747 |
| Cost of share-based payment to the CEO (see Note 21C below) | 182 | 582 | 488 |
| Professional services, net[58] | 4,745 | 5,008 | 4,513 |
| Other | 1,041 | 1,445 | 999 |
| **Total** | 9,811 | 10,629 | 9,442 |

### Note 19 – Financial expenses and income:

**A. Composition:**

| | For the year ended | | |
|---|---|---|---|
| | 31.12.2018 | 31.12.2017 | 31.12.2016 |
| **Expenses:** | | | |
| Due to bonds (Paragraph B below) | 48,954 | 66,937 | 66,494 |
| Due to liability to banks | 800 | - | - |
| Due to transactions in financial derivatives | - | 552 | 64 |
| Due to revaluation of short-term investments | 1,594 | 3,048 | 895 |
| Due to a guarantee fee to Delek Group (Note 12H4) | 402 | 492 | 492 |
| Due to changes in petroleum and gas asset retirement obligations due to lapse of time | 5,070 | 3,795 | 2,864 |
| Other | 612 | 220 | 641 |
| **Total expenses** | 57,432 | 75,044 | 71,450 |
| **Income:** | | | |
| Due to deposits in banks and short-term investments | 9,811 | 20,430 | 10,476 |
| Revaluation of royalties receivable and a loan that was extended (Note 8B) | 48,350 | 24,700 | - |
| Other | 988 | 1,742 | 509 |
| **Total income** | 59,149 | 46,872 | 10,985 |
| **Total financial income (expenses), net** | 1,717 | (28,172) | (60,465) |

[57] Including revenues from the revaluation of compensation to employees including a liability of share-based payment to the Partnership's employees in the sum of approx. $66 thousand (2017: including an expense of approx. $44 thousand; 2016: including revenues of approx. $339 thousand).
[58] Including expenses in the account year in the sum of approx. $1,654 thousand (2017: $1,836 thousand; 2016: $2,003 thousand) applied against a capital reserve (see Note 13F above).

**Note 19 – Financial expenses and income (Cont.):**

**B.** The total of direct and unspecific credit costs capitalized to petroleum and gas assets for the year ended December 31, 2018 and not included in the statement of comprehensive income amounted to approx. $108,940 thousand, in 2017: approx. $54,816 thousand, and in 2016: approx. $21,827 thousand. The cap rates used to determine the amount of the capitalized credit costs in 2018: approx. 5.0% - 7.8%, in 2017: approx. 5.1%-6.7%, and in 2016: approx. 4.7%.

**Note 20 – Petroleum 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 Income Tax Commissioner 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 term of the Regulations has been extended on an annual basis and was recently extended until June 30, 2015. An extension of the term of the Regulations has not yet been issued.
2. According to the approvals of the Income Tax Commission issued to the Partnership in the past, the Partnership undertook not to take loans in an amount exceeding 3% of the sum that will be raised from investors in the Partnership without the prior coordination and approval of the Income Tax Commission. For the purpose of raising loans for financing the Partnership's operations, the Partnership approaches the Income Tax Commission from time to time in order to receive the required approval as aforesaid.
3. According to Section 19 of the Profits and Natural Resources Taxation Law, 5771-2011 ("**Section 19**") regarding Section 63(a)(1) of the Ordinance, the share of each partner in the tax year will be calculated from the taxable income of the Partnership or from the losses thereof. Because the Partners bear the tax results of the revenues and expenses of the Partnership, the financial statements do not include taxes on income.
4. On October 4, 2018 the Partnership released final tax certificates for an entitled holder due to the holding of a participation unit for the tax year 2014 in the Partnership and in the Avner Partnership. It is noted that the income tax audit for the Partnerships' tax reports for 2015 has ended and an assessment agreement has been signed, but a tax certificate has not yet been released since the Income Tax Regulations have not yet been extended (a temporary certificate was released on December 13, 2017).
5. On December 13, 2017 and November 8, 2018, the Partnership released temporary tax certificates for an entitled holder for the holding of a participation unit for the tax years 2016 (in the Partnership and in the Avner Partnership) and 2017, respectively. Final tax certificates will be issued upon completion of the income tax authorities' audit process. The final tax certificates may be materially different than the temporary tax certificates. On an assessment to the best of judgment for the tax year 2016 see Section 13 below.

**Note 20 – Petroleum and gas profit levy and taxes (Cont.):**

**A. Information regarding income tax rules and the main arrangements existing as of the date of the statement of financial position (Cont.):**

**6.** It is noted that if, after the filing of the tax reports for the years 2016 and 2017, and after completion of the audit of the Tax Authority, it transpires that the Partnership paid advance payments in amounts which exceed the amounts required pursuant to the law, the balance will be returned to the Partnership; if it transpires that the final tax assessment is higher than the amounts paid by the Partnership, the Partnership will be required to act in accordance with the provisions of Section 19 of the law, and pay the tax balance deriving therefrom according to the rate of the share in the Partnership of the Entitled Holders who are body corporates and the rate of the share in the Partnership of the Entitled Holders who are individuals, for which purpose the taxable income of the individuals shall be deemed as being subject to the maximum tax rate, unless it is proven to the assessing officer that the tax rate applicable to such individual is lower than the said rate. Furthermore, the Partnership shall act in accordance with the judgment of the District Court, insofar as the Supreme Court does not rule otherwise in its decision on the appeal that was filed as specified in Paragraph C5 below.

**7.** In addition, Section 19 also prescribes that the General Partner shall be obligated to file a report on the Partnership's taxable income or losses, according to instructions determined by the Director, and the General Partner shall pay, upon the filing of the Partnership's annual report, the tax deriving therefrom on account of the tax owed by the partners in the Partnership in the tax year for which the report was filed, according to the rules prescribed by the law. In addition, it is prescribed that the assessing officer may determine advance payments on account of the tax owed by the partners in the Partnership for such tax year, and that such advance payments shall be paid by the General Partner out of the Partnership's funds.

**8.** In December 2017, the Partnership and the Tax Assessor for Large Enterprises executed an agreement for tax collection on account of the tax payable by the unit holders for the estimated taxable income from a business of the Partnership for 2017. Within the agreement, the Partnership supplemented an advance payments rate of 24% on the said estimated taxable income[59]. Note that the distribution carried out as specified in Note 13C2 above, was no less than the amount of the estimated taxable income multiplied by the maximal tax rate applicable to an individual for the estimated taxable income, net of the advance payments made with respect to the income from a business.

**9.** In December 2018 the Board of the General Partner and the Trustee approved a profit distribution to the holders of the participation units. In the context of the distribution, the Partnership supplemented an advance payment rate of 24% on the estimated taxable income[60] for 2018. It is noted that the distribution made as aforesaid in Note 13C2 above was no less than the amount of the estimated taxable income, multiplied by the maximum tax rate applicable to an individual for the estimated taxable income, net of the advances paid for the income from a business.

[59] It is clarified that the estimated taxable income is based on assessments and is subject to the audit of the Tax Authority.

[60] It is clarified that the estimated taxable income is based on assessments and is subject to audit by the Tax Authority.

**Note 20 – Petroleum and gas profit levy and taxes (Cont.):**

**A. Information regarding income tax rules and the main arrangements existing as of the date of the statement of financial position (Cont.):**

**10.** According to the Taxation of Profits and Natural Resources Law, 5771-2011, accelerated depreciation on investments at a rate of 10% shall be provided, with an option to choose depreciation at a variable rate up to the amount of the taxable income for such year. Furthermore, the depreciation rate with respect to an asset purchased in the years 2011-2013 will be 15% instead of 10% (see Paragraph B below).

**11.** The Partnership implements the provisions of Section 20B2 of the Profits and Nature Resources Taxation Law, 5771-2011 according to which the Partnership recognizes, in each tax year, depreciation expenses at the level of the taxable income, insofar as there is such, before the deduction of depreciation expenses which were required in such tax year, provided that the deduction will not exceed the rate specified in the law.

**12.** The tax issues, including the implementation of the Taxation of Profits and Natural Resources 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 impossible 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 impossible to foresee the position of the tax authorities. Since the Partnership's operations are subject to a unique tax regime which includes tax benefits, 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. See Section C5 below regarding court judgements pertaining to the interpretation of Section 19.

**13.** Against the background of the disputes that arose between the Partnership and the Tax Authority and disagreements on the amount of taxable income of the Partnerships for tax purposes of the year 2016, on November 22, 2018 assessments to the best of judgment were received from the Tax Authority according to Section 145(a)(2)(b) of the Income Tax Ordinance (in this section: the "**Tax Assessment**"), according to the taxable income from a business for 2016 of the Partnership and of the Avner Partnership was approx. \$130 million and approx. \$118 million, respectively (in lieu of the sum of approx. \$108 million and approx. \$96 million, respectively, as included in the Partnerships' tax reports that were filed with the Tax Authority), and the capital gain for 2016 of the Partnership and of the Avner Partnership was approx. \$47 million and approx. \$62 million, respectively (in lieu of the sum of approx. \$6 million and approx. \$15 million, respectively, as included in the Partnerships' tax reports filed with the Tax Authority).

The dispute pertains mainly to the interpretation of the method of recognition of financial expenses borne by the Partnerships in practice and the method of calculation of the capital gain from the sale of the Karish and Tanin leases. According to the Tax Assessments, and insofar as all of the Tax Authority's claims are granted, the Partnership will be required to supplement a payment of tax advances (including interest), on account of the holders of participation units in the Partnerships in the sum of approx. \$20 million each. It is noted that, in view of the aforesaid, a delay may occur in the issuance of final tax certificates to an entitled holder for the holding of a participation unit in the Partnership for the tax years 2016 and 2017 and in the Avner Partnership for the tax year 2016, pending completion of the proceedings that will be required to determine the final assessment.

**Note 20 – Petroleum 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.):**

**13. (Contd.):**

In the Partnership's estimation, based on an opinion of its legal advisors and past experience, the chances of most of the Partnership's claims being accepted are higher than 50%. On March 14, 2019 (after the date of the statement of financial position), the Partnership submitted administrative objections to the tax assessments as aforesaid, in order to exhaust the administrative and legal proceedings available thereto.

**14.** During September 2018, a refund of approx. $26.1 million was received from Income Tax in respect of tax advances paid in 2017 (mainly in connection with a tax advance that was paid on account of a capital gain, see Note 7C1F above) after setoff of tax payments made for 2015.

**15.** It is noted that disputes have arisen between the tax authorities 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 certain data in the levy reports for the Leviathan leases for the said years. Such disputes were adjudicated between the parties by judicial tribunals, and 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. 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.

**16.** It is noted that disputes have arisen between the Tax Authorities and the holders of rights in the Tamar venture as to the Tamar venture levy reports for the years 2013-2016, which disputes chiefly pertain to the manner of classification and quantification of certain data in the levy reports for such years. It is noted that the disputes as to the levy reports for the years 2013-2015 are adjudicated between the parties in the context of an appeal conducted at the Tel Aviv District Court, whereas the disputes pertaining to the levy reports for 2016 are adjudicated in the context of an administrative appeal before the Assessing Officer for Large Enterprises. It is noted that as of the period of the financial statements, such disputes have no effect on the financial statements, since the obligation to pay the levy has not arisen.

**17. Taxation in Cyprus:**

In accordance with the production sharing contract with the Cypriot Government, payment of the Cypriot Government's share in the gas and/or petroleum that shall be produced from Block 12, to the extent produced, includes a gross-up of the corporate tax payments that the owners of the rights in such project, including the Partnership, must pay the Republic of Cyprus.

**Note 20 – Petroleum 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.):**

**17. (Contd.):**

The Partnership received an approval from the Israel Tax Authority in respect of its operations in Block 12. Said approval prescribes, *inter alia*, the following provisions – the Partnership operations in Block 12 shall not prejudice the Partnership's status as a "partnership" for the purposes of the Income Tax Regulations (Rules for the Calculation of Tax due to the Holding and Selling of Participation Units in an Oil Exploration Partnership), 5749-1988; the income that shall be generated in Block 12 shall be considered income that is taxable in Israel and the tax shall be calculated according to Israeli law; should the exploration investments prove to be investments which do not justify production (dry well), said investments shall be recognized as an expense that will be spread over a five-year period; should the exploration investments prove to be recoverable investments, the Block 12 operations will be deemed a separate standalone sector for tax purposes, and the exploration investments will be recognized in Israel as an expense, solely against income from Cyprus (thus, expenses incurred by the Partnership in Cyprus for its operations in Block 12 will not be included in its tax reports in the context of expenses which may be deducted in Israel, but rather shall be deducted in the future from income that the Partnership will generate from Block 12), all subject to the law applying in Israel; the recognition method of income, including credit for taxes paid in Cyprus, will be effected according to the instructions of the Tax Authority Director, considering the conditions that will be relevant at the prevailing time and the conditions that were known at the time of issuance of the approval.

It is noted that the Petroleum Commissioner gave his approval, in accordance with Regulation 8 of Income Tax Regulations (Deductions from Income of Petroleum Right Holders), 5716-1956, for application of the Regulations to the Partnership also in Block 12, subject to conditions prescribed by him.

**B. Taxation of Profits and Natural Resources Law, 5771-2011:**

In April 2011, the Knesset passed the Taxation of Profits and Natural Resources Law, 5771-2011 (the "**Law**"). Implementation of the Law has led to a change in the taxation rules applicable to the Partnership's revenues, which include, *inter alia*, the introduction of a petroleum 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.

**Note 20 – Petroleum and gas profit levy and taxes (Cont.):**

**B. Taxation of Profits and Natural Resources Law, 5771-2011 (Cont.):**

The Law's main provisions are:

1. The introduction of a petroleum 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 as the ratio rises, the levy progressively increases up to a maximum rate of 50% when the ratio reaches 2.3. In addition, it was determined that the rate of the levy as aforesaid will be reduced as of 2016 by the product of multiplying 0.64 by the difference between the corporate tax rate set forth in Section 126 of the Income Tax Ordinance in respect of each tax year and the 18% tax rate. According to the corporate tax rate as of prescribed since 2016 forth the maximum rate will be 46.8%.

   Additional provisions were also determined regarding the levy, *inter alia*, the levy will be recognized as an expense for the purpose of calculation of income tax; the levy limits shall not include export plants; the levy shall be calculated and imposed in relation to each reservoir separately (ring fencing); in the case of payment by a holder of a petroleum right which is calculated as a percentage of the petroleum produced, the payment recipient will be charged with a levy payment in accordance with the amount of the payment received thereby, which amount will be deducted from the levy amount owed by the holder of the petroleum right.

   In addition, the Law prescribes rules for consolidation or separation of petroleum ventures for purposes of the Law.

   The provisions regarding the imposition of a petroleum and gas profits levy apply from April 10, 2011 and include transition provisions with respect to ventures that began commercial production by January 1, 2014.

   a) A venture with respect to which the commercial production commencement date occurs before the commencement date, will be subject to the provisions of this law with the following changes:

      1) If a levy payment duty applies with respect to such venture in the tax year which the commencement date occurs, the rate of the levy in such tax year will be half of the rate of the levy that would have been imposed on the petroleum profits if not for the provisions of this paragraph and no more than 10%;

      2) In the event that the levy coefficient in the tax year in which the commencement date occurs exceeds 1.5, rules were set for the manner of calculation of the levy coefficient in each tax year thereafter;

      3) The rate of the levy which will be imposed on the petroleum profits of the venture in each of the tax years 2012 to 2015 will be equal to half the rate of the levy that would have been imposed on the petroleum profits as aforesaid, if not for the provisions of this paragraph.

**Note 20 – Petroleum and gas profit levy and taxes (Cont.):**

**B. Taxation of Profits and Natural Resources Law, 5771-2011 (Cont.):**

**1. (Contd.):**

b) A venture with respect to which the commercial production commencement date occurs in the period between the commencement date and January 1, 2014, will be subject, *inter alia*, to the following provisions:

1. The minimal levy coefficient will be at a rate of 2 instead of 1.5 and the maximal rate will be 2.8 instead of 2.3;
2. The depreciation rate regarding an 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 project operator files a levy report, including, *inter alia*, accrued data regarding proceeds and investments for the purpose of calculating the R-factor, as specified in Section 1 above.

**C. Advance tax payments on account of the tax owed by the participation unit holders:**

1. Further to Note 13C and Paragraph A6 above, the sums of the advance tax payments were calculated according to the tax rates applicable to companies in 2017, i.e. 24%. It shall be further noted, that if after the filing of the report (as described in Section 2 below), and after completion of the Tax Authority audit, it shall be found that the Partnership has made advance payments in sums exceeding the required sums according to the law, the balance shall be refunded to the Partnership And if it transpires that the final tax assessment is higher than the amounts paid by the Partnership, the Partnership will be required to act in accordance with the provisions of Section 19 of the law, and pay the tax balance deriving therefrom.
2. According to the provisions of Section 19, the General Partner is obligated to file to the assessing officer a report (certified by an accountant) on the taxable income of the Partnership. Section 19 prescribes that upon the filing of the report, the General Partner is required to pay the tax deriving therefrom, on account of the tax owed by the entitled holders[61] in the tax year for which the report was filed (i.e. on the account of the entitled participation unit holders, as they will be on December 31 of each tax year). According to the provisions of Section 19, the tax that the General Partner is due to pay upon the filing of the report, shall be calculated according to the pro rate share in the Partnership of the entitled holders who are corporations and the pro rate share in the Partnership of the entitled holders who are individuals (the "**Weighted Tax Rate**"). For such purpose, the taxable income of the individuals shall be deemed to be subject to the maximal tax rate, unless it was proven to the assessing officer that the tax rate applying to such individual is lower than said rate.
3. The position of the Partnership is that the tax that will be paid by the General Partner (including the advance payments and including additional payments that shall be made in the future on account of the taxes of the same tax year and in deduction of refunds, if any) is paid on account of the tax owed by the entitled holders and constitutes a distribution by the Partnership, whereby the effective date for such distribution is the 31st of December of each tax year for which the advance payments were made.

[61] An entitled holder is anyone who held a participation unit as of December 31 of every tax year.

**Note 20 – Petroleum and gas profit levy and taxes (Cont.):**

**C. Advance tax payments on account of the tax owed by the participation unit holders (Cont.):**

4. Since, according to the position of the General Partner, the provisions of Section 19prevail over the provisions of the partnership agreement for the purpose of taxation of a petroleum partnership, and for as long as they are inconsistent with the arrangement prescribed in the partnership agreement, the Partnership shall act according to the provisions of the Taxation of Profits from Natural Resources Law, *in lieu* of the provisions of the partnership agreement, for the purpose of taxation of a petroleum partnership.

5. On October 30, 2016, the supervisor filed a motion for instructions with the court, with respect to the interpretation and implementation of Section 19 (the "**Motion**")[62]. On November 1, 2017, the judgment of the District Court was issued in the Motion. To the Partnership's understanding, the judgment determines as follows: (a) Section 19(a) of the Taxation of Profits from Natural Resources Law ("**Section 19(a)**") does not concern regulation of the internal relationship among the holders of the Partnership's participation units themselves, but rather only the manner of collection of the tax.

   Hence, payment of the tax pursuant to Section 19(a) should not be deemed as a distribution, and payment of the tax is not subject to the distribution tests; (b) The General Partner's proposal that alongside payment of the tax, the holders would be issued with a tax certificate in which the payment attribution will be uniform for each holder, without taking into account their status, cannot be accepted since this proposal entails underpayment of tax with respect to "individuals", which would necessitate additional collection actions and would prejudice the purpose of Section 19(a), which is streamlining the tax collection; (c) The court sees no justification for intervening in the management of the Partnership's affairs and requiring the Partnership to pay an amount exceeding the amount mandated by the provisions of Section 19(a)(6) to the holders of the participation units or to Income Tax; (d) So long as the collection arrangement set forth in Section 19(a) is in effect, the Partnership and/or the General Partner is required to find the proper method to balance between the additional expense entailed by the tax rate applicable to individuals holding the participation units and the expense entailed by the tax rate applicable to companies holding participation units. One of the methods is that on the date of payment of the tax by the General Partner, the General Partner will determine a balancing distribution that may be "notional" (a credit on the books until the actual distribution and accounting)[63] to those holders of participation units whose tax rate is lower than the tax rate applicable to individuals.

[62] At the request of Avner's supervisor, and with the parties' consent, on July 16, 2017, the court ordered that the identity of the parties in the proceeding be updated following the merger of the Avner Partnership with the Partnership. The Partnership's supervisor prior to the merger, was added as a petitioner (in addition to Avner's supervisor), the Partnership was joined *in lieu* of the Avner Partnership, the Partnership's General Partner was joined *in lieu* of the general partner of the Avner Partnership, and the Partnership's Limited Partner was joined *in lieu* of the limited partner of the Avner Partnership.

[63] According to the Partnership's estimation, insofar as a "balancing distribution" will be indeed implemented, as described in the judgment, the amount thereof will be approx. $56 million for tax years 2015-2016 and based on temporary tax certificates released by the Partnership in December 2017. It is noted that the ruling of the court as aforesaid, may change following an appeal that has been filed with the Supreme Court by the General Partner from the aforesaid judgment of the court. In view of the aforesaid, according to the Partnership's estimation based on the opinion of its legal counsel, due to the preliminary stage of the legal proceedings, and therefore the Partnership cannot, at this stage, estimate the manner of treatment that will be determined for the implementation of the balancing, if any, for the said tax years.

**Note 20 – Petroleum and gas profit levy and taxes (Cont.):**

**C. Advance tax payments on account of the tax owed by the participation unit holders (Cont.):**

**5. (Cont.):**

The court does not substitute itself for the General Partner, and insofar as it finds another arrangement that meets the requirements of the law (the partnership agreements and partnerships law) that apply to the Partnership and thereto, it may do so.

On December 31, 2017, the Partnership's General Partner filed an appeal from the District Court's judgment, in which the Supreme Court was moved to rule on the proper interpretation of Section 19, so as to determine a fixed, known and industry-wide method for the taxation of the liable income of petroleum partnerships, whereby the petroleum partnerships will all be able to act with certainty, *inter alia* while allocating the tax payment among the holders in an equal manner which would prevent discrimination of holders that are liable for a lower rate than the maximum tax rate that applies to an individual.

The Supreme Court was further moved to rule that: (a) the tax payment a petroleum partnership pays pursuant to the provisions of Section 10 should be allocated in an equal manner among all of the units in the Partnership; (b) accordingly, the Partnership is required to issue to the unit holders equal tax certificates, such that the tax that the Partnership paid on account of the tax owed by the partners in the Partnership is recorded on the tax certificate in a uniform amount for individuals and for a body corporates, without distinguishing between them, and each partner will be able to make use of this certificate, insofar as he requires, whether for the purpose of supplementation of the tax payment required of him, or for receipt of a tax refund; (c) alternatively, to rule that the District Court's decision, whereby the tax should be allocated to the partners differentially, shall apply prospectively only, while in relation to the past, the petroleum partnerships will be able to allocate the tax paid in an equal manner to the relevant holders, and accordingly they will be entitled to issue equal tax certificates; (d) alternatively, and insofar as it is determines that the tax payment in accordance with Section 19 does not constitute a distribution within the meaning thereof in the Companies Law, it shall be ruled that also a balancing payment that shall be made to holders of participation units which are a body corporate (in order to prevent subsidization among holders of units in the Partnership in the payment of the tax) does not constitute a distribution, in order to prevent discrimination of holders that are liable for a rate lower than the maximum tax rate applicable to an individual (such as companies or institutional bodies).

6. In November 2017, the Minister of Finance released a legislative memorandum for the Taxation of Profits from Natural Resources Law, 5778-2017 (the "**Memorandum**"), which includes several proposed amendments to the provisions of the Taxation of Profits from Natural Resources Law, further to the Gas Framework. The amendments contemplated in the Memorandum concern, *inter alia*, an amendment to the definition of the term "revenue" in the Taxation of Profits from Natural Resources Law, to also include payments for components ancillary to a sale as determined in the Gas Framework, the determination of several provisions enhancing control and enforcement of the Taxation of Profits from Natural Resources Law by the Tax Authority and the grant of incentives to the owners of certain rights in petroleum ventures of up to 50 BCM. In July 2018 the Ministerial Committee for Legislative Affairs approved the draft law, based on the Memorandum, for a first reading in the Knesset.

Notes to the Financial Statements for December 31, 2018 (Dollars in thousands)

**Note 21 – Transactions and balances vis-à-vis interested parties, related parties and control holders:**

**A. Balances:**

| | Note | December 31, 2018 Parent companies | December 31, 2018 Related parties and other interested parties | December 31, 2017 Parent companies | December 31, 2017 Related parties and other interested parties |
|---|---|---|---|---|---|
| Trade receivables | | - | 1,962 | - | 2,082 |
| Trade and other receivables | 5 | 22 | 65 | - | 178 |
| Other long-term assets | 8A | 2,207 | 2,188 | 2,405 | 1,639 |
| Trade and other payables | 9 | 2,409 | 2,238 | 1,948 | 597 |
| The highest current debt balance this year | | 22 | 1,197[64] | - | 34,020[65] |

**B. Transactions with related parties and interest parties:**

For the year ended December 31, 2018:

| | Note | Parent companies | Related parties and other interested parties |
|---|---|---|---|
| Revenues from gas sale[66] | 14 | - | ,13581 |
| Gas purchase costs as part of commercial arrangement | 7C5 | 105 | - |
| Expenses due to overriding royalties | 15 | 14,481 | ,17642 |
| Expenses of General Partner management fees | 12A | 960 | - |
| Compensation of directors | | - | 193 |
| Reimbursement of expenses from a parent company | 21E4 | 16 | - |
| Guarantee fee to Delek Group | 12H5 | 402 | - |
| Expenses due to control holder benefit against a capital reserve | 13F | 1,836 | - |
| D&O insurance | 21E5 | - | 177 |

[64] Current balance from gas sales to an affiliate held by Delek Group.
[65] Tamar Petroleum debt balance as part of the transaction for the transfer of 9.25% of the Partnership's rights in the Tamar and Dalit leases.
[66] Including the share of the parent company and a related party in the commercial arrangement, as stated in Note 7C5.

**Notes to the Financial Statements for December 31, 2018 (Dollars in thousands)**

**Note 21 – Transactions and balances vis-à-vis interested parties, related parties and control holders (Cont.):**

**B. Transactions with related parties and interest parties (Contd.):**

For the year ended December 31, 2017:

| | Note | Parent companies | Related parties and other interested parties |
|---|---|---|---|
| Revenues from gas sale[67] | 14 | 319 | 8,277 |
| Expenses due to overriding royalties | 15 | 8,201 | 6,502 |
| Expenses of General Partner management fees | 12A | 760 | 200 |
| Compensation of directors | | - | 223 |
| Guarantee fee to Delek Group | 12H4 | 492 | - |
| Expenses due to control holder benefit against a capital reserve | 13F | 2,418 | - |
| D&O Insurance | 21E | 286 | - |
| Interest revenues | | - | 106 |

For the year ended December 31, 2016:

| | Note | Parent companies | Related parties and other interested parties |
|---|---|---|---|
| Revenues from gas sale[68] | 14 | 1,154 | 7,138 |
| Expenses due to overriding royalties | 15 | 7,407 | 7,018 |
| Expenses of General Partner management fees | 12A | 747 | - |
| Compensation of directors | | - | 258 |
| Guarantee fee to Delek Group | 12H4 | 492 | - |
| Expenses due to control holder benefit against a capital reserve | 13F | 658 | 1,833 |
| D&O Insurance | 21E | 168 | - |

[67] Including the share of the parent company and a related party in the commercial arrangement, as aforesaid in Note 7C5.
[68] Including the share of the parent company and a related party in the commercial arrangement, as aforesaid in Note 7C5.

**Note 21 – Transactions and balances vis-à-vis interested parties, related parties and control holders (Cont.):**

**C. Terms of Employment of the CEO of the General Partner, Mr. Yossi Abu ("Mr. Abu"):**

The terms of office and employment of Mr. Abu are established in an employment agreement of June 2016, effective as of April 1, 2016 for a five-year period (the "**Employment Agreement**"). The Employment Agreement was approved on April 14, 2016 by the compensation committee and the board of directors of the General Partner and on June 5, 2016 by the general meeting of the participation unit holders, in accordance with the Partnership's compensation policy.

Under the Employment Agreement, Mr. Abu's monthly salary is in the gross sum of ILS 112.1[69] thousand (100%) (the salary is updated every three months according to the Consumer Price Index). Mr. Abu is entitled to the related benefits all in accordance with the policy of the General Partner. Mr. Abu is entitled to an annual bonus in every calendar year during the term of the Second Employment Agreement and a special one-time bonus, in accordance with the compensation policy. In the event that his employment is terminated, Mr. Abu will be entitled to an adjustment bonus and a retirement bonus, in accordance with the compensation policy. In addition, the General Partner granted Mr. Abu, in 2016, approx. 2,959,860[70] phantom units (the underlying asset of which is a participation unit granting a working interest in the rights of the Limited Partner in the Partnership (subject to adjustments as specified in the employment agreement) (the "**Phantom Units**").

The Phantom Units will vest in five installments, with the first and second installments vested on September 1, 2017 and the third installment vested on September 1, 2018, and the fourth and fifth installments vesting on September 1, 2019 and September 1, 2020, respectively (the "**Overall Package**"). Each of the installments included in the Overall Package is exercisable as of the vesting date of such installment and until the lapse of 90 days after the termination of Mr. Abu's employment under the employment agreement (i.e., June 30, 2021). The exercise price of the phantom units is ILS 11.33 for the first installment, plus 5% for every installment as of the second installment. The fair value of the phantom units granted to the CEO totals approx. ILS 7.4 million as of April 13, 2016 (the fair value estimate was performed according to the binomial model). The principal assumptions underpinning such valuation are as follows: (1) exercise price of ILS 11.33 for the first installment with an addition of 5% every year; (2) participation unit price of approx. ILS 10.79; (3) Standard deviation rate of 33.17%; (4) Risk-free interest rate of 1.02%; (5) Contractual duration of 5.22 years; (6) Abandonment rate after vesting period of 0%; (7) restriction of the maximal benefit which will be generated for Mr. Abu from the exercise of each Phantom Unit shall not exceed 100% of the exercise price specified for the Phantom Unit included in the exercised installment on the date of grant.

[69] As of December 31, 2018.

[70] Within the merger of the partnerships, 7,734,410 phantom units of Avner Partnership were exchanged with 1,453,835 phantom units of the Partnership.

**Note 21 – Transactions and balances vis-à-vis interested parties, related parties and control holders (Cont.):**

**C. Terms of Employment of the CEO of the General Partner, Mr. Yossi Abu ("Mr. Abu") (Cont.):**

On February 19, 2018 the Partnership announced that the CEO of the General Partner, Mr. Yossi Abu notified the Partnership that the board of directors of Delek Energy approved his appointment as the CEO of Delek Energy, subject to the receipt of all of the approvals required pursuant to law, in addition to his position as the CEO of the General Partner, and such that his main engagement will continue to be the CEO of the General Partner.

Following the aforesaid, Mr. Abu reached an agreement with the General Partner and Delek Energy, under which he will continue to serve in his current office as the CEO of the General Partner in an approx. 80% position (instead of 100%), and he will also concurrently serve as the CEO of Delek Energy in a 20% position, subject to the receipt of all of the approvals required therefor in the Partnership and in Delek Energy (the "**Change in the Terms of Employment**").

Mr. Abu will update the audit committee and the board of directors on any matter where a concern shall arise for the creation of a conflict of interests between his office as the CEO of the General Partner and his office as the CEO of Delek Energy, and he will act pursuant to their instructions on such matter. The parties agreed that the General Partner will continue to bear the entire compensation of Mr. Abu (100% position) and a settlement of accounts will be held between the General Partner and Delek Energy for bearing the share of Delek Energy (20%) of the total cost of Mr. Abu's compensation, including all of the compensation components to which he is entitled under the current employment terms pursuant to the Employment Agreement. Furthermore, for his service as a director in companies held by the Partnership or Delek Energy, Mr. Abu will be entitled to compensation as per the standard practice. It is clarified that the cost of employment of Mr. Abu is imposed on the General Partner only in the framework of the management services provided by the General Partner to the Partnership.

On May 17, 2018 the general meeting of the holders of the participation units in the Partnership approved the Change in the Terms of Employment of Mr. Abu. In addition, on July 3, 2018, the board of Delek Energy decided on the appointment of Mr. Abu as CEO of Delek Energy taking effect as of July 3, 2018. The Change in the Terms of Employment of Mr. Abu is effective as of such date.

Furthermore, on January 5, 2016, Ithaca granted Mr. Abu 200,000 options in the value of CAD 0.55 per option unit which were exercised during 2018 in consideration for approx. $218 thousand.

In 2018 Mr. Abu received an annual bonus in the amount of ILS 1,950 thousand for 2017 as well as a special bonus in the amount of ILS 250 thousand for the approval of a development plan and the adoption of an investment decision for the development of the Leviathan reservoir, with the balance of the special bonus, up to a sum of 6 gross monthly salaries (the compensation policy cap) to be paid upon the progress of the development of the Leviathan Project according to the planned timetables, and subject to the required approvals.

**Note 21 – Transactions and balances vis-à-vis interested parties, related parties and control holders (Cont.):**

**D.** Further to Note 7C4 in respect of the Partnership's exploration rights in Block 12 in Cyprus, as a condition for the endorsement, the Cypriot Government requested, in accordance with terms of the production sharing contract, that a performance guarantee, unlimited in amount, shall be provided in favor of the Republic of Cyprus to secure the fulfillment of all of the undertakings under the production sharing contract (the "**Guarantee**"), that was provided on the date of transfer of the rights by Delek Group.
Delek Group agreed to provide the Guarantee, against payment of a guarantee fee by the Partnership (see Note 12H4 above), as approved by the general meeting of participation unit holders of 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 Noble Cyprus under the production sharing contract are jointly and severally, the Partnership shall act to the best of its ability vis-à-vis Noble Cyprus and the parent company of Noble Cyprus, Noble Energy Inc. ("**Noble Inc.**"), which provided a guarantee, as aforesaid, for its subsidiary, Noble Cyprus, by virtue of the production sharing contract – in an attempt to reach arrangements for the division of responsibilities and mutual indemnification between the Partnership, Delek Group and Noble Cyprus and Noble Inc., in respect of the operations in Block 12, according to the respective holding percentage of the rights in Block 12;
   e) The Partnership shall provide Delek Group with a copy of any resolution and/or notice by the Cypriot authorities in connection with the production sharing contract and/or the Guarantee and will also act to inform Delek Energy of any event that may, to the best of its knowledge, result in the enforcement of the Guarantee.

**E. Additional information regarding transactions with related parties and interested parties:**

1. See Notes 12B and 15 above regarding the payment of royalties between the Partnership and its control holders and to an affiliate.
2. The Partnership is engaged in gas sale agreements with I.P.P. Delek Ashkelon Ltd. ("**Delek Ashkelon**") and I.P.P. Delek Sorek Ltd. and Delek Israel Ltd. (affiliates) (see Note 12C1 above). For information regarding sale volumes, see Section B above regarding revenues from the sale of gas to other interested parties.

**Note 21 – Transactions and balances vis-à-vis interested parties, related parties and control holders (Cont.):**

**E. Additional information regarding transactions with related parties and interested parties (Cont.):**

2. (Contd.)

Following are details with respect to the Delek Ashkelon natural gas supply agreement:
In July 2005, the Partnership, jointly with its partners in the Yam Tethys project, entered into a gas supply agreement with Delek Ashkelon, whereby Delek Ashkelon was granted an option to purchase an additional quantity of natural gas, on an interruptible basis, over and above the quantities addressed in the original agreement between the parties (the "**Original Agreement**"). In view of the continuous decline in the ability to supply natural gas from the Mari B reservoir, an amendment to the agreement was signed in November 2012, whereby it was agreed to update the maximum daily quantity that Delek Ashkelon would be entitled to purchase, subject to the limit on the maximum hourly quantity specified in the Original Agreement. For the additional daily quantity, Delek Ashkelon will pay a price that will be calculated according to a formula that is based on the electricity production tariff and includes a "floor price". The agreement is effective until June 30, 2022, and the balance of the contractual quantity to be supplied is approx. 0.5 BCM.

3. The General Partner of the Partnership entered into a lease agreement with Delek Group with respect to offices used by the General Partner and the Partnership, including a management fee agreement and an agreement for the division of the costs of renovation of the offices. The Partnership recorded expenses in the statement of comprehensive income against a capital reserve for its share in the aforesaid benefit in the sum of approx. $367 thousand (2017: approx. $402 thousand).

4. On July 24, 2018, the general meeting of the participation unit holders in the Partnership approved an engagement with Delek Group in an agreement regulating the division of worker employment costs. The terms of the engagement provide, *inter alia*, that the engagement is for a period of three years commencement on the date of approval by the general meeting. The arrangement will apply to employees and officers in pre-determined areas, the scope of employment of the workers by Delek Group companies shall not exceed a 5% position on an annual average, [and?] the total cost of employment to be borne by the Delek Group includes, *inter alia*, salary, options, related benefits, a proportionate share of office costs and other office overhead.

5. In December 2018, the Partnership and the General Partner engaged in a policy for insurance of the liability of directors and offices of the Partnership and of the General Partner, in the framework of a policy taken out by Delek Group for the period between January 1, 2019 and June 30, 2020, the premium amount for the entire insurance period shall be approx. $380 thousand. The sum of the expense recorded in the statement of comprehensive income totaled approx. $178 thousand (2017: $202 thousand).

6. During 2018, an agreement was executed between the Yam Tethys Partners (which include, *inter alia*, the Partnership and Delek Group) and the Tamar partners (which include, *inter alia*, the Partnership) for the sale of production surplus from the Yam Tethys reservoir to the Tamar partners, for their sale to the Tamar Project customers. The sale of such surplus is not anticipated to have a material effect on the Partnership's business results.

**Note 21 – Transactions and balances vis-à-vis interested parties, related parties and control holders (Cont.):**

**E. Additional information regarding transactions with related parties and interested parties (Cont.):**

7. For details regarding authorization by the board of directors of the General Partner to enter into a transaction with Ithaca (a company wholly owned by Delek Group) whereby Ithaca shall act as operator of the Alon D license, see Note 7C6 above.

8. The Partnership has additional engagements in which Delek Group has a personal interest, which are classified as negligible transactions, such as the receipt of "*Dalkan*" services [automatic billing for fueling] from Delek Israel, receipt of securities portfolio management services from Excellence Nessuah Investment Management Ltd., receipt of V.A.T reporting services from Delek Group, receipt of services from the NYX Herzliya Hotel of the Fattal Hotel Chain.

**Note 22 – Financial instruments:**

**A. Manner of determining the fair value of the financial instruments:**

Due to their nature, the fair value of financial instruments, such as cash and cash equivalents, trade and short-term receivables, and trade and short-term payables, is an adequate approximation to their book value.

| | | |
|---|---|---|
| Short-term non-negotiable assets and liabilities bearing interest with a fixed maturity date | - | Their book value reflects their fair value as of the date of the statements of financial position, since the average interest rate thereon is not materially different from the interest rate customary in the market for similar items as of the date of the statements of financial position. |
| Short-term amounts receivable and payable | - | The book value constitutes an approximation of their fair value. |
| Assets and liabilities with no maturity date | - | The fair value is determined according to the payable amount per demand on the report date. |
| Assets and liabilities at variable interest | - | The fair value of assets and liabilities at variable interest, due to which no material changes have occurred, was determined based on the contractual conditions of the instrument. |
| Interest rate SWAP and forward contracts | - | The fair value is based on the market price. In the absence of market price, the fair value is based on economic models. |

**Notes to the Financial Statements for December 31, 2018 (Dollars in thousands)**

## Note 22 – Financial instruments (Contd.):

### B. Fair value hierarchy:

For disclosure purposes, the Partnership classifies fair value measurements under one of the levels in the fair value hierarchy that reflects the significance of the data used when making the measurements. The fair value hierarchy is:

| | |
|---|---|
| Level 1 | - Quoted prices (unadjusted) in active markets for identical assets or identical liabilities. |
| Level 2 | - Inputs other than quoted prices included within Level 1, which are observable directly or indirectly. |
| Level 3 | - Inputs that are not based on observable market data (valuation techniques that use inputs which are not based on observable market data). |

Below are figures on the fair value hierarchy of the financial instruments that are measured in fair value that were recognized in the statement of financial position:

| | 31.12.2018 | | | |
|---|---|---|---|---|
| | Level 1 | Level 2 | Level 3 | Total |
| **Financial assets at fair value through profit or loss:** | | | | |
| - Bonds | 78,720 | - | - | 78,720 |
| - Royalties receivable from the Karish and Tanin leases (see Note 8B) | - | - | 113,100 | 113,100 |
| - ETFs | 28,136 | - | - | 28,136 |
| - Structured deposits | 25,483 | - | 4,974 | 30,457 |
| - Loan to Energean in the context of the sale of the Karish and Tanin leases (see Note 8B) | - | 91,500 | - | 91,500 |
| | 132,339 | 91,500 | 118,074 | 341,913 |

| | 31.12.2017 | | | |
|---|---|---|---|---|
| | Level 1 | Level 2 | Level 3 | Total |
| **Financial assets at fair value through profit or loss:** | | | | |
| - Bonds | 95,070 | - | - | 95,070 |
| - Contingent consideration from the sale of the Karish and Tanin leases in respect of future-production-based royalties | - | - | 88,600 | 88,600 |
| - ETFs | 14,093 | - | - | 14,093 |
| **Financial assets available for sale:** | | | | |
| Contingent consideration from the sale of the Karish and Tanin leases in respect of a final investment decision for the development of the Karish and Tanin leases | - | - | 78,500 | 78,500 |
| | 109,163 | - | 167,100 | 276,263 |
| **Financial liabilities at fair value through profit or loss** | | | | |
| - Financial derivatives | - | - | 126 | 126 |

**Notes to the Financial Statements for December 31, 2018 (Dollars in thousands)**

## Note 22 – Financial instruments (Cont.):

### B. Fair value hierarchy (Cont.):

Adjustment due to fair value measurements classified as level 3 in the financial instruments fair value hierarchy:

| | For the year ended December 31, 2018 | | | |
|---|---|---|---|---|
| | Structured deposits | Future production-based royalties | Contingent proceeds from the sale of the Karish and Tanin leases | Total |
| **Balance as of January 1** | 44,888 | 88,600 | 78,500 | 211,988 |
| Remeasurement recognized in profit or loss | 86 | 24,500 | 19,050 | 43,636 |
| Acquisitions | 15,000 | - | - | 15,000 |
| Disposals / revenues | (55,000) | - | (10,850) | (65,850) |
| Reclassification from level 3 | - | - | (86,700) | (86,700) |
| **Balance as of December 31** | 4,974 | 113,100 | - | 118,074 |

| | For the year ended December 31, 2017 | | | |
|---|---|---|---|---|
| | Financial derivatives | Future production-based royalties | Contingent proceeds from the sale of the Karish and Tanin leases | Total |
| **Balance as of January 1** | 432 | 73,700 | 66,600 | 140,732 |
| Remeasurement recognized in profit or loss | (558) | 14,900 | 9,800 | 24,531 |
| Remeasurement recognized in other comprehensive income | - | - | 2,100 | 2,100 |
| Acquisitions | 43 | - | - | 43 |
| Disposals / revenues | (43) | - | - | (432) |
| **Balance as of December 31** | (126) | 88,600 | 78,500 | 166,974 |

**Notes to the Financial Statements for December 31, 2018 (Dollars in thousands)**

## Note 22 – Financial instruments (Cont.):

### C. Fair value of financial instruments:

The fair value of the financial instruments presented in the financial statements matches or is close to their book value, with the exception of the bonds issued as stated in Note 10 above, whose fair value, as of December 31, 2018, is approx. $1,356 million (December 31, 2017: $1,695 million), and whose book value is approx. $1,348 million (December 31, 2017: approx. $1,664 million).

### D. Groups of financial instruments:

| | As of December 31, | |
|---|---|---|
| | **2018** | **2017** |
| **Financial assets:** | | |
| Cash and cash equivalents | 143,885 | 154,835 |
| Investments and deposits | 246,434 | 380,308 |
| Trade receivables | 45,481 | 46,506 |
| Trade and other receivables | 96,486 | 29,462 |
| Other long-term assets | 201,560 | 179,840 |
| **Total financial assets** | 733,846 | 790,951 |
| **Financial liabilities:** | | |
| Trade and other payables | 142,461 | 96,406 |
| Financial derivatives | - | 126 |
| Bonds (Note 10) | 1,347,575 | 1,663,740 |
| Long-term liabilities to banks (Note 10) | 1,238,143 | 468,967 |
| **Total financial liabilities** | 2,728,179 | 2,229,239 |

### E. Risk Management policy:

The Partnership’s transactions expose the Partnership to various financial risks, such as: market risk (including currency risk, fair value risk due to interest rate, linkage to the U.S. CPI and price risk), credit risk, liquidity risk and cash flow risk due to the exposure to the LIBOR interest rate. The general risk management plan of the Partnership focuses on acts to minimize possible negative effects on the Partnership’s financial performances. The Partnership at time uses derivative financial instruments to hedge certain exposures to risks.

### F. Market risks:

Market risks derive from the risk that the fair value or future cash flow of a financial instrument will change as a result of changes in market prices. Market risks include three types of risks: currency risk, other price risk and fair value risk due to interest rate as follows:

**Notes to the Financial Statements for December 31, 2018 (Dollars in thousands)**

**Note 22 – Financial instruments (Cont.):**

**F. Market Risks (Cont.):**

1. **Currency risk**:

   As of the date of approval of the financial statements, the Partnership has Shekel balances in the sum of approx. $38.5 million which were purchased in proximity to the date of the statement for distribution to holders of participation units in January 2019. Exchange rate risk derives mainly from assets and liabilities stated in ILS and from the fact that the tax advance payments made by the Partnership pursuant to Section 19 are determined based on a Shekel tax report.

2. **Interest risk**:

   An interest risk is the risk that the fair value or the future cash flows of financial assets will change as a result of changes in the market interest rates. The financial instruments that bear variable interest expose the Partnership to a cash flow risk due to changes in the interest rate. In addition, the Partnership is exposed to possible changes in the cash flow that may derive form changes in the LIBOR interest rate, mainly from an agreement for financing the share of the Partnership in the Leviathan project development costs (see Note 10C above). In the context of the Partnership's risk management policy, the Partnership performed during 2017 IRS-type cash flow hedging transactions that hedge against changes in the LIBOR interest rate in the sum of $1.1 billion.

   The cash flow hedging transactions were exercised by the Partnership during September 2017 and before their original termination date, with a loss which derived from the decrease in interest in an amount of approx. $4 million which was recorded to the statement of other comprehensive income for cash flow hedging transactions. According to the risk management policy, the Partnership continues to examine the purchase of hedges against exposures to market risks. In February and March 2019 (after the date of the statement of financial position), the Partnership made IRS-type cash flow hedging transactions which hedge the chances with LIBOR interest in the sum of approx. $400 million. The Partnership has short-term investments that bear variable interest. Following are the balances of financial instruments that bear interest according to their book value:

| | As of December 31, | |
|---|---|---|
| | **2018** | **2017** |
| **Financial instruments at variable interest:** | | |
| Assets: | | |
| Deposits in banks (including cash and cash equivalents) | 214,317 | 366,779 |
| Short-term investments | 59,766 | - |
| Trade and other receivables in the context of joint ventures | 81,285 | 27,782 |
| Long-term receivables in the context of joint ventures | 47,989 | 34,048 |
| | 403,357 | 428,609 |
| Liabilities: | | |
| Long-term liabilities to banks | 1,238,143 | 468,967 |
| Surplus of assets (liabilities) | (834,786) | (40,358) |

Notes to the Financial Statements for December 31, 2018 (Dollars in thousands)

## Note 22 – Financial instruments (Cont.):
### F. Market Risks (Cont.):
#### 2. Interest Risk (Cont.):

Following is the effect of the change in the event of a 0.5% change in the LIBOR interest rate, with the other variables remaining constant:

| | Effect on profit or loss | |
|---|---|---|
| | **Increase in interest rate** | **Decrease in interest rate** |
| | **0.5%** | **0.5%** |
| 2018 | (4,174) | 4,174 |
| 2017 | (202) | 202 |

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. $113.1 million (as of December 31, 2017 in the sum of approx. $88.6 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. $91.5 million (as of December 31, 2017: in the sum of approx. $78.5 million).

Following are tests of sensitivity to a change in the capitalization interest, with the other variables remaining constant:

| | As of December 31, 2018 | | | | |
|---|---|---|---|---|---|
| | Profit (loss) from the change in the capitalization interest | | | | |
| | 2% | 1% | Fair value | -1% | -2% |
| Royalties receivable from the Karish and Tanin leases | (14,368) | (7,534) | 113,100 | 8,327 | 17,557 |
| Loan to Energean in the context of the sale of the Karish and Tanin leases (See Note 8B above) | (5,666) | (2,915) | 91,500 | 3,092 | 6,373 |
| **Total** | **(20,034)** | **(10,449)** | **204,600** | **11,419** | **23,930** |

| | As of December 31, 2017 | | | | |
|---|---|---|---|---|---|
| | Profit (loss) from the change in the capitalization interest | | | | |
| | 2% | 1% | Fair value | -1% | -2% |
| Contingent consideration in respect of future-production-based royalties | (12,435) | (6,534) | 88,600 | 7,253 | 15,326 |
| Amounts receivable in respect of a final investment decision for development of the Karish and Tanin leases | (6,946) | (3,594) | 78,500 | 3,857 | 8,002 |
| **Total** | **(19,381)** | **(10,128)** | **167,100** | **11,110** | **23,328** |

**Notes to the Financial Statements for December 31, 2018 (Dollars in thousands)**

**Note 22 – Financial instruments (Cont.):**
**F. Market Risks (Cont.):**

3. **Price risk**:

**Natural gas and condensate prices risk**:

The prices paid by consumers for the natural gas in the reservoirs in which the Partnership is a partner, derive, *inter alia*, from the electricity production tariff, to which the gas agreements for private electricity customers are linked, from the U.S. CPI, and from the Brent barrel price (the "**Indices**"). For details on the various linkages in the natural gas price formulas, see Notes 12C1 and 12C2 above. It is noted with respect to the electricity production tariff that the frequent methodological changes made by the Electricity Authority (PUA-E) to the manner of calculation thereof, hinder the ability to predict it, and may lead to disagreements on the manner of calculation thereof between gas suppliers and customers .

A drop in the electricity production tariff (resulting, *inter alia*, from a price adjustment to be sought by the IEC, if any, according to the mechanism that was determined in the agreement that was signed therewith as stated in Note 12C1B of the above) and/or in the Brent prices and/or in the U.S. CPI may adversely affect the Partnership's revenues from the existing and future gas sale agreements. In respect of the fixing of the IEC price, see Note 12C1B9 above. Furthermore, a significant change in the prices of other energy sources (including coal and other gas substitutes), the reforms and decisions related to the electricity market, including changes in environment protection laws, may lead to a change in the consumption model of IEC and other large customers, which may reduce the demand for natural gas and lead to a decrease in the prices of natural gas in the economy.

**Securities and Commodities Prices Risk:**

The Partnership invests some of its surplus cash in dollar bonds, thereby exposing itself to the fluctuations in the bond prices, which is inherent to such market. The Partnership also invests in ETFs and structured deposits, the yield deriving from which is dependent on the performance of indices or commodities. Investment decisions are made by the management of the Partnership's General Partner, based on the recommendations of professional advisors and the guidance of the Investment Committee of the Board of the Partnership's General Partner.

The fair value of the bonds and ETFs as of the date of the report was approx. $78,720 thousand (December 31, 2017: $95,069 thousand) and approx. $28,136 thousand (December 31, 2017:14,093), respectively, and the fair value of such structured deposits was estimated at approx. $30,457 thousand (December 31, 2016: $44,888 thousand).

Following are sensitivity tests due to price change, with the other variables remaining constant:

| | As of December 31, 2018 | | | |
|---|---|---|---|---|
| | Profit (loss) from price change | | | |
| | Increase in prices of securities and commodities | | Decrease in prices of securities and commodities | |
| | 10% | 5% | 5% | 10% |
| Structured deposits | 2,553 | 1,276 | (1,276) | (2,553) |
| ETFs | 2,814 | 1,407 | (1,407) | (2,814) |
| Total 2018 | **5,367** | **2,683** | **(2,683)** | **(5,367)** |

**Notes to the Financial Statements for December 31, 2018 (Dollars in thousands)**

**Note 22 – Financial instruments (Cont.):**
**F. Market Risks (Cont.):**

**3. Price Risk (Cont.):**

| | As of December 31, 2017 | | | |
|---|---|---|---|---|
| | Profit (loss) from price change | | | |
| | Increase in prices of securities and commodities | | Decrease in prices of securities and commodities | |
| | 10% | 5% | 5% | 10% |
| Financial derivative | 1,176 | 249 | (137) | (193) |
| ETFs | 1,409 | 705 | (705) | (1,409) |
| Total 2017 | **2,585** | **954** | **(842)** | **(1,602)** |

| | Profit (loss) from price change | | | |
|---|---|---|---|---|
| | Increase in market interest rate | | Decrease in market interest rate | |
| | 2% | 1% | 1% | 2% |
| Effect of changes on the balances of short-term investments | | | | |
| 2018 | (2,082) | (1,041) | 1,041 | 2,082 |
| 2017 | (2,350) | (1,175) | 1,175 | 2,350 |

Further to Note 8B with respect to the sale of all of the Partnership's rights in the Karish and Tanin leases, the Partnership recorded amounts receivable in the sum of approx. \$113.1 million (as of December 31, 2017, approx. \$88.6 million) for royalties based on future production from the Karish and Tanin reservoirs.

Following are tests of sensitivity to a change in the gas prices, when the other variables remain constant:

| | As of December 31, 2018 | | | | |
|---|---|---|---|---|---|
| | Profit (loss) from the change in price | | | | |
| | 10% | 5% | Fair value | -5% | -10% |
| Royalties receivable from the Karish and Tanin leases | 4,557 | 3,603 | 113,100 | (3,539) | (4,494) |

| | As of December 31, 2017 | | | | |
|---|---|---|---|---|---|
| | Profit (loss) from the change in price | | | | |
| | 10% | 5% | Fair value | -5% | -10% |
| Amounts receivable in respect of a final investment decision to develop the Karish and Tanin leases | 4,565 | 1,474 | 88,600 | (951) | (4,597) |

**Notes to the Financial Statements for December 31, 2018 (Dollars in thousands)**

## Note 22 – Financial instruments (Cont.):

### 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.

1. The Partnership's principal customer is the IEC which accounted for approx. 48% of the sales in 2018 (approx. 54% of the sales in 2017). The trade receivables balance as of December 31, 2018 is mostly a current balance.

   The Partnership estimates that the credit risk vis-à-vis the IEC is low.

2. Turnover and aging of trade receivables, the value of which was not affected:

| | | Trade receivables balance as of December 31, 2018 | | | |
|---|---|---|---|---|---|
| | **Revenues for the year ended December 31, 2018** | **Total** | **Current balance** | **In dispute for more than 30 days** | **In dispute for more than 60 days** |
| IEC | 221,923 | 17,061 | 17,061 | - | - |
| Dalia | 45,285 | 3,747 | 3,747 | - | - |
| Other customers | ,190774 | 33,232 | ,24673 | - | ,8559 |
| **Total** | 457,982 | 54,040 | ,45481 | - | ,8559 |

The balances in dispute derive from electricity production tariff differences and are included in the other long-term assets item. Also see Note 12C1A8 above.

3. The Partnership has cash and cash equivalents and deposits that are mostly held with large banks in Israel and overseas. Accordingly, the Partnership expects no losses due to credit risks for said balances.

4. Short-term investments in corporate bonds:
   The Partnership maintains a low exposure to credit risk in connection with its investments in corporate bonds, by only investing in bonds and ETFs with an average rating of BBB- (by S&P) and above.

5. The balance of the financial assets in the statement of financial position as presented in Paragraph D above reflects the maximal exposure to credit risk as of the date of the statement of financial position.

### H. Liquidity Risk:

Liquidity risks result from the management of the Partnership's working capital, and from the financial expenses and principal repayments of the debt instruments of the Partnership. A liquidity risk is the risk that the Partnership will have difficulties in fulfilling undertakings related to financial liabilities.
The management of the General Partner reviews the cash flow forecasts on a monthly basis for a 12-month period at least, as well as information regarding the cash balances and the deposits.

**Notes to the Financial Statements for December 31, 2018 (Dollars in thousands)**

## Note 22 – Financial instruments (Cont.):
## H. Liquidity Risk (Cont.):

The Partnership strives to ensure that the cash, the held deposits and short-term investments, together with the forecasted income, shall always be sufficient to cover liabilities on the respective maturity dates thereof. The foregoing does not take into account the effects of extreme scenarios that cannot be foreseen.

The contractual maturities of the financial liabilities subsequent to the date of the statement of financial position (according to the various stated payment values that are different to their value in the books), based on the interest rates and exchange rates as of the date of the statement of financial position, are as follows:

| 2018 | 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 | 126,700 | - | - | - | - | 126,700 |
| Long-term liabilities to banks | - | - | 1,471,859 | - | - | 1,471,859 |
| Bonds | - | 47,773 | 837,620 | 404,480 | 337,318 | 1,627,191 |
| **Total** | 126,700 | 47,773 | 2,309,479 | 404,480 | 337,318 | 3,225,750 |

| 2017 | 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 | 96,406 | - | - | - | - | 96,406 |
| Long-term liabilities to banks | - | - | 578,060 | - | - | 578,060 |
| Bonds | - | 398,069 | 451,568 | 838,998 | 354,637 | 2,043,272 |
| **Total** | 96,406 | 398,069 | 1,029,628 | 838,998 | 354,637 | 2,717,738 |

### Changes in liabilities deriving from financing activity:

| | Balance as of January 1, 2018 | Cash Flow | Effect of changes in fair value | Effect of changes in amortized cost | Other changes | Balance as of December 31, 2018 |
|---|---|---|---|---|---|---|
| Bonds | 1,663,740 | (320,000) | - | (26,166) | - | 1,317,574 |
| Liabilities to banks | 468,967 | 775,384 | - | (6,208) | - | 1,238,143 |
| Financial derivative | 126 | - | - | - | (126)[71] | - |
| Profits for distribution, declared | 60,381 | (61,359) | - | - | 35,663 | 34,685 |
| **Total liabilities deriving from financing activity** | 2,193,214 | 394,025 | - | (32,374) | 35,537 | 2,590,402 |

[71] The effect of initial application of accounting standard IFRS 9.

**Notes to the Financial Statements for December 31, 2018 (Dollars in thousands)**

## Note 22 – Financial instruments (Cont.):
## H. Liquidity Risk (Cont.):

| | Balance as of January 1, 2017 | Cash Flow | Effect of changes in fair value | Effect of changes in amortized cost | Other changes | Balance as of December 31, 2017 |
|---|---|---|---|---|---|---|
| Bonds | 1,976,633 | (320,000) | - | 7,107 | - | 1,663,740 |
| Liabilities to banks | - | 462,173 | - | 6,794 | - | 468,967 |
| Profits for distribution, declared | 100,004 | (781,116) | - | - | 741,493 | 60,381 |
| Financial derivatives | - | (3,957) | 126 | - | 3,957 | 126 |
| **Total liabilities deriving from financing activity** | 2,076,637 | (642,900) | 126 | 13,901 | 745,450 | 2,193,214 |

## Note 23 – Subsequent events:

### A. Examination of a potential restructuring:

On March 17, 2019, the General Partner's board of directors decided to instruct the Partnership's management to examine and promote a plan for the splitting of the Partnership's assets (the "**Split**").

The Split plan being examined includes, *inter alia*, the following main stages: (a) all of the Partnership's assets and liabilities, primarily the Leviathan and Aphrodite reservoirs, with the exception of the assets and liabilities that are attributed to the Tamar and Dalit leases, shall be transferred to a foreign SPC to be established by the Partnership (the "**New Corporation**" and the "**Transferred Assets and Liabilities**"); (b) all of the New Corporation's shares shall be distributed by the Partnership as a distribution in kind to the holders of the Partnership's participation units as being on the record date for the distribution (the "**Participation Unit Holders**"); and (c) the New Corporation's shares shall be listed on the main stock exchange in London (**Main Market**), and the possibility of listing them in Israel at the same time shall be considered.

On the date of closing of the Split, the Participation Unit Holders shall continue to hold the Partnership, which shall hold, after the Split, the assets and liabilities attributed to the Tamar and Dalit leases, and the Participation Unit Holders shall additionally hold, at identical rates, shares in the New Corporation which shall hold, after the Split, the Transferred Assets and Liabilities.

The Split may provide another alternative for the implementation of Government Resolution No. 476 regarding the Gas Framework, such that the Participation Unit Holders who are not in the Partnership's control group will be able to continue to hold (through the Partnership) interests in the Tamar and Dalit leases, subject to the control holder selling to third parties its holdings in the General Partner and in the Partnership.

In the board's resolution, the Partnership's management was authorized to examine and promote the gamut of aspects pertaining to the Split plan and the performance thereof, including: the manner of treatment of the Partnership's liabilities; examination of the conditions for listing the shares of the New Corporation on the main stock exchange in London (Main Market) and/or in Israel; examination and handling of the regulatory and other approvals required.

**Note 23 – Subsequent events:**

**A. Examination of a potential restructuring (Contd.):**

The Partnership intends to act for receipt of a tax ruling from the Tax Authority, *inter alia* with the aim of enabling the performance of the Split with a tax deferral, both for the Partnership (until the sale of the assets in practice) and for the Participation Unit Holders (until the sale of the participation units or the shares of the New Corporation). Insofar as a tax ruling is obtained as aforesaid, tax payment will be made on the date of disposition of the holdings, rather than on the day of closing of the Split.

In addition to the aforesaid, the board decided to authorize the audit committee to work on and supervise the process of formation of the Split plan, in order to ensure that the best interests of the Partnership and all of the Participation Unit Holders dictate the formation and the terms and conditions of the Split plan, and in this context: (a) the audit committee shall examine the advantages and the disadvantages inherent in the Split from the perspective of the Participation Unit Holders; (b) the audit committee shall examine whether there are aspects of the Split transaction which may establish a material surplus link for the control holder and the disclosure that shall be given to such aspects; and (c) the audit committee shall examine whether a distribution in kind of the New Corporation's shares satisfies the distribution criteria.

It is clarified that if it is decided to promote the Split, it shall be presented for the approval of the organs according to the law, including approval by the general meeting of the Participation Unit Holders by a special majority, for the sake of caution, as required for the approval of an irregular transaction in which the control holder has a personal interest.

It is further noted that concurrently with the examination of the feasibility of the Split, the Partnership is continuing to examine and promote other alternatives to the sale of the balance of its holdings in the Tamar and Dalit leases.

It is clarified that the closing of the Split is contingent, *inter alia*, on the receipt of regulatory approvals (including approval by the Tax Authority) in Israel and abroad and approvals by third parties, and, at this stage, the feasibility of the Split has not yet been clarified and there is no certainty that it will be possible to execute the Split and on what conditions. It is further clarified that, in view of the foregoing, material changes may occur in the details of the Split plan.

**B.** For details regarding the resignation of the General Partner's CEO from office as a director of the company accounted for at equity, see Note 6G.

**C.** For details regarding approval of the development plan for the SW Tamar reservoir, see Note 7C1C.

**D.** For details regarding the Commissioner's request for details regarding the performance of an environmental survey and replacement of the operator in the Alon D license, see Note 7C6.

**E.** For details regarding the exercise of an option to purchase working interests in the Roy License, see Note 7C8.

**F.** For details regarding the Tamar Partners' signing of an amendment to the Dalia Energies agreement, see Note 12C1A2.

**G.** For details regarding an amendment to the gas supply agreement between the Tamar Partners and the IEC, see Note 12C1B9.

**H.** For details regarding the submission of an RFP for the supply of natural gas to Israel Electric Corporation Ltd., see Note 12C3.

**Note 23 – Subsequent events:**

**I.** For details regarding the filing of a class action and a motion for class certification thereof in connection with the offering of shares of Tamar Petroleum in July 2017, see Note 12I4.

**J.** For details regarding a complaint and an urgent motion for a provisional injunction pursuant to Section 65W(b) of the Partnerships Ordinance, against the Partnership, the Partnership's General Partner, and the royalty interest owners which was filed by the supervisor of the Partnership, see Note 12I5B.

**K.** For details regarding the signing of an agreement regarding final royalties reports for 2011-2013 between the Yam Tethys partners and the Ministry of Energy, see Note 15B4.

**L.** For details regarding IRS cash flow hedging transactions, see Note 22F2.

**M.** For details regarding the submission of administrative appeals regarding the 2016 tax assessments, see Note 20A13.

**N.** On March 19, 2019, the Partnership entered into an agreement with S.O.A Energy Israel Ltd. (the "**Seller**" or "**SOA**") for the purchase of interests at the rate of 25% (out of 100%) in each of the 405/New Ofek license (the "**New Ofek License**") and the 406/New Yahel license (the "**New Yahel License**"), which are onshore licenses, in the center and the north of the State of Israel, respectively (the "**Petroleum Assets**", the "**Licenses**", the "**Purchased Interests**", the "**Purchase Agreement**" and the "**Transaction**", respectively).

Insofar as the Transaction is closed, SOA shall act as operator in the Petroleum Assets.

**Following are key details from the Purchase Agreement**:

On the Transaction closing date, which shall occur immediately upon the fulfillment of the conditions precedent or waiver of the need for fulfillment thereof or on another date to be agreed by the parties in writing (the "**Effective Date**"), the Seller shall transfer to the Partnership the Purchased Interests, them being free and clear of any pledge, royalty (it is clarified that the Purchased Interests shall be subject to the Partnership's obligation to pay overriding royalties to interested parties in the Partnership and to third parties), liability, claim and third party rights.

In addition, the Partnership shall pay the Seller $1 million as reimbursement for past expenses incurred in relation to the activity in the Petroleum Assets. The Partnership undertook to bear the costs of production tests in the New Ofek License up to a sum total that shall not exceed $6,500,000. To the extent that the cost of the production tests exceeds the said amount, each of the partners in the New Ofek License, including the Partnership, shall pay its proportionate share in such additional cost, in accordance with the provisions of the Joint Operating Agreement (JOA) to be signed between the partners on the Effective Date.

Furthermore, the Partnership shall provide to the Ministry of Energy with guarantees at a rate of 50% of the guarantees required in connection with the Licenses, in the total amount of approx. $750 thousand (subject to the provision of the balance of the guarantee by the Seller). The closing of the Transaction is subject to the fulfillment of several conditions precedent, including: (1) receipt of approvals from the competent organs of the Seller and the Partnership, including approval by the meeting of the holders of the Partnership's participation units of an amendment to the limited partnership agreement, in order to allow the Partnership to participate in oil and/or gas exploration and production in the Petroleum Assets; (2) receipt of the consent of Globe and Capital to the transfer of the interests according to the Purchase Agreement; (3) receipt of the Commissioner's approval; and (4) receipt of approval from the Competition Authority, insofar as required.

**Note 23 – Subsequent events:**

**N. (Contd.):**

Insofar as the conditions precedent are not satisfied within one hundred and twenty days (with an option for extension by thirty additional days) from the date of the signing of the agreement, then, at any time after such date, each party is entitled, if it shall have, in all material respects, fulfilled its undertakings under the Purchase Agreement, to terminate the engagement in the Purchase Agreement by giving written notice to the other party.

**O.** For details with respect to a mediation concerning the Eran License, see Note 7C9C.

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Delek Drilling

# Additional Information about the partnership

2018

# Delek Drilling – Limited Partnership

## Chapter D

## Additional Details regarding the Partnership

## For the year ended December 31, 2018

***This report is a translation of Delek Drilling - Limited Partnership's Hebrew-language Additional Details regarding the Partnership, prepared solely for convenience purposes. Please note that the Hebrew version is the binding version, and in the event of any discrepancy, the Hebrew version shall prevail.***

| | | | |
|---|---|---|---|
| **<u>Name of Corporation:</u>** | Delek Drilling – Limited Partnership | **<u>Corporation No. at the Registrar:</u>** | 550013098 |
| **<u>Address:</u>** | 19 Abba Even Blvd., Herzliya Pituach, 4612001 | | |
| **<u>Telephone:</u>** | 09-9712424 | **<u>Facsimile:</u>** | 09-9712425 |
| **<u>Balance Sheet Date:</u>** | December 31, 2018 | **<u>Report Date:</u>** | March 21, 2019 |

**<u>Regulation 8B</u>:** **<u>Valuations</u>**

Below are details on material valuations on the issue of royalties and other receivables from the sale of the Partnership's rights in the "Tanin" I/16 and "Karish" I/17 leases to Energean Israel Limited ("**Energean**")[1] (for further details see Note 8B to the financial statements (Chapter C of this Report)):

(a) <u>Valuation of royalties' receivable from the sale of the Partnership's rights in Karish and Tanin leases</u>

| | |
|---|---|
| Identification of the subject matter of the valuation: | Royalties from Karish and Tanin leases. |
| Timing of the valuation: | As of December 31, 2018. |
| Value of the subject matter of the valuation shortly before the valuation date, had GAAP, including depreciation and amortization, not mandated changing its value in accordance with the valuation: | n/a |
| Value of the subject matter of the valuation that was determined in accordance with the valuation: | Approx. U.S. $ ("**$**" or "**Dollar**") 113.1 million, which are included in the Partnership's other long-term assets. |
| Identification of the Valuator and his qualifications, including education, experience in performing | GSE Financial Advisory Ltd. is a subsidiary of Giza Singer Even Ltd. (below jointly, the "**Valuator**"), which is a |

[1] Although none of the valuations amount to a very material valuation, the Partnership decided, for the convenience of the reader, to attach them to the Partnership's periodic report as of December 31, 2018, since the valuations were attached to the periodic reports for the first three quarters of 2018 as very material valuations.

| | |
|---|---|
| valuations for accounting purposes in reporting corporations and in scopes that are similar to or exceed those of the reported valuation, and dependence on the entity commissioning the valuation, including reference to indemnification agreements with the Valuator: | leading financial advisory and investment banking firm in Israel. The firm has vast experience in advising the major companies, the prominent privatizations and the important transactions in the Israeli economy, which it acquired over the course of its thirty years of activity. Giza Singer Even operates in three areas, through autonomous and independent business divisions: economic advisory services; investment banking, analytical research and corporate governance.<br>The work was performed by a team headed by Eitan Cohen, CPA, a partner and Head of the Economic Department at Giza Singer Even, who has more than ten years of experience in the fields of economic and business consulting, valuations of companies and financial instruments. Eitan is an accountant who holds a B.A. in Economics and Business Administration from Ben Gurion University and an M.Sc. in Financial Mathematics from Bar Ilan University.<br>The Valuator does not have any personal interest in and/or dependence on the Partnership and/or the General Partner of the Partnership, other than the fact that he received a fee for the valuation. Furthermore, the Valuator has confirmed that his fee is not dependent on the results of the valuation. |
| The valuation model used by the Valuator: | Expected discounted cash flows method while adjusting the discounting rates to the |

| | |
|---|---|
| | risks embodied in the cash flow projections. |
| The assumptions according to which the Valuator performed the valuation, in accordance with the valuation model[2]: | Below are the main assumptions underlying the valuation:<br><br>1. Period of production of gas from Karish reservoir: January 1, 2022 through September 30, 2033;<br><br>2. Average annual production rate from Karish reservoir: approx. 3.48 BCM of natural gas per year; rate of production of condensate from Karish reservoir according to a ratio of approx. 18.0 barrels of condensate to each 1 mmcf of natural gas produced from the reservoir;<br><br>3. Period of production of the gas from Tanin reservoir: July 1, 2033 through March 31, 2039;<br><br>4. Average annual production rate from Tanin reservoir: approx. 3.48 BCM of natural gas per year; rate of production of condensate from Tanin reservoir according to a ratio of approx. 5.3 barrels of condensate to each 1 mmcf of natural gas produced from the reservoir;<br><br>5. Royalties component capitalization rate: 11.5%;<br><br>6. Effective rate of royalties to be paid to the State due |

[2] It is noted that the assumptions under which the Valuator performed the valuation differ from the data set forth in the Energean Prospectus (as defined in Chapter A of this Report).

| | |
|---|---|
| | to the gas and condensate: 11.5%;<br><br>7. Gas price formula: the base price in the contracts according to which the valuation was performed, is estimated using the formula specified in the price mechanism between Energean and ICL and ORL and Energean and OPC;<br><br>8. Condensate price: the condensate price forecast was made based on the average long-term oil prices forecast of the World Bank[3] and the EIA[4] and based on the assumption that the condensate price will be derived from the Brent price, adjusted to differences in the oil quality;<br><br>9. Petroleum profit levy: pursuant to the Petroleum Profit Taxation Law, 5771-2011;<br><br>10. Corporate tax rate: 23%, according to the statutory tax rate in the course of the forecast years. |

(b) <u>The valuation of the Energean debt component deriving from the sale of the Partnership's rights in the Karish and Tanin leases</u>

| | |
|---|---|
| Identification of the subject matter of the valuation: | Energean's debt deriving from the sale of the Partnership's rights in Karish and Tanin |

[3] A World Bank Quarterly Report: Commodity Markets Outlook, October 2018.
[4] U.S. Energy Information Administration: Annual Energy Outlook 2019.

| | |
|---|---|
| | leases. |
| Timing of the valuation: | December 31, 2018. |
| Value of the subject matter of the valuation shortly before the valuation date, had GAAP, including depreciation and amortization, not mandated changing its value in accordance with the valuation: | Irrelevant |
| Value of the subject matter of the valuation that was determined in accordance with the valuation: | A total of approx. $91.5 million included within the Partnership's current assets and other long-term assets. |
| Identification of the Valuator and his qualifications, including education, experience in performing valuations for accounting purposes in reporting corporations and in scopes that are similar to or exceed those of the reported valuation, and dependence on the entity commissioning the valuation, including reference to indemnification agreements with the Valuator: | For details see subsection (a) above. |
| The valuation model used by the Valuator: | Expected Discounted Cash Flow method while adapting the discounting rates to the risks embodied in the cash flow projections. |
| The assumptions according to which the Valuator performed the valuation, in accordance with the valuation model: | Following is the main assumption underlying the valuation:<br>The debt component discounting rate: 7.5%. |

**Regulation 9D:** **Status of liabilities report according to payment dates**

Concurrently with the release of this periodic report, the Partnership is releasing an immediate report regarding the status of the Partnership's liabilities, according to payment dates, which constitutes an integral part of the periodic report.

**Regulation 10A:** **Summary of the Partnership's statements of comprehensive income for each one of the quarters in 2018 and for the entire Y2018**

See Section 2B of Part One of Chapter B of this Report (the Board of Directors' Report).

**Regulation 10C:** **Use of the proceeds from securities in reference to the proceeds' goals according to the prospectus**

According to a shelf prospectus (the "**Prospectus**") of May 25, 2016, which was extended until May 25, 2019 (see immediate report of May 23, 2018 (Ref. no. : 2018-01-050581)), and a shelf offering report of December 26, 2016, the Partnership issued bonds in the scope of approx. ILS 1,528,533 thousand[5]. The designation of the issue proceeds is investments and financing of the activity in the Partnership's oil assets, as specified in Section 5 of the Partnership Agreement and in Section 7 of Chapter A of this Report, and for financing of the Partnership's other current needs according to the Partnership Agreement, according to its discretion, and *inter alia* for-profit distributions. Until this report's release date, the Partnership has used the proceeds from the securities that were offered under the Prospectus, *inter alia*, for purposes of profit distributions and investments in the Partnership's petroleum assets.

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[5] It is noted that the said amount includes both bonds in the amount of ILS 767,847 thousand which were issued by the Partnership prior to the Merger of the Partnerships, and bonds in the amount of ILS 760,686 thousand which were issued by the Avner Oil Exploration – Limited Partnership ("**Avner Partnership**").

## Regulation 11: List of the Partnership's investments in subsidiaries and associated companies thereof[6]

| Name of the company | Type of security | No. of shares | Total par value | Share value in the Partnership's separate financial statement as of December 31, 2018 | Price of the Shares listed on the TASE as of December 31, 2018 In Agorot | % of the holding in the capital, in voting and in the authority to appoint directors | Balance of loans to subsidiaries and to associated companies as of December 31, 2018 (Dollars in thousands) | Main terms of the loans | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | Final maturity date | Linkage terms | Additional details |
| Tamar Petroleum Ltd.[7] | Ordinary shares | 20,000,000 | ILS 2,000,000 | 124,250 | 1,524 | In capital 22.6; in voting rights 13.42 | | - | - | - |
| Yam Tethys Ltd. | Ordinary shares | 48,500 | ILS 48,500 | - | - | 48.5 | - | - | - | - |
| Delek Drilling (Leviathan Financing) Ltd.[8] | Ordinary shares | 100 | ILS 100 | - | - | 100 | - | | | |
| Delek & Avner (Tamar Bond) Ltd.[9] | Ordinary shares | 200 | ILS 200 | - | - | 100 | 100,000 | December 2025 | Dollar | [10] |

[6] For further details regarding the Partnership's subsidiaries and associates, see Section 1.1.7 of Chapter A of this Report.

[7] Tamar Petroleum Ltd. ("**Tamar Petroleum**") is a public company holding 16.75% (out of 100%) in the Tamar and Dalit leases. For further details, see Section 1.1.7(g) of Chapter A of this Report. It is noted that until March 14, 2018, the Partnership held 40% of the capital interests in Tamar Petroleum.

[8] A Special Purpose Company (SPC) incorporated for the purpose of capital-raising. For a description of the Leviathan financing agreements signed in February 2017 by said company, see Section 7.20.1(a) of Chapter A of this Report.

[9] An SPC incorporated for the purpose of capital-raising. For a description of the bonds that were issued by said company, see Section 7.20.1(d) of Chapter A of this Report. The bond issue proceeds were extended to the Partnership as a loan whose balance (principal and interest), as of December 31, 2018, is approx. $960 million, bearing interest at the rate of the interest on the bonds that were issued thereby. For further details see Note 10B to the financial statements.

[10] The loan was extended in the framework of the bonds' issuance. The loan funds were deposited with a bank and serve as a safety cushion for the repayment of the principal of the bonds issued by the subsidiary, and bear interest at the interest rate received by the subsidiary in respect of such deposits. For additional details, see Note 10B to the Partnership's financial statements and Part Five of the Board of Directors' Report.

| Name of the company | Type of security | No. of shares | Total par value | Share value in the Partnership's separate financial statement as of December 31, 2018 | Price of the Shares listed on the TASE as of December 31, 2018 In Agorot | % of the holding in the capital, in voting and in the authority to appoint directors | Balance of loans to subsidiaries and to associated companies as of December 31, 2018 (Dollars in thousands) | Main terms of the loans | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Tamar 10 Inch Pipeline Ltd.[11] | Ordinary shares | 22,000 | ILS 2,200 | - | - | 22 | - | - | - | - |
| Leviathan Transportation System Ltd.[12] | Ordinary shares | 45,340 | ILS 4,534 | - | - | 45.34 | - | - | - | - |
| NBL Jordan Marketing Limited[13] | Ordinary shares | 4,534 | $4,534 | - | - | 45.34 | - | - | - | - |
| EMED Pipeline B.V.[14] | Ordinary shares | 5,000 | $5,000 | - | - | 25% | - | - | - | - |
| EMED Pipeline Holding Limited[15] | Ordinary shares | 5,000 | €5,000 | - | - | 50% | - | - | - | - |

[11] An SPC incorporated for the purpose of obtaining a license for transportation of natural gas from the Tamar project. For further details see Section 7.23.5(n)2 of Chapter A of this Report.

[12] An SPC incorporated for the purpose of obtaining a license for transportation of natural gas from the Leviathan project. For further details see Section 7.23.5(n)3 of Chapter A of this Report.

[13] The company was incorporated for the purpose of its engagement in the gas supply agreement with the Jordan National Electric Power Company. For further details see Section 1.1.7(f) and 7.11.5(b)1 of Chapter A of this Report.

[14] An SPC incorporated in the Netherlands regarding an EMG transaction, whose shares are held as follows: EMED Pipeline Holding Limited (see footnote 15 below) – 25%; Noble Energy International Ltd. – 25%; and Sphinx EG BV, a fully owned (100%) subsidiary of East Gas Company S.A.E. – 50%. (For further details regarding the EMG transaction, see Section 7.25.7 of Chapter A of this Report).

[15] An SPC incorporated in Cyprus for the EMG transaction, fully owned (100%) by the Partnership (For further details regarding the EMG transaction see Section 7.25.7 of Chapter A of this Report).

**Regulation 12:** **Changes in investments in subsidiaries and associated companies during the Report period**

For details on the investment in Tamar Petroleum, see Note 6 to the financial statements.

**Regulation 13:** **Income of subsidiaries and associated companies of the Partnership and income therefrom**

| Company name | Profit (loss) before tax | Other comprehensive income (loss) | Profit (loss) after tax | Dividends received as of December 31, 2018 | Dividends received after December 31, 2018 | Dividend payment dates after December 31, 2018 | Management fees received as of December 31, 2018 | Management fees received after December 31, 2018 | Management fees payment dates after December 31, 2018 | Interest | Interest payment dates |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Dollars in thousands | Dollars in thousands | Dollars in thousands | Dollars in thousands | Dollars in thousands | | Dollars in thousands | Dollars in thousands | | Dollars in thousands | |
| Tamar Petroleum Ltd. | 136,097 | 98,818 | 98,818 | 16,124 | - | - | [16]- | - | - | - | - |
| Delek & Avner (Tamar Bond) Ltd. | (419) | (419) | (419) | - | - | - | - | - | - | - | - |
| Delek Drilling (Leviathan Financing) Ltd. | (9,085) | (9,085) | (9,085) | - | - | - | - | - | - | - | - |

[16] See footnote 23.

## **Regulation 21: Compensation for interested parties and senior officers**[17]

(a) Set forth below is a specification regarding the compensation granted in the Report year, , to the highest-paid senior officers of the General Partner and/or of the Partnership in connection with their term of office at the General Partner and/or the Partnership, as well as regarding the compensation granted to interested parties of the General Partner and/or the Partnership in connection with services that they provided as office holders at the General Partner and/or the Partnership in 2018 (in Dollars in thousands)[18]:

[17] For further details regarding the terms of employment of the officers and the interested parties mentioned in the table, see Regulation 21(b) below.

[18] Since the cost of provision of the management services by the General Partner to the Partnership (which includes, *inter alia*, the cost of Mr. Abu's employment) is higher than the management fees and reimbursement of expenses that are paid to the General Partner (in accordance with the Partnership Agreement as stated in Regulation 21(b)(7) below), the Partnership's financial statements include the total cost of the management services that exceeds such management fees in a capital reserve recorded due to a benefit granted to the Partnership by the General Partner and/or the General Partner's controlling shareholder, in the context of G&A expenses, in the amount of approx. 1.8 million Dollars. For further details see Regulation 21(b)(2) below.

| Senior officers of the Partnership and/or the General Partner | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Details of Compensation Recipient** | | | | **Compensation for Services** | | | | | | | **Other Compensation** | | | **Total** |
| **Name** | **Title** | **Scope of position** | **Rate of holding in participation units** | **Salary** | **Bonus** | **Share-based payment** | **Manage-ment fees** | **Consult-ing fees** | **Comm-ission** | **Other** | **Interest** | **Rent** | **Other** | |
| Yossi Abu[19] | CEO of Delek Drilling Management (1993) Ltd. (the "**General Partner**") | 80% | 0.05% | 422.8 | 611.9 | 277.7 | - | - | - | 32.3 | - | - | 55.2 | 1,399.9[20] |
| Yossi Gvura[21] | Deputy CEO | 100% | - | 345.1 | 278.2 | (13.1) | - | - | - | 26.6 | - | - | 54 | 690.8 |
| Yaniv Friedman | Deputy CEO | 100% | - | 344.9 | 166.9 | (15.8) | - | - | - | 23 | - | - | 45.2 | 564.2 |
| Zvi Karcz | VP Exploration | 100% | | 291.4 | 130.6 | 20 | - | - | - | 16.3 | - | - | 35.2 | 493.5 |
| Nadav Perry | VP Regulatory and Public Affairs | 100% | - | 239.4 | 50.1 | - | - | - | - | - | - | - | 21.4 | 310.9 |

[19]Since July 3, 2018, Mr. Yossi Abu serves as the CEO of Delek Energy Systems Ltd. ("**Delek Energy**") at a 20% position and as the CEO of the General Partner of the Partnership at an 80% position, as extensively detailed in Regulation 21(b)(2) below. Since Mr. Abu is employed by the General Partner, which also bears the cost of his employment, the position percentage stated in the table represents the portion out of the cost of the salary of the officer, as recognized in the Partnership's financial statements.

[20] This amount excludes compensation of approx. 218 thousand Dollars in respect of options that were granted to Mr. Abu by Ithaca Energy Inc.("**Ithaca**"), a company fully owned (100%) by Delek Group Ltd., for Mr. Abu's office as a Director in Ithaca. Note that the General Partner in the Partnership was entitled to compensation for Mr. Abu's office as a director and a member of the audit committee of Ithaca, in the amount of 65,000 Canadian Dollars per year. It if further noted that on March 1, 2018, Mr. Abu terminated his office as a director of Ithaca.

[21] Mr. Yossi Gvura serves as an executive VP at the Partnership (at a 90% position) and at the General Partner (at a 10% position), and respectively, the Partnership (90%) and the General Partner (10%) bear the cost of his employment.

| Interested parties of the General Partner and/or the Partnership | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Details of Compensation Recipient** | | | | **Compensation for Services** | | | | | | | **Other Compensation** | | | **Total** |
| **Name** | **Title** | **Scope of position** | **Rate of holding in participation units** | **Salary** | **Bonus** | **Share-based payment** | **Manage-ment fees** | **Consult-ing fees** | **Comm-ission** | **Other** | **Interest** | **Rent** | **Other** | |
| Delek Drilling Management (1993) Ltd. | General Partner | - | - | - | - | - | 960[22] | - | - | 216[23] | - | - | - | 1,176 |
| Fahn Kanne & Co., CPAs, and CPA Micha Blumenthal together with Gissin & Keidar | Supervisor | - | - | 267 | - | | - | - | - | | - | - | | 267[24] |
| Delek Drilling Trusts Ltd. | Trustee and limited partner | - | - | 1 | - | - | - | - | - | - | - | - | - | 1 |
| Outside directors[25] | - | - | - | 192.7 | - | - | - | - | - | - | - | - | - | 192.7 |

[22] For further details on management fees which are paid to the General Partner by the Partnership, see Regulation 21(b)(7) below.

[23] A total of approx. $169 thousand for the office of Mr. Abu as a director of Ithaca (up to the end of his office on March 1, 2018) and a total of approx. $47 thousand for Mr. Abu's service at Tamar Petroleum.

[24] Not including reimbursement supervisor's expenses for the legal fees regarding the legal proceeding in respect of the Partnership's profits taxation issue, at a total sum of approx. ILS 399 thousand plus VAT, as specified in Regulation 21(b)(8) below.

[25] Messrs. Amos Yaron and Jacob Zack have been serving as outside directors of the board of directors of the Partnership's General Partner since October 22, 2015 (an initial term of office which was extended on October 10, 2018 for an additional 3-year term of office, up to October 22, 2021). Mr. Eytan Rozenman served as an outside director of the board of directors of the Partnership's General Partner since the date of closing of the Merger of the Partnerships i.e., since May 17, 2017 until the date of termination of his office on October 22, 2018. It is noted that subsequent to the Report Year, on January 28, 2019, it was resolved to appoint Mr. Efraim Sadka as an outside director for the board of the Partnership's General Partner for a 3-year term of office commencing on April 1, 2019. Therefore, the figures in the table do not include compensation pertaining to Mr. Sadka's office.

(b) Set forth below is a specification regarding the terms of office and employment of officers in the Partnership and/or in the General Partner:

(1) Compensation policy

With respect to the compensation policy for officers in the Partnership and in the General Partner that was adopted by the Partnership for a 3-year period, effective from June 5, 2016, see immediate report of the Partnership on convening a meeting of the Partnership's participation unit holders dated April 15, 2016 (Ref. no. 2016-01-049417), as amended on May 30, 2016 (Ref. no. 2016-01-039408), and an immediate report of the Partnership on the results of the unit holders' meeting dated June 5, 2016 (Ref. no. 2016-01-044880), the information appearing in which is incorporated herein by reference (the "**Compensation Policy**"). On December 27, 2018, the unit holders meeting approved an amendment to Section 13 of the Compensation Policy on the issue of insurance and indemnification for the directors and officers. For details see an immediate report of the Partnership regarding the convening of the Partnership's participation unit holders meeting dated November 20, 2018 (Ref. no.: 2018-01-105829), as amended on November 21, 2018 and December 26, 2018 (Ref. nos.: 2018-01-106279 and 2018-01-119173, respectively), and a report of the meeting's results of December 27, 2018 (Ref. no.: 2018-01-119824), the information appearing in which is incorporated herein by way of reference.

(2) Yossi Abu

Since April 1, 2011, Mr. Yossi Abu ("**Mr. Abu**") has served as the General Partner's CEO. Mr. Abu's current terms of office and employment are anchored in an employment agreement from June 2016 which came into effect from April 1, 2016, for a five-year period (in this Section: the "**Employment Agreement**"). The Second Employment Agreement was approved on April 14, 2016, by the compensation committee and the board of the General Partner and on June 5, 2016, by the general meeting of the holders of the participation units of the Partnership, in accordance with the compensation policy provided in Subsection (1) above.

On May 17, 2018, the meeting of the Partnership's participation unit holders approved that Mr. Abu will continue to serve in his present position as the CEO of the General Partner in an 80%-position (instead of a full-time position), and will also simultaneously serve as the CEO of Delek Energy in a 20%-position, commencing on July 3, 2018 (the date of receipt of all of the necessary approvals at the Partnership and at Delek Energy). It was further resolved that Mr. Abu will apprise the audit committee and the board of directors of any matter that raises concern of a conflict of interests between his service as the CEO of the General Partner and his service as the CEO of Delek Energy, and will follow their instructions on such matter. The parties agreed that the General Partner would continue to bear Mr. Abu's full salary (full-time position), and an accounting shall be made between the General Partner and Delek Energy in respect of Delek Energy's bearing of its share (20%) in the total cost of Mr. Abu's remuneration, including all compensation components to which he is entitled under the Employment Agreement. In addition, for his office as a director of companies held by the Partnership or Delek Energy, Mr. Abu will be entitled to the standard compensation. Apart from the aforesaid changes, no other changes have occurred in Mr. Abu's terms of employment as the CEO of the General Partner under the Employment Agreement, as specified below.

As aforesaid, the cost of Mr. Abu's employment applies to the General Partner only, within the management services provided by the General Partner to the Partnership. See for this purpose also footnote 18 above. For further details, see immediate report regarding the results of the meeting of May 17, 2018 (Ref. no.: 2018-01-049456) and an immediate report regarding the convening of the meeting dated March 26, 2018 (Ref. no.: 2018-01-024246) (as amended on May 7, 2018 (Ref. no.: 2018-01-036228) and on May 15, 2018 (Ref. no.: 2018-01-048433)), the information appearing in which is incorporated herein by reference.

Under the Employment Agreement, Mr. Abu's monthly salary is approx. ILS 112.1 thousand gross (100%)[26] (the salary is updated every 3 months in accordance with the CPI). Mr. Abu is entitled to the related benefits that are accepted among managers in the economy and in this context: contributions to a pension fund and/or managers' insurance; contributions to a study fund; loss of work capacity insurance; a car; bearing of communication expenses (mobile phone, internet, newspapers, etc.); participation in professional training; annual leave; recuperation pay; sick pay pursuant to the law; health insurance; reimbursement of *per diem* expenses from the General Partner in the context and for the purpose of performing his duties at the General Partner, including expenses of overseas travel, all in accordance with the General Partner's policy. Furthermore, Mr. Abu is included in insurance arrangements and is entitled to indemnification and an

[26] As of December 31, 2018.

exemption for officers. Mr. Abu is entitled to an annual bonus, each calendar year, in the period of the Employment Agreement and to a special one-time bonus, in accordance with the compensation policy. In the event of discontinuation of his employment, Mr. Abu will be entitled to an adjustment bonus and a retirement bonus, in accordance with the compensation policy. In addition the General Partner granted Mr. Abu approx. 2,959,860 phantom units (whose underlying asset is a participation unit which confers a right of participation in the rights of the limited partner in the Partnership (subject to adjustments as specified in the Employment Agreement) (the "**Phantom Units**"))[27]. The Phantom Units will vest in five installments, while the first and second installments vested on September 1, 2017, the third installment vested on September 1, 2018 and the fourth and fifth installments will vest on September 1, 2019 and September 1, 2020, respectively (the "**Total Package**"). Each one of the installments included in the Total Package is exercisable from the vesting date of such installment until the expiration of 90 days from the discontinuation of Mr. Abu's employment pursuant to the Employment Agreement (i.e. June 30, 2021). The exercise price of the phantom units that were issued by the General Partner (in this Section: "**Delek Options**") is ILS 11.33 for the first installment; the exercise price of the phantom units that were issued by the General Partner of Avner Partnership (in this Section: "**Avner Options**") is ILS 10.55 for the first installment (according to the adjustment mechanism set forth in the Employment Agreement), plus 5% for each installment from the first installment.

According to a valuation received by the General Partner, the economic value of the Phantom Units as of December 31, 2018, was approx. ILS 6,463.6 thousand, and was calculated using the Binomial model, based on the following assumptions: (1) price of participation unit as of December 31, 2018 – ILS 9.82; (2) the exercise price of each option (adjusted to profit distribution and tax advances) was calculated according to ILS 7.81 (Delek Options)/ ILS 8.18 (Avner Options) for the first installment, ILS .837 (Delek Options)/ ILS 8.77 (Avner Options) for the second installment, ILS 8.97 (Delek Options)/ ILS 9.41 (Avner Options) for the third installment, ILS 9.59 (Delek Options)/

[27] It is noted that simultaneously with the granting of 1,506,025 phantom units whose underlying asset is a participation unit which confers a right of participation in the rights of the limited partner in the Partnership, Mr. Abu was granted 7,734,410 phantom units whose underlying asset is a participation unit which confers a right of participation in the rights of the limited partner in the Avner Partnership (in this footnote: the "**Phantom Units in Avner**"). Upon the closing of the Merger of the Partnerships, the Phantom Units in Avner were exchanged for additional phantom units in the Partnership, in accordance with the adjustment mechanism that is prescribed in the Employment Agreement, such that as of the date of this report, Mr. Abu holds 2,959,860 phantom units in the Partnership.

ILS 10.03 (Avner Options) for the fourth installment and ILS 10.25 (Delek Options)/ ILS 10.72 (Avner Options) for the fifth installment; (3) standard deviation at the rate of 30.09%; (4) risk-free interest rate of approx. 0.9%; (5) contractual life of approx. 2.5 years; (6) rate of abandonment after the vesting period that was taken into account - 0%; (7) limitation of the maximum benefit to derive for Mr. Abu from the exercise of each phantom unit shall not exceed 100% of the exercise price that was determined for the phantom unit that is included in the installment exercised on the granting date.

Furthermore, on January 5, 2016, Ithaca granted Mr. Abu 200,000 options, at a value of 0.55 Canadian Dollar per option unit which were exercised during 2018 in consideration for approx. $218 thousand.

In 2018 Mr. Abu received an annual bonus in the amount of ILS 1,950 thousand for 2017 as well as a special bonus in the amount of ILS 250 thousand for the approval of a development plan and the adoption of an investment plan for the development of the Leviathan Reservoir, with the remainder of the special bonus, up to the level of 6 gross monthly salaries (the Compensation Policy cap) will be paid upon the progress of the development of the Leviathan Project according to the planned timetables, and subject to the necessary approvals.

The annual bonus was granted to Mr. Abu based on the following components:

(a) A component depending on a business target (20%) – for the sale of 9.25% of the Partnership's holdings in the Tamar and Dalit to Tamar Petroleum – a total of approx. ILS 390 thousand;

(b) A component dependent on the following quantitative tests (60%): (1) change in the annual adjusted profit[28] (25%): the bonus for the change in the adjusted net profit[29] is paid linearly due to change of 90%-120%, the threshold condition for compliance with this measure being the adjusted net profit for the year in respect of which the bonus is granted not falling below $50 million. In 2017, the change in the adjusted net profit exceeded the determined

[28] The rate received from division of the adjusted net profit (as defined below) in the year for which the bonus is paid, by the average adjusted net profit of the Partnership in the three years preceding the year for which the bonus is paid ("**Change of the Adjusted Net Profit**").

[29] In this regard, "**Adjusted Net Profit**" shall mean the net profit attributed to holders of the participation units in the Partnership in the year for which the bonus is granted, without considering expenses for exploration wells as presented in the Partnership's statement of comprehensive income for that year.

range, and therefore Mr. Abu was entitled, due to that measure, to an annual bonus of approx. ILS 488 thousand; (2) capital raising or debt raising by the Partnership (whether directly or indirectly), with its share of the said raising not falling below 200 million Dollars, or the signing by the Partnership, together with its partners (if any), of binding contracts for the sale of natural gas in a scope exceeding 25 BCM or the signing of export agreements, all in the course of the year for which the bonus is paid (20%). In 2017, Mr. Abu met the measure specified in Subsection (2) above, and therefore Mr. Abu was entitled, due to that measure, to an annual bonus of approx. ILS 390 thousand; (3) the performance of actual investments by the Partnership in a petroleum asset in a total which will be no less than $50 million (not including investments in exploration wells) or the adoption of an investment resolution by the Partnership together with its partners (if any) in a petroleum asset in a sum total exceeding $300 million (based on a 100%) (not including a decision on investment in an exploration well) (15%). Mr. Abu met the criterion specified in subsection (3) above and therefore Mr. Abu was entitled due to that criterion to an annual bonus of approx. ILS 292 thousand.

(c) Board of directors' discretion component (20%): approx. ILS 390 thousand.

For further details on the Employment Agreement and its terms and conditions, see the Partnership's immediate report on convening the unit holders' meeting of April 15, 2016 (Ref. no. 2016-01-049417) as amended on May 30, 2016 (Ref. no. 2016-01-039408), and the Partnership's immediate report on the results of the unit holders' meeting dated June 5, 2016 (Ref. no. 2016-01-044880), the information appearing in which is incorporated herein by reference.

(3) Yossi Gvura

Commencing on July 19, 2012 and until July 31, 2017, Mr. Yossi Gvura ("**Mr. Gvura**") served as Deputy CEO of Financial Affairs at the Partnership. Since August 1, 2017 Mr. Gvura has been serving as Deputy CEO of the Partnership (90% of a full-time position), and of the General Partner (10% of a full-time position) and accordingly, the Partnership (90%) and the General Partner (10%) bear the cost of his employment (in this Section: the "**Employer**").

Mr. Gvura has been employed as aforesaid pursuant to an employment agreement effective since January 1, 2016 (in this section, the "**Employment Agreement**"). The Employment

Agreement was approved on July 13, 2016, by the compensation committee and the board of directors of the General Partner, in accordance with the compensation policy mentioned in Subsection (1) above.

Pursuant to the Employment Agreement, the terms and conditions of Mr. Gvura’s office and employment are as follows:

Mr. Gvura's monthly salary is approx. ILS 81.1 thousand gross[30] (the salary is updated every 3 months according to the CPI). In accordance with the Employment Agreement, Mr. Gvura is entitled to accepted social benefits, a study fund, full contributions to a pension plan, annual leave, sick days and recuperation pay. The Employer further provides Mr. Gvura with a car, as accepted for his position in the Partnership and in the General Partner, 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 Employer. Mr. Gvura is further entitled to additional related benefits, such as his inclusion in officer insurance, indemnification and exemption arrangements, maintenance of a landline and a mobile telephone and bearing of costs of reasonable uses thereof, subscription to a daily newspaper at Mr. Gvura’s choice, reimbursement of expenses for the performance of his duties, and reimbursement of *per diem* expenses in accordance with the Employer's procedures, as being from time to time, participation in professional training, medical assessments and private health insurance at the Employer’s expense. The Employer will be entitled to give Mr. Gvura an annual bonus, each year, in respect of the previous calendar year, provided that he will be employed by the Employer at least 3 months in that year and a special one-time bonus and a signing/retention bonus, and all in accordance with the compensation policy. In addition, the Employment Agreement includes provisions regarding maintaining confidentiality and a non-competition clause for a period of 3 months.

In addition to the aforesaid, Mr. Gvura was allotted 727,398 phantom units, whose underlying asset is a participation unit which confers a right of participation in the rights of the limited partner in the Partnership, the cost of which is borne by the Partnership and the General Partner (in this section, the “**Phantom Units**”).[31] The Phantom Units will vest in three

[30] As of December 31, 2018.

[31] Note that simultaneously with the granting of 361,272 phantom units whose underlying asset is a participation unit which confers a right of participation in the rights of the limited partner in the Partnership, Mr. Gvura was granted 1,947,798 phantom units, whose underlying asset is a participation unit which confers a right of participation in the rights of the limited partner in the Avner Partnership

equal installments, while the first installment vested upon the expiration of 2 years from July 13, 2016 and the second and third installments will vest after the expiration of 3 years from July 13, 2016 (in this section, the "**Total Package**"). Each one of the installments is exercisable commencing from the date of the vesting of such installment until the expiration of 90 days after the expiration of the vesting period of the third installment, subject to adjustments. The exercise price of the Phantom Units that were issued by the Partnership and the General Partner (in this Section: "**Delek Options**") was ILS 14.15; The exercise price of the Phantom Units that were issued by Avner Partnership and the General Partner therein (in this Section: "**Avner Options**") was ILS 12.66 for the first installment (according to the adjustment mechanism set forth in the Employment Agreement) plus 5% for each installment commencing from the second installment.

According to a valuation received by the Employer, the economic value of the said Phantom Units as of December 31, 2018, was approx. ILS 311.6 thousand, and was calculated using the Binomial model, based on the following assumptions: (1) price of participation unit as of December 31, 2018 – ILS9.82; (2) the exercise price of each option (adjusted to profit distribution) was calculated according to ILS 10.63 (Delek Options) / ILS 10.30 (Avner Options) for the first installment, ILS 11.34 (Delek Options) / ILS 10.99 (Avner Options) for the second installment, and ILS 12.08 (Delek Options) / ILS 11.73 (Avner Options) for the third installment; (3) standard deviation rate – 24.98%; (4) risk-free interest rate of approx. 0.43%; (5) contractual life of approx. 0.78 years; (6) rate of abandonment after the vesting period that was taken into account – 0%; (7) limitation of the maximum benefit to derive for Mr. Abu from the exercise of each phantom unit shall not exceed 100% of the exercise price that was determined for the phantom unit included in the installment that is exercised on the date of grant.

In 2018 Mr. Gvura received an annual bonus in the amount of ILS 1,000 thousand for 2017.

(4) Yaniv Friedman

Mr. Yaniv Friedman ("**Mr. Friedman**") serves as Deputy CEO at the Partnership in a full-time position pursuant to an employment agreement effective since November 1, 2015 (in this section, the "**Employment Agreement**"). The

(in this footnote: the "**Phantom Units in Avner**"). Upon the closing of the Merger of the Partnerships, the Phantom Units in Avner were exchanged for additional phantom units in the Partnership, in accordance with the adjustment mechanism that is prescribed in the Employment Agreement, such that as of the date of this report, Mr. Gvura holds 727,398 phantom units in the Partnership.

Employment Agreement was approved on July 13, 2016 by the compensation committee and the board of directors of the General Partner, in accordance with the compensation policy mentioned in Subsection (1) above.

Pursuant to the Employment Agreement the terms of office and employment of Mr. Friedman are as follows:

Mr. Friedman's monthly salary is approx. ILS 80.3 thousand gross[32] (the salary is updated every 3 months according to the CPI). In accordance with the Employment Agreement, Mr. Friedman is entitled to accepted social benefits, a study fund, full contributions to a pension plan, annual leave, sick days and recuperation pay. The Partnership further provides Mr. Friedman with a car, as accepted for his status at the Partnership, and bears any and all expenses entailed by use of the car. The value of the use of the car is grossed-up and paid by the Partnership. Mr. Friedman is further entitled to additional related benefits, such as his inclusion in officer insurance, indemnification and exemption arrangements, maintenance of a landline and a mobile telephone and bearing of costs of reasonable use thereof, subscription to a daily newspaper at Mr. Friedman's choice, reimbursement of expenses for the performance of his duties, reimbursement of *per diem* expenses in accordance with the Partnership's procedures, as being from time to time, participation in professional training, medical assessments and private health insurance at the Partnership's expense. The Partnership will be entitled to give Mr. Friedman an annual bonus, each year, in respect of the previous calendar year, provided that he will be employed by the Partnership at least 3 months in that year and a special one-time bonus and a signing/retention bonus, and all in accordance with the compensation policy. In addition, the Employment Agreement includes provisions regarding maintaining confidentiality and a non-competition clause for a period of 3 months. The Partnership bears the full cost of his employment (100%).

In addition to the aforesaid, Mr. Friedman was allotted 872,880 phantom units, whose underlying asset is a participation unit which confers a right of participation in the rights of the limited partner in the Partnership, the cost of which is borne by the Partnership (in this section, the "**Phantom Units**").[33] The

[32] As of December 31, 2018.

[33] Note that simultaneously with the granting of 433,527 phantom units whose underlying asset is a participation unit which confers a right of participation in the rights of the limited partner in the Partnership, Mr. Friedman was granted 2,337,360 phantom units, whose underlying asset is a participation unit which confers a right of participation in the rights of the limited partner in the Avner Partnership (in this Footnote: the "**Phantom Units in Avner**"). Upon the closing of the Merger of the

exercise price of the Phantom Units that were issued by the Partnership and the General Partner was ILS 14.15; The exercise price of the Phantom Units that were issued by the Avner Partnership and the General Partner therein was ILS 12.66 for the first installment (according to the adjustment mechanism set forth in the Employment Agreement) plus 5% for each installment from the second installment.

The Phantom Units will vest in three equal installments, while the first installment vested upon the expiration of 2 years from July 13, 2016 and the second and third installments will vest upon the expiration of 3 years from July 13, 2016 (in this section, the "**Total Package**"). Each one of the installments is exercisable commencing from the date of vesting of such installment until the expiration of 90 days after the expiration of the vesting period of the third installment, subject to adjustments. The exercise price of the Phantom Units was ILS 14.15 for the first installment plus 5% for each installment from the second installment. According to a valuation received by the Partnership, the economic value of the Phantom Units as of December 31, 2018, that were granted to Mr. Friedman under the Employment Agreement, was approx. ILS 373.9 thousand, and was calculated using the Binomial model, based on the assumptions that were specified as provided in Mr. Gvura's terms of employment.

In 2018 Mr. Friedman received an annual bonus in the amount of ILS 600 thousand in respect of 2017.

(5) Zvi Karcz

Mr. Zvi Karcz ("**Mr. Karcz**") serves as VP Exploration at the Partnership in a full-time position since August 12, 2014 (before that he was employed as the chief geologist).

Mr. Karcz's gross monthly salary is approx. ILS 70 thousand[34], which 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 accepted social benefits, a study fund, a pension plan, annual leave days, sick days and recuperation pay. The Partnership provides Mr. Karcz with a car, as accepted for his position, and

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Partnerships, the Phantom Units in Avner were exchanged for additional phantom units in the Partnership, in accordance with the adjustment mechanism that is prescribed in the Employment Agreement, such that as of the date of this report, Mr. Friedman holds 872,880 phantom units in the Partnership.

[34] As of December 31, 2018. In March, 2018, the General Partner's board of directors and compensation committee approved an update to Mr. Karcz' salary commencing from January 1, 2018, to a total of ILS 69,300 gross.

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. Karcz is further entitled to additional related benefits, such as his inclusion in officer insurance and indemnification arrangements, mobile telephone maintenance, payment of expenses in respect of reasonable use of his home phone, subscription to a daily newspaper, reimbursement of expenses for the performance of his duties, and reimbursement of *per diem* expenses during foreign travel on behalf of the Partnership. The parties may terminate the Employment Agreement at any time by giving a 3-month prior written notice. In addition, the Employment Agreement includes provisions regarding maintaining confidentiality and a non-competition clause for a period of 9 months. Mr. Karcz is entitled to an adjustment bonus at a sum equal to 50% of his gross salary for the entire non-competition period (i.e., a bonus in a total amount of up to 4.5 gross monthly salaries). The Partnership bears the full cost of his employment (100%).

In addition to the aforesaid, in March 2018, the compensation committee and board of directors of the General Partner approved the granting of approx. 174,064 phantom units to Mr. Karcz, whose underlying asset is a participation unit which confers a right of participation in the rights of the limited partner in the Partnership, the cost of which is borne by the Partnership (in this section, the "**Phantom Units**"). The Phantom Units will vest in three equal installments, while the first installment will vest after the expiration of 2 years from March 12, 2018 and the second and third installments will vest after the expiration of 3 years from March 12, 2018 (in this section, the "**Total Package**"). The first installment shall be exercisable during the period commencing from the aforesaid date of vesting and ending one year after the end of the vesting period of such installment, and the second and third installments shall be exercisable during the period commencing from the date of vesting of each installment and ending one year after the end of the vesting period of each installment, subject to adjustments. The exercise price of the Phantom Units is ILS 11.75 for the first installment plus 5% for each installment from the second installment, subject to adjustments. According to a valuation received by the Partnership, as of December 31, 2018 the economic value of the Phantom Units which were granted to Mr. Karcz, totaled approx. ILS 232.1 thousand, and was calculated using the Binomial model, based on the following assumptions: assumptions: (1) price of participation unit as of December 31, 2018 – ILS 9.82; (2) the exercise price of each option was calculated according to ILS 11.54 for the first installment, ILS 12.13 for the second installment and ILS 12.74 for the third installment; (3) standard deviation – 30.8% for the first installment, 31.4% for the second and third installments; (4) risk-free interest rate of approx. .085% for the first installment and 1.13% for the second and third installments; (5) contractual life of 2.2 years for the first installment and 3.2 years for the second and third installments; (6) rate of abandonment after the vesting period that was taken into account - 0%; (7) limitation of the maximum benefit to derive for Mr. Karcz from the exercise of each phantom unit shall not exceed 100% of the exercise price that was determined for the phantom unit that is included in the installment exercised on the date of grant.

In March 2018, the compensation committee and the board of the General Partner approved for Mr. Karcz a one-time retention bonus of ILS 207, 900. The retention bonus will be paid in three equal installments as follows: two installments were paid together with the compensation for the months of March 2018 and January 2019; a third installment will be paid together with the salary of the month of January 2020 provided that he will be employed by the Partnership on December 31, 2019.

Furthermore, in 2018, Mr. Karcz received an annual bonus from the Partnership in the sum of approx. ILS 400 thousand for 2017.

(6) Nadav Perry

Mr. Nadav Perry (“**Mr. Perry**”) has been serving as the VP Regulatory & Public Affairs on a full-time basis since June 14, 2015 (before then he served as the head of public affairs).

Mr. Perry's monthly salary is approx. ILS 56.7 thousand gross[35]. In accordance with the terms of his employment (in this section: the "**Employment Agreement**"), Mr. Perry is entitled to accepted social benefits, a study fund, a pension plan, annual leave days, sick days and recuperation pay. The Partnership provides Mr. Perry with a car, as accepted 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. Perry is further entitled to additional related benefits, such as his inclusion in officer insurance and indemnification arrangements, maintaining a mobile phone, and payment of reimbursement of *per diem* expenses during foreign travel on behalf of the Partnership. The parties may terminate the Employment Agreement at any time by giving prior written notice of 3 months. In addition, the Employment Agreement

[35] As of December 31, 2018. In May 2018 the Compensation committee and the Board approved the update of Mr. Perry’s monthly salary commencing from May 2018 salary, to a total of ILS 56 thousand.

includes provisions regarding maintaining confidentiality and a non-competition clause for a period of 3 months. The Partnership bears the full cost of his employment (100%).

In 2018 Mr. Perry received an annual bonus from the Partnership in the sum of approx. ILS 180 thousand for 2017.

(7) <u>The General Partner</u>

The General Partner is entitled, according to the Partnership Agreement, to 0.01% of the Partnership's income and bears 0.01% of the expenses and losses of the Partnership and expenses and losses of the Partnership which, due to the limitation of the limited partner's liability for liabilities of the Partnership, are not borne by the limited partner.

The General Partner is entitled, according to the Partnership Agreement, to regular management fees in an amount in ILS equal to U.S. $40,000 per month[36] and in addition, to a management fee at a rate of 7.5% of half of the Partnership's expenses for petroleum exploration activities, on a quarterly basis, and no less than a total amount of $120,000 per quarter.

The General Partner is also entitled to reimbursement of any and all direct expenses entailed by management of the Partnership and incurred by the General Partner. Unless the supervisor's approval is received for expenses of other types, the said expenses shall include only the following expenses:

Fees for accounting services, legal advice, geological advice, investment advice, reservoir engineering and geophysical advice, engineering advice, economic (financial) advice, insurance advice, strategic and media advice, investor relations advice, regulatory advice, marketing advice and reimbursement of expenses in connection with financing and marketing activity, and expenses in respect of preparation of financial statements for the joint transactions, expenses of preparing financial statements and reports pursuant to the Securities Law, 5728-1968 and expenses of preparing certificates for tax purposes, payments that are required to be made to the ISA, to

[36] It is noted that the management fees are paid for management of the Partnership, including in respect of the services of the General Partner's directors (who are not outside directors), the General Partner's CEO, comptroller services, secretarial services and rent for the Partnership's offices. The Partnership's offices are located in a building that is owned by Delek Group, the Partnership's control holder. Since the cost of provision of the management services by the General Partner to the Partnership is higher than the management fees and the reimbursements of expenses that are paid to the General Partner as aforesaid, the Partnership's financial statements include the total costs exceeding management fees, in a capital reserve, that amounted to approx. $1.8 million.

TASE, to the Registrar of Companies and to the Registrar of Partnerships.

The aforesaid notwithstanding, the Partnership may directly employ employees and/or officers who will provide the Partnership with services of the type for which the General Partner is entitled to reimbursement of expenses as aforesaid, in which case the Partnership shall bear the full cost of their salary, and the General Partner will not be entitled to reimbursement of expenses in respect of such services.

(8) The Supervisor

The supervisor is entitled to receive from the trustee, out of the trust assets, compensation of approx. ILS 80[37] thousand per month (plus V.A.T). The monthly compensation will be updated every three months in accordance with changes in the CPI in relation to the index rate for May 2017.

Notwithstanding the aforesaid, in the event of the publication of a prospectus (including a shelf prospectus), the supervisor will be entitled to additional compensation for his additional work that is entailed by the publication of the prospectus, in the amount equal in ILS to $40,000 (plus V.A.T, if applicable), irrespective of the actual working hours (in this section: the "**Additional Compensation”**. It is clarified that in the case of a shelf prospectus, the Additional Compensation also includes compensation in respect of all of the work that shall be required of the supervisor after publication of a shelf prospectus, in connection with a shelf prospectus in respect of which the supervisor received the Additional Compensation, insofar as required, including shelf reports published according to a shelf prospectus and/or any offering performed according to a shelf prospectus and/or any financing round carried out according to a shelf prospectus ("**Works After the Publication of the Shelf Prospectus**"). After the supervisor is paid the Additional Compensation, the supervisor will not be entitled to any additional payment for his work in connection with the publication of a prospectus as aforesaid, in respect of which the Additional Compensation was paid to the supervisor, as well as in connection with his work after the publication of the shelf prospectus as aforesaid.

The supervisor is further entitled to a payment equal in ILS to $40,000 (plus V.A.T), irrespective of actual working hours, for his work, insofar as required, in connection with the closing of

[37] As of December 31, 2018.

financing agreements made against a pledge of a petroleum asset of the Partnership.

In addition, the supervisor is entitled to reimbursement of additional expenses, subject to the approval of a general meeting of the Partnership's participation unit holders therefor, or that the expenses are in an amount and of a type approved by a general meeting as aforesaid. Note that on December 22, 2016, the meeting of the unit holders, without derogating from the provisions of the Partnership Agreement and the Trust Agreement, approved that the type of expenses for which the supervisor will be entitled to a reimbursement of expenses from the trust assets will include travel expenses to meetings of the organs of the Partnership, meetings with the General Partner's management and meetings with the representatives of the General Partner vis-à-vis various regulators, courier services, and parking expenses due to all of the aforesaid and that the expense reimbursement amount as aforesaid shall not exceed ILS 1,000 (plus VAT) per month, all in accordance with a detailed expense report to be delivered by the supervisor to the Partnership, all effective from October 22, 2015.

On March 20, 2018 the general meeting of the Partnership's participation unit holders approved the following resolutions[38]: (1) to approve reimbursement for the legal fee expenses of the supervisor, for the legal proceeding with respect to the matter of the taxation of the Partnership's profits; (2) to approve the continued handling by the supervisor of an appeal that was filed by the General Partner, including an approval to pay the legal fees of the supervisor within the appeal from the results of the legal proceeding in an amount which shall not exceed ILS 150 thousand, plus V.A.T for a period of a year; (3) to approve reimbursement of expenses to the supervisor for the appointment of an accountant as an expert on behalf of the supervisor for the provision of an opinion pertaining to the date of return of investment in the Tamar Project, in an amount which will not exceed ILS 150 thousand, plus V.A.T. For further details regarding the aforesaid special meeting, see the Partnership's immediate reports of March 11, 2018 (Ref. no. 2018-01-019071) and March 20, 2018 (Ref. no.: 2018-01-022110) the information included in which is incorporated herein by reference.

Furthermore, on September 6, 2018, the Partnership's participation unit holders' general meeting approved a budget for the Supervisor's overseeing the process of examining the

[38] For details regarding the supervisor's motion to the court to order the General Partner, *inter alia*, to bear the costs of the supervisor, see Section 4.3.2 of Chapter A of this Report.

date of return on investment in the Tamar Project for a period of up to 12 months from the date of such meeting (in this Section: the “**Approval Period**”) for the performance of the following payments: a. The Supervisor’s overseeing budget for the Approval Period; b. Economic expert budget for the Approval Period; c. Legal advice which will be provided by the firm of Matry, Meiri & Co. For further details regarding the aforesaid special meeting, see immediate reports of the Partnership dated September 2, 2018 (Ref. no.: 2018-01-081628) and September 12, 2018 (Ref. no.: 2018-01-083635) the information appearing in which is incorporated herein by reference.

(9) The Trustee

The trustee is entitled to receive out of the trust assets a fee equal to U.S. $1,000 (plus V.A.T) for every year in which it serves as a trustee according to the Trust Agreement (or a proportionate share of such amount in respect of part of a year). This amount will be paid to the trustee on the last day of the year in respect of which it is being paid. In addition, the trustee is entitled to receive expenses explicitly permitted in the Trust Agreement or which were approved in advance and in writing by the supervisor.

(10) Outside directors

On October 22, 2015, the general meeting of the holders of the Partnership’s participation units decided that Messrs. Amos Yaron and Jacob Zack, who were appointed on this date as outside directors by such meeting, would be entitled to annual compensation and participation compensation, in accordance with the fixed amounts appearing in the Second Schedule and Third Schedule to the Companies Regulations (Rules Regarding Compensation and Expenses for an Outside Director), 5760-2000 (the “**Compensation Regulations**”), as being from time to time, and in accordance with the Partnership’s rank, as being from time to time. Commencing from the beginning of his second term of office (i.e., October 22, 2018), Mr. Zack, who is classified as an expert outside director, as such term is defined in the Compensation Regulations, will be entitled to participation compensation and annual compensation at the “maximum amount” set forth in the Fourth Schedule to the Compensation Regulations, as being from time to time, and according to the rank of the Partnership, as being from time to time.

For further details regarding the appointment of the aforesaid outside directors for a second term of office, see immediate (amending) report for the convening of a meeting dated

September 20, 2018 and an immediate report on the results of the meeting of the Partnership’s participation unit holders on October 10, 2018 (Ref. no.: 2018-01-085579 and 2018-01-091300, respectively) the information appearing in which is incorporated herein by reference.

Pursuant to the decision adopted by the general meeting of the Partnership’s participation unit holders on January 28, 2019 on the appointment of Mr. Efraim Sadka as an outside director (commencing on April 1, 2019), it was resolved that Mr. Sadka, who is classified as an expert outside director, as such term is defined in the Compensation Regulations, will be entitled, commencing from the beginning of his office as aforesaid, to participation compensation and annual compensation at the “maximum amount” set forth in the Fourth Schedule to the Compensation Regulations, as being from time to time, and according to the rank of the Partnership, as being from time to time.

**Regulation 21A: The Partnership's controlling interest holder**

The controlling interest holder (indirectly) of the Partnership is Mr. Yitzhak Sharon (Tshuva).

**Regulation 22: Transactions of the Partnership with the General Partner or transactions in which the General Partner's controlling shareholder has a personal interest**

Set forth below are details, according to the best of the Partnership's knowledge, regarding any transaction with the General Partner or the General Partner's controlling shareholder, or in the approval of which the General Partner's controlling shareholder has a personal interest, in which the Partnership or a corporation controlled thereby or an affiliate of the Partnership engaged during or after the Report Year until the Report release date or which is still in effect on the date of the Report, with the exception of negligible transactions, as defined in Section 6 of Part Three of Chapter B of this Report (the Board of Directors' Report):

(a) According to the Partnership Agreement, as updated from time to time, the General Partner is entitled to management fees as specified in Regulation 21(7)(b) above.

(b) According to an agreement from 1993, Delek Royalties (2012) Ltd. (“**Delek Royalties**”)[39] and Delek Group Ltd.

[39] On June 17, 2018 Delek Energy and Delek Royalties notified the Partnership that Delek Energy’s right to receive royalties from the Partnership’s share (22%) in oil and/or gas and/or other valuable materials which will be produced and used from the Tamar and Dalit leases was transferred to Delek

("**Delek Group**") (will be jointly referred to below as: the "**Royalty Owner**")[40] are entitled to receive an overriding royalty at the Tamar Project, as specified in Section 7.27.12(b)1 of Chapter A of this Report. In 2018, the Partnership recorded expenses for royalties to the Royalty Owners for Tamar and Yam Tethys Projects in the total sum of approx. $ 26.3 million.

(c) Upon the closing of the Merger of the Partnerships, Cohen Development and Industrial Buildings Ltd.[41] ("**Cohen Development**") is entitled to royalties from the Partnership, as specified in Section 7.27.12(b)2 of Chapter A of this Report. In 2018, the Partnership recorded expenses for royalties at the Tamar and Yam Tethys Projects to Cohen Development in a total sum of approx. $5.9 million.

(d) With respect to engagements in agreements for the supply of natural gas with affiliates:

1. On July 1, 2005, the Partnership engaged, together with its partners in the Yam Tethys project, in an agreement for the supply of gas with I.P.P Delek Ashkelon Ltd. ("**Delek Ashkelon**"), a company controlled by Delek Group, (the "**Original Agreement**"). On November 25, 2012, in view of the continued decline in the ability to supply natural gas from the Mari B reservoir, an amendment to the agreement was executed wherein it was agreed to increase the maximal daily quantity that Delek Ashkelon would be entitled to purchase. For the additional daily quantity, Delek Ashkelon shall pay a price that will be calculated according to a formula based on the electricity production tariff and includes a "floor price". The agreement is in effect until June 30, 2022 and the remaining contractual quantity for supply is approx. 0.5 BCM. In 2018, the Partnership's share in revenues from the sale of natural gas to Delek Ashkelon was approx. $6.6 million.

2. On December 5, 2013, the Partnership engaged, together with its other partners in the Tamar Project (in this section: the "**Sellers**") in an agreement for the

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Royalties and that the registration in the Petroleum Register was corrected accordingly. In view of the aforesaid, since June 1, 2018, the Partnership pays all of the said royalty proceeds directly to Delek Royalties.

[40] The right to a royalty was granted in the said agreement to Delek Investments and Properties Ltd. ("**Delek Investments**"). On April 16, 2012, effective from December 31, 2011, Delek Investments was merged into Delek Group according to the provisions of Part One of Part Eight of the Companies Law, and was thus liquidated.

[41] Cohen Development is a public company controlled by Delek Group.

supply of natural gas (in this Section: the "**Supply Agreement**" or the "**Agreement**") with Delek, The Israel Fuel Corporation Ltd. (in this section: "**Delek Israel**" or the "**Purchaser**"), a company controlled by Delek Group, with a total scope of up to approx. 0.46 BCM (Billion Cubic Meters) (in this section: the "**Total Contractual Quantity**"), according to the conditions specified in the Supply Agreement. The term of the Supply Agreement began during Q1/2015 and is expected to end upon the expiration of approx. 7 years or on the date which Delek Israel will have consumed the Total Contractual Quantity, whichever is earlier. The Purchaser undertook to Take or Pay for a minimal annual quantity of gas at a scope and according to the mechanism set in the Supply Agreement. The gas price set in the Agreement will be linked to the Brent prices including a "floor price" and a "cap price", all according to the formula set in the Agreement. For details regarding the supply of gas according to this agreement in the interim period, see Section 7.13.4(a)(3)(d) of Chapter A of this Report. In 2018, the Partnership's share in the income from the sale of natural gas to Delek Israel was approx. $132 thousand.

3. On March 8, 2014 the Partnership engaged together with its other partners in the Tamar project (in this Section: the "**Sellers**") in an agreement for the supply of natural gas (which was amended on May 8, 2015) (in this Section: the "**Supply Agreement**" or the "**Agreement**") with IPP Delek Sorek Ltd. ("**Delek Sorek**"), a company controlled (indirectly) by Delek Group. Within the Agreement, the Sellers undertook to supply Delek Sorek with natural gas at a total scope of up to approx. 3.3 BCM (Billion Cubic Meters) (in this Section: the "**Total Contractual Quantity**") according to the conditions specified in the Supply Agreement. The term of the Supply Agreement began during Q3/2016 and is expected to end upon the expiration of approx. 15 years or on the date which Delek Sorek shall have consumed the Total Contractual Quantity, whichever is earlier. The parties have a right to extend the term of the Supply Agreement until such time as the Total Contractual Quantity is consumed and for a term of two more years at the most. Delek Sorek undertook to Take or Pay for a minimal annual quantity of gas at a scope and according to the mechanism set in the Supply Agreement. Furthermore, it was determined that the gas price in the Agreement will be linked to the weighted production rate as shall be determined from time to time by the Public Utility Authority – Electricity and includes

a "bottom" price, all according to the formula set in the Supply Agreement. For details regarding the supply of gas according to this agreement in the interim period, see Section 7.13.4(a)(3)(d) of Chapter A of this Report. In 2018, the Partnership's share in the revenues from the sale of natural gas to Delek Sorek was approx. $5.9 million.

(e) With respect to the provision of a performance guarantee, unlimited in amount, by Delek Group in favor of the Republic of Cyprus to secure fulfillment of all of the Partnership's undertakings by virtue of a franchise agreement dated October 24, 2008 (a Production Sharing Contract) which confers petroleum and/or gas exploration, appraisal, development and production rights within the area of the exclusive economic zone of the Republic of Cyprus in the area known as Block 12, see Section 7.8.3(m) of Chapter A of this Report. The guarantee fee that was paid by the Partnership to Delek Group in 2018 amounted to approx. $402 thousand[42].

(f) With respect to the engagement of the Yam Tethys Partners with the Tamar Partners in an agreement of July 23, 2012, whereby the Yam Tethys Partners will grant the Tamar Partners rights to use the existing facilities in the Yam Tethys Project as well as the right to upgrade and/or build facilities for the purpose of transporting and storing natural gas from the Tamar Project, see Section 7.27.13 of Chapter A of this Report[43].

(g) With respect to the outline for sale of natural gas from the Yam Tethys project to the Tamar project customers, see Section 7.3.4(e) of Chapter A of this Report. In 2018 the Partnership's share in the cost of the purchase of gas from the share of Delek Group in the Yam Tethys project amounted to a total of approx. $105 thousand.

[42] The said engagement was approved on April 14, 2013 by the board of the General Partner and on April 18, 2013 by the general meeting of the participation unit holders. On July 8, 2018 the audit committee approved that the fixing of the payment for the guarantee for a guarantee period of 25 years which was set on the date of the approval of the guarantee transaction for the first time, is a reasonable period.

[43] The said engagement was approved on July 23, 2012 by the board of directors of the General Partner.

(h) On July 24, 2018, the special general meeting of the Partnership's participation unit holders, approved, further to the approval by the audit committee dated March 7, 2018 and May 10, 2018 and the approval of the board of the General Partner dated March 12, 2018, May 14, 2018 and June 14, 2018, the engagement of the Partnership with Delek Group in an agreement which regulates the manner of distribution of the costs of employment of professional employees of the partnership which would be employed by Delek Group and its subsidiaries, according and subject to the terms of the arrangement, for a 3-year period commencing on the date of approval by the general meeting as aforesaid. For details see Regulation 29 (c) (4) below. For the cost of the transaction as aforesaid, the Partnership charged Delek Group in 2018 with a sum total of approx. $16 thousand.

(i) In respect of the approval of framework conditions for a period of three years for future engagements of the General Partner and/or the Partnership, from time to time and without requiring further approval by the general meeting of the Partnership's participation unit holders therefor, in a policy for the insurance of liability of directors and officers in the Partnership and the General Partner, within a group insurance policy taken out by Delek Group for itself and for subsidiaries and affiliates, in whole or in part, including the Partnership and the General Partner (the "**Group Policy**"), with Phoenix Insurance Company Ltd. (the "**Phoenix**") or with another insurer, in Israel or overseas, including the insurance of the liability of controlling entities or their relatives in their capacity, as in effect from time to time, as officers of the Partnership and/or the General Partner, for a premium and under the conditions specified in the meeting convening report dated November 20, 2018 (Ref. no.: 2018-01-105829, as amended on November 21, 2018 and on December 26, 2018 (Ref. no.: 2018-01-106279, 2018-01-119173), the information appearing in which is incorporated herein by reference (the "**Framework Conditions**"). On December 16, 2018, the compensation committee and the board of directors of the General Partner approved the engagement of the Partnership in a policy for insurance of the liability of directors and officers under the Group Policy and according to the Framework Conditions, for a period commencing on January 1, 2019 until June 30, 2020 at a premium of approx. $910 thousand for the insurance period (approx. $607 thousand per year) (the Partnership's share is approx. $380 for the insurance period and approx. $253 thousand per year) this is in addition to an (independent) policy for insurance of the liability of directors and officers in the Partnership and in the General

Partner (the "**Independent Policy**") with Phoenix for a period commencing on January 1, 2019 and ending on June 30, 2020 at a premium of approx. $207 thousand for the period (approx. $138 thousand per year) under conditions complying with the amended Compensation Policy dated December 27, 2018 on this matter (as specified in Regulation 21(b)(1) above).

(j) For details regarding transactions which are subject, *inter alia*, to the approval of the Partnership's participation unit holders regarding the Partnership's engagement with Ithaca regarding its appointment as an operator at the Alon D/367 license, and regarding a possibility of splitting the Partnership's assets, see immediate reports of March 18, 2019 (Ref. no.: 2019-01-022125, 2019-01-022080 and 2019-01-022086, respectively), the information appearing in which is incorporated herein by reference.

<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 Chapter B of this Report (the Board of Directors' Report), such as: receipt of "*dalkan* [automatic billing for fueling]" services from Delek Israel, receipt of securities portfolio management services from Excellence Nessuah Asset Management Ltd., receipt of V.A.T reporting services from Delek Group, receipt of services from NYX Hotel Herzliya of the Fattal Hotel Chain, distribution of the project manager's position percentage between Delek Group and the Partnership and engagement in an agreement for reimbursement of the employment expenses of the project manager with the Delek Group and engagement in the Independent Policy, as specified in Regulation 22(i) above.

**Regulation 24:** **Holdings of interested parties and senior officers**

For details regarding holdings of interested parties and senior officers of the Partnership and/or of the General Partner as of December 31, 2018, see the Partnership's immediate report of January 7, 2019 (Ref. no. 2019-01-002191), the information appearing in which is incorporated herein by reference.

**Regulation 24A:** **Authorized capital, issued capital and convertible securities**

| | **Authorized Capital Par Value** | **Issued and Paid-Up Capital Par Value** |
|---|---|---|
| Participation units of par value ILS 1 each | 1,173,814,690.76 | 1,173,814,690.76 |

As of the Report release date, the Partnership has no convertible securities.

**Regulation 24B:** **Register of the Partnership's participation unit holders**

| **Name of Holder** | **Quantity Held** |
|---|---|
| Delek Group | 1 |
| The Transfer Agent of Israel Discount Bank Ltd. | 1,173,115,208.02 |
| Chaya Leventhal | 1.19 |
| Nathan Turkia | 1 |
| Yaakov Maroz | 1 |
| Moshe Kramer | 1.19 |
| Avner Andera | 1 |
| Ariel Yanko | 289.47 |
| Ran Levy | 184.8 |
| Tova Berger | 12 |
| Azriel Zolti | 1.19 |
| Varda and Baruch Kotlarsky | 143,562.10 |
| Daniel Goldstein | 18.80 |
| Tuvia Even | 1,317.67 |
| Daniel Dayan | 234,962.37 |
| Dorit Dayan | 234,962.37 |
| Yosef Vank | 52,505.44 |
| Amikam Reshef | 590.60 |
| Tamar and Avraham Adani | 62.59 |
| Yosef Nadaf | 973.87 |
| Sarah Morah | 30,032.89 |
| Yehuda Luria | 0.19 |
| **Total** | **1,173,814,690.76** |

**Regulation 25A:** **Registered address**

Address: 19 Abba Even Blvd., Herzliya Pituach, 4612001.
Telephone: 09-9712424
Facsimile: 09-9712425
E-mail address: saris@delekng.co.il

## Regulation 26: The General Partner's directors[44]

| | Details | Assi Bartfeld | Leora Pratt Levin | Gabriel Last |
|---|---|---|---|---|
| 1 | I.D. number: | 065474108 | 057906919 | 004787933 |
| 2 | Position at the General Partner: | Chairman of the Board | Director | Director |
| 3 | Date of birth: | February 24, 1952 | October 12, 1962 | September 9, 1946 |
| 4 | Address for service of process: | 19 Abba Even Blvd., Herzliya Pituach, 4612001 | 19 Abba Even Blvd., Herzliya Pituach, 4612001 | 19 Abba Even Blvd., Herzliya Pituach, 4612001 |
| 5 | Nationality: | Israeli | Israeli | Israeli |
| 6 | Membership of board committees: | Investment committee | No | No |
| 7 | (a) Is he an outside director: | No | No | No |
| | (b) If so, does he have accounting and financial expertise or professional qualifications: | - | - | - |
| | (c) If so, is he an expert outside director[45] : | - | - | - |
| | (d) If not, is he eligible to be appointed as an independent director: | No | No | No |
| 8 | Is he an employee of the General Partner, a subsidiary, an affiliate or of an interested party: | CEO of Delek Group and director of various subsidiaries in the Delek Group. | Senior VP, Chief Legal Counsel and Secretary of Delek Group and director in various subsidiaries of Delek Group. | Chairman of the Board of Delek Group and a director in subsidiaries of Delek Group. |
| 9 | The date on which his term of office as a director began: | May 15, 2003, began serving as Chairman of the Board on February 1, 2016 | August 26, 2015 | May 17, 2001 |
| 10 | His education: | B.A. in Economics from Tel Aviv University. | LLB from the University of Reading, England, B.A. in Political Science from Tel Aviv University. | LL.B from Tel Aviv University, M.A. in Social Sciences and Mathematics from the University of Haifa and A.M.P (a management program for senior officers) from Harvard University, U.S.A. |
| 11 | His occupation in the last five years: | CEO of Delek Group, and a director of subsidiaries of Delek Group. | Senior VP, Chief Legal Counsel and Secretary of Delek Group and director in various subsidiaries of Delek Group. | Chairman of the Board of Delek Group and a director of subsidiaries of Delek Group. |

[44] The specification of this Regulation, presents the directors holding office on the board of the General Partner as of the Report release date. It is noted that on October 22, 2018, Mr. Eytan Rozenman completed his service as an outside director. Furthermore, on December 31, 2018 Ms. Carmit Elroy and Mr. Malcolm Hoenlein completed their service as directors. On January 28, 2019 (subsequent to the report year) the appointment of Mr. Efraim Sadka as an outside director was approved for a three (3) year term of office, which will commence on April 1, 2019.

[45] Within the meaning of the term in Section 1 of the Companies Regulations (Rules regarding Compensation and Expenses of Outside Directors), 5760-2000.

| | **Details** | **Assi Bartfeld** | **Leora Pratt Levin** | **Gabriel Last** |
|---|---|---|---|---|
| 12 | Other corporations in which he serves as a director: | Chairman of the board in the following companies: Cohen Development, Phoenix Holdings Ltd. and Delek Royalties (2012) Ltd., and a director of the following companies: Delek Israel, Delek Automotive Systems Ltd., Delek Petroleum Ltd., Avner Oil & Gas Ltd., Phoenix Insurance Company Ltd., Delek Ashkelon., Phoenix Holdings Ltd., Delek Sea Maagan 2011 Ltd., Delek Israel Holdings Group Ltd., Ithaca, Delek Group Royalty Ltd., IDE Holdings Ltd. and private subsidiaries of Delek Group and of the Partnership (SPC's). | Delek Energy, Cohen Development, Phoenix Holdings Ltd., Phoenix Insurance Company Ltd. | Chairman of the Board of Delek Group, Delek Energy and the Delek Foundation for Education, Culture and Science (CIC), and serves as a director of the following companies: Delek Ashkelon, Delek Energy, Delek Petroleum Ltd., Delek Israel, Delek Infrastructures Ltd., Delek Royalties Group Ltd., Avner Oil & Gas Ltd., Delek Power Plant Management Ltd. and private subsidiaries of the Partnership (SPC's). |
| 13 | Is he a relative of another interested party of the General Partner: | No | No | No |
| 14 | Does the General Partner deem him as having accounting and financial expertise for purposes of compliance with the minimum number determined by the board of directors pursuant to Section 92(a)(12) of the Companies Law, 5759-1999: | Yes | No | No |

| | Details | Amos Yaron | Jacob Zack | Ronnie Bar-On | Barak Mashraki |
|---|---|---|---|---|---|
| 1 | I.D. number: | 005301262 | 004868048 | 008516262 | 029714086 |
| 2 | Position at the General Partner: | Outside Director | Outside Director | Independent director | Director |
| 3 | Date of birth: | February 5, 1940 | April 11, 1946 | June 2, 1948 | January 28, 1973 |
| 4 | Address for service of process: | 22 Shazar St., Ramat Gan | 5 Hashoftim St., Herzliya 46447 | 8 Unitzman St., Tel Aviv Jaffa | 19 Abba Even Blvd., Herzliya Pituach, 4612001 |
| 5 | Nationality: | Israeli | Israeli | Israeli | Israeli |
| 6 | Membership of board committees: | Audit committee member<br>Compensation committee member<br>Member of the Financial Statements Review Committee ("**Finance Committee**"<br>Investment committee member | Audit committee member<br>Compensation committee member | Audit committee member<br>Finance committee member<br>Compensation committee member<br>Investment committee member | No |
| 7 | (a) Is he an outside director: | Yes | No | No | No |
| | (b) If so, does he have accounting and financial expertise or professional qualifications: | Holds professional qualification | Holds accounting and financial expertise | - | - |
| | (c) If so, is he an expert outside director[46] : | No | Yes | - | - |
| | (d) If not, is he eligible to be appointed as an independent director: | - | | Serves as an independent director | No |
| 8 | Is he an employee of the General Partner, a subsidiary, an affiliate or of an interested party: | No | No. | No | CEO and director of Cohen Development, Executive VP and CFO of Delek Group, director of various subsidiaries of Delek Group. |
| 9 | The date on which his term of office as a director began: | October 22, 2015 | October 22, 2015 | January 4, 2016 | June 30, 2017 |
| 10 | His education: | B.A. in General History, Tel Aviv University, Graduate of the National Security College. | B.A. in Accounting and Economics from the Tel Aviv University, MBA from Tel Aviv University, CPA | LL.B in Law from the Hebrew University of Jerusalem. | B.A. in Accounting and Economics from Bar Ilan University. |
| 11 | His occupation in the last five years: | Consultant to the Israel Aerospace Industries Ltd., director at ICIC – Israeli Credit Insurance Company Ltd. of the Harel Group | Chairman of the board of Hayun Computers Ltd. | Member of Knesset and member of the Israeli government, member of the board of the following companies: Gazit-Globe Ltd., Alrov Properties and Lodgings Ltd., IDB Development Corp. Ltd., Migdal Makefet Pension and Provident Funds Ltd. | Executive VP and CFO, Senior Finance VP of Delek Group; CEO and director of Cohen Development; director of subsidiaries of Delek Group. |
| 12 | Other corporations in which he serves as a director: | | | Gazit-Globe Ltd., Alrov Properties and Lodgings Ltd. | Cohen Development, Delek Israel, Delek Petroleum Ltd., Phoenix Holdings Ltd., Ratio Petroleum–Limited Partnership, Delek Sea |

[46] Within the meaning of the term in Section 1 of the Companies Regulations (Rules regarding Compensation and Expenses of Outside Directors), 5760-2000.

| | Details | Amos Yaron | Jacob Zack | Ronnie Bar-On | Barak Mashraki |
|---|---|---|---|---|---|
| | | | | | Maagan 2011 Ltd.., Delek Israel Holdings Group Ltd., Delek Infrastructures Ltd., Delek Sorek, Delek Ashkelon, Delek Energy, Delek Power Plant Management Ltd., C.T. Maya Property Company Ltd., Cohen Development (1979) Ltd., Cohen Family Properties Ltd., Cohen Development Shesh Ltd., Delek Group Royalty Ltd. and private subsidiaries of the Partnership (SPCs). |
| 13 | Is he a relative of another interested party of the General Partner: | No. | No | No | No |

## Regulation 26A: Senior officers of the General Partner and/or the Partnership[47]

| Officer | I.D. no. | Date of birth | Date of commencement of term of office | Position at the General Partner, at a subsidiary, at an affiliate or at an interested party: | Is he an interested party in the General Partner and/or in the Partnership | Is he a relative of another senior officer or of an interested party of the General Partner | His education | His experience in the last five years |
|---|---|---|---|---|---|---|---|---|
| **Yossi Abu** | 033840372 | December 7, 1977 | April 1, 2011 | CEO of the General Partner, CEO of Delek Energy[49], director of private subsidiaries of the Partnership (SPCs). | Yes | No | LL.B in Law from the Hebrew University of Jerusalem. Attorney-at-law, member of the Israel Bar Association. | CEO of Avner Oil & Gas Ltd., Chairman of the board of Tamar Petroleum[48], director of Ithaca in private subsidiaries of the Partners and private companies owned by him. |
| **Yossi Gvura** | 027790997 | June 9, 1970 | Deputy CEO since August 1, 2018. Prior thereto served as CFO at the General Partner – from April 1, 2011, and as Deputy CEO of Financial Affairs at the Partnership and the General Partner– from July 19, 2012. | Deputy CEO at the Partnership and the General Partner and director of private subsidiaries of the Partnership (SPCs). | No | No | B.A. in Economics and Accounting from Ruppin Academic Center and LL.M in law from Bar-Ilan University. | CFO at the Partnership and the General Partner, Deputy CEO of Financial Affairs at the Partnership, the General Partner, Avner Partnership and Avner Oil & Gas Ltd., director in private subsidiaries of the Partnership. |
| **Yaniv Friedman** | 027300300 | April 1, 1974 | November 1, 2015 | Deputy CEO of the Partnership. | No | No | LL.B in Law from Tel Aviv University. | Deputy CEO of Ellomay Capital Ltd., VP Strategy at the Avner Partnership. |
| **Zvi Karcz** | 059784355 | February 24, 1967 | August 12, 2014 | VP Explorations at the Partnership. | No | No | B.Sc. in Geology from the Hebrew University of Jerusalem, M.Sc. in Geology from the Hebrew University of Jerusalem and Ph.D. in Geology from Columbia University, New York, U.S.A. | Chief Geologist of the Partnership and Avner Partnership. |

[47] The specification of this regulation presents the officers holding office at the General Partner and/or the Partnership as of the Report release date. It is noted that on February 28, 2018 Mr. Tal Levi completed his office as a comptroller of the Partnership and the General Partner.
[48] On March 6, 2019 Mr. Abu completed his service as a director at Tamar Petroleum. For further details see immediate report dated March 6, 2019 (Ref. no: 2019-01-019365).
[49] Regarding the appointment of Mr. Abu as the CEO of Delek Energy see Regulation 21(b)(2) above.

| **Officer** | **I.D. no.** | **Date of birth** | **Date of commencement of term of office** | **Position at the General Partner, at a subsidiary, at an affiliate or at an interested party:** | **Is he an interested party in the General Partner and/or in the Partnership** | **Is he a relative of another senior officer or of an interested party of the General Partner** | **His education** | **His experience in the last five years** |
|---|---|---|---|---|---|---|---|---|
| **Ronen Edward** | 024652745 | October 13, 1969 | August 1, 2017 | CFO at the Partnership and the General Partner. | No | No | B.A. in Accounting and Business Administration from the College of Management. | CFO at the Avner Partnership and Avner Oil & Gas Ltd.. |
| **Sari Singer Kaufman** | 037485174 | February 22, 1980 | May 14, 2018, VP, Legal Counsel.<br>August 1, 2017-May 14, 2018 Legal Counsel<br>March 11, 2012 – August 1, 2017-Attorney | General Counsel, VP at the Partnership. | No | No | LL.B in Law from Tel Aviv University. | Attorney at the Partnership and Avner Partnership. |
| **Nadav Perry** | 040365447 | April 24, 1980 | June 14, 2015 | VP Regulatory and Public Affairs | No | No | B.A. in Government, Diplomacy and Strategy from the Interdisciplinary Center Herzliya, MBA from Bar Ilan University. | Heads the Public Affairs segment of the Partnership, Political reporter on the Channel 10 news and broadcaster on the Knesset channel - Israeli News Company. |
| **Saar Prag** | 037693942 | October 17, 1975 | August 1, 2017 | Manager of Natural Gas Trade at the Partnership. | No | No | LL.B in Law from the Hebrew University of Jerusalem. | Chief General Counsel at Paz Ashdod Refinery Ltd., partner at Shlomo Nass & Co. law office. |
| **Ofer Oberlander** | 021359518 | December 6, 1979 | March 17, 2019 | Project manager | No | No | B.A. in Economics and Business Management and a Research MA in Economics, both from the Ben Gurion University of the Negev | Responsible for economic information and research at the Partnership and at Avner Partnership. |
| **Gali Gana** | 059674770 | June 2, 1965 | February 1, 2016 | Internal auditor of the Partnership and the General Partner of the Partnership, and chief internal auditor of Delek Group and subsidiaries thereof. | No | No | CPA, B.A. in Business Administration, majoring in accounting, from the College of Management and M.A. in Public Administration and Internal Audit from Bar-Ilan University, certified information system auditor (CISA), certified internal auditor (CIA), certification in risk management assurance (CRMA), Certified in Risk and Information Systems Control (CRISC). | Partner at Rosenblum-Holtzman, CPA. |

**Regulation 26B**: **Independent authorized signatories**

There are no independent authorized signatories at the General Partner or at the Partnership.

**Regulation 27**: **The Partnership's CPAs**

Ziv Haft CPAs, of 46-48 Menachem Begin Rd., Tel Aviv and the accounting firm of Kost, Forrer, Gabbay & Kasierer of 144 Menachem Begin Rd., Tel Aviv, jointly serve as the auditors of the Partnership.

**Regulation 29:** **Recommendations and decisions of the directors**

**Regulation 29 (a)**: On December 24, 2018 the board of the Partnership's General Partner, resolved, after receiving the recommendation of the Partnership's General Partner's Financial Statements Review Committee to distribute profits in a total amount of ILS 130 million, with the effective date for distribution being December 31, 2018 and the distribution date being January 14, 2019. For further details see immediate report dated December 31, 2018 (Amending Report) (Ref. no.: 2018-01-120982) the information appearing in which is incorporated herein by reference.

Regulation 29(C): (1) For the resolutions of the special general meeting of the Partnership's participation units' holders dated March 20, 2018 regarding reimbursement of the Supervisor's expenses, see Regulation 21(b)(8) above.

(2) On May 17, 2018 the special general meeting of the Partnership's participation unit holders approved the resolutions as follows:

a. Approval of the changes in the terms of office and employment of Mr. Yossi Abu, CEO of the General Partner, as extensively detailed in Regulation 21(b)(2) above.

b. Authorization of the General Partner to carry out an issuance of participation units and/or securities convertible into participation units, see Section 7.22.1(g) of Chapter A of this Report.

Further details regarding the aforesaid special meeting are included in the immediate reports of the Partnership dated May 17, 2018 (Ref. no.: 2018-01-049456) and of May 7, 2018 (Ref. no.: 2018-01-036228), the details appearing in which are incorporated herein by reference.

(3) On July 1, 2018, the special general meeting of the Partnership's participation unit holders approved, according to Section 9.4 of the Partnership Agreement, to avoid profit distribution for the sake of their investment in the purchase of rights only in EMG in order to allow for engagement with EMG regarding the use of the existing gas pipeline between Israel and Egypt and the facilities owned thereby solely for the sake of piping natural gas. Further details regarding the aforesaid special meeting are included in the immediate reports of the Partnership dated July 1, 2018 (Ref. no.: 2018-01-063043) and June 28, 2018 (Ref. no.: 2018-01-062350) the details appearing in which are incorporated herein by reference.

(4) On July 24, 2018 the special general meeting of the Partnership's participation unit holders approved the Partnership's engagement with Delek Group in an agreement which settles the distribution of employment costs of the Partnership's employees and officers, in the field of management and business development, economics, regulation and geology (the "**Employees**") according and subject to the terms of the arrangement, under which, *inter alia*, the full compensation of the Employees will be paid by the Partnership, and Delek Group will pay the Partnership its share in their employment cost, according to their actual position percentage. The scope of employment by the Employees by Delek Group companies will not exceed a 5%-position on an annual average scope. It is clarified that the Employees shall continue to be deemed solely as employees of the Partnership, and there are no and will be no employment relations between the Employees and the Delek Group companies. The arrangement is for a 3-year period commencing on the date of approval by the general meeting. Further details regarding the aforesaid special meeting are included in the Partnership's immediate reports dated July 25, 2018 (Ref. no.: 2018-01-070198) and June 17, 2018 (Ref. no.: 2018-01-058279), the details appearing in which are incorporated herein by reference.

(5) For the resolutions of the special general meeting of the Partnership's participation unit holders dated September 6, 2018 regarding reimbursement of the Supervisor's expenses, see Regulations 21(b)(8) above.

(6) On October 10, 2018 the Partnership's participation unit holders special general meeting approved the appointment of Messrs. Jacob Zack and Amos Yaron as outside directors for the board of directors of the Partnership's General Partner, for a three (3) year term of office, commencing on the end date of their current office, namely: October 22, 2018. The meeting resolved not to approve the appointment of Mr. Eytan Rozenman as an outside director for another term of office, and

therefore, Mr. Rozenman ceased his service as an outside director on October 22, 2018. Further details regarding the aforesaid special meeting are included in the Partnership's immediate report dated October 10, 2018 (Ref. no.: 2018-01-091300) and September 20, 2018 (Ref. No.: 2018-01-085579), the details appearing in which are incorporated herein by reference.

(7) On December 27, 2018 the Partnership's participation unit holders special general meeting approved the following resolutions:

a. To update Section 13 of the Compensation Policy for officers at the Partnership and the General Partner, as approved in the unit holder meeting on June 5, 2016, on the issue of insurance and indemnification for directors and officers, as extensively specified in Regulation 21(b)(1) above.

b. To approve framework conditions for a three-year period for future engagements of the General Partner and/or the Partnership, in a policy for the insurance of the Partnership's and General Partner directors and officers liability within a group insurance policy taken out by Delek Group, as extensively specified in Regulation 22(i) above.

Further details regarding the aforesaid special meeting are included in the Partnership's immediate reports dated December 27, 2018 (Ref. no.: 2018-01-119824) and December 26, 2018 (Ref. no.: 2018-01-119173) the details appearing in which are incorporated herein by reference.

(8) On January 28, 2019, the Partnership's participation unit holders special general meeting approved the appointment of Mr. Efraim Sadka as an outside director for the board of the Partnership's General Partner, for a three (3) year term of office commencing on April 1, 2019. Further details regarding the aforesaid special meeting are included in the Partnership's immediate reports of January 28, 2019 (Ref. no.: 20149-01-008335) and December 26, 2018 (Ref. no.: 2018-01-115258) the details appearing in which are incorporated herein by reference.

**Regulation 29A: Decisions of the Partnership**

Regulation 29A(4): Exemption, insurance or undertaking to indemnify an officer

(a) On July 17, 2012, the Partnership's unit holders meeting approved the amendment of the Partnership Agreement to include the granting of indemnification undertakings and letters of exemption from liability to directors of the General Partner who are not controlling shareholders of the General Partner and/or controlling interest holders of the Partnership and/or their relatives, who shall hold office, from time to time, at the General Partner and/or at subsidiaries of the Partnership (and who are not outside directors). In accordance with amendments made in the Partnership Agreement as provided in the resolution of the meeting of July 17, 2012, the board of directors of the General Partner resolved on July 19, 2012 to approve the granting of letters of exemption and indemnification to officers of the General Partner and the Partnership. For details regarding indemnification undertakings that were granted to the outside directors of the General Partner's board, Messrs. Jacob Zack and Amos Yaron, see the Partnership's immediate report regarding the convening of a general meeting of the Partnership's participation unit holders of October 14, 2015 (Ref. no. 2015-01-135165), and the Partnership's immediate report regarding the outcome of the unit holder meeting of October 22, 2015 (Ref. no. 2015-01-140634), the information appearing in which is included herein by way of reference. For details on insurance and indemnification that may be granted to officers of the Partnership and/or the General Partner, see Section 13 of the compensation policy that was adopted, as provided in Regulation 21(b)(1) above. It is stated in this context, that according to the resolution of the general meeting of the Partnership's participation unit holders dated January 28, 2019, for the appointment of Mr. Efraim Sadka as an outside director, commencing on April 1, 2019, Mr. Sadka will be entitled to be included in the Partnership's arrangement for the insurance of the liability of directors and officers according to the Partnership's Compensation Policy, and to an indemnification undertaking, similarly to the other outside directors on the board of the General Partner, as aforesaid.

(b) With respect to the approval of framework conditions for a three-year period for future engagements of the General Partner and/or the Partnership, in a policy for insurance of the liability of directors and officers of the Partnership and of the General Partner, within a group insurance policy taken out by the Delek Group and regarding the engagement of the General Partner and/or the Partnership in a policy for insurance within the group policy as aforesaid, , see Regulation 22(i) above.

**Delek Drilling - Limited Partnership**

**By the General Partner, Delek Drilling Management (1993) Ltd.**

Names and position of signatories:

Assi Bartfeld, Chairman of the Board
Yossi Abu, CEO

Date: March 21, 2019

Delek Drilling

# Report on the Effectiveness of Internal Controls for Financial Reporting and Disclosure

2018

# Delek Drilling – Limited Partnership

# Chapter E

## Annual Report on the Effectiveness of Internal Control over Financial Reporting and Disclosure Pursuant to Regulation 9B(a) of the Securities Regulations (Immediate and Periodic Reports), 5730-1970

***This report is a translation of Delek Drilling - Limited Partnership's Hebrew-language Annual Report on the Effectiveness of Internal Control over Financial Reporting and Disclosure Pursuant to Regulation 9B(a) of the Securities Regulations (Immediate and Periodic Reports), 5730-1970), prepared solely for convenience purposes. Please note that the Hebrew version is the binding version, and in any event of discrepancy, the Hebrew version shall prevail.***

# Delek Drilling – Limited Partnership

**Annual report for 2018 on the effectiveness of internal control over financial reporting and disclosure pursuant to Regulation 9B(a) of the Securities Regulations (Immediate and Periodic Reports), 5730-1970**:

The management of the general partner in Delek Drilling – Limited Partnership (the "**General Partner**" and "**Partnership**", respectively), under the supervision of the board of directors of the General Partner, is responsible for setting and maintaining proper internal control over financial reporting and disclosure at the Partnership.

For this purpose, the members of the management are:

1. Asi Bartfeld, Chairman of the Board of the General Partner;
2. Yossi Abu, CEO of the General Partner;
3. Yossi Gvura, Deputy CEO and Market Risk Manager;
4. Yaniv Friedman, Deputy CEO.

Internal control over financial reporting and disclosure consists of controls and procedures existing at the Partnership, designed by, or under the supervision of, the CEO and the most senior financial officer, or by anyone actually performing such functions, under the supervision of the board of directors of the General Partner, which are designed to provide reasonable assurance regarding the reliability of the financial reporting and the preparation of the reports according to the law, and to ensure that information which the Partnership is required to disclose in reports released thereby according to the law is gathered, processed, summarized and reported within the time frames and in the format set forth by the law.

Internal control includes, *inter alia*, controls and procedures designed to ensure that information which the Partnership is thus required to disclose, is gathered and transferred to the management of the General Partner, including the CEO and the most senior financial officer, or anyone actually performing such functions, in order to enable the timely decision making in reference to the disclosure requirement.

Due to its inherent limitation, internal control over financial reporting and disclosure is not designed to provide absolute assurance that misrepresentation or omission of information in the reports will be avoided or discovered.

The management of the General Partner, under the supervision of the board of directors of the General Partner, has performed an examination and evaluation of the internal control over financial reporting and disclosure in the Partnership and of the effectiveness thereof and included: entity-level controls, including control over the process of preparation and closing of financial reporting, general control over information systems, control over the accounting process vis-à-vis the operators of the joint transactions, and controls over the process of management of cash, including investments and process of raising and management of bonds and loans.

Based on the evaluation of the effectiveness performed by the management of the General Partner under the supervision of the board of directors of the General Partner, as specified above, the board of directors and the management of the General Partner came to the conclusion that the internal control over financial reporting and disclosure at the Partnership, as of December 31, 2018, is effective.

Statement of CEO pursuant to Regulation 9B(d)(1):

**Statement of Managers**

**Statement of CEO**

I, Yossi Abu, represent that:

(1) I have reviewed the periodic report of Delek Drilling – Limited Partnership (the "**Partnership**") for 2018 (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 periods and as of the dates covered by the Reports;

(4) I have disclosed to the Partnership's auditors, the board of directors and the audit and financial statements review committees of the General Partner in the Partnership, based on my most current evaluation of internal control over financial reporting and disclosure:

    (a) Any and all significant flaws and material weaknesses in the setting or maintaining internal control over financial reporting and disclosure which may reasonably adversely affect the Partnership's ability to gather, process, summarize or report financial information in a manner which casts a doubt on the reliability of the financial reporting and preparation of the financial statements in conformity with the provisions of the law; and –

    (b) Any fraud, either material or immaterial, which involves the CEO or anyone reporting to him directly or which involves other employees who play a significant role in internal control over financial reporting and disclosure;

(5) I, myself or jointly with others at the General Partner in the Partnership:

    (a) Have set controls and procedures or confirmed that such controls and procedures have been set and maintained under my supervision, which are designed to ensure that material information in reference to the Partnership is presented to me by others at the General Partner in the Partnership, particularly during the preparation of the Reports; and –

(b) Have set controls and procedures or confirmed that such controls and procedures have been set and maintained under my supervision, which are designed to reasonably ensure reliability of financial reporting and preparation of the financial statements in conformity with the provisions of the law, including in conformity with GAAP;

(c) Have evaluated the effectiveness of internal control over financial reporting and disclosure, and presented in this report the conclusions of the board of directors and the management of the General Partner in the Partnership with regard to the effectiveness of the internal control as aforesaid, as of the date of the Reports.

The aforesaid does not derogate from my responsibility or from the responsibility of any other person, pursuant to any law.

| March 21, 2019 | Yossi Abu | CEO | |
|---|---|---|---|
| Date | Full Name | Position | Signature |

Statement of the most senior financial officer pursuant to Regulation 9B(d)(2):

**Statement of Managers**

**Statement of the most senior financial officer**

I, Yossi Gvura, represent that:

(1) I have reviewed the financial statements and other financial information included in the reports of Delek Drilling – Limited Partnership (the "**Partnership**") for 2018 (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 periods and as of the dates covered by the Reports;

(4) I have disclosed to the Partnership's auditors and to the board of directors and the audit and financial statement review committees of the General Partner in the Partnership, based on my most current evaluation of internal control over financial reporting and disclosure:

    (a) Any and all significant flaws and material weaknesses in the setting or maintaining internal control over financial reporting and disclosure insofar as the same pertain to the financial statements and the other financial information included in the Reports, which may reasonably adversely affect the Partnership's ability to gather, process, summarize or report financial information in a manner which casts a doubt on the reliability of the financial reporting and preparation of the financial statements in conformity with the provisions of the law; and –

    (b) Any fraud, either material or immaterial, which involves the CEO or anyone reporting to him or which involves other employees who play a significant role in internal control over financial reporting and disclosure;

(5) I, myself or jointly with others at the General Partner in the Partnership:

    (a) Have set controls and procedures, or confirmed that such controls and procedures have been set and maintained under my supervision, which are designed to ensure that material information in reference to the Partnership, insofar as the same is relevant to the financial statements and other financial information included in the Reports, is presented to me by others at the Partnership, particularly during the preparation of the Reports; and

(b) Have set controls and procedures or confirmed that such controls and procedures have been set and maintained under our supervision, which are designed to reasonably ensure reliability of financial reporting and preparation of the financial statements in conformity with the provisions of the law, including in conformity with GAAP;

(c) Have evaluated the effectiveness of the internal controls over financial reporting and disclosure, insofar as the same pertain to the financial statements and the other financial information included in the Reports, as of the date of the Reports; My conclusions with regard to my aforesaid evaluation were presented to the board of directors and the management of the General Partner in the Partnership, and are incorporated in this report.

The aforesaid does not derogate from my responsibility or from the responsibility of any other person, pursuant to any law.

| March 21, 2019 | Yossi Gvura, CPA | Deputy CEO | |
|---|---|---|---|
| Date | Full Name | Position | Signature |

Delek Drilling

# Valuations

2018

# Delek Drilling – Limited Partnership

## Valuations of Royalties and the Debt Component

## From the sale of I/16 “Tanin” and I/17 “Karish” Leases

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**March 2019**

***This document is a translation of the original Hebrew-language document of Giza Singer Even Ltd. of March 2019. 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.***

**Giza Singer Even Ltd**.
Aviv Tower 7 Jabotinsky Ramat Gan 5252007 Tel. 03-5213000
www.gse.co.il

GIZA SINGER EVEN

## Table of Contents

# 1. Introduction and Limitation of Liability

## 1.1 General

This work (the "**Work**" and/or the "**Opinion**") was prepared by GSE Financial Advisory Ltd. ("**GSE**") for the purpose of valuation of the royalties to which the limited partnership Delek Drilling[1] ("**Delek Drilling**" and/or the "**Partnership**") is entitled for the sale of its rights in the I/16 "Tanin" and I/17 "Karish" Leases (the "**Leases**") as of December 31, 2018 (the "**Valuation Date**") according to the management's requirement. We are aware that the Work is intended to be used by Delek Drilling, *inter alia*¸ for quarterly and periodic financial statements, and therefore we agree that the Work 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, all as specified in the engagement letter of November 3, 2016.

For the preparation of the Work 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 Work 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 consideration 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 Work does not constitute a due diligence inspection and does not replace it. Furthermore, the Work is also not intended to determine the value of the consideration for the specific investor and it does not constitute legal advice or opinion.

The Work does not include accounting auditing regarding the compliance with the accounting principles. GSE Financial Advisory is not responsible for the manner of accounting presentation of the financial statements of the Partnership regarding the accuracy and integrity of the data and the implications of such accounting presentation, if any.

Should the Information and data on which GSE relied, be incomplete, inaccurate or unreliable, the results of this Work may change. We reserve the right for ourselves, to re-update the Work in view of new data which were not presented to us. For the avoidance of doubt, this Work is valid as of the date of signing hereof only.

[1] On May 17, 2017, Delek Drilling merged with the partnership Avner Oil Exploration – Limited Partnership ("**Avner**", hereinafter jointly: the "**Partnerships**") and as a result, Avner partnership was stricken off with no dissolution.

**It is emphasized that the Information specified in this Work, 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, the royalties agreed therein, and the fulfilment of the conditions precedent therein, constitutes 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 shall further note that upon our valuation of the consideration, we relied on the assumption that the transaction for the sale of rights in the Karish and Tanin Leases was made at market conditions between a willing buyer and seller, and we were not presented with any information which might contradict this assumption.

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 Work. Furthermore, we confirm that our fee is not dependent on the results of the Work.

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 Work in whole or in part.

### 1.2 Sources of Information

<u>The main sources of information used in the preparation of the Opinion are specified below:</u>

- Financial statements of the Partnership
- Information regarding the terms of the transaction and forecasts received from the Partnership
- Prospectus released by Energean Oil & Gas plc (the parent company of Energean Israel Limited) of March 16, 2018 (the "**Prospectus**") including the resource report prepared by Netherland Sewell and Associate Inc. ("**NASI**")
- Agreement for the sale of the rights in the Karish and Tanin Leases
- Immediate reports of publicly traded companies and overt information released on websites (including Energean's website), journalistic articles or other public sources
- Internal sources and databases of Giza Singer Even
- Meetings and/or phone calls with office holders at the Partnership

## 1.3 Details of the valuating company

GSE Financial Advisory Ltd. Is a subsidiary of Giza Singer Even Ltd., which is a leading financial advisory and investment banking firm in Israel. The firm has extensive experience in the advising of the large companies, the prominent privatizations and the important transactions in the Israeli market, which it accrued over its thirty years of operation. Giza Singer Even operates in three fields, through independent business divisions: financial advisory; investment banking; analytical research and corporate governance.

The Work was carried out by a team headed by CPA Eitan Cohen, a partner and head of the economic department at Giza Singer Even with experience of over ten years in the fields of economic and business advisory, company valuations and financial instruments. In the past he served as the head of the economic department in an entrepreneurial company in the field of infrastructures and as a manager at the economic department of KPMG (Somekh Chaikin). Eitan is an accountant, holds a BA in economics and business administration from the Ben Gurion University and an MSc in Financial Mathematics from Bar Ilan University.

Sincerely,

GSE Financial Advisory

March 21, 2019

# 2. Executive Summary

## 2.1 Background

Delek Drilling is a public limited partnership (in the meaning thereof in the Partnerships Ordinance) listed on the Tel Aviv Stock Exchange (TASE). The Partnership engages in the exploration, development and production of petroleum, natural gas and condensate.

During the years 2012 and 2013 the Partnership reported to TASE that the Tanin and Karish gas reservoirs constitute natural gas discoveries. Following 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 Prospectus of Energean Oil & Gas plc, the parent company of Energean Israel Limited[2] ("**Energean**" and/or the "**Purchaser**") of March 16, 2018[3]:

| Lease | Reserves and Contingent Resources* | |
|---|---|---|
| | Natural Gas (BCM) | Hydrocarbon Liquids (MMBBL) |
| Karish | 45.0 | 28.7 |
| Tanin | 21.7 | 4.1 |
| **Total** | **66.7** | **32.8** |

* The reserves in the 2P category constitute more than 90% of the aggregate of natural gas resources in the reservoir (2P+2C), according to Energean's report of August 16, 2018 on the London Stock Exchange. It is noted that Energean has not released an updated resource report, which is audited by a third party, that is updated in a manner consistent with the aforesaid release.

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**"), the Partnerships and Noble Energy Mediterranean ("**Noble**") were required, *inter alia*, to sell their holdings in the Karish and Tanin reservoirs in order to comply with the conditions which would entitle them to an exemption from several provisions of the Restrictive Trade Practices Law, 5748-1988 (the "**Restrictive Trade Practices Law**").

On August 16, 2016, an agreement was executed for the sale of all of the rights in Karish and Tanin between Delek Drilling and Avner Oil Exploration - Limited Partnership ("**Avner**") (jointly, the "**Partnerships**") and Energean, within which the Partnerships are entitled to consideration in the amount of $148.5 million, comprising cash payment of $40 million (paid on the date of the transaction closing) and $108.5 million which will be paid spread into 10 annual equal payments plus interest, with this amount depending on the Purchaser's decision to develop the reservoir[4] (the "**Debt Component**"). Furthermore, the Partnerships will be entitled to royalties from the revenues generated for the Purchaser from the sale of natural gas and condensate produced from the Leases, at the rates of 7.5% (before the payment of

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[2] Formerly Ocean Energean Oil and Gas Ltd.
[3] According to the NSAI resource report attached to Energean Prospectus, Net Resources.
[4] Making of a Final Investment Decision (FID) regarding the development of the Leases or on the date which the total expenses of the Purchaser regarding the development of the Leases exceeded $150 million (whichever is earlier).

petroleum profit levy) and 8.25% (after payment of petroleum profit levy), net of the rate of the existing royalties[5], by which the Partnership is charged regarding the original share of Delek Drilling and Avner in the Leases (the "**Royalties**'). On December 27, 2016, the Partnerships announced that the closing conditions for the transaction were fulfilled. On March 27, 2018, Energean notified the Partnership of the adoption of a decision of investment for the development of Karish reservoir.

## 2.2 Result of the Valuation

The valuation of the consideration was performed in the Discounted Cash Flow (DCF) method. According to the assumptions specified in the Work itself, the value of the Royalties in the transaction as of the Valuation Date is estimated at approx. $113.1 million. For specification regarding the valuation of the Debt Component, see Annex B.

Below is the sensitivity analysis for the value of the Royalties in relation to the cap rate and the changes in the natural gas prices (U.S. $ in millions):

| | | Change in the Natural Gas Price Vector (U.S. $ per mmbtu) | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | (1.50) | (1.00) | (0.50) | - | 0.50 | 1.00 | 1.50 |
| **Change in Cap Rates (in Base Points)** | +250bp | 79.4 | 86.0 | 90.3 | 95.5 | 100.6 | 104.9 | 111.7 |
| | +150bp | 84.9 | 91.9 | 96.5 | 102.1 | 107.5 | 112.1 | 119.4 |
| | +50bp | 90.9 | 98.3 | 103.3 | 109.2 | 115.1 | 120.0 | 127.8 |
| | - | 94.2 | 101.8 | 107.0 | **113.1** | 119.2 | 124.3 | 132.4 |
| | -50bp | 97.6 | 105.5 | 110.8 | 117.2 | 123.5 | 128.7 | 137.1 |
| | -150bp | 105.0 | 113.4 | 119.2 | 125.9 | 132.7 | 138.4 | 147.5 |
| | -250bp | 113.1 | 122.1 | 128.4 | 135.6 | 143.0 | 149.2 | 159.0 |

[5] As defined in the reports of Delek Drilling and Avner to the TASE on December 25, 2016.

# 3. Description of the Partnership's Business

## 3.1 Description of the Partnership

Delek Drilling is a limited partnership (within the meaning thereof in the Partnerships Ordinance) listed on the TASE. The Partnership engages in the exploration, development and production of petroleum, natural gas and condensate. Following is a description of the overriding royalties' mechanisms applicable to the Partnership as of the date hereof with respect to its original share in the Karish and Tanin leases (approx. 52.9%):

| Overriding Royalties | For 50% of the Revenues from the Karish and Tanin Leases | For 50% of the Revenues from the Karish and Tanin Leases |
|---|---|---|
| Offshore petroleum assets | 3% before the Investment Recovery Date[6] | 6% |
| | 13% after the Investment Recovery Date | |
| Onshore petroleum assets | 5% before the Investment Recovery Date | |
| | 15% after the Investment Recovery Date | |

## 3.2 Description of the Business Field

### 3.2.1 General

As aforesaid, the main field of business of the Partnership, is the exploration, development and production of petroleum, natural gas and condensate, in Israel and in Cyprus and the review of various infrastructure alternatives for natural gas flow to other target markets. The nature 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 as specified below:

[6] The term "**Investment Recovery Date**" means the date after the signing of the agreement for the transfer of rights between the Partnership and Delek Energy Systems and Delek Israel (now Delek Group) which was signed in 1993 (as amended from time to time) according to which the Net Proceeds Value which the Partnership received or is entitled to receive for petroleum and/or gas and/or other valuable materials which were produced and used from the petroleum asset (i.e. – license or lease) where the finding is located, calculated in Dollars shall reach an amount which is equal to the full Value of All of the Partnership's Expenses in such petroleum asset calculated in Dollars.
The term "**Net Proceeds Value**" means the value of all of the proceeds as shall be approved by the accountants of the Partnership for petroleum and/or gas and/or other valuables which were produced and used from the petroleum asset (i.e. – license or lease) (the "**Gross Proceeds Value**" after the deduction of all of the production costs thereof and royalties paid in respect thereof.
The term the "**Value of All of the Partnership's Expenses**" means all of the expenses incurred by the Partnership in the petroleum asset (i.e. – license or lease) where the petroleum and/or the gas and/or the other valuables are produced but excluding expenses (up to the Net Proceeds Value) which were deducted from the Gross Proceeds Value for the determination of the amount of the all of the Net Proceeds Value and as they shall be approved by the Partnership's accountants.
For details and elaboration regarding agreements pertaining to the payment of royalties to the State and to interested parties in and to third parties of in Partnership, see Section 7.27.12 of the periodic report for 2018 of Delek Drilling.

- "Preliminary Permit" is intended to allow the permit holders a sufficient time margin to carry out inspections in order to estimate the chances of discovering hydrocarbons (except for exploration wells) and it is granted for a period of up to 18 months.

- "License" grants the license holder a right to explore natural gas and petroleum in the license area and to drill exploration wells. The license is granted for a period of up to 7 years.

- "Lease" grants the receiver of the lease the right to explore and produce natural gas and petroleum and is valid for a period of 30 years with an option for an extension of 20 additional years.

In addition, the Natural Gas Sector Law, 5760-2000 regulates mainly the issue of transmission, distribution and marketing of natural gas in Israel.

The natural gas sector in Israel began developing upon the discoveries of the natural gas reservoirs Noa and Mari B in the years 1999-2000, these discoveries allowed companies in the market, headed by the Israel Electric Corporation, 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 energetic independence of Israel and the development and expansion of uses of natural gas in the Israeli market.

### 3.2.2 Exploration and Development of Natural Gas Reservoirs

Exploration and development of natural gas reservoirs is a long and complex process, characterized by extensive uncertainty and significant capital investments throughout the entire stages of the process. There are material differences between the exploration and development of natural gas reservoirs onshore which are considered relatively simple and exploration and development offshore, which require larger money inputs and unique technologies, under more complex and dangerous conditions.

A typical process of exploration, development and production of natural gas in any area may include, *inter alia*, the following stages: Initial analysis of existing geological and geophysical data, for the selection of areas presenting exploration potential; Performance of geophysical surveys; the drilling of an exploration well and other tests (at this stage there is a possibility of discovering a dry well and cessation of the process); final analysis of the results of the drilling and, in the event of a natural gas finding, performance of an analysis of financial data and initial evaluation of the format and cost of development; formulation of a development plan and preparation of a financial plan for the project; final analysis of the data and making a decision whether the finding (the discovery) is commercial (at this stage too it is possible that the survey results will indicate that the finding is not commercial and the development of the reservoir will be ceased); performance of the reservoir's development work, including the drilling of production wells, laying pipelines, building treatment facilities etc.; regular operation and maintenance.

The natural gas market in Israel is young relative to other gas markets in the world, and for the purpose of developing it in the best effective manner, cooperation is required with multi-national companies which will provide the local players resources, knowledge and experience. In this context we shall emphasize that multi-national companies can invest and operate throughout the world, and they naturally weight, within the calculation of their cost-effectiveness, the potential profitability and the actual profitability in different locations around the world compared with the restrictions, costs and risks derived from the geopolitical condition and the regulatory environment in each area.

### 3.2.3 Benefits

The use of natural gas holds many benefits for the Israeli market, including:

- **Saving of energy costs in industry and in electricity production –** The low price of natural gas compared with currently common alternative fuels such as diesel oil and fuel oil, leads to significant saving of production costs, and thereby also to a decrease in the final product prices whose production costs mainly consist of the costs of electricity. Most of the power plants constructed in recent years in Israel operate by means of natural gas turbines and are characterized by low construction costs[7], shorter construction time, smaller areas of land[8] and many operational advantages. In addition to the relatively low price, natural gas is a more efficient energetic source than other fuels and it allows power plants and enterprises to reach a high energetic efficiency level which is also ultimately reflected in cost saving[9]. According to the estimates of the Natural Gas Authority[10], the transition to natural gas in the years 2004-2017 saved the Israeli market an estimated total of approx. ILS 54.4 billion. Most of such saving derives from the electricity sector, total consumption by which in 2017 amounted to approx. 8.5 BCM, which represents 83% of the demand for natural gas. The rest of the amount saved due to the transition to use of natural gas is primarily attributed to industrial plants, total consumption by which in 2017 amounted to approx. 1.8 BCM.

- **Clean Energy –** The main substances emitted from the burning of natural gas are carbon dioxide and water vapor. Since coal and petroleum are more complex fuels, with a higher ratio of Carbon and Nitrogen and Sulphur components, then upon their combustion contaminants at higher contamination levels are released, including ash particles of materials which are not burned but are present in the atmosphere and add to the air pollution. The natural gas combustion on the other hand, releases a small quantity of contaminants while reducing air pollution and maintaining a cleaner and healthier environment.

- **Energetic Independence –** The geopolitical characteristics of Israel make it an energetic island which cannot import fuels from neighboring countries and 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 will provide the Israeli industry energetic security in the long term and will reduce its dependence on international energy prices.

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[7] About half of the cost of a coal power plant, about a third of the cost of a nuclear power plant and about 15% of a wind energy operated plant.

[8] The natural gas is transported by an underground pipe and unlike other fuels, requires no storage areas.

[9] Power plants operated with coal or fuel oil only utilize approx. 40% of the initial energy directed to the production of electricity. A combined cycle power plant combining a gas turbine and a steam turbine is more efficient and uses 55% of the energy. Cogeneration stations utilizing the thermal energy produced in the production process reach an efficiency level of approx. 80%.

[10] https://www.gov.il/BlobFolder/guide/natural_gas_basics/he/ng_2017.pdf.

- **Natural gas as a governmental source of income through taxation -** The Israeli natural gas market is expected to benefit the local economy also directly through governmental revenues from the taxation of the companies and from the VAT from sales to the ultimate consumer. Moreover, the Israeli market has a few unique taxation systems which apply to the natural gas sector and similarly to all of the other fuel products, the natural gas is also subject to excise tax. Furthermore, according to the Petroleum Law, the State is entitled to charge 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 approx. 20%-50% (depending, *inter alia*, on the corporate tax rate) of the revenues of the holders of the petroleum rights, net of royalties, operation costs and development costs.

### 3.2.4 Customers

The natural gas market in Israel comprises several layers of consumers differentiated from each other in the nature of their activity and the characteristics of the natural gas consumption:

- **Israel Electric Corporation** (IEC) – The IEC constitutes for the Tamar project partners a very important anchor customer, *inter alia*, for the obtaining of financing for the construction of infrastructure for production of natural gas and development of the reservoirs. In fact, without the existence of the transaction for the sale of natural gas to the IEC, it might not have been possible to secure the financing required for the development of the Tamar project. The IEC is a governmental company supervised by the Electricity Authority ("PUA-E"), *inter alia*, regarding the costs of inputs for electricity production, particularly, the costs of natural gas.

  In 2017, consumption of natural gas for electricity production constituted approx. 83%[11] of the total natural gas consumption in the market, similarly to 2016. The share of the IEC represented approx. 63% of the natural gas consumption for electricity production in 2017, compared with approx. 61% in 2016, approx. 65% in 2015 and approx. 74% in 2014. The remaining demand is by private electricity producers and this trend is expected to continue in the coming years.

- **Private Electricity Producers –** In terms of the volume of natural gas consumption, the tier of private electricity producers ("**PEPs**") is second to the IEC in importance. In 2017, consumption by PEPs totaled approx. 3.2 BCM[12].

  Private electricity producers are divided into several types, according to the production technology which they use: conventional PEP, cogeneration facilities, pumped energy, renewable energies PEPs and large enterprises that constructed power plants for themselves for which they received a self-production license. As to the status of the PEPs in the natural gas sector, Section 93 of the Natural Gas Sector Law defines that natural gas sold to a PEP is a product subject to control under the Control of Prices of Commodities and Services Law, 5756-1996.

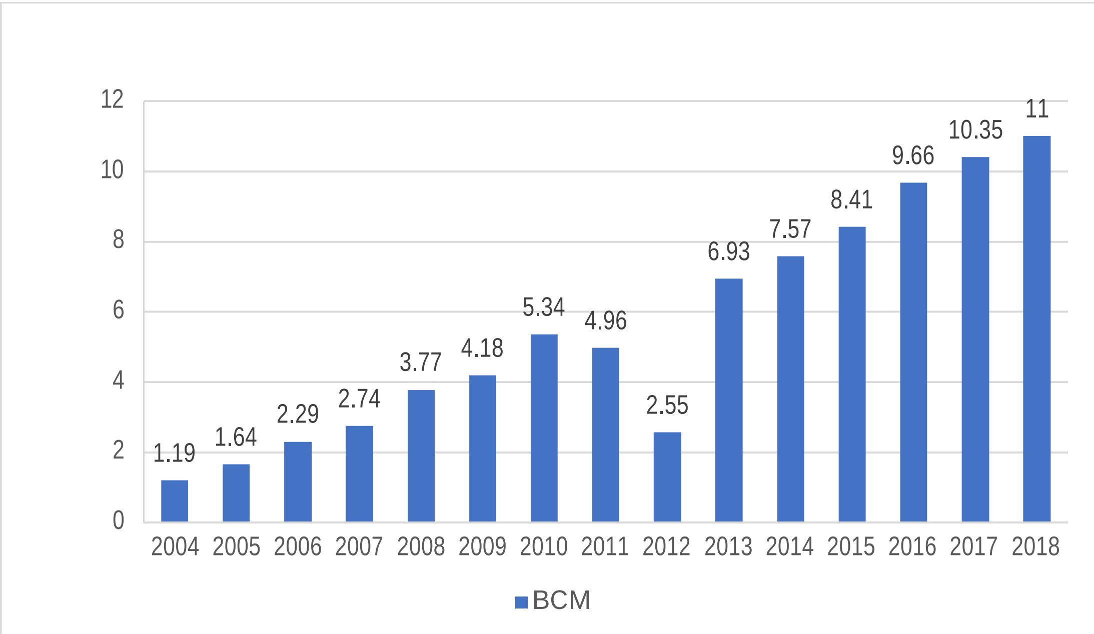
- **Large Industry Consumers –** This tier of consumers comprises several significant consumers, which are essential to the development of the Israeli gas sector. Consumers

[11] https://www.gov.il/BlobFolder/guide/natural_gas_basics/he/ng_2017.pdf
[12] Including gas consumption by industrial plants for electricity production purposes.

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 electricity needs, 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 2017, total natural gas consumption by the industry sector amounted to approx. 1.81 BCM, an increase of 11% compared with 2016. The increase chiefly derives from the connection of new consumers to the distribution network and 4 additional consumers that consume CNG.[13]

- **Medium and small consumers** – The distribution networks' consumers sector which includes mainly medium and small enterprises and businesses, such as laundries and bakeries, is a relatively new sector in the natural gas sector which began executing agreements for purchase and infrastructure conversion performance only in recent years. These consumers typically consume low gas pressure, at a relatively small amount, non-continuous over a whole day (24 hours), some of which not yet connected to the onshore transmission systems, or the distribution, and therefore consuming Condensed Natural Gas (CNG) – a temporary and not optimal solution, since the cost of consumption can reach twice the cost of the natural gas which is transmitted trough the distribution system.

- **Chart 1 – Natural Gas Consumption in the years 2004-2018 (Source: the Natural Gas Authority and estimated in the energy market)**




[13] Excluding gas consumption by industrial plants for electricity production purposes.

### 3.2.5 Demand Forecast

Below are the main factors expected to motivate growth in natural gas demand:

- **Transition to the use of natural gas by private electricity producers and industrial plants –** In 2013, private electricity producers started using natural gas. In addition, the demand in the industrial sector grew and in recent years there is significant conversion from use of petroleum distillates in the industry to use of natural gas. There is also a trend of connecting additional industrial plants to the natural gas distribution network.

- **Increasing the demands in the electricity sector -** In recent years a trend is apparent for the conversion from using petroleum and coal distillates at the IEC power plants to the use of natural gas (in December 2015, the Minister of Energy, Dr. Yuval Steinitz decided of the reduction of 15% use of coal for electricity production in 2016 compared with 2015). Commencing in 2017 another reduction of 5% occurred and in total, a reduction of 20% compared with the use made in 2015.

  In August 2016 the Minister of Energy announced his decision to shut down four coal production units of IEC upon the connection of three gas reservoirs to the shore and the construction of new natural gas operated power plants within up to six years. Following that, in September 2016, emission permits were received by the IEC under the Clean Air Law, 5768-2008 with respect to its coal power plants sites, which included, *inter alia*, an obligation to continue installing emission reduction measures, as well as the shutdown of units 1-4 in the coal power plant at the "Rabin Lights" site, no later than January 1, 2022. On May 28, 2017, the website of the Ministry of Energy released a notice regarding the decision of the Minister of Energy according to which the private sector will construct the natural gas operated power plants instead of the coal units 1-4 at the "Rabin Lights", *inter alia,* in order to ensure compliance with the timetables that he prescribed for the cessation of coal use at these units.

  In November 2017, the Minister of Energy decided of principles of policy on the issue of minimal operation of coal production units, according to which natural gas electricity production shall be granted preference at any time to electricity production with coal, while operating the coal units at a minimal load which allows flexibility and reliability of the supply to the market.

  In January 2018 the Minister of Energy announced that he had decided to instruct the IEC to reduce the use of coal for electricity production at a rate of 30% compared with 2015 according to the announcement of the Ministry of Energy and the Ministry of Environmental Protection, this decision will lead to significant reduction of air pollution from the coal power plants and is expected to increase demand for natural gas in the market. According to the announcement of the Ministries, these steps, which were approved by the Minister of Energy, as well as power plants according to the Clean Air Law, 5768-2008 will lead to more than 70% of the electricity production in the market relying on natural gas and renewable energies in the end of 2018.

  In March 2018 the Finance Committee of the Knesset and thereafter the Plenum of the Knesset approved the orders, in which it was provided, *inter alia*, that commencing on March 15, 2019 the excise tax on coal will be increased by approx. 125% in view of the government's policy to gross up external costs of fuels and encourage the expansion of use of natural gas.

In addition, it was decided that from January 1, 2024, the excise tax on compressed natural gas (CNG) will increase gradually, subject to the existence of no less than 25 CNG fueling stations that shall receive all of the approvals required for operation. It was further determined that from May 1, 2018, the reimbursement of excise on diesel oil, which is used mainly for transportation purposes, will gradually be cancelled. On February 20, 2019, the Minister of Finance signed an order postponing the expected rise in excise on coal, from March 2019 to 2021, in order to reduce the increase in electricity prices of January 2019.

On June 3, 2018, the government approved a reform in the electricity sector and at the IEC (the "**Reform**"). The Reform includes, *inter alia*, the following steps which will be carried out in the course of the next eight years:

a. The IEC will sell, during the next 5 years, around 19 production units, which it currently holds, at 5 different sites, which constitute approx. one half of the production of electricity using gas: (a) Alon Tavor – within 18 months from the date of approval of the Reform; (b) Ramat Hovav – within two and a half years from the date of approval of the Reform; (c) Reading – within three years from the date of approval of the Reform; (d) eastern Hagit – within four years from the date of approval of the Reform; (e) Eshkol – within five years from the date of approval of the Reform.

b. The IEC will build two modern production units using natural gas at Orot Rabin, as part of the trend to reduce the use of coal in the electricity production process, as was expressed also in the notice of the Minister of Energy of January 3, 2018, as specified above, in lieu of the coal units 1 to 4 which are expected to close down .This activity will be incorporated in a wholly-owned subsidiary of the IEC.

Further to the foregoing approval of the Reform, on July 29, 2018 the government approved cessation of the current operation of the (coal-fired) electricity production units 1 to 4 at the Orot Rabin power plant, subject to fulfillment of conditions precedent (connection of three natural gas suppliers to the shore and commencement of operation of a first CCGT (combined cycle power plant) with a capacity of approx. 600 watts which will be built by a subsidiary of the IEC) from June 2022.

On October 9, 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 by means of using 80% natural gas and 20% renewable energies as of 2030, with a final shutdown of the coal-based power plants in Hadera and in Ashkelon in 2028.

b. The industry sector – Production of 95% of the energy and steam required by the industry by means of natural gas as of 2030.

c. The transportation sector – A gradual transition to electric cars and natural gas trucks and the imposition of an absolute ban on the import of cars that operate on polluting fuels as of 2030.

The aforesaid has several main advantages, including, *inter alia*, the reduction of electricity production costs, since the natural gas is a more efficient energy source compared with the main energy sources currently used by the IEC (coal, diesel oil and fuel oil). Natural gas is also a cleaner source of energy compared with the sources of energy mentioned above, thereby increasing the demand for natural gas on account of more contaminating sources of energy.

- **Improvement in the diplomatic relations with neighboring countries** – Recently, the relations with several neighboring countries, the business relations with which are strategic for the State of Israel in general and for the gas companies in particular, have demonstrated a trend of improvement. In this context we shall note the export agreement signed on September 26, 2016 between the Leviathan Partnership and the Jordanian electric corporation (NEPCO), for the supply of up to 45 BCM of natural gas for a period of about 15 years (we note that the closing conditions in the agreement have been fulfilled, and that the gas transmission pipeline is currently under construction), and the agreements signed on February 19, 2018 between the partners in the Tamar project and the Leviathan project and the Egyptian Dolphinus, for the supply of approx. 64 BCM of natural gas for a period of about 10 years. It is noted that on September 26, 2018, an agreement was signed (subject to the fulfillment of closing conditions, as specified in the Partnership's report) between EMED (a company held by Delek Drilling (25%), Noble Energy (25%) and the East Gas Company (50%)) for the acquisition of 39% of EMG, which owns a subsea pipeline for the transport of gas between Israel and Egypt, in the context of which, upon the closing of the acquisition transaction, the capacity and operation rights in connection with the EMG pipeline shall be transferred to the purchaser (EMED), for execution of the agreements with Dolphinus, as described above.

- According to publications by the Ministry of Energy, the amount of natural gas consumed in the market in 2017 totaled approx. 10.35 BCM, an increase of approx. 7% compared with 2016. Total natural gas consumption for electricity production was estimated at approx. 8.5 BCM, representing approx. 83% of the total natural gas consumption. Furthermore, natural gas consumption by the industry sector was estimated at approx. 1.81 BCM. The scope of the use of natural gas in Israel in 2018 is estimated by various entities in the energy market at approx. 11 BCM, which constitutes an annual increase of approx. 6% relative to 2017.

  The natural gas demand forecast released by the Gas Authority[14] is based, *inter alia,* on continued growth of electricity consumption with a multi-annual average of approx. 3%, with minimal use of diesel oil and fuel oil, reliance on coal plants at a similar scope to the current scope, except for the construction of new plants (assuming that coal units at the Rabin Lights power plant will not be converted to the use of natural gas), transition to natural gas as a primary fuel for electricity production commencing in 2014 and gradual assimilation of renewable energies. Furthermore, the forecast takes into account gradual

[14] Source: http://energy.gov.il/Subjects/NG/Pages/GxmsMniNGEconomy.aspx.

conversion into use of natural gas in transportation, as well as local production of methanol and ammonia in the petrochemical industry.

According to forecasts that were published by various entities in the market, including forecasts which were included in the Tamar reservoir's partners reports to TASE, the level of demand for natural gas in the years 2020 and 2025 will be approx. 14 BCM and 19 BCM, respectively.

### 3.2.6 Regulatory Environment

The production of natural gas from reservoirs in the territorial waters of the State of Israel and the sale thereof are subject to regulatory restrictions pertaining to the amount of gas produced and restrictions on exporting the gas outside of Israel and pertaining to the gas prices. In addition, the production and sale of natural gas from the Tamar, Leviathan, Karish and Tanin reservoirs and/or another reservoir, are subject to further regulatory restrictions, as specified below:

- **Royalties to the State of Israel –** Under the Petroleum Law, a lease holder is charged with 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 manner of calculation of the value at the wellhead for the Tamar reservoir is under discussion between the Petroleum Commissioner and the partners in the Tamar reservoir and the manner of calculation has not been set yet. Currently the partners in the Tamar project pay advance payments on account of royalties at the rate of 11.65% of the Tamar project revenues. The manner of calculation of the royalties for the Leviathan, Karish and Tanin reservoirs has not been determined yet.

- **Taxation of Profits from Natural Resources Law** - The Resources Taxation Law prescribes a levy on petroleum and gas profits according to a mechanism which relates the rate of the levy and the ratio of the net accrued revenues from the petroleum and gas production project and the total accrued investments for the initial exploration and development of the reservoir ("**Investment Coverage Ratio**"). The minimal levy at a rate of 20% will be charged when the Investment Coverage Ratio will reach 1.5 and will increase gradually to a rate of 50% (depending, *inter alia*, on the Corporate Tax rate) when the Investment Coverage Ratio shall reach 2.3. The levy will be calculated and imposed on each reservoir separately.

- **Antitrust and exemption from the provisions of the Restrictive Trade Practices Law** – In August 2015, a government resolution was made regarding a framework for the regulation of the natural gas market in Israel including with respect to the rights of the Partnership in the natural gas reservoirs Tamar, Leviathan, Karish and Tanin which took effect on December 17, 2015 upon the grant of an exemption from several provisions of the Restrictive Trade Practices Law, 5748-1988 (the "**Gas Framework**").

  The Gas Framework grants an exemption to Delek Drilling, Noble and Ratio from the restrictive arrangements pertaining to the Leviathan reservoir. Furthermore, The Gas Framework grants an exemption from Delek Drilling and Noble being the holders of a monopoly with respect to the Tamar and Leviathan reservoirs (the "**Exemption**"). The grant of the Exemption as described above is subject, *inter alia*, to the fulfillment of the following conditions:

- The sale of the rights of Delek Drilling and Noble in the Karish and Tanin reservoirs to a third party, not related to any of them, within 14 months from the date of grant of the Exemption or from the date of release of a new regulation draft by the Petroleum Commissioner pertaining to the qualifying conditions for an operator, whichever is later. We shall note that on August 16, 2016, an agreement was executed for the sale of all of the rights in the Karish and Tanin Leases between Delek Drilling and Energean.

- The sale of the entire rights of Delek Drilling in Tamar Reservoir to a third party unrelated thereto or to any of the holders of rights in the Leviathan, Karish and Tanin reservoirs as well as restriction of the rights of Noble in the Tamar reservoir to a maximum 25% rate within 72 months. As of the date of the Work, the Partnership holds directly 22% of the Tamar reservoir. Furthermore, we shall note that in January 2018 Noble sold Tamar Petroleum Ltd. 7.5% of its rights in the Tamar reservoir, and as a result, it went down to a 25% holding rate in the Tamar reservoir.

- 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 Control** – In the period between the taking effect of the Gas Framework until the fulfilment of the entire conditions of the Exemption, the price control in the natural gas sector by virtue of the Restrictive Trade Practices Law will be limited to the imposition of reporting requirements regarding profitability and the gas price, provided that during this period the holders of rights in Tamar and Leviathan shall offer potential consumers a price based on the weighted average price of the prices in the agreements existing in the reservoirs or prices in export agreements. Following is a summary of the price and linkage alternatives released within Government Resolution 476 of August 16, 2015:

  - **Alternative 1** – A price which will be set and updated according to the formula P(T) = R(T-2)/Q(T-2). With P(T) being the base price; R(T-2) being the amount of revenues from the total sales of natural gas carried out in the quarter preceding the quarter which preceded the date of execution of the agreement by the holder of a lease; and Q(T-2) being the aggregate amount of natural gas, supplied to the consumers in the quarter preceding the quarter which preceded the date of execution of the agreement by a holder of a lease. The base price will be updated based on the result obtained from the calculation according to the aforesaid formula.

- **Alternative 2** – A price which will be set according to the price of a Brent oil barrel, as calculated according to the formula optimal for the consumer prevailing on the date of resolution, in agreements of the lease holders for supply from the "Tamar" field.

- **Alternative 3** – The holders of rights in the leases will offer the potential consumers who are Private Electricity Producers (PEP) holding a license for installed capacity of 20 Megawatt or more per site, in addition also the alternative which includes linkage to the weighted production tariff published by the PAU-E as specified below:

  - **Conventional electricity producers** – simple average of the prices set in the contracts of the three large PEPs, and of the linkage under such contracts;

  - **Cogeneration electricity producers –** simple average of the prices set on the date of the government resolution in the cogeneration contracts linked to the weighted production tariff and the linkage under such contracts;

  The aforesaid averages will be calculated by the Natural Gas Authority according to data provided thereto by the holders of rights in the leases. Following are the linkage formulas for private electricity producers for Q4/2018:

  <u>Conventional Private Electricity Producer</u>

  CP$ = 5.71 * (53.3%* Pt/Pt0 + 46.7%* Pt/Pt0 * Ns0/Ns)

  <u>Cogeneration Private Electricity Producer</u>

  CP$ = 5.81 * (90%* Pt/Pt0 + 10%* Pt/Pt0 * Ns0/Ns)

  Whereby:

  | | | |
  |---|---|---|
  | CP$ | - | Indexed monthly price in $ per MMBTU |
  | Pt | - | Production component tariff known on the last date of the month preceding the month of calculation of the price |
  | Pt0 | - | Base production component tariff = ILS 0.3463 per kilowatt per hour |
  | Ns | - | Monthly average of Shekel-Dollar exchange rate as of the month of calculation of the price |
  | Ns0 | - | Dollar base rate = ILS 3.65 per Dollar |

  The lease holders will offer the consumer a floor price according to the offering in the existing agreements according to increments of $5.2 per MMBTU, $5 per MMBTU and $4.7 per MMBTU and the update mechanism will begin according to the last change which occurred in the production component. As of December 2018, the floor price is $4.7 per MMBTU.

- The option to choose among the price alternatives specified above will be made available to the Purchaser only just before the engagement in a contract. Furthermore, the holders of rights in the leases will be entitled to offer the potential consumers a discount on prices deriving from the alternatives specified above. In addition, the parties to the agreement will be entitled to elect any method of updating the base price, provided that it will be reasonable and accepted in the natural gas agreements in Israel or worldwide. In such case, the base price will be updated according to the linkage method selected.

### 3.2.7 Transactions for the purchase of natural gas from Karish and Tanin gas reservoirs

In December 2017 an agreement was executed for the sale of natural gas between Energean and 3 companies held by the Israeli Corporation Ltd. (Israel Chemicals ("**ICL**"), Oil Refineries Ltd. ("**ORL**") and OPC Energy Ltd. ("**OPC**") which is the second largest natural gas consumer in Israel after IEC, at a total scope of approx. 39 BCM for 15 years.

**The price mechanism between Energean and ICL and ORL, which are the main purchasers in the transaction (purchased 30 BCM of the total amount) is set as follows:**

When PT is larger than 43.47:

$CP = 3 + ((P_0 * PT/PT_0) * 0.5)$

When PT is smaller than 43.47:

$CP = P_0 * PT/PT_0$

Whereby:

| | | |
|---|---|---|
| P0 | - | $3.975 per MMBTU of natural gas |
| PT0 | - | Equal to 28.8 |
| PT | - | The weighted average of the production component tariff as published from time to time by the PAU-E |
| Ns | - | Monthly average of Shekel-Dollar exchange rate as of the month of calculation of the price |

In Addition, within the aforesaid agreements, there is a floor price of $3.975 per MMBTU of natural gas.

**The price mechanism between Energean and OPC is set as follows**:

$CP = P0 * PT/PT0$

Whereby:

| | | |
|---|---|---|
| P0 | - | $3.975 per MMBTU of natural gas |
| PT0 | - | Equal to 28.0 when PT is higher than 26.4<br>Equal to 26.4 when PT is lower than or equal to 26.4 |
| PT | - | The weighted average of the production component tariff as published from time to time by the PAU-E |

Furthermore, within the aforesaid agreements, there is a floor price of $3.975 per MMBTU of natural gas when PT is larger than or equal to 26.4 and a floor price of $3.8 per MMBTU of natural gas when PT is smaller than 26.4.

### 3.2.8 Risk and Uncertainty Factors

The exploration and findings development operations of petroleum and natural gas involves significant monetary expenses in conditions of uncertainty resulting in a very high financial risk level. Following is a specification of risk and uncertainty factors with significant effect on the operations of the Purchaser of the Karish and Tanin reservoirs and the proceeds expected therefrom:

- **Changes in the electricity production tariff, price indices, alternative energy sources prices –** The prices paid by the consumers for the natural gas derive, *inter alia*, from the electricity production tariff, 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 energy sources alternative to gas. A decline in tariffs can adversely affect also the prices which will be obtained from the Karish and Tanin reservoirs and the economic merit in the development thereof.

- **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 on gas supply –** In recent years, several significant gas reservoirs were discovered in Israel in amounts which significantly exceed the estimates of the Ministry of Energy regarding the needs of the local market. In addition, in 2015, a material natural gas reservoir was discovered in Egypt ("**Zohar**") and in 2018, a natural gas reservoir was discovered in Block 6 in Cyprus, these reservoirs could have a negative effect on the capacity of natural gas export from Israel on the one hand, and they could lead to an increase in competition in the natural gas market in Israel by increasing the supply (through import) on the other hand. Also, further findings may be discovered in the future, both in Israel and in other countries in the eastern Mediterranean Basin, whose development could lead to the entrance of other competitors on the supply of natural gas to the local market and to neighboring countries, and thus increase the scope of competition in the sector.

- **Restrictions on export –** Limiting the amount of exportable gas may have adverse effects in the form of surplus supply in the domestic market and reduced tariffs which may also adversely affect the prices obtained from the Karish and Tanin reservoirs and the economic merit in the development thereof. In this context, it is noted that, according to the Adiri Committee's draft recommendations of July 2018, the gas export quotas as determined in Government Resolution 442 shall remain unchanged. However, according to the Committee's recommendations, the formula for calculating the export quota shall be changed, such that it will be higher relative to the formula determined by Government Resolution 442, solely for gas reservoirs that have not yet been discovered.

- **Dependence on the proper working order of the Israeli National Transmission System** – The ability to supply gas which will be produced from the reservoirs to the potential consumers is dependent, *inter alia*, on the proper working order of the Israeli National Transmission System for the supply of gas and of the regional distribution networks.

- **Dependence on contractors and on professional services and equipment providers –** As of the date hereof**,** there are in Israel no contractors that are performing most of the actions required for the construction and operation of natural gas and oil reservoirs, and therefore there is a dependence of the companies working in the sector on foreign contractors for the performance of such work. Furthermore, the number of facilities that are capable of drilling and performing development activities offshore, in general, and in deep-water, in particular, is relatively small and there is a chance that no suitable facility 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** – Petroleum and gas exploration and production activities are exposed to a variety of risks, such as uncontrolled eruption of liquids and gas from the well, explosion, collapse of the well and other events which could affect the functioning of the production and transmission system, each of which could cause destruction or damage to petroleum or gas wells, the transmission and production facilities, exploration equipment etc. There is also a risk of liability for damage deriving from contamination due to the eruption and/or leakage of liquid and/or a gas leak. Despite the insurance existing in the market, not all of the possible risks are covered or are coverable.

- **Solely estimated costs and timetables and the option of lack of means –** Estimated costs for the performance of exploration and development activities and estimated timetables for the performance thereof are based solely on general estimates and could deviate significantly. The exploration plans could significantly change, *inter alia*, following failures and/or findings which will be obtained during the performance of such actions and lead to significant gaps in the timetables and the estimated costs of such activities. In certain cases, the purchaser could also waive the performance of certain activities required according to the work plan of the reservoirs and lose its 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.

- **Environmental regulation –** The companies that operate in the natural gas sector are subject to a range of laws, regulations and directives on the issue of environmental protection, which relate to various matters such as: leaking of oil, natural gas or of other pollutants into the marine environment, the release into the sea of polluting substances and waste of various types (wastewater, residues of drilling equipment, drilling mud, slurry, etc.), chemical substances used at the various work stages, emission of pollutants into the air, light and noise nuisances, construction of piping infrastructures on the seabed and related facilities. In addition, the companies are required, through the operators of the projects, to obtain approvals from entities authorized under the Petroleum Law, the Natural Gas Sector Law and other laws (such as environmental protection laws) for the purpose of their activity.

- **Further risk factors** – There are other factors which contribute to the uncertainty prevailing in the operating segment including difficulties in obtaining financing, information security risks, dependence on material customers, dependence on weather and sea conditions, cancellation or expiration of rights and petroleum assets and more.

### 3.2.9 Developments in the Market

- **Raising senior debt from a lenders' consortium** - On March 2, 2018 an agreement for the raising of senior debt in the amount of approx. $1.275 billion[15] was executed between Energean Oil & Gas plc and a consortium of local and international lenders towards the development of the Karish reservoir.

- **The offering of Energean on the London Stock Exchange** – On March 15, 2018 the parent company of Energean, Energean Oil & Gas plc completed an initial public offering on the London Stock Exchange, within that offering, it raised approx. $460 million, designated to be used, *inter alia*, for the development of the Karish reservoir.

- **Adoption of an investment decision** – On March 27, 2018, Energean notified the Partnership of the adoption of a decision of investment in the development of the Karish reservoir, and on March 29, 2018 it paid the Partnership the first payment in the amount of $10.85 million.

- **Drilling of an exploration well** – On June 25, 2018, Energean announced that the company's board of directors had approved the drilling of an exploration well in the Karish lease, which commenced in March 2019.

  On March 4, 2019, Energean announced commencement of the execution of the drilling plan in Israel, which includes the drilling of 3 production wells in the Karish reservoir, and an exploration drilling in the North Karish reservoir, which is intended to verify the presence of approx. 1.3 TCF of natural gas, with a 69% chance of success.

- **Resource classification** – On August 16, 2018, Energean notified that approx. 92% of the contingent resources of natural gas and hydrocarbon liquids in the best estimate category (2C) in the Karish and Tanin reservoirs were classified as reserves (2P), with no change in the total of all contingent resources (2C) and reserves (2P) together. It is noted that Energean has not released a third party resource report that is updated in a manner consistent with the aforesaid release.

- **Listing of Energean on the Israeli Stock Exchange** – On October 29, 2018, trading of Energean's parent company, Energean Oil & Gas plc, was launched on the Tel Aviv Stock

[15] See page 289 of Energean's Prospectus of March 22, 2018.

Exchange as a cross-listed company whose shares are additionally also premium-listed on the London Stock Exchange.

- **Commencement of manufacture of Energean's floating production facility** – On November 27, 2018, Energean announced commencement of manufacture, in China, of the floating rig (FPSO) that is due to be used by the Karish and Tanin reservoirs, and which is expected to be transferred to the Karish gas field in late 2020.

- **Signing of an agreement for the sale of gas with IPM Beer Tuvia Ltd. –** On January 2, 2019, Energean announced the signing of an agreement for the sale of up to 5.5 BCM of gas for a period of 19 years to IPM Beer Tuvia, subject to receipt of approvals and to the success of the 4 wells that are expected to be drilled in 2019, the first of which will be an exploration well in "Karish North", which commenced in March 2019.

- **Amendment to the gas supply agreement between the Tamar partnerships and the IEC –** On February 17, 2019, Delek Drilling publicized that the board of directors of the Partnership's general partner had approved an amendment to the agreement between the Tamar partnerships and the IEC, in the framework of which the price linkage clause determined in the agreement will not be implemented. Consequently, the gas prices will not rise from January 2019 until July 1, 2021 (the first price adjustment date set forth in the agreement between the Tamar partnerships and the IEC). The amendment to the agreement between the parties is expected to be signed upon receipt of the regulatory approvals required by the IEC. We shall note that the amendment to the agreement does not affect the projected prices in our work, since the price fixing mechanism, as described above, will end before commencement of the production of the gas expected from the Karish reservoir in our work (2022).

## 4. Description of the Transaction of Sale of Rights in the Karish and Tanin Leases

### 4.1 The Sold Rights

On February 7, 2012 and on May 22, 2013, the Partnerships reported to TASE that the Tanin and Karish gas leases, respectively, constitute natural gas discoveries. The share of each of the Partnerships in each of the Leases is 26.4705% (the share of Noble – 47.059%). It is noted that in May 2017, Delek Drilling merged with Avner and consequently the Avner partnership was stricken off without dissolution.

On August 16, 2015, a government resolution was made regarding a framework for the regulation of the natural gas market in Israel including with respect to the rights of the Partnership in the natural gas reservoirs Tamar, Leviathan, Karish and Tanin (the "**Gas Framework**" or the "**Framework**"). Within the Framework the gas and petroleum corporations active in the gas market in Israel, including the Partnerships, were granted an exemption from several provisions of the Restrictive Trade Practices Law given compliance with several conditions, including the sale of Karish and Tanin Leases within 14 months.

On November 14, 2015, the Partnerships announced that they purchased from Noble the right to sell the share of Noble in the Karish and Tanin Leases, in equal parts, in consideration for a total amount of approx. $67 million. According to the agreement between the Partnerships and Noble, the latter will not be entitled to any further consideration for the sale of the rights to a third party.

On August 16, 2016, an agreement was executed for the sale of all of the rights in the Karish and Tanin Leases between Delek Drilling and Avner and Energean Israel Ltd. (formerly Ocean Energean Oil and Gas Ltd.), a company registered in Cyprus which is a subsidiary of Energean E&P Holdings Ltd. ("**Energean**" and/or the "**Purchaser**")[16]. The main activity of the Purchaser is exploration, development and production of gas and petroleum reservoirs in Greece and other countries in the Balkan and Middle East area.

On December 27, 2016, the Partnerships announced that the closing conditions for the transaction were fulfilled. On March 27, 2018, Energean notified the Partnership of the adoption of a decision of investment for the development of Karish reservoir.

Following is a specification of the amounts of natural gas and hydrocarbon liquids (condensate and natural gas liquids) at the Karish and Tanin reservoirs (100%) which were released in the Energean Prospectus of March 16, 2018[17]:

| Lease | Reserves and Contingent Resources* | |
|---|---|---|
| | Natural Gas (BCM) | Hydrocarbon Liquids (MMBBL) |
| Karish | 45.0 | 28.7 |
| Tanin | 21.7 | 4.1 |
| **Total** | **66.7** | **32.8** |

[16] Energean Israel Ltd. serves as the operational arm of Energean E&P Holdings Ltd. in Israel.
[17] According to reports received by Energean from NSAI, Net Resources.

* The reserves in the 2P category constitute more than 90% of the aggregate of natural gas resources in the reservoir (2P+2C), according to Energean's report of August 16, 2018 on the London Stock Exchange. It is noted that Energean has not released an updated resource report, which is audited by a third party, that is updated in a manner consistent with the aforesaid release.

### 4.2 The Consideration

Following is a description of the consideration components in the Purchase Agreement:

a. The Purchaser will purchase from Delek Drilling (the "**Seller**") all of the rights of the Seller and of Noble in Karish and Tanin Leases (the "**Sold Rights**").

b. In consideration for the Sold Rights, the Purchaser will pay the Seller a total amount of $148.5 million which will be received in the following manner:

   i. Cash payment of $10 million which was paid to the Seller on the transaction closing date;

   ii. An additional payment of $30 million which was paid to the Seller on the transaction closing date;

   iii. The consideration balance, in an amount of $108.5 million, will be paid to the Seller in ten annual equal installments plus interest according to the mechanism set in the agreement. These payments will be made immediately after the date on which a Final Investment Decision (FID) will be adopted regarding the development of the Leases, or on the date which the total expenses of the Purchaser in relation to the development of the Leases will exceed $150 million, whichever is earlier (for elaboration see Annex B);

   iv. Note that on March 27, 2108, Energean notified the Partnership of making an Investment Decision in the development of Karish reservoir and on March 29, 2018 it paid the Partnership the first payment in an amount of $10.85 million.

   v. The Purchaser will transfer to the Seller 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[18] borne by the Partnerships in respect of their original share in the Leases.

[18] As defined in the reports of Delek Drilling and Avner to the TASE on December 25, 2016.

# 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 Seller in ten equal annual payments plus interest commencing from the date on which the Purchaser made a Final Investment Decision (FID) or the Purchaser invested in the development of the reservoir an aggregate sum exceeding $150 million (the "**Investment Decision**"), whichever is earlier. Therefore, this consideration component is similar in its nature to a financial debt of the Purchaser to the Seller, which is contingent upon the development of the Leases, whether by a Final Investment Decision (FID) or the actual performance of the investment (the "**Debt Component**").

   Note that on March 27, 2018 Energean notified the Partnership of the adoption of a Decision of Investment in the development of the Karish reservoir and therefore the Debt Component is defined as deferred consideration. As to the valuation of the Debt Component see Annex B.

ii. Royalties from revenues (net of existing royalties[19]) which will be paid to the Seller at rates of 7.5% before the Levy and 8.25% after the Levy. Therefore, the royalties are also contingent upon the development of the Leases and the ability of the Purchaser to produce revenues from natural gas and condensate from the reservoirs (the "**Royalties**").

According to the characteristics of the consideration components specified above and in view of our estimate of the materialization of the transaction and development of the reservoirs, 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 development of the reservoirs and the cash flow.

## 5.2 Work Assumptions

### 5.2.1 General

The main work assumptions as specified below are based on market data from public sources, information appearing in the Prospectus released by Energean on March 16, 2018, and the financial model of holdings which was received from the Partnership and whose main assumptions were examined by us and were found to be reasonable. **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**

[19] The sold rights will be transferred to the Purchaser together with the existing royalties in the Leases borne by each of the Sellers, with respect to their original share (26.4705%).

**regarding the types of the hydrocarbon liquids which will be produced from the reservoirs and in respect of which royalties will be paid to the Partnership, constitute forward-looking information in the meaning thereof in the Securities Law, 5728-1968, which there is no certainty of the materialization thereof, in whole or in part, in the said manner or in any other manner.**

### 5.2.2 The Valuation Date

The valuation was carried out as of December 31, 2018.

### 5.2.3 Timetable

Within our Work we assumed that in order to develop the Leases and provide the amounts of gas assumed, Energean will be required to execute agreements for the sale of natural gas. The agreements executed between Energean and the Israeli Corporation, Dorad, Rapak and Edeltech reflect the sale of more than 90% of the natural gas resources in the reservoirs and support the reasonability and feasibility of the estimate that the reservoirs will be developed.

Note that the development of the natural gas reservoirs Karish and Tanin is a strategic move for the State of Israel with respect to the variation of the gas supply sources and redundancy regarding the infrastructures of transporting natural gas onshore. Therefore, in our estimation, there is high probability that the State of Israel will act so that the reservoirs will be developed by the removal of possible barriers on the way to the development of the reservoirs.

On March 22, 2018, Energean announced the adoption of a Decision of Investment for the development of the Karish and Tanin reservoirs, and as a result of the Purchase Agreement, the first payment for the Debt Component was received on March 29, 2018 (the other annual payments will be received on March 31 of each of the years 2019-2027). Furthermore, it was assumed that the development of the reservoirs will be done gradually, such that the commencement of the production from Tanin lease will begin towards the completion of the production from Karish lease.

### 5.2.4 Quantity forecast and annual production rate

From an analysis of the demand forecast in the local market as released on the MAYA system by the Partnership, it arises that the total projected annual demand in the market during the running-in period and in the beginning of the commercial operation period in 2022, is expected to be approx. 15-18 BCM with the main demand deriving from an increase in electricity production (as a result of natural growth) and as a result of the conversion of coal plants to the use of natural gas (as specified in Section 3.2.5 above).

According to the development plan of the reservoirs released by Energean in the Prospectus, Energean estimates that it is expected to sell approx. 5.0 BCM on average throughout the years of the forecast, out of which approx. 3.3 BCM to 3.8 BCM are within the Take or Pay mechanisms included in the agreements with its customers. Therefore, we assumed a natural gas production rate of approx. 3.0 BCM in the first year of operation, with a gradual increase up to a rate of maximal annual natural gas sale rate of approx. 4.0 BCM from the third year of operation onwards, with the annual condensate quantity deriving from the ratio between the overall condensate quantity and the overall natural gas quantity, in each reservoir, and based on the work assumption that all of the hydrocarbon liquids which will be produced are of the condensate type (for a specification of the annual production rate forecast see Annex A).

Following is a summary of the assumptions regarding the date of commencement of production and annual production with respect to each of the Leases:

| Lease | Karish | Tanin |
|---|---|---|
| Operation period commencement | 1/2022 | 7/2033 |
| Operation period end | 9/2033 | 3/2039 |
| Natural Gas | | |
| Average annual production rate (BCM) | 3.83 | 3.77 |
| Total (BCM) | 45.0 | 21.7 |
| Condensate | | |
| Production ratio* | 18.06 | 5.35 |
| Total (MMBBL) | 28.7 | 4.1 |

* bbl of condensate per 1 mmcf of natural gas

### 5.2.5 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, and the parameters specified below:

  i. **The Production Component Tariff**: as of the Valuation Date, the production component tariff is 29.09 Agorot, as determined commencing from January 2019. 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, and by other production costs. According to our forecasts, the production component tariff is expected to range between approx. 28.4 and 31.3 Agorot throughout 2019-2037.

  ii. **ICL and ORL** – floor price of US$3.975 per mmbtu according to an agreement between the company and ICL and ORL.

  iii. **OPC** – floor price of US$3.975 per mmbtu when the production component is larger or equal to 26.4 Agorot, and a floor price of US$3.8 per mmbtu when the production component is lower than 26.4 according to an agreement between the company and OPC.

- It was assumed that the gas amount which will be sold will be equally distributed between Private Electricity Producers (contracts such as the contract with OPC) and industrial producers (contracts such as the contracts with ICL and ORL).

### 5.2.6 Condensate Prices Forecast

The condensate prices forecast was estimated based on the average of the long-term petroleum prices forecast of the World Bank[20] and the EIA[21] and based on the Partnership's assumption that the condensate price will be derived from the Brent price while corresponding to the differences in the petroleum quality.

### 5.2.7 The Royalties Rate

The rate of the royalties to be paid to the State was set, according to the Petroleum Law, at 12.5% of the value of the gas at the wellhead. The actual royalties' rate is lower as a result of deduction of expenses for the transmission systems and the treatment of the gas up to the gas delivery point on shore. According to the Partnership's estimates, it was assumed that the effective royalty rate which will be paid to the State for the gas and condensate is 11.5%. Furthermore, the rate of the existing royalties in the Leases, borne by each of the Partnerships were similarly adjusted. We shall note that the actual rate of royalties could change and is not final.

### 5.2.8 Petroleum Profits Levy

The Petroleum Profits Levy is a progressive levy which is set according to a mechanism which connects the rate of the levy to the ratio of the net accrued revenues from the petroleum and gas production project and the total accrued investments for the exploration and initial development of the reservoir (the "**Investment Coverage Ratio**"). The minimal levy at a rate of 20% will be charged when the Investment Coverage Ratio will reach 1.5 and rise gradually to a rate of 50% (according to the corporate tax rate[22]) with the Investment Coverage Ratio reaching 2.3. The levy will be calculated and imposed for every reservoir separately.

Within the cash flow forecast for the royalties, we deducted the levy from the net royalties (after offsetting the existing royalties) which will be received by the Partnership from each lease, based on the rate of the levy calculated in the financial model of each of the Leases.

### 5.2.9 Royalties Cap Rate

We estimated the royalties cap rate at approx. 11.5% (before tax) and it was calculated in the following manner:

- We estimated the operating cap rate derived from the Leviathan reservoir as of December 31, 2018 through a comparison of the following: (1) the present value of the cash flow forecast (before tax) attributed to Ratio's share in the Leviathan reservoir (the forecast was released on February 28, 2018), with (2) the asset value of Ratio (the average market value of the participation units and the bonds of Ratio in the three months ended December 31, 2018, plus the net financial debt balances (excluding the bond balances) of Ratio as of September 30, 2018), based on the assumption that the value of Ratio mainly reflects the value of its share in the Leviathan reservoir. The calculated cap rate is estimated at approx. 13.25% (before tax).

[20] A world Bank Quarterly Report: Commodity Markets Outlook, October 2018
[21] U.S Energy Information Administration: Annual Energy Outlook 2019
[22] Corporate tax of 23% was assumed according to the historical tax rate known as of the date of the valuation.

- In view of the fact that the cap rate that was calculated above derives, *inter alia*, from forecasts that were released around 12 months ago, and in view of the expected decrease in the level of the natural gas prices relative to the projected level of the prices which prevailed at the time of the forecast (February 2018), and in view of the decline that was recorded in the oil price forecast, from which the condensate price directly derives, and in view of other parameters that changed between the periods, we examined the effect of the changes in the forecasts on the deriving cap rates for the reservoir, through examination of the gap between the cap rate of the Tamar reservoir, as derives from the asset value of Isramco in proximity to the date of release of the updated forecasts[23] of the Tamar reservoir of February 10, 2019 (using a methodology similar to the calculation of the cap rate for the Leviathan reservoir as described above), and based on the updated forecasts for the projected cash flows which were released by Isramco on February 10, 2019, compared with the previous forecasts of February 7, 2018. The gap in the calculated cap rates between the said forecasts was estimated at approx. 1.5%. Accordingly, we deducted this rate from the operating cap rate calculated for Leviathan above (13.25%). Consequently, we estimated the standardized operating cap rate for Leviathan at approx. 11.75% (before tax).

- We performed an adjustment in respect of the royalties risk level: the cap rate deriving from the asset value and the forecast as aforesaid is a cap rate which reflects the risk level of the operating cash flow. For the purpose of adjusting the operating cap rate to the cap rate of the royalties, whose risk level is the same as the risk level of the income, a deduction of approx. 1.25% was performed, which reflects the surplus risks that apply to the operating cash flow, including unexpected operating expenses, exposure to losses, working capital and a discrepancy in income and expenses linked to indices and exchange rates. This rate is estimated through a calculation of the gap between the operating cap rate and the royalties cap rate, which derive from the Tamar reservoir (using a methodology similar to the calculation of the cap rate for the Leviathan reservoir as described above) as of December 31, 2018. This gap is estimated through a calculation of the difference between the average cap rates, which derive from the asset value of Isramco and Tamar Petroleum (reflecting the operating risk of the Tamar reservoir) and the cap rate deriving from the asset value of Delek Royalties (reflecting the royalties risk of the Tamar reservoir).

- We added a 1% premium in view of the surplus risks inherent in the Karish and Tanin reservoirs relative to Leviathan as aforesaid.

- In accordance with the aforesaid, the calculated royalties cap rate for the Karish and Tanin reservoirs is estimated at approx. 11.5% (before tax).

## 5.3 Results of the Valuation

According to the assumptions specified in the Work itself, the value of the royalties is estimated at approx. $113.1 million. For details regarding the valuation of the debt component, see Annex

[23] Average asset value over a period of 10 days before and 10 days after the date of release of the forecasts.

B.

## 5.4 Sensitivity Analyses

Following is an analysis of the sensitivity of the royalties' value to 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) | +250bp | 79.4 | 86.0 | 90.3 | 95.5 | 100.6 | 104.9 | 111.7 |
| | +150bp | 84.9 | 91.9 | 96.5 | 102.1 | 107.5 | 112.1 | 119.4 |
| | +50bp | 90.9 | 98.3 | 103.3 | 109.2 | 115.1 | 120.0 | 127.8 |
| | - | 94.2 | 101.8 | 107.0 | **113.1** | 119.2 | 124.3 | 132.4 |
| | -50bp | 97.6 | 105.5 | 110.8 | 117.2 | 123.5 | 128.7 | 137.1 |
| | -150bp | 105.0 | 113.4 | 119.2 | 125.9 | 132.7 | 138.4 | 147.5 |
| | -250bp | 113.1 | 122.1 | 128.4 | 135.6 | 143.0 | 149.2 | 159.0 |

Following is an analysis of the sensitivity of the royalties' value to 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) | +250bp | 81.6 | 89.8 | 93.1 | 95.5 | 97.1 | 100.4 | 103.9 |
| | +150bp | 87.6 | 96.2 | 99.6 | 102.1 | 103.6 | 106.9 | 110.5 |
| | +50bp | 94.2 | 103.3 | 106.7 | 109.2 | 110.7 | 114.1 | 117.7 |
| | - | 97.9 | 107.2 | 110.6 | **113.1** | 114.6 | 118.0 | 121.5 |
| | -50bp | 101.7 | 111.2 | 114.6 | 117.2 | 118.6 | 122.1 | 125.5 |
| | -150bp | 110.0 | 120.0 | 123.4 | 125.9 | 127.4 | 130.8 | 134.2 |
| | -250bp | 119.3 | 129.8 | 133.2 | 135.6 | 137.0 | 140.5 | 143.7 |

Following is an analysis of the sensitivity of the royalties' value to 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) | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | (15.00) | (10.00) | (5.00) | - | 5.00 | 10.00 | 15.00 |
| Change in Cap Rates (in Base Points) | +250bp | 94.1 | 93.2 | 94.4 | 95.5 | 96.7 | 98.0 | 99.2 |
| | +150bp | 100.5 | 99.6 | 100.8 | 102.1 | 103.3 | 104.6 | 105.9 |
| | +50bp | 107.6 | 106.6 | 107.9 | 109.2 | 110.6 | 111.9 | 113.3 |
| | - | 111.4 | 110.4 | 111.7 | **113.1** | 114.5 | 115.9 | 117.3 |
| | -50bp | 115.4 | 114.3 | 115.8 | 117.2 | 118.5 | 120.0 | 121.5 |
| | -150bp | 124.0 | 122.9 | 124.4 | 125.9 | 127.4 | 129.0 | 130.5 |
| | -250bp | 133.6 | 132.5 | 134.1 | 135.6 | 137.2 | 138.9 | 140.6 |

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## Annex A – Cash Flow Forecast (Nominal)

| Year | Unit | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Production | | | | | | | | | | | | | |
| Gas production - Karish | bcm/y | - | - | - | 3.00 | 3.50 | 4.00 | 4.00 | 4.00 | 4.00 | 4.00 | 4.00 | 4.00 |
| Gas production - Tanin | bcm/y | - | - | - | - | - | - | - | - | - | - | - | - |
| Condensate production - Karish | bbl/y m | - | - | - | 1.91 | 2.23 | 2.55 | 2.55 | 2.55 | 2.55 | 2.55 | 2.55 | 2.55 |
| Condensate production - Tanin | bbl/y m | - | - | - | - | - | - | - | - | - | - | - | - |
| Prices | | | | | | | | | | | | | |
| Natural gas price | US$ | - | - | - | 4.00 | 4.17 | 4.17 | 4.22 | 4.28 | 4.34 | 4.05 | 4.02 | 4.03 |
| Condensate Price | US$ | - | - | - | 68.84 | 70.94 | 73.82 | 76.36 | 79.43 | 82.29 | 84.78 | 87.29 | 89.77 |
| Revenues | | | | | | | | | | | | | |
| Karish - Revenues | | | | | | | | | | | | | |
| Natural Gas Revenues | US$ MM | - | - | - | 432.3 | 524.7 | 600.2 | 607.2 | 615.8 | 624.7 | 582.9 | 578.2 | 580.1 |
| Condensate Revenues | US$ MM | - | - | - | 131.7 | 158.3 | 188.3 | 194.8 | 202.6 | 209.9 | 216.3 | 222.7 | 229.0 |
| Total Gross Revenues | US$ MM | - | - | - | 564.0 | 683.0 | 788.5 | 802.0 | 818.4 | 834.6 | 799.2 | 800.9 | 809.1 |
| Tanin - Revenues | | | | | | | | | | | | | |
| Natural Gas Revenues | US$ MM | - | - | - | - | - | - | - | - | - | - | - | - |
| Condensate Revenues | US$ MM | - | - | - | - | - | - | - | - | - | - | - | - |
| Total Gross Revenues | US$ MM | - | - | - | - | - | - | - | - | - | - | - | - |
| K&T - Total Gross Revenues | US$ MM | - | - | - | 564.0 | 683.0 | 788.5 | 802.0 | 818.4 | 834.6 | 799.2 | 800.9 | 809.1 |
| Delek Drilling - Transaction Revenues | | | | | | | | | | | | | |
| Transaction ORRI, Net* | US$ MM | - | - | - | 26.6 | 32.2 | 32.3 | 18.2 | 16.3 | 17.2 | 14.0 | 12.8 | 12.8 |
| **Total Discounted Transaction Revenues** | US$ MM | **-** | **-** | **-** | **18.1** | **19.7** | **17.9** | **9.0** | **7.2** | **6.8** | **5.0** | **4.1** | **3.6** |

*Net of Existing ORRI net of Petroleum Tax

| Year | Unit | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Production | | | | | | | | | | | |
| Gas production - Karish | bcm/y | 4.00 | 4.00 | 2.50 | - | - | - | - | - | - | - |
| Gas production - Tanin | bcm/y | - | - | 1.45 | 4.00 | 4.00 | 4.00 | 4.00 | 4.00 | 0.25 | - |
| Condensate production - Karish | bbl/y m | 2.55 | 2.55 | 1.59 | - | - | - | - | - | - | - |
| Condensate production - Tanin | bbl/y m | - | - | 0.27 | 0.76 | 0.76 | 0.76 | 0.76 | 0.76 | 0.05 | - |
| Prices | | | | | | | | | | | |
| Natural gas price | US$ | 4.07 | 4.11 | 4.17 | 4.22 | 4.28 | 4.33 | 4.39 | 4.39 | 4.39 | 4.39 |
| Condensate Price | US$ | 92.92 | 96.10 | 99.31 | 102.55 | 105.84 | 109.16 | 112.50 | 115.85 | 119.23 | 122.64 |
| Revenues | | | | | | | | | | | |
| Karish - Revenues | | | | | | | | | | | |
| Natural Gas Revenues | US$ MM | 585.5 | 592.2 | 375.1 | - | - | - | - | - | - | - |
| Condensate Revenues | US$ MM | 237.0 | 245.2 | 158.3 | - | - | - | - | - | - | - |
| Total Gross Revenues | US$ MM | 822.6 | 837.4 | 533.4 | - | - | - | - | - | - | - |
| Tanin - Revenues | | | | | | | | | | | |
| Natural Gas Revenues | US$ MM | - | - | 217.0 | 607.7 | 615.4 | 623.3 | 631.3 | 631.3 | 40.0 | - |
| Condensate Revenues | US$ MM | - | - | 27.1 | 77.5 | 80.0 | 82.5 | 85.0 | 87.6 | 5.7 | - |
| Total Gross Revenues | US$ MM | - | - | 244.2 | 685.2 | 695.4 | 705.8 | 716.3 | 718.9 | 45.7 | - |
| K&T - Total Gross Revenues | US$ MM | 822.6 | 837.4 | 777.6 | 685.2 | 695.4 | 705.8 | 716.3 | 718.9 | 45.7 | - |
| Delek Drilling - Transaction Revenues | | | | | | | | | | | |
| Transaction ORRI, Net* | US$ MM | 13.0 | 13.2 | 19.9 | 23.9 | 12.5 | 11.6 | 11.3 | 11.3 | 0.7 | - |
| **Total Discounted Transaction Revenues** | US$ MM | **3.3** | **3.0** | **4.1** | **4.5** | **2.1** | **1.7** | **1.5** | **1.4** | **0.1** | **-** |

*Net of Existing ORRI net of Petroleum Tax

## Annex B – Valuation of the Debt Component

### A. General

Within the agreement for the sale of all of the rights in the Leases it was provided that the Partnership will be entitled, *inter alia*, to consideration in an amount of $108.5 million which will be paid in ten equal annual payments plus interest commencing from the date on which the Purchaser made a Final Investment Decision (FID) or the Purchaser invested in the development of the reservoir an aggregate sum exceeding $150 million, whichever is earlier. Therefore, this consideration component is similar in its nature to a financial debt of the Purchaser, contingent upon the development of the Leases, whether by a Final Investment Decision (FID) or by an actual performance of investment. In view of the Investment Decision adoption of March 2018, the Debt Component was defined within this Work as deferred consideration and valued as a financial debt.

### B. Cap Rate

The cap rate of the Debt Component was estimated at 7.5% according to the methodology described in Section 5.2.9.1 of the work carried out by us as of December 31, 2017, according to which it was assumed that the cap rate after the Investment Decision is approx. 7.5%, based on the average rate of return of the Ratio Series B bond, after the release of the FID for the Leviathan reservoir plus a non-negotiability premium of approx. 0.5%. In the work as of December 31, 2017, it was assumed that the Investment Decision would be made towards the end of Q1/2019 and that the cap rate would be gradually reduced by approx. 0.5% up to this date. However, since the Investment Decision for the Karish reservoir occurred already during Q1/2018, in this Work the cap rate was set at 7.5% as aforesaid, similarly to the cap rate estimated in the previous work as of September 30, 2018.

We shall note that according to the report in the Energean Prospectus[24], on March 2, 2018, it executed with a consortium of local and international lenders an agreement for the raising of senior debt in the sum of approx. $1.275 billion, in favor of the development of Karish reservoir (the "**Financing Agreement**"). According to the terms of the Financing Agreement, the senior debt will be paid by a single payment upon the lapse of 3.75 years, with the interest for the first year being LIBOR plus a 3.75% margin; the interest for the second year is LIBOR plus a margin of 4%; the interest for the third year is LIBOR plus a margin of 4.25%; the interest for the last 9 months is LIBOR plus a margin of 4.75% (the weighted average of the margin is 4.15%). The fixed interest included in the Financing Agreement was estimated by us at approx. 6.8% through a transaction for the swap of variable interest (LIBOR 3 months) to fixed interest (IRS – Interest Rate Swap) plus the average margin.

According to information received from the Partnership, the senior debt is at a higher seniority level than the level of the debt component contemplated in our Work. In addition, in our estimate, on the date of the valuation, not all of the conditions precedent in the Financing Agreement have been fulfilled yet and no withdrawal has been actually carried out yet, and therefore, it was assumed that the cap rate of the Debt Component is higher than the rate of return embedded in the senior debt.

### C. The results of the valuation

[24] See page 289 of Energean's Prospectus of March 22, 2018.

According to the balance of the cash flows expected to be received by the Partnership (9 equal annual payment in the sum of $10.85 million, plus interest commencing on March 31, 2019), the value of the Debt Component was estimated at approx. $91.5 million.

Following is an analysis of the sensitivity of the Debt Component to the cap rate (U.S.$ in millions):

| | **Profit (Loss) from Changes** | | **Fair value** | **Profit (Loss) from Changes** | |
|---|---|---|---|---|---|
| Change in the cap rate | 2% | 1% | $ in thousands | -1% | -2% |
| **Total** | **(5.7)** | **(2.9)** | **91.5** | **3.1** | **6.4** |

# Definitions

| | |
|---|---|
| **Delek Drilling Limited Partnership** | Delek Drilling Limited Partnership |
| **Avner** | Avner Oil Exploration - Limited Partnership |
| **Natural Gas** | A gas mixture containing mainly Methane, used mainly for the production of electricity and as a source of energy for industry |
| **The Purchaser/Energean** | Energean E&P Holdings Ltd. through Energean Israel Limited (Formerly Ocean Energean Oil and Gas Ltd.). |
| **The Partnerships/Sellers** | Delek Drilling and Avner |
| **The Petroleum Law** | The Petroleum Law, 5712-1952 |
| **The Gas Framework or the Framework** | The resolution of the Israeli government on the creation of a framework for increasing the amount of natural gas produced from the Tamar natural gas field and the quick development of the Leviathan, Karish and Tanin natural gas fields as well as other gas fields |
| **Noble** | Noble Energy Mediterranean Ltd. |
| **Condensate** | Hydrocarbon liquid created during the production of natural gas, used as raw material for the production of fuels and constitutes a petroleum substitute |
| **Petroleum Asset** | A lease with 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 |
| **Ratio** | Ratio Oil Exploration (1992), Limited Partnership |
| **Isramco** | Isramco Negev 2, Limited Partnership |
| **BCM** | Billion Cubic Meters |
| **DCF** | Discounted Cash Flows |
| **FID** | The date on which the Purchaser adopted a decision for the investment for the development of Karish and Tanin natural gas reservoirs |
| **LNG** | Liquid Natural Gas |
| **MMBTU** | A Million BTU – an energy unit used as a basis for the determination of natural gas prices |