ESTIMATES

of

RESERVES AND FUTURE REVENUE

to the

TAMAR PETROLEUM LTD. INTEREST

in

CERTAIN GAS PROPERTIES

located in

TAMAR AND TAMAR SOUTHWEST FIELDS
TAMAR LEASE I/12, OFFSHORE ISRAEL

as of

DECEMBER 31, 2021

BASED ON PRICE AND COST PARAMETERS

specified by

TAMAR PETROLEUM LTD.

NETHERLAND, SEWELL & ASSOCIATES, INC.

WORLDWIDE PETROLEUM CONSULTANTS

ENGINEERING • GEOLOGY
GEOPHYSICS • PETROPHYSICS

March 3, 2022

Tamar Petroleum Ltd.
11 Galgalei Haplada Street
Herzliya 4672211
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, 2021, to the Tamar Petroleum Ltd. (Tamar Petroleum) interest in certain gas properties located in Tamar and Tamar Southwest Fields, Tamar Lease I/12, offshore Israel. It is our understanding that Tamar Petroleum owns a 16.75 percent direct working interest in these properties. Reserves in Tamar Southwest Field that extend beyond the Tamar Lease boundary 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 Tamar Petroleum, 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 Tamar Petroleum'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 Tamar Petroleum working interest reserves for these properties, as of December 31, 2021, to be:

	Gas Reserves (BCF)		Condensate Reserves (MMBBL)	
Category	Gross (100%)	Working Interest	Gross (100%)	Working Interest
Proved (1P)	7,592.9	1,271.8	9.9	1.7
Probable	2,582.7	432.6	3.4	0.6
Proved + Probable (2P)	10,175.6	1,704.4	13.2	2.2
Possible	2,468.3	413.4	3.2	0.5
Proved + Probable + Possible (3P)	12,643.9	2,117.9	16.4	2.8

Totals may not add because of rounding.

We estimate the future net revenue after levy and corporate income taxes, discounted at 0, 5, 10, 15, and 20 percent, to the Tamar Petroleum interest in these properties, as of December 31, 2021, to be:

	Future Net Revenue After Levy and Corporate Income Taxes (MM$)				
Category	Discounted at 0%	Discounted at 5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
Proved (1P)	2,150.8	1,379.7	964.4	722.7	571.8
Probable	866.1	303.8	121.0	56.2	31.4
Proved + Probable (2P)	3,016.8	1,683.5	1,085.4	778.9	603.2
Possible	916.9	238.3	69.9	23.1	8.5
Proved + Probable + Possible (3P)	3,933.7	1,921.8	1,155.3	802.0	611.8

Totals may not add because of rounding.

We estimate the gross (100 percent) reserves for these properties by field, as of December 31, 2021, to be:

	Tamar		Tamar Southwest		Total	
Category	Gas (BCF)	Condensate (MMBBL)	Gas (BCF)	Condensate (MMBBL)	Gas (BCF)	Condensate (MMBBL)
Proved (1P)	6,796.5	8.8	796.4	1.0	7,592.9	9.9
Probable	2,423.6	3.2	159.1	0.2	2,582.7	3.4
Proved + Probable (2P)	9,220.0	12.0	955.6	1.2	10,175.6	13.2
Possible	2,366.0	3.1	102.2	0.1	2,468.3	3.2
Proved + Probable + Possible (3P)	11,586.1	15.1	1,057.8	1.4	12,643.9	16.4

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. Monetary values shown in this report are expressed in United States dollars ($) or millions of United States dollars (MM$). For reference, the March 2, 2022, exchange rate was 3.24 Israeli New Shekels per United States dollar.

Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. The 1P reserves are inclusive of proved developed producing and proved undeveloped reserves. Our study indicates that as of December 31, 2021, there are no proved developed non-producing reserves for these properties. The project maturity subclass for these reserves is on production. The estimates of reserves and future revenue included herein have not been adjusted for risk. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated.

Working interest revenue shown in this report is Tamar Petroleum's share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for Tamar Petroleum's share of royalties, capital costs, abandonment costs, operating expenses, and Tamar Petroleum'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 Tamar Petroleum's historical production and operating expense data.

As requested, this report has been prepared using gas and condensate prices specified by Tamar Petroleum. Gas prices are based on Tamar Petroleum's estimates of expected approved and future sales contracts. These contract prices are derived mainly from various formulae that include indexation to the Consumer Price Index, the Power Generation Tariffs published by The Electricity Authority, or an average of long-term forecasts for Brent Crude prices provided by various institutions. Condensate prices are based on Brent Crude prices and are adjusted for quality, transportation fees, and market differentials.

Operating costs used in this report are based on operating expense records of Tamar Petroleum. Operating costs are limited to direct project-level costs, insurance costs, workover costs, indirect headquarters general and administrative overhead expenses, and Tamar Petroleum's estimate of the portion of the operator's headquarters general and administrative overhead expenses that can be directly attributed to this project; Chevron Mediterranean Limited is the operator of the properties. Based on 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 escalated for inflation using rates specified by Tamar Petroleum.

Capital costs used in this report were provided by Tamar Petroleum 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 Tamar Petroleum that are required for the above purpose, including ongoing maintenance projects, 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 Tamar Petroleum'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, with the exception of maintenance capital projects, which are escalated for inflation using rates specified by Tamar Petroleum.

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 Tamar Petroleum 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 Tamar Petroleum 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 Tamar Petroleum, 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 Tamar Petroleum. It should be noted that the actual production profile for each category may be lower or higher than the production profile used to calculate the estimates of future net revenue used in this report, and no sensitivity analysis was performed with respect to the production profile of the wells.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, seismic data, core data, well test data, production data, historical price and cost information, and property ownership interests. We were provided with all the necessary data to prepare the estimates for these properties, and we were not limited from access to any material we believe may be relevant. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with generally accepted petroleum engineering and evaluation principles set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the SPE (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, analogy, and reservoir modeling, that we considered to be appropriate and necessary to classify, categorize, and estimate reserves in accordance with the 2018 PRMS definitions and guidelines. Certain parameters used in our volumetric analyses are summarized in Tables VII and VIII. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

Netherland, Sewell & Associates, Inc. (NSAI) was engaged on December 15, 2021, by Mr. Yuval Raikin, Chief Financial Officer of Tamar Petroleum, to perform this assessment. The data used in our estimates were obtained from Tamar Petroleum, Chevron Mediterranean Limited, 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 Tamar Petroleum.

QUALIFICATIONS

NSAI performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. We provide a complete range of geological, geophysical, petrophysical, and engineering services, and we have the technical expertise and ability to perform these services in any oil and gas producing area in the world. The staff are familiar with the recognized industry reserves and resources definitions, specifically those promulgated by the U.S. Securities and Exchange Commission, by the Alberta Securities Commission, and by the SPE, Society of Petroleum Evaluation Engineers, World Petroleum Council, and American Association of Petroleum Geologists. The technical persons primarily responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards.

This assessment has been led by Mr. John R. Cliver and Mr. Zachary R. Long. Mr. Cliver and Mr. Long are Vice Presidents in the firm's Houston office at 1301 McKinney Street, Suite 3200, Houston, Texas 77010, USA. Mr. Cliver is a Licensed Professional Engineer (Texas Registration No. 107216). He has been practicing consulting petroleum engineering at NSAI since 2009 and has over 5 years of prior industry experience. Mr. Long is a Licensed Professional Geoscientist (Texas Registration No. 11792). He has been practicing consulting petroleum geoscience at NSAI since 2007 and has over 2 years of prior industry experience.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

By:
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

By:
John R. Cliver, P.E. 107216
Vice President

STATE OF TEXAS
J. R. CLIVER
107216
LICENSED
PROFESSIONAL ENGINEER

Date Signed: March 3, 2022

By:
Zachary R. Long, P.G. 11792
Vice President

STATE OF TEXAS
Z. R. LONG
GEOLOGY
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LICENSED
PROFESSIONAL GEOSCIENTIST

Date Signed: March 3, 2022

JRC:PNH

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.

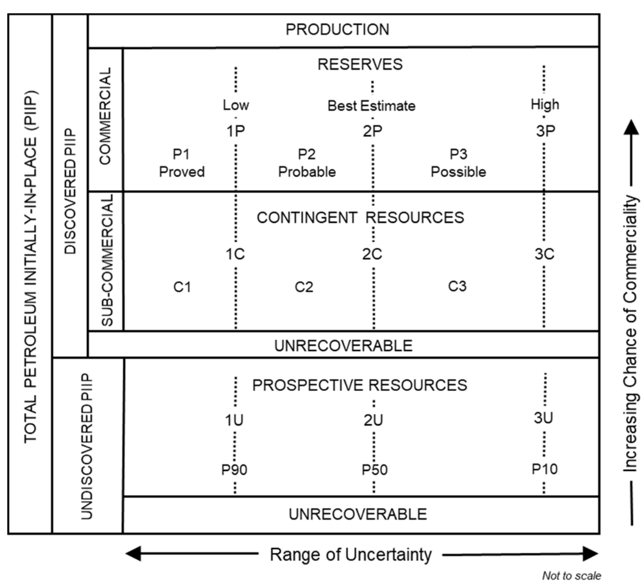

Figure 1.1—Resources classification framework

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).

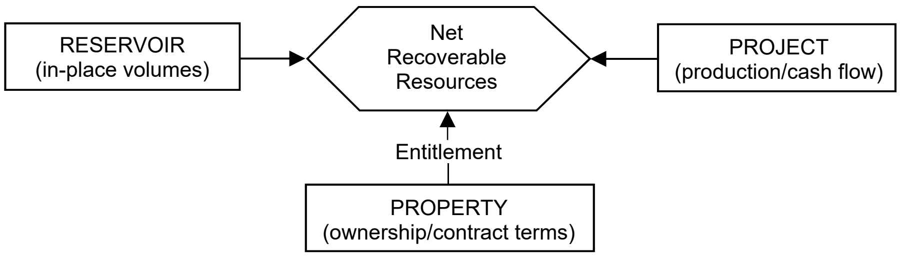

Figure 1.2—Resources evaluation

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).

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. To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability (see Section 2.1.2, Determination of Commerciality). This includes the requirement that there is evidence of firm intention to proceed with development within a reasonable time-frame. A reasonable time-frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While five years is recommended as a benchmark, a longer time-frame could be applied where, for example, development of an economic project is deferred at the option of the producer for, among other things, market-related reasons or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented. To be included in the Reserves class, there must be a high confidence in the commercial maturity and economic producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.
On Production	The development project is currently producing or capable of producing and selling petroleum to market.	The key criterion is that the project is receiving income from sales, rather than that the approved development project is necessarily complete. Includes Developed Producing Reserves. The project decision gate is the decision to initiate or continue economic production from the project.
Approved for Development	All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is ready to begin or is under way.	At this point, it must be certain that the development project is going ahead. The project must not be subject to any contingencies, such as outstanding regulatory approvals or sales contracts. Forecast capital expenditures should be included in the reporting entity's current or following year's approved budget. The project decision gate is the decision to start investing capital in the construction of production facilities and/or drilling development wells.

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Class/Sub-Class	Definition	Guidelines
Justified for Development	Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals/contracts will be obtained.	To move to this level of project maturity, and hence have Reserves associated with it, the development project must be commercially viable at the time of reporting (see Section 2.1.2, Determination of Commerciality) and the specific circumstances of the project. All participating entities have agreed and there is evidence of a committed project (firm intention to proceed with development within a reasonable time-frame). There must be no known contingencies that could preclude the development from proceeding (see Reserves class). The project decision gate is the decision by the reporting entity and its partners, if any, that the project has reached a level of technical and commercial maturity sufficient to justify proceeding with development at that point in time.
Contingent Resources	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable owing to one or more contingencies.	Contingent Resources may include, for example, projects for which there are currently no viable markets, where commercial recovery is dependent on technology under development, where evaluation of the accumulation is insufficient to clearly assess commerciality, where the development plan is not yet approved, or where regulatory or social acceptance issues may exist. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by the economic status.
Development Pending	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.	The project is seen to have reasonable potential for eventual commercial development, to the extent that further data acquisition (e.g., drilling, seismic data) and/or evaluations are currently ongoing with a view to confirming that the project is commercially viable and providing the basis for selection of an appropriate development plan. The critical contingencies have been identified and are reasonably expected to be resolved within a reasonable time-frame. Note that disappointing appraisal/evaluation results could lead to a reclassification of the project to On Hold or Not Viable status. The project decision gate is the decision to undertake further data acquisition and/or studies designed to move the project to a level of technical and commercial maturity at which a decision can be made to proceed with development and production.
Development on Hold	A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay.	The project is seen to have potential for commercial development. Development may be subject to a significant time delay. Note that a change in circumstances, such that there is no longer a probable chance that a critical contingency can be removed in the foreseeable future, could lead to a reclassification of the project to Not Viable status. The project decision gate is the decision to either proceed with additional evaluation designed to clarify the potential for eventual commercial development or to temporarily suspend or delay further activities pending resolution of external contingencies.
Development Unclarified	A discovered accumulation where project activities are under evaluation and where justification as a commercial development is unknown based on available information.	The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are ongoing to clarify the potential for eventual commercial development. This sub-class requires active appraisal or evaluation and should not be maintained without a plan for future evaluation. The sub-class should reflect the actions required to move a project toward commercial maturity and economic production.

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Class/Sub-Class	Definition	Guidelines
Development Not Viable	A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time because of limited production potential.	The project is not seen to have potential for eventual commercial development at the time of reporting, but the theoretically recoverable quantities are recorded so that the potential opportunity will be recognized in the event of a major change in technology or commercial conditions. The project decision gate is the decision not to undertake further data acquisition or studies on the project for the foreseeable future.
Prospective Resources	Those quantities of petroleum that are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.	Potential accumulations are evaluated according to the chance of geologic discovery and, assuming a discovery, the estimated quantities that would be recoverable under defined development projects. It is recognized that the development programs will be of significantly less detail and depend more heavily on analog developments in the earlier phases of exploration.
Prospect	A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.	Project activities are focused on assessing the chance of geologic discovery and, assuming discovery, the range of potential recoverable quantities under a commercial development program.
Lead	A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation to be classified as a Prospect.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to confirm whether or not the Lead can be matured into a Prospect. Such evaluation includes the assessment of the chance of geologic discovery and, assuming discovery, the range of potential recovery under feasible development scenarios.
Play	A project associated with a prospective trend of potential prospects, but that requires more data acquisition and/or evaluation to define specific Leads or Prospects.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to define specific Leads or Prospects for more detailed analysis of their chance of geologic discovery and, assuming discovery, the range of potential recovery under hypothetical development scenarios.

Table 2—Reserves Status Definitions and Guidelines

Status	Definition	Guidelines
Developed Reserves	Expected quantities to be recovered from existing wells and facilities.	Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well. Where required facilities become unavailable, it may be necessary to reclassify Developed Reserves as Undeveloped. Developed Reserves may be further sub-classified as Producing or Non-producing.
Developed Producing Reserves	Expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.	Improved recovery Reserves are considered producing only after the improved recovery project is in operation.
Developed Non-Producing Reserves	Shut-in and behind-pipe Reserves.	Shut-in Reserves are expected to be recovered from (1) completion intervals that are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

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Status	Definition	Guidelines
Undeveloped Reserves	Quantities expected to be recovered through future significant investments.	Undeveloped Reserves are to be produced (1) from new wells on undrilled acreage in known accumulations, (2) from deepening existing wells to a different (but known) reservoir, (3) from infill wells that will increase recovery, or (4) where a relatively large expenditure (e.g., when compared to the cost of drilling a new well) is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects.

Table 3—Reserves Category Definitions and Guidelines

Category	Definition	Guidelines
Proved Reserves	Those quantities of petroleum that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable from a given date forward from known reservoirs and under defined economic conditions, operating methods, and government regulations.	If deterministic methods are used, the term "reasonable certainty" is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the estimate. The area of the reservoir considered as Proved includes (1) the area delineated by drilling and defined by fluid contacts, if any, and (2) adjacent undrilled portions of the reservoir that can reasonably be judged as continuous with it and commercially productive on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, Proved quantities in a reservoir are limited by the LKH as seen in a well penetration unless otherwise indicated by definitive geoscience, engineering, or performance data. Such definitive information may include pressure gradient analysis and seismic indicators. Seismic data alone may not be sufficient to define fluid contacts for Proved reserves. Reserves in undeveloped locations may be classified as Proved provided that: A. The locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially mature and economically productive. B. Interpretations of available geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with drilled Proved locations. For Proved Reserves, the recovery efficiency applied to these reservoirs should be defined based on a range of possibilities supported by analogs and sound engineering judgment considering the characteristics of the Proved area and the applied development program.
Probable Reserves	Those additional Reserves that analysis of geoscience and engineering data indicates are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves.	It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate. Probable Reserves may be assigned to areas of a reservoir adjacent to Proved where data control or interpretations of available data are less certain. The interpreted reservoir continuity may not meet the reasonable certainty criteria. Probable estimates also include incremental recoveries associated with project recovery efficiencies beyond that assumed for Proved.

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Category	Definition	Guidelines
Possible Reserves	Those additional reserves that analysis of geoscience and engineering data indicates are less likely to be recoverable than Probable Reserves.	The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high-estimate scenario. When probabilistic methods are used, there should be at least a 10% probability (P10) that the actual quantities recovered will equal or exceed the 3P estimate. Possible Reserves may be assigned to areas of a reservoir adjacent to Probable where data control and interpretations of available data are progressively less certain. Frequently, this may be in areas where geoscience and engineering data are unable to clearly define the area and vertical reservoir limits of economic production from the reservoir by a defined, commercially mature project. Possible estimates also include incremental quantities associated with project recovery efficiencies beyond that assumed for Probable.
Probable and Possible Reserves	See above for separate criteria for Probable Reserves and Possible Reserves.	The 2P and 3P estimates may be based on reasonable alternative technical interpretations within the reservoir and/or subject project that are clearly documented, including comparisons to results in successful similar projects. In conventional accumulations, Probable and/or Possible Reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from Proved areas by minor faulting or other geological discontinuities and have not been penetrated by a wellbore but are interpreted to be in communication with the known (Proved) reservoir. Probable or Possible Reserves may be assigned to areas that are structurally higher than the Proved area. Possible (and in some cases, Probable) Reserves may be assigned to areas that are structurally lower than the adjacent Proved or 2P area. Caution should be exercised in assigning Reserves to adjacent reservoirs isolated by major, potentially sealing faults until this reservoir is penetrated and evaluated as commercially mature and economically productive. Justification for assigning Reserves in such cases should be clearly documented. Reserves should not be assigned to areas that are clearly separated from a known accumulation by non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results); such areas may contain Prospective Resources. In conventional accumulations, where drilling has defined a highest known oil elevation and there exists the potential for an associated gas cap, Proved Reserves of oil should only be assigned in the structurally higher portions of the reservoir if there is reasonable certainty that such portions are initially above bubble point pressure based on documented engineering analyses. Reservoir portions that do not meet this certainty may be assigned as Probable and Possible oil and/or gas based on reservoir fluid properties and pressure gradient interpretations.

REVENUE, COSTS, AND TAXES
PROVED (1P) RESERVES
TAMAR PETROLEUM LTD. INTEREST
TAMAR AND TAMAR SOUTHWEST FIELDS, TAMAR LEASE I/12, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2021

Period Ending	Working Interest Revenue (MM$)	Royalties State (MM$)	Royalties Interested Party (MM$)	Royalties Third Party (MM$)	Royalties Total (MM$)	Net Capital Costs (MM$)	Net Abandonment Costs (MM$)	Net Operating Expenses[1] (MM$)	Fututre Net Revenue Before Levy and Corporate Income Taxes Discounted at 0% (MM$)
12-31-2022	275.4	31.1	-	13.6	44.8	13.0	-	33.4	184.2
12-31-2023	264.5	29.9	-	13.1	43.0	47.2	-	33.4	140.9
12-31-2024	269.4	30.4	-	13.4	43.8	44.3	-	31.9	149.5
12-31-2025	280.3	31.7	-	13.9	45.6	22.1	-	31.4	181.2
12-31-2026	290.7	32.8	-	14.4	47.3	0.9	-	31.9	210.7
12-31-2027	313.6	35.4	-	15.5	51.0	0.9	-	32.5	229.2
12-31-2028	326.9	36.9	-	16.2	53.1	17.4	-	33.2	223.2
12-31-2029	333.6	37.7	-	16.5	54.2	17.4	-	33.9	228.1
12-31-2030	336.1	38.0	-	16.7	54.6	1.0	-	34.5	246.0
12-31-2031	358.0	40.5	-	17.7	58.2	1.0	-	35.2	263.6
12-31-2032	365.8	41.3	-	18.1	59.5	1.0	-	35.9	269.4
12-31-2033	371.1	41.9	-	18.4	60.3	17.5	-	36.6	256.7
12-31-2034	375.9	42.5	-	18.6	61.1	17.5	-	37.4	259.9
12-31-2035	380.8	43.0	-	18.9	61.9	14.5	-	38.1	266.3
12-31-2036	383.4	43.3	-	19.0	62.3	5.5	-	38.9	276.7
12-31-2037	322.2	36.4	-	16.0	52.4	1.1	-	38.9	229.9
12-31-2038	262.3	29.6	-	13.0	42.6	1.1	-	38.9	179.6
12-31-2039	222.3	25.1	-	11.0	36.1	1.1	-	39.2	145.8
12-31-2040	193.6	21.9	-	9.6	31.5	1.2	-	39.6	121.4
12-31-2041	172.7	19.5	-	8.6	28.1	1.2	-	40.2	103.3
12-31-2042	155.0	17.5	-	7.7	25.2	1.2	-	40.7	87.9
12-31-2043	139.1	15.7	-	6.9	22.6	1.2	-	41.3	73.9
12-31-2044	124.8	14.1	-	6.2	20.3	1.3	-	42.0	61.3
12-31-2045	112.0	12.7	-	5.5	18.2	1.3	-	42.6	49.9
12-31-2046	100.5	11.4	-	5.0	16.3	1.3	14.2	43.3	25.3
12-31-2047	57.3	6.5	-	2.8	9.3	1.3	14.2	43.7	-11.2
12-31-2048	22.6	2.6	-	1.1	3.7	1.4	14.2	44.1	-40.8
12-31-2049	-	-	-	-	-	-	-	-	-
12-31-2050	-	-	-	-	-	-	-	-	-
12-31-2051	-	-	-	-	-	-	-	-	-
12-31-2052	-	-	-	-	-	-	-	-	-
12-31-2053	-	-	-	-	-	-	-	-	-
12-31-2054	-	-	-	-	-	-	-	-	-
12-31-2055	-	-	-	-	-	-	-	-	-
12-31-2056	-	-	-	-	-	-	-	-	-
12-31-2057	-	-	-	-	-	-	-	-	-
12-31-2058	-	-	-	-	-	-	-	-	-
Total	6,810.1	769.5	-	337.5	1,107.0	235.8	42.7	1,012.9	4,411.8

Totals may not add because of rounding.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

NETHERLAND, SEWELL & ASSOCIATES, INC.

REVENUE, COSTS, AND TAXES
PROVED (1P) RESERVES
TAMAR PETROLEUM LTD. INTEREST
TAMAR AND TAMAR SOUTHWEST FIELDS, TAMAR LEASE I/12, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2021

Period Ending	Levy Rate[2] (%)	Levy[2] (MM$)	Fututre Net Revenue After Levy and Before Corporate Income Taxes Discounted at 0% (MM$)	Corporate Income Tax Rate[3] (%)	Corporate Income Taxes[3] (MM$)	Future Net Revenue After Levy and Corporate Income Taxes: Discounted at 0% (MM$)	Discounted at 5% (MM$)	Discounted at 10% (MM$)	Discounted at 15% (MM$)	Discounted at 20% (MM$)
12-31-2022	30.2	55.4	128.8	23.0	7.2	121.6	118.7	116.0	113.4	111.0
12-31-2023	34.9	49.1	91.8	23.0	6.2	85.6	79.5	74.2	69.4	65.1
12-31-2024	38.6	57.7	91.7	23.0	3.3	88.4	78.3	69.7	62.3	56.0
12-31-2025	43.0	77.9	103.3	23.0	-	103.3	87.1	74.0	63.3	54.6
12-31-2026	46.6	98.2	112.5	23.0	-	112.5	90.3	73.3	60.0	49.5
12-31-2027	46.8	107.3	121.9	23.0	-	121.9	93.2	72.2	56.5	44.7
12-31-2028	46.8	104.4	118.7	23.0	9.3	109.5	79.7	58.9	44.1	33.5
12-31-2029	46.8	106.7	121.3	23.0	15.3	106.1	73.6	51.9	37.2	27.0
12-31-2030	46.8	115.1	130.9	23.0	13.2	117.6	77.7	52.3	35.9	25.0
12-31-2031	46.8	123.4	140.3	23.0	15.2	125.1	78.7	50.6	33.2	22.1
12-31-2032	46.8	126.1	143.3	23.0	15.7	127.6	76.4	46.9	29.4	18.8
12-31-2033	46.8	120.1	136.5	23.0	18.6	117.9	67.3	39.4	23.6	14.5
12-31-2034	46.8	121.6	138.3	23.0	20.6	117.6	63.9	35.7	20.5	12.0
12-31-2035	46.8	124.6	141.7	23.0	21.7	120.0	62.1	33.1	18.2	10.2
12-31-2036	46.8	129.5	147.2	23.0	21.2	126.0	62.1	31.6	16.6	9.0
12-31-2037	46.8	107.6	122.3	23.0	16.4	105.9	49.7	24.2	12.1	6.3
12-31-2038	46.8	84.0	95.5	23.0	12.2	83.4	37.3	17.3	8.3	4.1
12-31-2039	46.8	68.2	77.6	23.0	9.7	67.8	28.9	12.8	5.9	2.8
12-31-2040	46.8	56.8	64.6	23.0	8.1	56.5	22.9	9.7	4.3	1.9
12-31-2041	46.8	48.4	55.0	23.0	6.5	48.4	18.7	7.5	3.2	1.4
12-31-2042	46.8	41.1	46.8	23.0	5.2	41.5	15.3	5.9	2.4	1.0
12-31-2043	46.8	34.6	39.3	23.0	4.0	35.3	12.4	4.5	1.7	0.7
12-31-2044	46.8	28.7	32.6	23.0	3.3	29.3	9.8	3.4	1.3	0.5
12-31-2045	46.8	23.3	26.5	23.0	2.6	23.9	7.6	2.5	0.9	0.3
12-31-2046	46.8	11.8	13.5	23.0	3.5	10.0	3.0	1.0	0.3	0.1
12-31-2047	46.8	-	-11.2	23.0	-	-11.2	-3.2	-1.0	-0.3	-0.1
12-31-2048	46.8	-	-40.8	23.0	-	-40.8	-11.2	-3.3	-1.0	-0.3
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	-	-	-	-	-	-
12-31-2055	-	-	-	23.0	-	-	-	-	-	-
12-31-2056	-	-	-	23.0	-	-	-	-	-	-
12-31-2057	-	-	-	23.0	-	-	-	-	-	-
12-31-2058	-	-	-	23.0	-	-	-	-	-	-
Total		2,021.9	2,389.9		239.1	2,150.8	1,379.7	964.4	722.7	571.8

Totals may not add because of rounding.

(1) Operating costs are limited to direct project-level costs, insurance costs, workover costs, indirect headquarters general and administrative overhead expenses, and Tamar Petroleum's estimate of the portion of the operator's headquarters general and administrative overhead expenses that can be directly attributed to this project.
(2) Oil and gas profits levy rates and estimates are provided by Tamar Petroleum.
(3) Corporate income tax rates and estimates of corporate income taxes are provided by Tamar Petroleum 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
TAMAR PETROLEUM LTD. INTEREST
TAMAR AND TAMAR SOUTHWEST FIELDS, TAMAR LEASE I/12, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2021

Period Ending	Working Interest Revenue (MM$)	Royalties: State (MM$)	Royalties: Interested Party (MM$)	Royalties: Third Party (MM$)	Royalties: Total (MM$)	Net Capital Costs (MM$)	Net Abandonment Costs (MM$)	Net Operating Expenses(1) (MM$)	Fututre Net Revenue Before Levy and Corporate Income Taxes Discounted at 0% (MM$)
12-31-2022	-	-	-	-	-	-	-	-	-
12-31-2023	-	-	-	-	-	-21.2	-	-	21.2
12-31-2024	-	-	-	-	-	-42.5	-	-	42.5
12-31-2025	-	-	-	-	-	21.2	-	-0.1	-21.2
12-31-2026	-	-	-	-	-	42.5	-	-0.1	-42.4
12-31-2027	-	-	-	-	-	-	-	-	-
12-31-2028	-	-	-	-	-	-16.5	-	-	16.5
12-31-2029	-	-	-	-	-	-16.5	-	-	16.5
12-31-2030	-	-	-	-	-	-	-	-	-
12-31-2031	-	-	-	-	-	-	-	-	-
12-31-2032	-	-	-	-	-	-	-	-	-
12-31-2033	-	-	-	-	-	-16.5	-	-	16.5
12-31-2034	-	-	-	-	-	-16.5	-	-	16.5
12-31-2035	-	-	-	-	-	19.5	-	-	-19.5
12-31-2036	3.5	0.4	-	0.2	0.6	-4.5	-	0.0	7.3
12-31-2037	70.6	8.0	-	3.5	11.5	8.2	-	0.8	50.1
12-31-2038	136.7	15.4	-	6.8	22.2	29.2	-	1.5	83.7
12-31-2039	182.9	20.7	-	9.1	29.7	13.4	-	2.1	137.7
12-31-2040	217.8	24.6	-	10.8	35.4	33.0	-	2.5	147.0
12-31-2041	246.8	27.9	-	12.2	40.1	-	-	2.8	203.9
12-31-2042	244.2	27.6	-	12.1	39.7	-	-	2.8	201.7
12-31-2043	214.5	24.2	-	10.6	34.9	-	-	2.4	177.2
12-31-2044	188.3	21.3	-	9.3	30.6	-	-	2.1	155.5
12-31-2045	165.3	18.7	-	8.2	26.9	-	-	1.9	136.5
12-31-2046	145.1	16.4	-	7.2	23.6	-	-14.2	1.6	134.1
12-31-2047	160.2	18.1	-	7.9	26.0	-	-14.2	1.8	146.6
12-31-2048	170.0	19.2	-	8.4	27.6	-0.0	-14.2	1.9	154.7
12-31-2049	170.6	19.3	-	8.5	27.7	1.4	-	46.7	94.8
12-31-2050	151.1	17.1	-	7.5	24.6	1.4	-	47.4	77.7
12-31-2051	133.8	15.1	-	6.6	21.8	1.4	15.0	48.1	47.5
12-31-2052	118.5	13.4	-	5.9	19.3	1.5	15.0	48.8	33.9
12-31-2053	96.0	10.9	-	4.8	15.6	1.5	15.0	49.5	14.3
12-31-2054	-	-	-	-	-	-	-	-	-
12-31-2055	-	-	-	-	-	-	-	-	-
12-31-2056	-	-	-	-	-	-	-	-	-
12-31-2057	-	-	-	-	-	-	-	-	-
12-31-2058	-	-	-	-	-	-	-	-	-
Total	2,815.7	318.2	-	139.5	457.7	40.2	2.4	264.6	2,050.8

Totals may not add because of rounding.

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
TAMAR PETROLEUM LTD. INTEREST
TAMAR AND TAMAR SOUTHWEST FIELDS, TAMAR LEASE I/12, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2021

Period Ending	Levy Rate[(2)] (%)	Levy[(2)] (MM$)	Fututre Net Revenue After Levy and Before Corporate Income Taxes Discounted at 0% (MM$)	Corporate Income Tax Rate[(3)] (%)	Corporate Income Taxes[(3)] (MM$)	Future Net Revenue After Levy and Corporate Income Taxes: Discounted at 0% (MM$)	Discounted at 5% (MM$)	Discounted at 10% (MM$)	Discounted at 15% (MM$)	Discounted at 20% (MM$)
12-31-2022	30.2	-	-	23.0	-	-	-	-	-	-
12-31-2023	35.3	8.1	13.1	23.0	-1.9	15.0	13.9	13.0	12.2	11.4
12-31-2024	40.1	19.2	23.2	23.0	-3.3	26.6	23.5	20.9	18.7	16.9
12-31-2025	44.2	-7.1	-14.1	23.0	1.6	-15.7	-13.2	-11.3	-9.6	-8.3
12-31-2026	46.7	-19.6	-22.8	23.0	1.1	-23.9	-19.2	-15.6	-12.8	-10.5
12-31-2027	46.8	-	-	23.0	0.9	-0.9	-0.7	-0.5	-0.4	-0.3
12-31-2028	46.8	7.7	8.8	23.0	2.6	6.1	4.5	3.3	2.5	1.9
12-31-2029	46.8	7.7	8.8	23.0	-1.4	10.2	7.0	5.0	3.6	2.6
12-31-2030	46.8	-	-	23.0	0.8	-0.8	-0.5	-0.3	-0.2	-0.2
12-31-2031	46.8	-	-	23.0	0.8	-0.8	-0.5	-0.3	-0.2	-0.1
12-31-2032	46.8	-	-	23.0	0.8	-0.8	-0.5	-0.3	-0.2	-0.1
12-31-2033	46.8	7.7	8.8	23.0	-1.0	9.8	5.6	3.3	2.0	1.2
12-31-2034	46.8	7.7	8.8	23.0	-1.1	9.9	5.4	3.0	1.7	1.0
12-31-2035	46.8	-9.1	-10.4	23.0	2.2	-12.6	-6.5	-3.5	-1.9	-1.1
12-31-2036	46.8	3.4	3.9	23.0	-0.0	3.9	1.9	1.0	0.5	0.3
12-31-2037	46.8	23.4	26.6	23.0	9.2	17.4	8.2	4.0	2.0	1.0
12-31-2038	46.8	39.2	44.5	23.0	17.9	26.6	11.9	5.5	2.7	1.3
12-31-2039	46.8	64.4	73.2	23.0	19.9	53.4	22.7	10.1	4.6	2.2
12-31-2040	46.8	68.8	78.2	23.0	24.8	53.4	21.7	9.2	4.0	1.8
12-31-2041	46.8	95.4	108.5	23.0	23.4	85.0	32.8	13.3	5.6	2.4
12-31-2042	46.8	94.4	107.3	23.0	23.2	84.1	30.9	11.9	4.8	2.0
12-31-2043	46.8	82.9	94.3	23.0	20.2	74.1	25.9	9.5	3.7	1.5
12-31-2044	46.8	72.8	82.7	23.0	17.2	65.5	21.9	7.7	2.8	1.1
12-31-2045	46.8	63.9	72.6	23.0	14.5	58.1	18.5	6.2	2.2	0.8
12-31-2046	46.8	62.8	71.3	23.0	11.5	59.9	18.1	5.8	1.9	0.7
12-31-2047	46.8	63.3	83.2	23.0	13.2	70.0	20.2	6.2	2.0	0.7
12-31-2048	46.8	53.3	101.4	23.0	11.6	89.7	24.6	7.2	2.2	0.7
12-31-2049	46.8	44.4	50.4	23.0	10.5	39.9	10.4	2.9	0.9	0.3
12-31-2050	46.8	36.4	41.4	23.0	8.7	32.7	8.1	2.2	0.6	0.2
12-31-2051	46.8	22.2	25.3	23.0	9.1	16.2	3.8	1.0	0.3	0.1
12-31-2052	46.8	15.9	18.0	23.0	7.3	10.7	2.4	0.6	0.2	0.0
12-31-2053	46.8	6.7	7.6	23.0	4.6	3.0	0.6	0.1	0.0	0.0
12-31-2054	-	-	-	23.0	-	-	-	-	-	-
12-31-2055	-	-	-	23.0	-	-	-	-	-	-
12-31-2056	-	-	-	23.0	-	-	-	-	-	-
12-31-2057	-	-	-	23.0	-	-	-	-	-	-
12-31-2058	-	-	-	23.0	-	-	-	-	-	-
Total		936.0	1,114.8		248.7	866.1	303.8	121.0	56.2	31.4

Totals may not add because of rounding.

(1) Operating costs are limited to direct project-level costs, insurance costs, workover costs, indirect headquarters general and administrative overhead expenses, and Tamar Petroleum's estimate of the portion of the operator's headquarters general and administrative overhead expenses that can be directly attributed to this project.
(2) Oil and gas profits levy rates and estimates are provided by Tamar Petroleum.
(3) Corporate income tax rates and estimates of corporate income taxes are provided by Tamar Petroleum 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
PROVED + PROBABLE (2P) RESERVES
TAMAR PETROLEUM LTD. INTEREST
TAMAR AND TAMAR SOUTHWEST FIELDS, TAMAR LEASE I/12, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2021

Period Ending	Working Interest Revenue (MM$)	Royalties				Net Capital Costs (MM$)	Net Abandonment Costs (MM$)	Net Operating Expenses[1] (MM$)	Fututre Net Revenue Before Levy and Corporate Income Taxes Discounted at 0% (MM$)
		State (MM$)	Interested Party (MM$)	Third Party (MM$)	Total (MM$)				
12-31-2022	275.4	31.1	-	13.6	44.8	13.0	-	33.4	184.2
12-31-2023	264.5	29.9	-	13.1	43.0	26.0	-	33.4	162.2
12-31-2024	269.4	30.4	-	13.4	43.8	1.8	-	31.9	191.9
12-31-2025	280.3	31.7	-	13.9	45.6	43.3	-	31.4	160.0
12-31-2026	290.7	32.8	-	14.4	47.3	43.4	-	31.8	168.2
12-31-2027	313.6	35.4	-	15.5	51.0	0.9	-	32.5	229.2
12-31-2028	326.9	36.9	-	16.2	53.1	0.9	-	33.2	239.7
12-31-2029	333.6	37.7	-	16.5	54.2	0.9	-	33.9	244.5
12-31-2030	336.1	38.0	-	16.7	54.6	1.0	-	34.5	246.0
12-31-2031	358.0	40.5	-	17.7	58.2	1.0	-	35.2	263.6
12-31-2032	365.8	41.3	-	18.1	59.5	1.0	-	35.9	269.4
12-31-2033	371.1	41.9	-	18.4	60.3	1.0	-	36.6	273.1
12-31-2034	375.9	42.5	-	18.6	61.1	1.0	-	37.4	276.3
12-31-2035	380.8	43.0	-	18.9	61.9	34.0	-	38.1	246.8
12-31-2036	386.8	43.7	-	19.2	62.9	1.1	-	38.9	284.0
12-31-2037	392.8	44.4	-	19.5	63.9	9.3	-	39.7	280.0
12-31-2038	398.9	45.1	-	19.8	64.8	30.3	-	40.5	263.3
12-31-2039	405.1	45.8	-	20.1	65.9	14.5	-	41.3	283.5
12-31-2040	411.5	46.5	-	20.4	66.9	34.1	-	42.1	268.4
12-31-2041	419.6	47.4	-	20.8	68.2	1.2	-	42.9	307.3
12-31-2042	399.2	45.1	-	19.8	64.9	1.2	-	43.5	289.6
12-31-2043	353.6	40.0	-	17.5	57.5	1.2	-	43.7	251.1
12-31-2044	313.1	35.4	-	15.5	50.9	1.3	-	44.1	216.8
12-31-2045	277.3	31.3	-	13.7	45.1	1.3	-	44.5	186.4
12-31-2046	245.6	27.8	-	12.2	39.9	1.3	-	45.0	159.4
12-31-2047	217.5	24.6	-	10.8	35.4	1.3	-	45.5	135.3
12-31-2048	192.6	21.8	-	9.5	31.3	1.4	-	46.1	113.9
12-31-2049	170.6	19.3	-	8.5	27.7	1.4	-	46.7	94.8
12-31-2050	151.1	17.1	-	7.5	24.6	1.4	-	47.4	77.7
12-31-2051	133.8	15.1	-	6.6	21.8	1.4	15.0	48.1	47.5
12-31-2052	118.5	13.4	-	5.9	19.3	1.5	15.0	48.8	33.9
12-31-2053	96.0	10.9	-	4.8	15.6	1.5	15.0	49.5	14.3
12-31-2054	-	-	-	-	-	-	-	-	-
12-31-2055	-	-	-	-	-	-	-	-	-
12-31-2056	-	-	-	-	-	-	-	-	-
12-31-2057	-	-	-	-	-	-	-	-	-
12-31-2058	-	-	-	-	-	-	-	-	-
Total	9,625.8	1,087.7	-	477.0	1,564.7	276.0	45.1	1,277.5	6,462.6

Totals may not add because of rounding.

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REVENUE, COSTS, AND TAXES
PROVED + PROBABLE (2P) RESERVES
TAMAR PETROLEUM LTD. INTEREST
TAMAR AND TAMAR SOUTHWEST FIELDS, TAMAR LEASE I/12, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2021

Period Ending	Levy Rate[2] (%)	Levy[2] (MM$)	Fututre Net Revenue After Levy and Before Corporate Income Taxes Discounted at 0% (MM$)	Corporate Income Tax Rate[3] (%)	Corporate Income Taxes[3] (MM$)	Future Net Revenue After Levy and Corporate Income Taxes				
						Discounted at 0% (MM$)	Discounted at 5% (MM$)	Discounted at 10% (MM$)	Discounted at 15% (MM$)	Discounted at 20% (MM$)
12-31-2022	30.2	55.4	128.8	23.0	7.2	121.6	118.7	116.0	113.4	111.0
12-31-2023	35.3	57.2	104.9	23.0	4.4	100.6	93.5	87.2	81.5	76.5
12-31-2024	40.1	77.0	115.0	23.0	-	115.0	101.8	90.6	81.1	72.9
12-31-2025	44.2	70.8	89.2	23.0	1.6	87.6	73.8	62.7	53.7	46.3
12-31-2026	46.7	78.5	89.7	23.0	1.1	88.6	71.1	57.7	47.2	39.0
12-31-2027	46.8	107.3	121.9	23.0	0.9	121.1	92.6	71.7	56.1	44.4
12-31-2028	46.8	112.2	127.5	23.0	11.9	115.6	84.2	62.2	46.6	35.3
12-31-2029	46.8	114.4	130.1	23.0	13.9	116.2	80.6	56.9	40.7	29.6
12-31-2030	46.8	115.1	130.9	23.0	14.0	116.9	77.2	52.0	35.6	24.8
12-31-2031	46.8	123.4	140.3	23.0	15.9	124.4	78.2	50.3	33.0	22.0
12-31-2032	46.8	126.1	143.3	23.0	16.5	126.8	76.0	46.6	29.2	18.7
12-31-2033	46.8	127.8	145.3	23.0	17.6	127.7	72.9	42.7	25.6	15.7
12-31-2034	46.8	129.3	147.0	23.0	19.5	127.5	69.3	38.7	22.2	13.1
12-31-2035	46.8	115.5	131.3	23.0	23.8	107.4	55.6	29.7	16.3	9.2
12-31-2036	46.8	132.9	151.1	23.0	21.1	130.0	64.1	32.6	17.1	9.2
12-31-2037	46.8	131.0	148.9	23.0	25.6	123.4	57.9	28.2	14.1	7.3
12-31-2038	46.8	123.2	140.1	23.0	30.1	110.0	49.2	22.8	11.0	5.4
12-31-2039	46.8	132.7	150.8	23.0	29.6	121.2	51.6	22.9	10.5	5.0
12-31-2040	46.8	125.6	142.8	23.0	32.9	109.9	44.6	18.8	8.3	3.8
12-31-2041	46.8	143.8	163.5	23.0	30.0	133.5	51.5	20.8	8.7	3.8
12-31-2042	46.8	135.5	154.1	23.0	28.4	125.7	46.2	17.8	7.2	3.0
12-31-2043	46.8	117.5	133.6	23.0	24.2	109.4	38.3	14.1	5.4	2.2
12-31-2044	46.8	101.5	115.4	23.0	20.5	94.9	31.6	11.1	4.1	1.6
12-31-2045	46.8	87.2	99.2	23.0	17.2	82.0	26.1	8.7	3.1	1.1
12-31-2046	46.8	74.6	84.8	23.0	15.0	69.8	21.1	6.8	2.3	0.8
12-31-2047	46.8	63.3	72.0	23.0	13.2	58.8	17.0	5.2	1.7	0.6
12-31-2048	46.8	53.3	60.6	23.0	11.6	49.0	13.4	3.9	1.2	0.4
12-31-2049	46.8	44.4	50.4	23.0	10.5	39.9	10.4	2.9	0.9	0.3
12-31-2050	46.8	36.4	41.4	23.0	8.7	32.7	8.1	2.2	0.6	0.2
12-31-2051	46.8	22.2	25.3	23.0	9.1	16.2	3.8	1.0	0.3	0.1
12-31-2052	46.8	15.9	18.0	23.0	7.3	10.7	2.4	0.6	0.2	0.0
12-31-2053	46.8	6.7	7.6	23.0	4.6	3.0	0.6	0.1	0.0	0.0
12-31-2054	-	-	-	23.0	-	-	-	-	-	-
12-31-2055	-	-	-	23.0	-	-	-	-	-	-
12-31-2056	-	-	-	23.0	-	-	-	-	-	-
12-31-2057	-	-	-	23.0	-	-	-	-	-	-
12-31-2058	-	-	-	23.0	-	-	-	-	-	-
Total		2,957.9	3,504.7		487.8	3,016.8	1,683.5	1,085.4	778.9	603.2

Totals may not add because of rounding.

(1) Operating costs are limited to direct project-level costs, insurance costs, workover costs, indirect headquarters general and administrative overhead expenses, and Tamar Petroleum's estimate of the portion of the operator's headquarters general and administrative overhead expenses that can be directly attributed to this project.
(2) Oil and gas profits levy rates and estimates are provided by Tamar Petroleum.
(3) Corporate income tax rates and estimates of corporate income taxes are provided by Tamar Petroleum and are its expected corporate income taxes per year.

NETHERLAND, SEWELL & ASSOCIATES, INC.

REVENUE, COSTS, AND TAXES
POSSIBLE RESERVES
TAMAR PETROLEUM LTD. INTEREST
TAMAR AND TAMAR SOUTHWEST FIELDS, TAMAR LEASE I/12, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2021

Period Ending	Working Interest Revenue (MM$)	Royalties: State (MM$)	Royalties: Interested Party (MM$)	Royalties: Third Party (MM$)	Royalties: Total (MM$)	Net Capital Costs (MM$)	Net Abandonment Costs (MM$)	Net Operating Expenses[1] (MM$)	Fututre Net Revenue Before Levy and Corporate Income Taxes Discounted at 0% (MM$)
12-31-2022	-	-	-	-	-	-	-	-	-
12-31-2023	-	-	-	-	-	-	-	-	-
12-31-2024	-	-	-	-	-	-	-	-	-
12-31-2025	-	-	-	-	-	-	-	-	-
12-31-2026	-	-	-	-	-	-	-	-	-
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	-	-	-	-	-	-33.0	-	-	33.0
12-31-2036	-	-	-	-	-	-	-	-	-
12-31-2037	-	-	-	-	-	-8.2	-	-	8.2
12-31-2038	-	-	-	-	-	-29.2	-	-	29.2
12-31-2039	-	-	-	-	-	-13.4	-	-	13.4
12-31-2040	-	-	-	-	-	-	-	-	-
12-31-2041	-	-	-	-	-	-	-	-	-
12-31-2042	28.6	3.2	-	1.4	4.7	50.8	-	0.3	-27.2
12-31-2043	82.7	9.3	-	4.1	13.4	16.5	-	0.9	51.9
12-31-2044	131.8	14.9	-	6.5	21.4	16.5	-	1.5	92.4
12-31-2045	176.4	19.9	-	8.7	28.7	-	-	2.0	145.7
12-31-2046	217.0	24.5	-	10.8	35.3	-	-	2.5	179.3
12-31-2047	246.7	27.9	-	12.2	40.1	-	-	2.8	203.8
12-31-2048	229.9	26.0	-	11.4	37.4	-	-	2.6	189.9
12-31-2049	207.5	23.4	-	10.3	33.7	-	-	2.3	171.4
12-31-2050	187.3	21.2	-	9.3	30.4	-	-	2.1	154.7
12-31-2051	169.0	19.1	-	8.4	27.5	-	-15.0	1.9	154.6
12-31-2052	172.3	19.5	-	8.5	28.0	-	-15.0	1.9	157.4
12-31-2053	181.2	20.5	-	9.0	29.4	0.0	-15.0	2.1	164.7
12-31-2054	249.8	28.2	-	12.4	40.6	1.5	-	52.3	155.4
12-31-2055	221.2	25.0	-	11.0	36.0	1.6	-	52.9	130.8
12-31-2056	195.5	22.1	-	9.7	31.8	1.6	15.0	53.6	93.5
12-31-2057	175.7	19.9	-	8.7	28.6	1.6	15.0	54.4	76.1
12-31-2058	157.7	17.8	-	7.8	25.6	1.6	15.0	55.3	60.1
Total	3,030.3	342.4	-	150.2	492.6	7.9	-	291.5	2,238.4

Totals may not add because of rounding.

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
POSSIBLE RESERVES
TAMAR PETROLEUM LTD. INTEREST
TAMAR AND TAMAR SOUTHWEST FIELDS, TAMAR LEASE I/12, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2021

			Fututre Net Revenue After Levy and Before Corporate Income Taxes	Corporate Income Tax	Corporate Income	Future Net Revenue After Levy and Corporate Income Taxes				
Period Ending	Levy Rate[2] (%)	Levy[2] (MM$)	Discounted at 0% (MM$)	Rate[3] (%)	Taxes[3] (MM$)	Discounted at 0% (MM$)	Discounted at 5% (MM$)	Discounted at 10% (MM$)	Discounted at 15% (MM$)	Discounted at 20% (MM$)
12-31-2022	30.2	-	-	23.0	-	-	-	-	-	-
12-31-2023	35.3	-	-	23.0	-	-	-	-	-	-
12-31-2024	40.1	-	-	23.0	-	-	-	-	-	-
12-31-2025	44.2	-	-	23.0	-	-	-	-	-	-
12-31-2026	46.7	-	-	23.0	-	-	-	-	-	-
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	15.4	17.5	23.0	-3.5	21.1	10.9	5.8	3.2	1.8
12-31-2036	46.8	-	-	23.0	0.8	-0.8	-0.4	-0.2	-0.1	-0.1
12-31-2037	46.8	3.9	4.4	23.0	-0.1	4.5	2.1	1.0	0.5	0.3
12-31-2038	46.8	13.7	15.5	23.0	-2.2	17.7	7.9	3.7	1.8	0.9
12-31-2039	46.8	6.3	7.1	23.0	0.2	7.0	3.0	1.3	0.6	0.3
12-31-2040	46.8	-	-	23.0	1.9	-1.9	-0.8	-0.3	-0.1	-0.1
12-31-2041	46.8	-	-	23.0	1.9	-1.9	-0.7	-0.3	-0.1	-0.1
12-31-2042	46.8	-12.7	-14.5	23.0	10.3	-24.7	-9.1	-3.5	-1.4	-0.6
12-31-2043	46.8	24.3	27.6	23.0	10.9	16.7	5.8	2.2	0.8	0.3
12-31-2044	46.8	43.3	49.2	23.0	15.5	33.7	11.2	3.9	1.5	0.6
12-31-2045	46.8	68.2	77.5	23.0	17.8	59.7	19.0	6.4	2.2	0.8
12-31-2046	46.8	83.9	95.4	23.0	21.2	74.2	22.4	7.2	2.4	0.9
12-31-2047	46.8	95.4	108.4	23.0	24.2	84.2	24.3	7.4	2.4	0.8
12-31-2048	46.8	88.9	101.0	23.0	22.3	78.7	21.6	6.3	1.9	0.6
12-31-2049	46.8	80.2	91.2	23.0	19.4	71.8	18.8	5.2	1.5	0.5
12-31-2050	46.8	72.4	82.3	23.0	17.1	65.2	16.2	4.3	1.2	0.4
12-31-2051	46.8	72.4	82.3	23.0	13.7	68.5	16.3	4.1	1.1	0.3
12-31-2052	46.8	73.7	83.7	23.0	14.2	69.6	15.7	3.8	1.0	0.3
12-31-2053	46.8	77.1	87.6	23.0	16.5	71.1	15.3	3.5	0.9	0.2
12-31-2054	46.8	72.7	82.7	23.0	18.6	64.1	13.1	2.9	0.7	0.2
12-31-2055	46.8	61.2	69.6	23.0	15.9	53.7	10.5	2.2	0.5	0.1
12-31-2056	46.8	43.7	49.7	23.0	14.7	35.0	6.5	1.3	0.3	0.1
12-31-2057	46.8	35.6	40.5	23.0	12.4	28.0	5.0	1.0	0.2	0.0
12-31-2058	46.8	28.1	32.0	23.0	10.1	21.8	3.7	0.7	0.1	0.0
Total		1,047.6	1,190.8		273.9	916.9	238.3	69.9	23.1	8.5

Totals may not add because of rounding.

(1) Operating costs are limited to direct project-level costs, insurance costs, workover costs, indirect headquarters general and administrative overhead expenses, and Tamar Petroleum's estimate of the portion of the operator's headquarters general and administrative overhead expenses that can be directly attributed to this project.

(2) Oil and gas profits levy rates and estimates are provided by Tamar Petroleum.

(3) Corporate income tax rates and estimates of corporate income taxes are provided by Tamar Petroleum 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
PROVED + PROBABLE + POSSIBLE (3P) RESERVES
TAMAR PETROLEUM LTD. INTEREST
TAMAR AND TAMAR SOUTHWEST FIELDS, TAMAR LEASE I/12, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2021

Period Ending	Working Interest Revenue (MM$)	Royalties State (MM$)	Royalties Interested Party (MM$)	Royalties Third Party (MM$)	Royalties Total (MM$)	Net Capital Costs (MM$)	Net Abandonment Costs (MM$)	Net Operating Expenses[1] (MM$)	Fututre Net Revenue Before Levy and Corporate Income Taxes Discounted at 0% (MM$)
12-31-2022	275.4	31.1	-	13.6	44.8	13.0	-	33.4	184.2
12-31-2023	264.5	29.9	-	13.1	43.0	26.0	-	33.4	162.2
12-31-2024	269.4	30.4	-	13.4	43.8	1.8	-	31.9	191.9
12-31-2025	280.3	31.7	-	13.9	45.6	43.3	-	31.4	160.0
12-31-2026	290.7	32.8	-	14.4	47.3	43.4	-	31.8	168.2
12-31-2027	313.6	35.4	-	15.5	51.0	0.9	-	32.5	229.2
12-31-2028	326.9	36.9	-	16.2	53.1	0.9	-	33.2	239.7
12-31-2029	333.6	37.7	-	16.5	54.2	0.9	-	33.9	244.5
12-31-2030	336.1	38.0	-	16.7	54.6	1.0	-	34.5	246.0
12-31-2031	358.0	40.5	-	17.7	58.2	1.0	-	35.2	263.6
12-31-2032	365.8	41.3	-	18.1	59.5	1.0	-	35.9	269.4
12-31-2033	371.1	41.9	-	18.4	60.3	1.0	-	36.6	273.1
12-31-2034	375.9	42.5	-	18.6	61.1	1.0	-	37.4	276.3
12-31-2035	380.8	43.0	-	18.9	61.9	1.1	-	38.1	279.7
12-31-2036	386.8	43.7	-	19.2	62.9	1.1	-	38.9	284.0
12-31-2037	392.8	44.4	-	19.5	63.9	1.1	-	39.7	288.2
12-31-2038	398.9	45.1	-	19.8	64.8	1.1	-	40.5	292.5
12-31-2039	405.1	45.8	-	20.1	65.9	1.1	-	41.3	296.9
12-31-2040	411.5	46.5	-	20.4	66.9	34.1	-	42.1	268.4
12-31-2041	419.6	47.4	-	20.8	68.2	1.2	-	42.9	307.3
12-31-2042	427.9	48.3	-	21.2	69.5	52.0	-	43.8	262.5
12-31-2043	436.3	49.3	-	21.6	70.9	17.7	-	44.7	303.0
12-31-2044	444.9	50.3	-	22.0	72.3	17.7	-	45.6	309.3
12-31-2045	453.7	51.3	-	22.5	73.7	1.3	-	46.5	332.2
12-31-2046	462.6	52.3	-	22.9	75.2	1.3	-	47.4	338.7
12-31-2047	464.3	52.5	-	23.0	75.5	1.3	-	48.3	339.2
12-31-2048	422.5	47.7	-	20.9	68.7	1.4	-	48.7	303.8
12-31-2049	378.1	42.7	-	18.7	61.5	1.4	-	49.0	266.2
12-31-2050	338.3	38.2	-	16.8	55.0	1.4	-	49.5	232.4
12-31-2051	302.8	34.2	-	15.0	49.2	1.4	-	50.0	202.1
12-31-2052	290.8	32.9	-	14.4	47.3	1.5	-	50.8	191.3
12-31-2053	277.2	31.3	-	13.7	45.1	1.5	-	51.6	179.1
12-31-2054	249.8	28.2	-	12.4	40.6	1.5	-	52.3	155.4
12-31-2055	221.2	25.0	-	11.0	36.0	1.6	-	52.9	130.8
12-31-2056	195.5	22.1	-	9.7	31.8	1.6	15.0	53.6	93.5
12-31-2057	175.7	19.9	-	8.7	28.6	1.6	15.0	54.4	76.1
12-31-2058	157.7	17.8	-	7.8	25.6	1.6	15.0	55.3	60.1
Total	12,656.1	1,430.1	-	627.1	2,057.3	283.8	45.1	1,568.9	8,701.0

Totals may not add because of rounding.

NETHERLAND, SEWELL & ASSOCIATES, INC.

REVENUE, COSTS, AND TAXES
PROVED + PROBABLE + POSSIBLE (3P) RESERVES
TAMAR PETROLEUM LTD. INTEREST
TAMAR AND TAMAR SOUTHWEST FIELDS, TAMAR LEASE I/12, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2021

Period Ending	Levy Rate[(2)] (%)	Levy[(2)] (MM$)	Fututre Net Revenue After Levy and Before Corporate Income Taxes Discounted at 0% (MM$)	Corporate Income Tax Rate[(3)] (%)	Corporate Income Taxes[(3)] (MM$)	Future Net Revenue After Levy and Corporate Income Taxes				
						Discounted at 0% (MM$)	Discounted at 5% (MM$)	Discounted at 10% (MM$)	Discounted at 15% (MM$)	Discounted at 20% (MM$)
12-31-2022	30.2	55.4	128.8	23.0	7.2	121.6	118.7	116.0	113.4	111.0
12-31-2023	35.3	57.2	104.9	23.0	4.4	100.6	93.5	87.2	81.5	76.5
12-31-2024	40.1	77.0	115.0	23.0	-	115.0	101.8	90.6	81.1	72.9
12-31-2025	44.2	70.8	89.2	23.0	1.6	87.6	73.8	62.7	53.7	46.3
12-31-2026	46.7	78.5	89.7	23.0	1.1	88.6	71.1	57.7	47.2	39.0
12-31-2027	46.8	107.3	121.9	23.0	0.9	121.1	92.6	71.7	56.1	44.4
12-31-2028	46.8	112.2	127.5	23.0	11.9	115.6	84.2	62.2	46.6	35.3
12-31-2029	46.8	114.4	130.1	23.0	13.9	116.2	80.6	56.9	40.7	29.6
12-31-2030	46.8	115.1	130.9	23.0	14.0	116.9	77.2	52.0	35.6	24.8
12-31-2031	46.8	123.4	140.3	23.0	15.9	124.4	78.2	50.3	33.0	22.0
12-31-2032	46.8	126.1	143.3	23.0	16.5	126.8	76.0	46.6	29.2	18.7
12-31-2033	46.8	127.8	145.3	23.0	17.6	127.7	72.9	42.7	25.6	15.7
12-31-2034	46.8	129.3	147.0	23.0	19.5	127.5	69.3	38.7	22.2	13.1
12-31-2035	46.8	130.9	148.8	23.0	20.3	128.5	66.5	35.5	19.5	11.0
12-31-2036	46.8	132.9	151.1	23.0	21.9	129.2	63.7	32.4	17.0	9.2
12-31-2037	46.8	134.9	153.3	23.0	25.4	127.9	60.0	29.2	14.7	7.6
12-31-2038	46.8	136.9	155.6	23.0	27.9	127.7	57.1	26.5	12.7	6.3
12-31-2039	46.8	138.9	157.9	23.0	29.8	128.2	54.6	24.2	11.1	5.3
12-31-2040	46.8	125.6	142.8	23.0	34.8	108.0	43.8	18.5	8.1	3.7
12-31-2041	46.8	143.8	163.5	23.0	31.9	131.5	50.8	20.5	8.6	3.8
12-31-2042	46.8	122.8	139.6	23.0	38.7	100.9	37.1	14.3	5.7	2.4
12-31-2043	46.8	141.8	161.2	23.0	35.1	126.1	44.2	16.2	6.2	2.5
12-31-2044	46.8	144.7	164.5	23.0	36.0	128.5	42.9	15.1	5.5	2.1
12-31-2045	46.8	155.4	176.7	23.0	35.0	141.7	45.0	15.1	5.3	2.0
12-31-2046	46.8	158.5	180.2	23.0	36.2	144.0	43.6	13.9	4.7	1.7
12-31-2047	46.8	158.7	180.4	23.0	37.4	143.1	41.2	12.6	4.1	1.4
12-31-2048	46.8	142.2	161.6	23.0	34.0	127.7	35.0	10.2	3.1	1.0
12-31-2049	46.8	124.6	141.6	23.0	29.9	111.7	29.2	8.1	2.4	0.7
12-31-2050	46.8	108.8	123.7	23.0	25.8	97.9	24.4	6.5	1.8	0.5
12-31-2051	46.8	94.6	107.5	23.0	22.8	84.7	20.1	5.1	1.4	0.4
12-31-2052	46.8	89.5	101.8	23.0	21.5	80.3	18.1	4.4	1.1	0.3
12-31-2053	46.8	83.8	95.3	23.0	21.1	74.1	15.9	3.7	0.9	0.2
12-31-2054	46.8	72.7	82.7	23.0	18.6	64.1	13.1	2.9	0.7	0.2
12-31-2055	46.8	61.2	69.6	23.0	15.9	53.7	10.5	2.2	0.5	0.1
12-31-2056	46.8	43.7	49.7	23.0	14.7	35.0	6.5	1.3	0.3	0.1
12-31-2057	46.8	35.6	40.5	23.0	12.4	28.0	5.0	1.0	0.2	0.0
12-31-2058	46.8	28.1	32.0	23.0	10.1	21.8	3.7	0.7	0.1	0.0
Total		4,005.5	4,695.5		761.7	3,933.7	1,921.8	1,155.3	802.0	611.8

Totals may not add because of rounding.

(1) Operating costs are limited to direct project-level costs, insurance costs, workover costs, indirect headquarters general and administrative overhead expenses, and Tamar Petroleum's estimate of the portion of the operator's headquarters general and administrative overhead expenses that can be directly attributed to this project.
(2) Oil and gas profits levy rates and estimates are provided by Tamar Petroleum.
(3) Corporate income tax rates and estimates of corporate income taxes are provided by Tamar Petroleum 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
TAMAR PETROLEUM LTD. INTEREST
TAMAR AND TAMAR SOUTHWEST FIELDS, TAMAR LEASE I/12, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2021

Year	Tamar Petroleum Working Interest Production (BCF)	Average Per Production Unit ($/MCF)				Reserves Depletion Rate[1] (%)
		Price Received	Royalties Paid	Production Costs	Net Revenue	
2021[2]	51.6	4.63	0.73	0.50	3.40	2.9
2020	49.2	5.15	0.84	0.40	3.92	2.7
2019	62.2	5.63	0.93	0.46	4.24	3.3

Note: Values in this table have been provided by Tamar Petroleum; these values are based on historical data since January 2019 and include condensate production, revenue, and costs.

[1] The reserves depletion rate is the percentage of yearly gas produced to the estimated proved plus probable reserves at the beginning of that year.
[2] The 2021 data is representative of unaudited financial data.

VOLUMETRIC INPUT SUMMARY
TAMAR FIELD, TAMAR LEASE I/12, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2021

	Gross Rock Volume (acre-feet)			Area (acres)			Average Gross Thickness[1] (feet)			Net-to-Gross Ratio (decimal)		
Reservoir	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate
A Sand	2,485,750	2,594,825	2,845,871	21,711	21,711	22,935	114	120	124	0.88	0.93	0.93
B Sand	1,610,760	1,693,767	1,782,698	15,027	15,027	15,158	107	113	118	0.72	0.85	0.85
C Sand	1,901,019	1,964,971	2,063,220	9,095	9,095	9,095	209	216	227	0.87	0.90	0.90

	Porosity[2] (decimal)			Gas Saturation (decimal)			Gas Formation Volume Factor (SCF/RCF)[3]			Gas Recovery Factor (decimal)		
Reservoir	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate
A Sand	0.26	0.26	0.25	0.75	0.78	0.83	372	372	372	0.62	0.67	0.72
B Sand	0.25	0.24	0.24	0.76	0.79	0.82	372	372	372	0.62	0.67	0.72
C Sand	0.25	0.24	0.24	0.78	0.81	0.83	372	372	372	0.62	0.67	0.72

Note: For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, seismic data, core data, well test data, production data, historical price and cost information, and property ownership interests.

(1) Average gross thickness is calculated by dividing the gross rock volume by the area.
(2) The increasing net-to-gross ratio between cases includes lower porosity rock which results in a lower porosity in the best and high estimate cases relative to the low estimate case.
(3) The abbreviation SCF/RCF represents standard cubic feet per reservoir cubic foot.

NETHERLAND, SEWELL & ASSOCIATES, INC.

VOLUMETRIC INPUT SUMMARY
TAMAR SOUTHWEST FIELD, TAMAR LEASE I/12, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2021

	Gross Rock Volume (acre-feet)			Area (acres)			Average Gross Thickness[1] (feet)			Net-to-Gross Ratio (decimal)		
Reservoir	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate
A Sand	300,301	318,108	318,108	2,517	2,517	2,517	119	126	126	0.99	1.00	1.00
B Sand	128,228	137,183	137,183	1,065	1,065	1,065	120	129	129	0.82	0.87	0.88

	Porosity (decimal)			Gas Saturation (decimal)			Gas Formation Volume Factor (SCF/RCF)[2]			Gas Recovery Factor (decimal)		
Reservoir	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate
A Sand	0.24	0.24	0.24	0.84	0.87	0.89	372	372	372	0.62	0.67	0.72
B Sand	0.22	0.22	0.22	0.78	0.81	0.85	372	372	372	0.62	0.67	0.72

Note: For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, seismic data, core data, well test data, production data, historical price and cost information, and property ownership interests.

(1) Average gross thickness is calculated by dividing the gross rock volume by the area.

(2) The abbreviation SCF/RCF represents standard cubic feet per reservoir cubic foot.