RESERVES REPORT MAHARAJALELA JAMALULALAM FIELD

BLOCK B, OFFSHORE BRUNEI

As of January 1, 2025

Prepared for:
Hibiscus EP (Brunei) B.V.

Prepared by:
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Eleanor Rollett		29/08/2025

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Date: 29 August 2025

Hibiscus EP (Brunei) B.V.
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Dear Sirs,

EVALUATION OF MAHARAJALELA JAMALULALAM FIELD, OFFSHORE BRUNEI

In response to a request by Hibiscus EP (Brunei) B.V. ("Hibiscus" or "HEB"), and the Letter of Engagement dated 6th January 2025 with Hibiscus (the "Agreement"), Tetra Tech RPS Energy Limited ("TTRPSE") has completed an independent evaluation of the Maharajalela Jamalulalam (MLJ) Field, in Block B offshore Brunei. The field had been acquired by Hibiscus from TotalEnergies Holdings International B.V. ("Total") in 2024. A Conditional Sales and Purchase Agreement was executed in June 2024, with the acquisition completed on 14th October 2024 – on which date Hibiscus became the Operator.

Hibiscus has a total of 37.5% working interest in the Block B Concession.

This report is issued by TTRPSE under the appointment by Hibiscus to conduct an independent reserves evaluation of the Asset to satisfy Paragraph 10, Part II of Practice Note 32 of the Main Market Listing Requirements of Bursa Malaysia Securities Berhad ("Bursa Securities"); and is produced as part of the Services detailed therein and subject to the terms and conditions of the Agreement. This Reserves Report has been prepared solely for the use of Hibiscus, its other advisors and Bursa Securities and is intended for publication on Hibiscus Petroleum Berhad's ("HPB") website and for HPB shareholders' inspection.

We have estimated Proved, Probable and Possible Reserves as of 1 January 2025. All Reserves and Resources definitions and estimates shown in this report are based on the 2018 Petroleum Resource Management System of SPE/WPC/AAPG/SPEE/SEG/SPWLA/EAGE ("PRMS"). This Reserves Report has been prepared in compliance with the requirements for reporting oil and gas activities as specified in Practice Note 32 of the Main Market Listing Requirements of Bursa Securities and the disclosure requirements and contents of reports as prescribed in Chapter 17, Division 1, Part II of the Prospectus Guidelines issued by the Securities Commission Malaysia's ("SC") in relation to Specific Requirements For A Corporation with MOG Exploration or Extraction Assets.

The work was undertaken by a team of petroleum engineers, geoscientists and economists and is based on data supplied by Hibiscus in a dataroom dated January 9th 2025 after Hibiscus became the Operator. Our approach has been to audit data made available by Hibiscus.

In estimating Reserves, we have used standard geoscience and petroleum engineering techniques. We have estimated the degree of uncertainty inherent in the measurements and interpretation of the data and have calculated a range of recoverable volumes, based on predicted field performance and contracted gas sales.

We have taken the working interest that Hibiscus holds in the MLJ Field as presented by Hibiscus. We have not investigated, nor do we make any warranty as to Hibiscus' interest in the asset.

A site visit was not conducted.

Prospective Resources volumes have not been evaluated by TTRPSE as they are outside the scope of this report.

TTRPSE estimates of Reserves and Contingent Resources are provided in the Executive Summary and in Section 8.5.

QUALIFICATIONS

TTRPSE is an independent consultancy specialising in petroleum reservoir evaluation and economic analysis. The provision of professional services has been solely on a fee basis. Eleanor Rollett, Principal Advisor, has supervised this evaluation. Eleanor Rollett is a Chartered Geologist with over 30 years' experience in upstream oil and gas. The project had been managed on a day-to-day basis by Adolfo Perez who has >20 years' experience in upstream oil and gas, and subsequently by David Element who has >35 years' upstream oil and gas experience. Other TTRPSE employees involved in this work hold at least a Master's degree in geology, geophysics, petroleum engineering or a related subject or have at least five years of relevant experience in the practice of geology, geophysics, or petroleum engineering.

BASIS OF OPINION

The evaluation presented in this report reflects our informed judgment, based on accepted standards of professional investigation, but is subject to generally recognized uncertainties associated with the interpretation of geological, geophysical, and engineering data. The evaluation has been conducted within our understanding of petroleum legislation, taxation and other regulations that currently apply to these interests. However, TTRPSE is not in a position to attest to the property title, financial interest relationships or encumbrances related to the property. Our estimates of Reserves are based on data provided by Hibiscus. We have accepted, without independent verification, the accuracy and completeness of this data.

The report represents TTRPSE's best professional judgment and should not be considered a guarantee or prediction of results. It should be understood that any evaluation, particularly one involving future performance and development activities may be subject to significant variations over short periods of time as and when new information becomes available. This report relates specifically and solely to the subject assets and is conditional upon various assumptions that are described herein. This report must, therefore, be read in its entirety. This report was provided for the sole use of Hibiscus and their corporate advisors on a fee basis.

This report may be reproduced in its entirety. However, excerpts may only be reproduced or published (as required for regulated securities reporting purposes) with the express written permission of TTRPSE.

Yours sincerely,
for Tetra Tech RPS Energy Limited

Eleanor Rollett
Principal Advisor

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Name	Role	Signature
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James Hodson	Geoscience Lead	
David Element	Reservoir Engineering Lead	
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1. EXECUTIVE SUMMARY

In response to a request by Hibiscus EP (Brunei) B.V. (“Hibiscus”), and the Letter of Engagement dated 6 January 2025 with Hibiscus (the “Agreement”), Tetra Tech RPS Energy Limited (“TTRPSE”) has completed an independent evaluation of the Maharajalela Jamalulalam (MLJ) Field, in Block B offshore Brunei. The field is currently operated by Hibiscus.

1.1 Overview of Maharajalela Jamalulalam (MLJ) Field

Block B offshore Brunei contains the MLJ Field which was discovered in 1989 by the Maharajalela North well and which was appraised and developed in the 1990s with first gas in 1999. Since 1999 the field has been producing gas and condensate from three unmanned platforms in relatively shallow (less than 100 m) water depths. The field consists of a complex faulted system that is divided into elongated structural compartments. The northern panel (MLJ North) extends into a third party’s licensed area. In June 2024 Hibiscus acquired Total’s interest in the field (37.5%) and became the operator effective 14th October 2024.

The block has some remaining prospectivity according to Hibiscus but a review of prospectivity was not within the scope of this project.

Given the nature of this audit a site visit was not undertaken.

For the purposes of this Report, Third Party Gas is gas and associated condensate for which the Block B Joint Venture (“BBJV”) has been licensed by a third party, subject to payment of a Licence Fee thereto, to produce, process and sell.

All Reserves and Contingent Resource estimate herein are reported to PRMS 2018 standards. This report fulfils the requirements stipulated in Chapter 17, Part II, Division1 of the Securities Commission Malaysia’s Prospectus Guidelines for a Competent Person’s Report.

1.2 Health, Safety, Security and Environment (“HSSE”)

Hibiscus is an international operator that adheres to stringent HSSE standards as indicated in their health-hygiene, safety, security, societal, environment & quality policy in which it emphasizes the following industry standard commitment:

- Protect the health-hygiene, safety and security of personnel
- Protect the environment
- Safeguard our production facilities and assets
- Contribute to the sustainable development of neighbouring communities and addressing stakeholder expectations
- Maximize energy efficiency

1.3 Surface Review

There are three unmanned production platforms - MLJ1, MLJ2 and MLJ3. No processing occurs offshore, and multiphase production is exported to an onshore processing plant (“OPP”) at Lumut. At Lumut, gas and liquids are separated, and condensate and water stabilised at 60 barg and gas is processed to remove mercury and traces of H_2S. Gas is sent to Brunei LNG Sendirian Berhad (“BLNG”) plant at 43 barg, and condensate and water exported to Seria Crude Oil Terminal (“SCOT”) at 20 barg.

A total of 22 exploration, appraisal and development wells have been drilled.

During 2024 a total of 10 wells were active producers (MLJ1-06, MLJ1-07, MLJ2-01, MLJ2-06, MLJ2-07, MLJ3-01, MLJ3-02, MLJ3-04, MLJ3-05 and MLJ3-06).

A sanctioned and funded Low Pressure Compressor is being installed onshore in the 4th Quarter of 2025 and expected to be running by the end of the year.

1.4 Third Party Arrangement

The northern panel (MLJ North) extends into a third party's licensed area. From November 2022 until March 2026. two reservoir layers (Layers 1 and 2) have been on a Gas Production Agreement (GPA) with agreed terms with the third party. The Agreement allows for production of gas via Block B, Brunei.

Additional future tranches of third-party gas are subject to future agreed production agreements and subject to future negotiations. This is anticipated to be negotiable beyond year 2026 when the current agreement expires.

Future production from Layer 3 (via one of the existing wells) could also be on the same terms as the prior arranged terms.

TTRPSE is not in a position to opine on the terms of the third-party arrangement, and it was not part of the scope of this report.

1.5 Subsurface and Resource Evaluation

The field comprises a complex faulted system that is divided into elongated structural compartments ("panels"), limited by major sealing normal faults. Hydrocarbons have been found in eight dynamically independent panels, each subdivided into tens of different reservoir levels of Late Miocene age. Pressure regimes vary with depth and age with highest pressures in the deepest reservoir in the northwesternmost panels and wells.

Reservoir fluids are considered gas-condensate, but compositions vary from one reservoir to another, which gives variations in condensate richness.

TTRPSE has not independently verified initial hydrocarbons in place volumes as part of this audit due to the maturity of the assets.

We have reviewed production and cost forecasts prepared by Hibiscus. We also reviewed a set of dynamic models from Total, which had not been available previously through the Total pre-Acquisition dataroom exercise that TTRPSE concluded for Hibiscus in 2024. The quality of rate and pressure history matching in these models is somewhat variable, and we consider that in their current state these models would not be useful for predicting the productivity of infill wells and the gains from well interventions (especially new perforations).

Instead, we have developed a material balance reservoir model coupled to a simple surface network model to validate results from the dynamic models and to forecast recoverable volumes.

The Reserves forecast case assumes:

- No further activity (NFA) for all wells in the South / West / JMB / JAM panels
- A programme of 2025 and 2026 workovers
- A 2026 velocity string programme.
- The LP compression project which is expected to come on stream in November 2025.

The operator is considering two additional projects:

- New well B1-15k in mid 2029
- Additional MLJ North workover to perforate Layer 3 immediately after the B1-15K well in early 2030.

Although it had been expected that both of these projects would be classified as Contingent Resources, the MLJ North Layer 3 workover project has been forecast to add only 7 Bscf incremental gas recovery, and is uneconomic in the Best Case. This project is not classified as a Contingent Resource project in our final summary.

TTRPSE estimates of Reserves are provided in Table 1-1 to Table 1-3 and TTRPSE estimates of Contingent Resources in Table 1-4 to Table 1-6.

1.6 Economic Analysis

The Economic Limit Test ("ELT") performed for the determination of Reserves is based on TTRPSE's estimates of recoverable volumes, a review of the company's estimates of Capex, Opex, and Abex; and inclusion of other financial information and assumptions, as outlined in Section 7.

The licences are assumed to reach its economic limit when the cumulative value of its net cash flow (excluding Abex) before tax ceases to increase. All projects to be classified as Reserves must be economic under defined conditions[1]. TTRPSE has therefore assessed the future economic viability of each case on the basis of its pre-tax undiscounted Net Cash Flow Money Of the Day ("MOD").

An annual inflation rate of 2 per cent has been built into the ELT.

1.7 Reserves and Contingent Resources Summary

A summary of Reserves is provided in Table 1-1 to Table 1-3 for Gas, Condensate, and Barrels of Oil Equivalent, respectively.
The effective date of this report is 1 January 2025.

Appendix C tabulates Reserves for two additional effective dates:

- 1 January 2023. This is the effective date of the transaction / acquisition from Total. The previous Competent Person's Report which TTRPSE prepared for Hibiscus also had an effective date of 1 January 2023[2]
- 14 October 2024. This is the closing date of the acquisition from Total, and the date on which Hibiscus became the Operator.

Third Party Gas which is produced, processed and sold by BBJV (and is net to Hibiscus) is included in the production and cost profiles and impacts economics, but is not included as Reserves or Contingent Resources by TTRPSE in this Report.

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[1] *PRMS 2018: 3.1.2.1 Economic determination of a project is tested assuming a zero percent discount rate (i.e., undiscounted). A project with a positive undiscounted cumulative net cash flow is considered economic.*

[2] Competent Person's Report Maharajalela Jamalulalam Field, Block B, Offshore Brunei. RPS 793-TA000016, 15 June 2024.

SUMMARY OF GAS RESERVES
As of 1 January 2025
BASE CASE PRICES AND COSTS

	Full Field Gross Reserves[1] (Bscf)			Net Entitlement Reserves[2] (Bscf)		
	1P	2P	3P	1P	2P	3P
MLJ	325	422	517	122	158	194

Notes:

[1] *Gross field Reserves (100% basis) after economic limit test. Economic limit in year 2038 for 1P; year 2039 for 2P and 3P.*

[2] *Hibiscus' net entitlement based on its 37.5% working interest; after economic limit test. Royalties are paid in cash and treated as production tax. Therefore is not deducted from Hibiscus' Net Entitlement.*

Table 1-1: Gas Reserves in MLJ Field as of 1 January 2025

SUMMARY OF CONDENSATE RESERVES
As of 1 January 2025
BASE CASE PRICES AND COSTS

	Full Field Gross Reserves[1] (MMstb)			Net Entitlement Reserves[2] (MMstb)		
	1P	2P	3P	1P	2P	3P
MLJ	5.0	8.6	15.9	1.9	3.2	6.0

Notes:

[1] *Gross field Reserves (100% basis) after economic limit test. Economic limit in year 2038 for 1P; year 2039 for 2P and 3P.*

[2] *Hibiscus' net entitlement based on its 37.5% working interest; after economic limit test. Royalties are paid in cash and treated as production tax. Therefore is not deducted from Hibiscus' Net Entitlement.*

Table 1-2: Condensate Reserves in MLJ Field as of 1 January 2025

SUMMARY OF GAS AND CONDENSATE RESERVES (BOE)
As of 1 January 2025
BASE CASE PRICES AND COSTS

	Full Field Gross Reserves[1] (MMboe)[3]			Net Entitlement Reserves[2] (MMboe)[3]		
	1P	2P	3P	1P	2P	3P
MLJ	59.2	79.0	102.0	22.2	29.6	38.3

Notes:

[1] *Gross field Reserves (100% basis) after economic limit test. Economic limit in year 2038 for 1P; year 2039 for 2P and 3P.*

[2] *Hibiscus' net entitlement based on its 37.5% working interest; after economic limit test. Royalties are paid in cash and treated as production tax. Therefore is not deducted from Hibiscus' Net Entitlement.*

[3] *Conversion rate of 6,000 standard cubic feet per boe.*

Table 1-3: Oil Equivalent Reserves in MLJ Field as of 1 January 2025

TTRPSE has classified recoverable volumes from well B1-15K as Contingent Resources – Development Pending, with an estimated Chance of Development (Pd) of over 80%. The MLJ North Layer 3 workover project is estimated to contribute just 7 Bscf incremental gas (Best Case). This project is uneconomic in the Low Case and Best Case and inconsequential in the High Case. This project is not classified as a Contingent Resource project in our final summary.

A summary of Contingent Resources is presented in Table 1-4 to Table 1-6, with an effective date of 1 January 2025

Appendix C tabulates Contingent Resources for two additional effective dates:

- 1 January 2023. This is the effective date of the transaction / acquisition from Total. The previous Competent Person's Report which TTRPSE prepared for Hibiscus also had an effective date of 1 January 2023[3].
- 14 October 2024. This is the closing date of the acquisition from Total, and the date on which Hibiscus became the Operator.

SUMMARY OF GAS CONTINGENT RESOURCES
As of 1 January 2025
BASE CASE PRICES AND COSTS

		Full Field Gross Contingent Resources[1] (Bscf)			Net Entitlement Contingent Resources[2] (Bscf)		
Field	**Project**	**1C**	**2C**	**3C**	**1C**	**2C**	**3C**
MLJ	**MLJ North Layer 3 Workover**	0	0	0	0	0	0
MLJ	**B1-15K**	17	32	45	6	12	17
Total[3, 4]		**17**	**32**	**45**	**6**	**12**	**17**

Notes:

[1] Gross field Contingent Resources (100% basis). Economic limit in year 2038 for 1C; year 2039 for 2C and 3C.

[2] Hibiscus' net entitlement based on its 37.5% working interest; after economic limit test. Royalties are paid in cash and treated as production tax. Therefore is not deducted from Hibiscus' Net Entitlement.

[3] PRMS recommends that for reporting purposes, assessment results should not incorporate statistical aggregation beyond the field, property, or project level. As such, TTRPSE' totals were summed arithmetically and as a result, the total 1C Contingent Resources may be a very conservative assessment and the total 3C Contingent Resources a very optimistic assessment.

[4] It should be noted that all TTRPSE forecasts are cut off at 2039.

[5] Pre economic limit production forecast for 2C and 3C ends in year 2038 and 2039, respectively.

Table 1-4: Gas Contingent Resources in MLJ Field as of 1 January 2025

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[3] Competent Person's Report Maharajalela Jamalulalam Field, Block B, Offshore Brunei. RPS 793-TA000016, 15 June 2024.

SUMMARY OF CONDENSATE CONTINGENT RESOURCES
As of 1 January 2025
BASE CASE PRICES AND COSTS

		Full Field Gross Contingent Resources[1] (MMstb)			Net Entitlement Contingent Resources[2] (MMstb)		
Field	**Project**	**1C**	**2C**	**3C**	**1C**	**2C**	**3C**
MLJ	**MLJ North Layer 3 Workover**	0.0	0.0	0.0	0.0	0.0	0.0
MLJ	**B1-15K**	0.3	0.7	1.4	0.1	0.2	0.5
Total[3]		**0.3**	**0.7**	**1.4**	**0.1**	**0.2**	**0.5**

Notes:

[1] Gross field Contingent Resources (100% basis). Economic limit in year 2038 for 1C; year 2039 for 2C and 3C.

[2] Hibiscus' net entitlement based on its 37.5% working interest; after economic limit test. Royalties are paid in cash and treated as production tax. Therefore, is not deducted from Hibiscus' Net Entitlement.

[3] PRMS recommends that for reporting purposes, assessment results should not incorporate statistical aggregation beyond the field, property, or project level. As such, TTRPSE's totals were summed arithmetically and as a result, the total 1C Contingent Resources may be a very conservative assessment and the total 3C Contingent Resources a very optimistic assessment.

[4] Pre economic limit production forecast for 2C and 3C ends in year 2038 and 2039, respectively.

Table 1-5: Condensate Contingent Resources in MLJ Field as of 1 January 2025

SUMMARY OF GAS AND CONDENSATE CONTINGENT RESOURCES (BOE)
As of 1 January 2025
BASE CASE PRICES AND COSTS

		Full Field Gross Contingent Resources[1] (MMboe)[3]			Net Entitlement Contingent Resources[2] (MMboe)[3]		
Field	**Project**	**1C**	**2C**	**3C**	**1C**	**2C**	**3C**
MLJ	**MLJ North Layer 3 Workover**	0.0	0.0	0.0	0.0	0.0	0.0
MLJ	**B1-15K**	3.0	6.0	8.9	1.1	2.2	3.3
Total[4]		**3.0**	**6.0**	**8.9**	**1.1**	**2.2**	**3.3**

Notes:

[1] Gross field Contingent Resources (100% basis). Economic limit in year 2038 for 1C; year 2039 for 2C and 3C.

[2] Hibiscus' net entitlement based on its 37.5% working interest; after economic limit test. Royalties are paid in cash and treated as production tax. Therefore, is not deducted from Hibiscus' Net Entitlement.

[3] Conversion rate of 6,000 standard cubic feet per boe.

[4] PRMS recommends that for reporting purposes, assessment results should not incorporate statistical aggregation beyond the field, property, or project level. As such, TTRPSE's totals were summed arithmetically and as a result, the total 1C Contingent Resources may be a very conservative assessment and the total 3C Contingent Resources a very optimistic assessment.

[5] Pre economic limit production forecast for 2C and 3C ends in year 2038 and 2039, respectively.

Table 1-6: Summary of Oil Equivalent Contingent Resources in MLJ Field as of 1 January 2025

2. INTRODUCTION

In response to a request by Hibiscus EP (Brunei) B.V. ("Hibiscus"), and the Letter of Engagement dated 6th January 2025 with Hibiscus, Tetra Tech RPS Energy Limited ("TTRPSE") has completed an independent evaluation of the Maharajalela Jamalulalam (MLJ) Field, Block B, offshore Brunei.

Block B is currently operated by Hibiscus. The report is based on an audit of material made available by Hibiscus in January 2025 after coming into Operatorship of the asset in October 2024. Given the nature of the audit a site visit was not undertaken. The block has some remaining prospectivity but a review of prospectivity was not in the scope of this project.

All Reserves and Contingent Resource estimate herein are reported to PRMS 2018 standards. This report fulfils the requirements stipulated in Chapter 17, Part II, Division1 of the Securities Commission Malaysia's Prospectus Guidelines for a Competent Person's Report.

For the purposes of this Report, Third Party Gas is gas and associated condensate for which the Block B Joint Venture ("BBJV") has been licensed by a third party, subject to payment of a Licence Fee thereto, to produce, process and sell. These volumes are included in the production and cost profiles, and impact field economics, but are not included as Reserves or Contingent Resources by TTRPSE in this Report.

The effective date of this evaluation is 1 January 2025.

2.1 Brunei Block B

Block B offshore Brunei contains MLJ Field which was discovered in 1989 by the Maharajalela North well and which was appraised and developed during the 1990s with first gas in 1999. It has total area of 276 km^2 and is approximately 50 km offshore Brunei. Since 1999, the field has been producing gas and condensate from three unmanned platforms in relatively shallow (less than 100 m) water depths. The field consists of a complex faulted system that is divided into elongated structural compartments. The northern panel (MLJ North) extends into a third party's licensed area. The location of the block is shown in Figure 2-1.

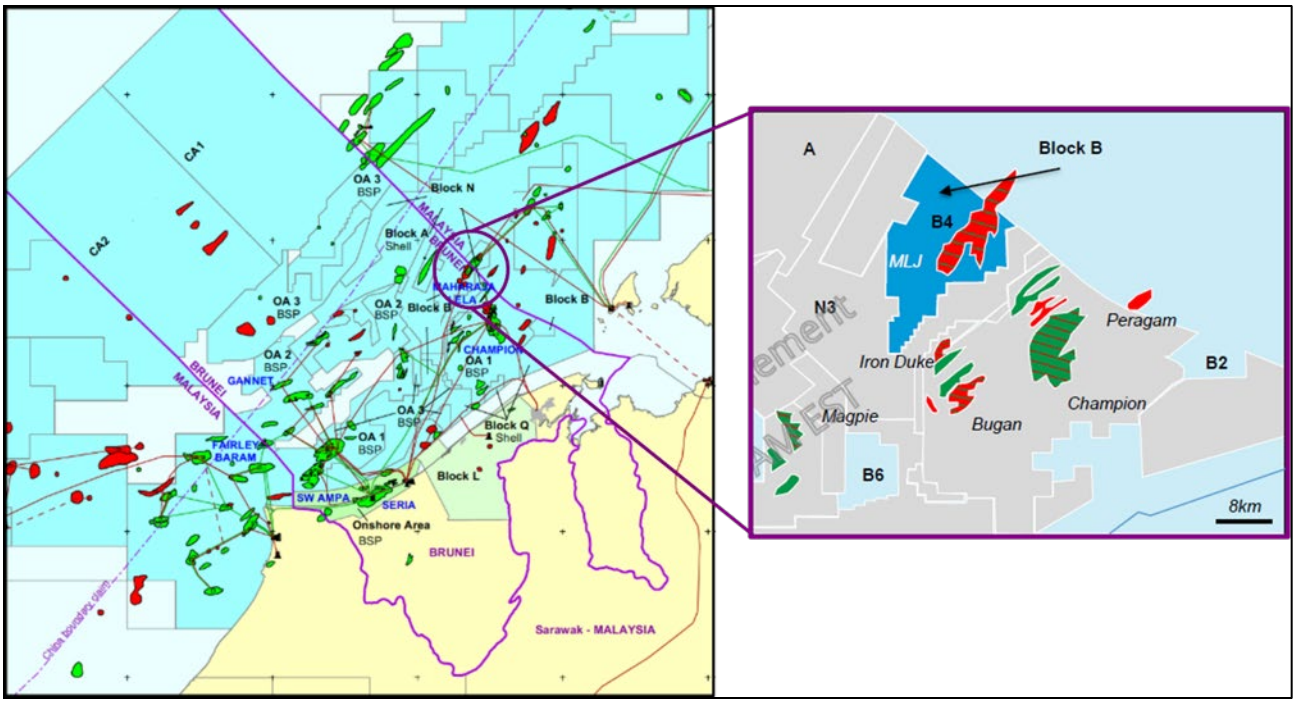

Figure 2-1: Location Map

The MLJ Field has been producing since 1999 under a Petroleum Mining Agreement ("PMA"), with the gas delivered to the BLNG plant. On 12 February 2014, the PMA, originally planned to end in November 2019, was extended for 10 years to 23 November 2029 with an option to extend for a further 10 years to 23 November 2039.

Gas is sold to BLNG under a Gas Sale Agreement ("GSA"). The first GSA ran from 1999 to 2013. In December 2013, a new GSA was signed for a period of 20 years to 1 April 2033. The first Annual Contract Quantity ("ACQ") period ended in March 2023. The second ACQ period started in April 2023 and lasts until March 2032.

Produced liquids are handled and managed at the terminal operated by Brunei Shell Petroleum ("BSP") via the Operating Services Agreement ("OSA"). Liquids are exported to the Seria Crude Oil Terminal ("SCOT") for processing under the OSA. An OSA was signed in March 2017 and a subsequent amendment agreed in March 2023 to update the Nomination and Allocation Procedure.

Hibiscus' acquisition of Total's 37.5% operated interest in the Maharajalela Jamalulalam (MLJ) Field was completed on 14th October 2024. The asset was handed over to Hibiscus on 14th October 2024 after a Conditional Sales and Purchase Agreement was executed in June 2024.

Country	Licence Type	Operator	Hibiscus Interest	Development Status	Licence Expiry Date	Partners
Brunei	PMA	Hibiscus	37.5%	Producing	November 2029 (option to extend to November 2039)	Shell Deepwater Borneo BV (35.0%) Brunei Energy Exploration (27.5%)

Table 2-1: Summary of MLJ Field

2.2 Third Party Arrangement

The northern panel (MLJ North) extends into a third party's licensed area. From November 2022 until March 2026. two reservoir layers (Layers 1 and 2) have been on a Gas Production Agreement (GPA) with agreed terms with the third party. The Agreement allows for production of gas via Block B, Brunei.

Additional future tranches of Third Party Gas are subject to future agreed production agreements and subject to future negotiations. This is anticipated to be negotiable beyond year 2026 when the current agreement expires.

Once compression starts in late 2025, the Hibiscus Block B wells will be produced to meet the requirement of the sales contract. If there is additional ullage, Third Party Gas will be produced to maximise revenue for the JV.

TTRPSE is not in a position to opine on the terms of the third-party arrangement, and it was not part of the scope of this report.

3. BASIS OF OPINION

This report was prepared in response to a request by Hibiscus, and the Letter of Engagement dated 6 January 2025 with Hibiscus. This report is issued by TTRPSE under this appointment and is produced as part of the Services detailed therein and subject to the terms and conditions of the Agreement.

All volume and resource definitions and estimates shown in this report are based on the 2018 Petroleum Resource Management System ("PRMS") of SPE/WPC/AAPG/SPEE/SEG/SPWLA/EAGE. This report fulfils the requirements stipulated in Chapter 17, Part II, Division1 of the Securities Commission Malaysia's Prospectus Guidelines for a Competent Person's Report.

In preparing forecasts, we have used standard petroleum engineering techniques. We have estimated the degree of uncertainty inherent in the measurements and interpretation of the data and have calculated a range of recoverable volumes, based on predicted field performance.

The work is based solely on data supplied by Hibiscus. Our estimates of recoverable volumes and associated costs are based on the data provided and we have accepted, without independent verification, the accuracy of these data.

The evaluation presented herein reflects our informed judgment, based on accepted standards of professional investigation, but is subject to generally recognised uncertainties associated with the interpretation of geological and engineering data. The evaluation has been conducted within our understanding of petroleum legislation, taxation and other regulations that currently apply to these interests.

TTRPSE is not in a position to attest to the property title, financial interest relationships or encumbrances related to the properties.

It should be understood that any evaluation, particularly one involving future performance and development activities may be subject to significant variations over short periods of time as new information becomes available.

3.1 Methodology

Our approach has been to review production history and provide low, base and high case production forecasts for the existing well stock and the planned additional activity described in the Vendor's Information Memorandum (IM). The capital and operating cost forecasts have been reviewed for the planned activities.

A detailed review of the condition of the facilities, the environmental and safety performance of the facilities and site visits to the facilities was not within the scope of this project.

3.2 Database

The effective date of the Reserves and Contingent Resource estimates and valuation is 1 January 2025.

Future costs from 2025 onwards were used in the evaluation, based on information received as of January 2025. The evaluation used the TTRPSE Q2 2025 price forecasts as stated in Section 8.3.

3.3 Site Visit

A detailed review of the condition of the facilities, the environmental and safety performance of the facilities and site visits to the facilities was not within the scope of this project.

4. MLJ FIELD FACILITIES

The MLJ Field comprises a complex faulted system that is divided into elongated structural compartments ("panels"), limited by major sealing normal faults. Hydrocarbons have been found in eight dynamically independent panels, each subdivided into tens of different reservoir levels. There are three unmanned production platforms - MLJ1, MLJ2 and MLJ3. No processing occurs offshore, and multiphase production is exported to the onshore processing plant ("OPP") at Lumut. At Lumut, gas and liquids are separated, and condensate and water stabilised at 60 barg and gas is processed to remove mercury and traces of H_2S. Gas is sent to Brunei LNG Sendirian Berhad (BLNG) at 43 barg, and condensate and water exported to SCOT at 20 barg (Figure 4-1). The maximum gas handling rate is 201 MMscf/d and liquid rate is 18 Mstb/d.

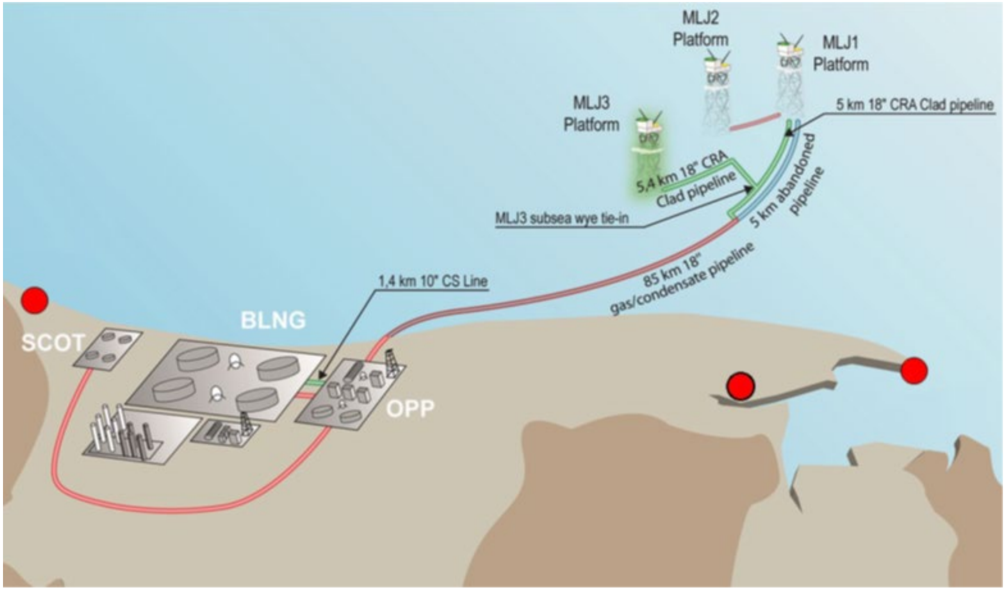

Figure 4-1: Block B Facilities Diagram

The asset was handed over from Total to Hibiscus on 14th October 2024. The last monthly production data shared with TTRPSE in the dataroom setup by Hibiscus EPB included data up to September 2024.

A total of 22 exploration, appraisal and development wells have been drilled. As of end 2022[4], there were 15 active gas producers (four wells on MLJ1 platform, five wells on MLJ2 platform and six wells on the MLJ3 platform).

The production data shared with TTRPSE shows that in the 6 months up to September 2024, there were 10 active gas producers (two wells on MLJ1 platform, three wells on MLJ2 platform and five wells on the MLJ3 platform).

The original MLJ development produced gas, condensate, and condensation water from the MLJ1 and MLJ2 wellhead platforms that are interconnected by a 12" 2.5 km inter-field pipeline. In 2015/16, a redevelopment project, called the MLJ South Project, consisted of debottlenecking of the OPP to increase export in high pressure mode (from 4.1 Mscm/d to 5.0 Mscm/d) and installation of a third HPHT platform MLJ3 with 12 slots. First gas from the MLJ3 platform was in July 2016.

[4] The effective date of this report is 1 January 2025.

In 2024, TTRPSE prepared a Competent Person's Report for Hibiscus with an effective date of 1 January 2023. For that report, analysis of field performance focussed on the wells which had been producing during late-2022. In December 2022, production was from the following panels and wells:

- MLJ North panel production from wells MLJ1-06 and MLJ1-07
- JAM panel production from well MLJ1-02
- JMB panel production from perforations in MLJ1-01
- West panel production from wells MLJ1-01, MLJ2-01, MLJ2-02, MLJ2-03
- B1 panel production from well MLJ2-06
- A panel production from wells MLJ2-07, MLJ3-02 and MLJ3-06
- C1/C2 panel production from wells MLJ3-01 and MLJ3-03
- B2 panel production from wells MLJ3-04 and MLJ3-05

During recent years, there have been a number well interventions. In 2019, perforations of four wells, in 2021 perforations on six wells, and in 2022 perforations and well clean-up on two wells. In 2023, four wells were intervened into with three wells successful whilst one encountered a fish in hole. In 2024 a campaign to perforate two wells including to rectify the fish in hole on the well from 2023 was planned and completed successfully.

The effective date of this current report is 1 January 2025. The panels with wells producing during September 2024 are shown in Table 4-1.

Panel	Platform	Producing Wells
MLJ North	MLJ1	MLJ1-06 (MLJ1-07 produced January and July 2024)
JMB	MLJ1	None
JAM	MLJ1	None
West	MLJ1	None
	MLJ2	MLJ2-01
B1	MLJ2	MLJ2-06
A	MLJ2	MLJ2-07
	MLJ3	MLJ3-02, MLJ3-06
C1/C2	MLJ3	None (MLJ3-01 produced from January to July 2024)
B2	MLJ3	MLJ3-05 (MLJ3-04 produced from January to August 2024)

Table 4-1: September 2024 Producing Wells

For 2025, learning from Hibiscus experience working offshore North Borneo, well programmes are expected to start early avoiding monsoon windows, where five wells are to be entered into to capture additional production opportunities. Similarly in 2026 another five wells are expected to be entered into to enhance production.

Once compression starts in late 2025, the Hibiscus Block B wells will be produced to meet the requirement of the sales contract. If there is additional ullage, Third Party Gas will be produced to maximise revenue for the JV.

Review of facilities integrity, operational performance, maintenance status and safety performance is beyond the scope of the TTRPSE remit.

4.1 Planned Activities

A planned project to increase field life by decreasing OPP arrival pressure was sanctioned in 2023. Work is ongoing and the project is expected to be completed by November 2025. The project is designed to increase the current rates at 57 bar to deliver approximately 3.8 Mscm/d rates operating initially at a minimum pressure of40 bar in MP mode and after 2029 at 27 bar in LP mode after a compressor re-wheeling. This should enable field life extension to at least 2039.

Further well intervention work is planned. An interventions campaign for six wells is planned in 2025, with a planned commencement date of 1 April and the following sequence:

- MLJ2-01 – Production Enhancement
- MLJ2-07 – Production Enhancement
- MLJ2-03 – Well Integrity
- MLJ3-05 – Production Enhancement
- MLJ3-01 – Production Enhancement
- MLJ3-02 – Production enhancement

Installation of velocity strings is scheduled for wells MLJ3-01 and MLJ3-04.

Start-up of the Low Pressure Compressor is scheduled for November 2025.

The following two projects have been included in the forecasts for economic evaluation consideration:

- MLJ North Layer 3 additional sand unit perforation
- B1-15k well to be drilled from the MLJ3 platform (the target is in the 2013 FDP) which will produce reservoirs proven and unproduced by MLJ2-06 and also appraise and eventually produce the deeper 15k reservoirs in the B1 panel.

Low incremental recovery volumes have been estimated for the MLJ1-07 deepening project (see Section 6.5.4). The economic evaluation confirms that this project is not commercial, and so no Contingent Resource volumes have been booked for this project (see Section 8.5).

5. GEOLOGICAL EVALUATION

Block B is located in a structurally complex zone within a highly subsiding part of the shelf constrained to the east by the regional listric fault of the Champion Field and to the west by the major counter regional Frigate-Perdana fault (located deep bellow Pelican structure). Within this sub-basin, the FK-01/FMS-01 fault is an important NNE-SSW, NW-dipping normal fault probably connected at depth with the Frigate-Perdana fault. These listric and counter regional faults create important accommodation space for prograding Upper Miocene deltaic and shallow marine sediments.

Depositional sequences are predominantly sandy (fine to very fine sand) and bound above and below by transgressive surfaces and thin shales with excellent sealing properties. The resulting reservoir interval in each panel comprises several tens of individual reservoir layers of good quality sandstones generally dynamically sealed from each other by thin shale layers. Little variation of this depositional setting is seen for the whole reservoir interval of in excess of 2,000 m. Panels have different pressure regimes with deeper, higher-pressure panels being towards the northwest (Figure 5-1).

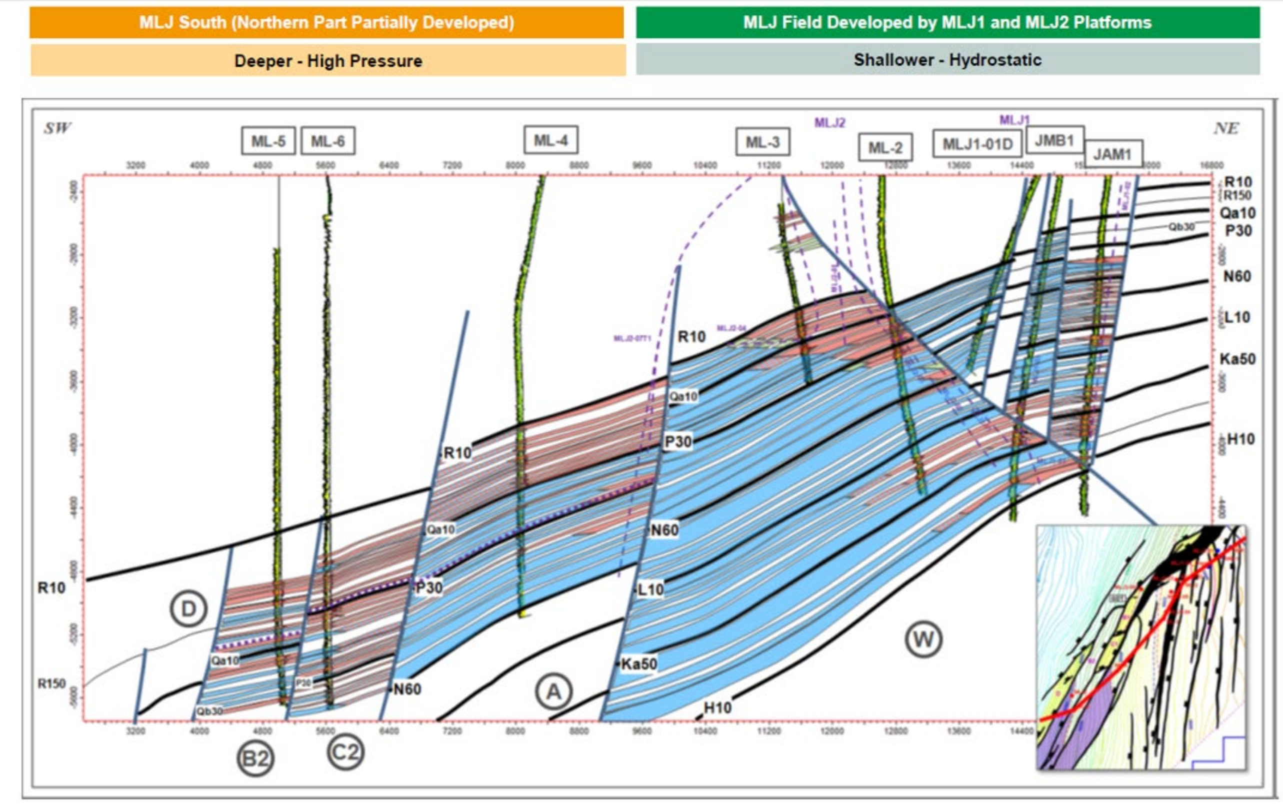

Figure 5-1: Schematic SW-NE Geologic Cross Section Through MLJ Field

5.1 Geological Assessment

5.1.1 Geophysics

The field is covered by 1,243 km^2 of 3D seismic acquired in five surveys between 1989 to 2004. The data sets have been merged and reprocessed with a reference PreStack Time Migration (PreSTM) dataset (BB06) used for the latest interpretation.

The 3D seismic was not available in the Virtual Data Room (VDR) for the 2024 CPR, or in the 2025 supplied Petrel static models, so TTRPSE was unable to audit the seismic interpretation or depth conversion. Seismic had historically been on Total proprietary software platforms. At time of writing Hibiscus is still in the process of converting these to commercial platforms such as Petrel.

5.1.2 Geology

The static models developed by Total (the previous operator) were provided in the 2024 VDR. Given the maturity of the asset and the limited time available TTRPSE did not review the models in detail apart from the areas around planned new wells.

The supplied static models included:

- 2022_MLJ_SOUTH_WORK_CP.pet
- 2022_MLJ_WEST_WORK_HRL_CP.pet
- The 2022_MLJ_NORTH_PV2015_3_CP.pet

These are clearly working Petrel projects and contain multiple iterations of structural grid and modelled reservoir and fluid properties (NTG, Porosity, fluid contacts and Sw). They also contain multiple volumetric cases. No documentation for the model builds or the volumetric cases was available in the VDR. It was noted that the most recent drill wells were incorporated in the model builds for the appropriate areas.

The 2022_MLJ_SOUTH_WORK_CP.pet model incorporated the ML4, ML5, ML6 Exploration wells and the MLJ2-06st1, MLJ2-07, MLJ2-07, MLJ3-06, MLJ3-02, MLJ3-01, MLJ3-03, MLJ3-04, MLJ3-05 Development wells in the model build.

The 2022_MLJ_WEST_WORK_HRL_CP.pet model incorporated the ML2, ML3 Exploration wells and the MLJ1-01DB, MLJ1-03, MLJ2-02, MLJ2-02, MLJ2-03, MLJ2-04, MLJ2-05 Development wells in the model build.

The 2022_MLJ_NORTH_PV2015_3_CP.pet included the ML-1, MLJ1-06, MLJ1-06T, MLJ1-07b, MLJ2-06, MLJ2-06T1 for control on the Maharajalela area.

From a brief review, TTRPSE believes the models are probably reasonable for estimation of in-place volume. However, we make some observations.

NTG and PHIT properties appear to have been distributed in the grid using kriging[5]. Total had stated that this approach was used as there is “lateral continuity and good well data coverage within gas pool support”. The kriged properties use a spherical variogram with long axis of 4000 m and short axis of 1500 m. The NTG and PHIE logs were upscaled using arithmetic averaging.

The result of this approach is that the NTG and PHIE properties are quite smoothly distributed both laterally and vertically through the field and there are places where the connectivity could be overestimated (Figure 5-2 and Figure 5-3). Therefore, we would caution against using the static models as a basis for simulation. No dynamic models were available for review in the VDR.

There is no variation in reservoir properties between Low, Best, and High Case models. Total only appears to have varied the input fluid contacts in the panels included in the volumetric cases. However, given the maturity of the asset with distribution of well control, a range of in-place volumes is probably not critical.

Sw has been modelled using a saturation-height function. No documentation on the derivation of this function was available for review. The 2022_MLJ_SOUTH_WORK_CP.pet model appears to use a Sw-ht function consistent with Document 4.2.3.1.2.1[5], which uses three porosity-permeability transforms for given porosity classes.

[5] VDR Document No. 4.2.3.1.2.1 – 2019-03-06 BBJV Technical Workshop Static Model.pdf

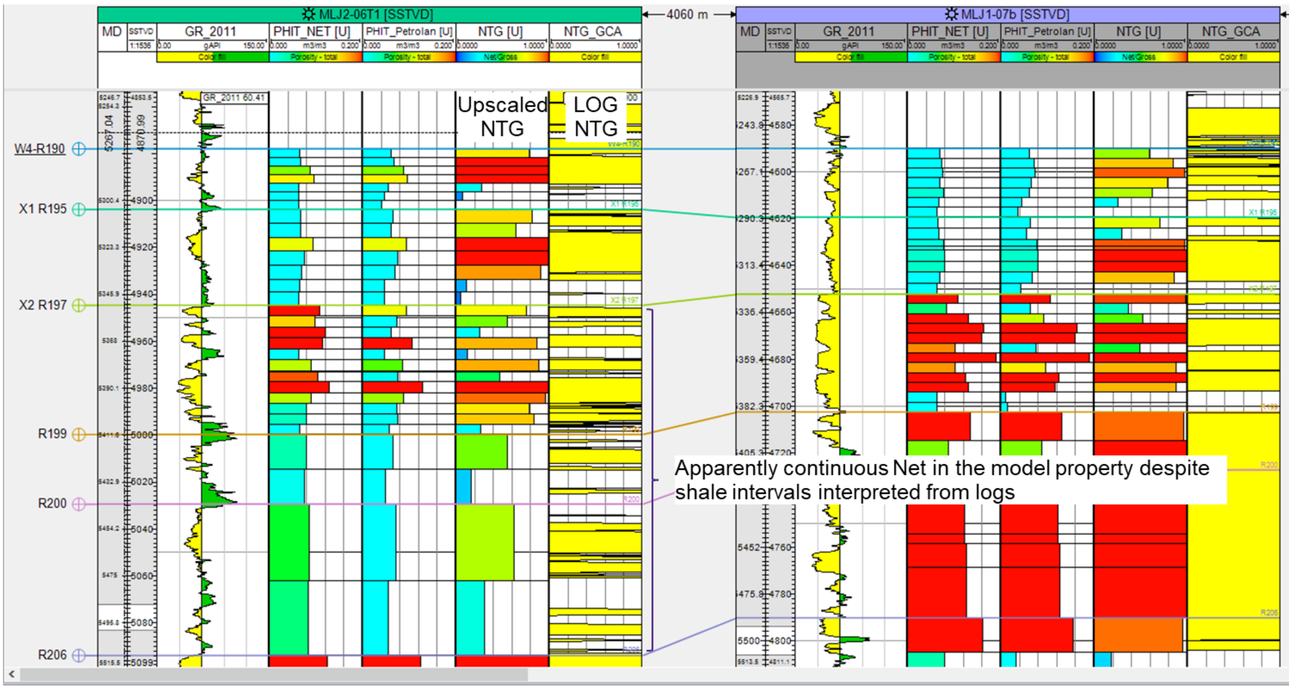

Figure 5-2: Comparison of upscaled and log-derived NTG.

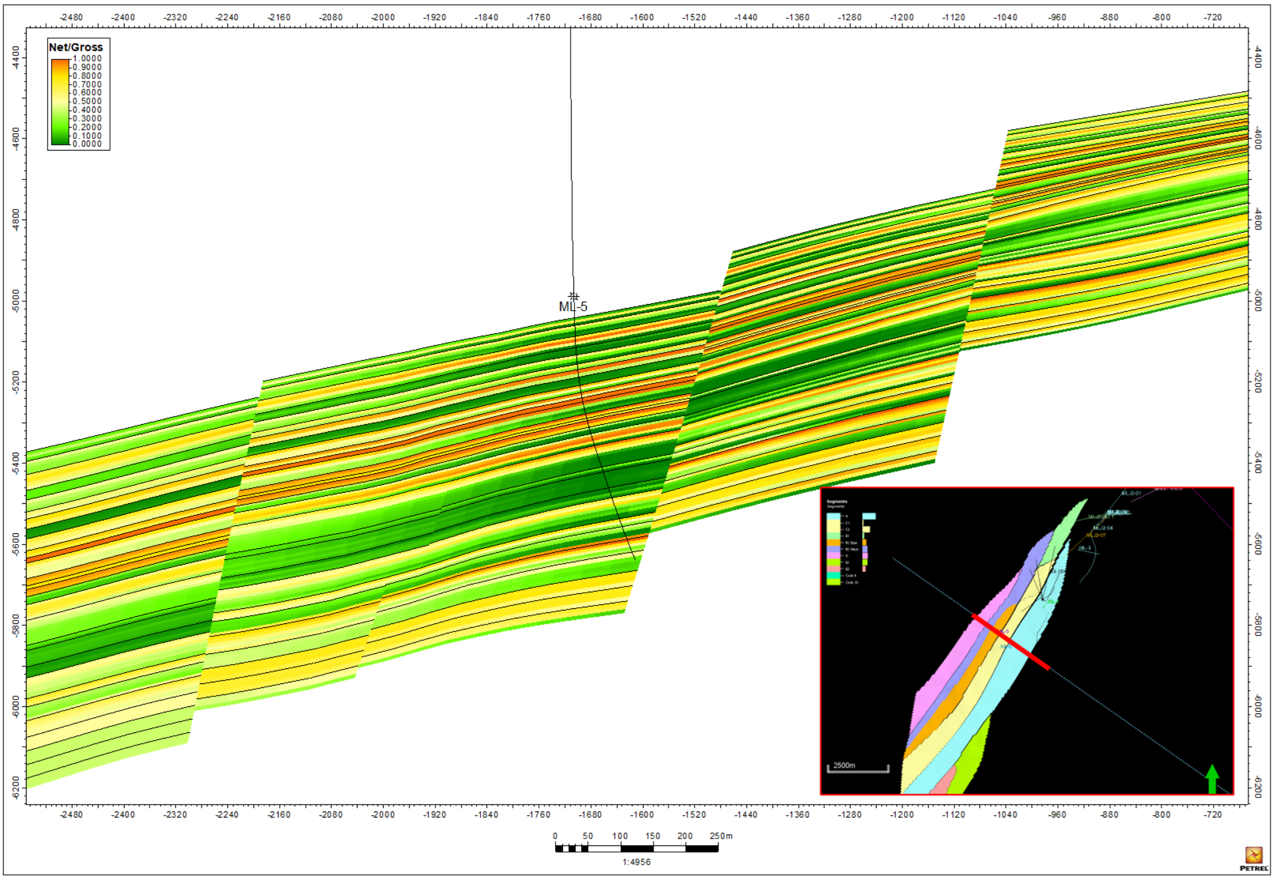

Figure 5-3: Cross-section through NTG property.

5.1.2.1 Contingent Projects– Planned Wells

Two planned well activities have been assessed in this report:

- Well B1-15k new drill
- MLJ1-07 well intervention completion into deeper Layer 3 unit

Details for these two wells were provided in Technical Workshop presentations included in the VDR from the 2024 CPR. TTRPSE has reviewed these presentations, which give some geological and in-place background to the planned wells.

5.1.2.2 B1-15k well

B1-15k is planned to target the R190 to Qb54 reservoirs in the B1 Panel (Figure 5-4). The R190 to R214 reservoirs were penetrated by the MLJ2-06T1 well and are gas-bearing and Total (the previous operator) call these “development/infill targets” for B1-15k. Total called the deeper R214 to Qb54 reservoirs “appraisal targets”. However, MLJ2-06T1 penetrated the FMS22 bounding fault of the B1 Panel before reaching these deeper 15k reservoirs (Figure 5-5). Total’s approach was to use offset wells as analogues and assume that the R214-Qb54 reservoirs will be gas-bearing in B1-15k (e.g. by comparison to MLJ3-05; Figure 5-6). In TTRPSE’s opinion, given the interpretation that the bounding faults are sealing, these deeper reservoirs remain prospective in the B1 Panel. Material supplied in the VDR for the 2024 CPR indicates that there had been some discussion to this effect amongst the partners based on previous infill drilling Technical Workshops, with the uncertainty of the fault tip on the main bounding faults being one issue. As seismic data were unavailable, TTRPSE was unable review the fault interpretation.

The in-place volume results derived from the static model are consistent with those quoted by Total in their Technical Workshop presentations (according to material in the VDR for the 2024 CPR and the 2025 Hibiscus Dataroom). Total’s quoted volumes were adopted for evaluation of the Contingent Resources associated with well B1-15k.

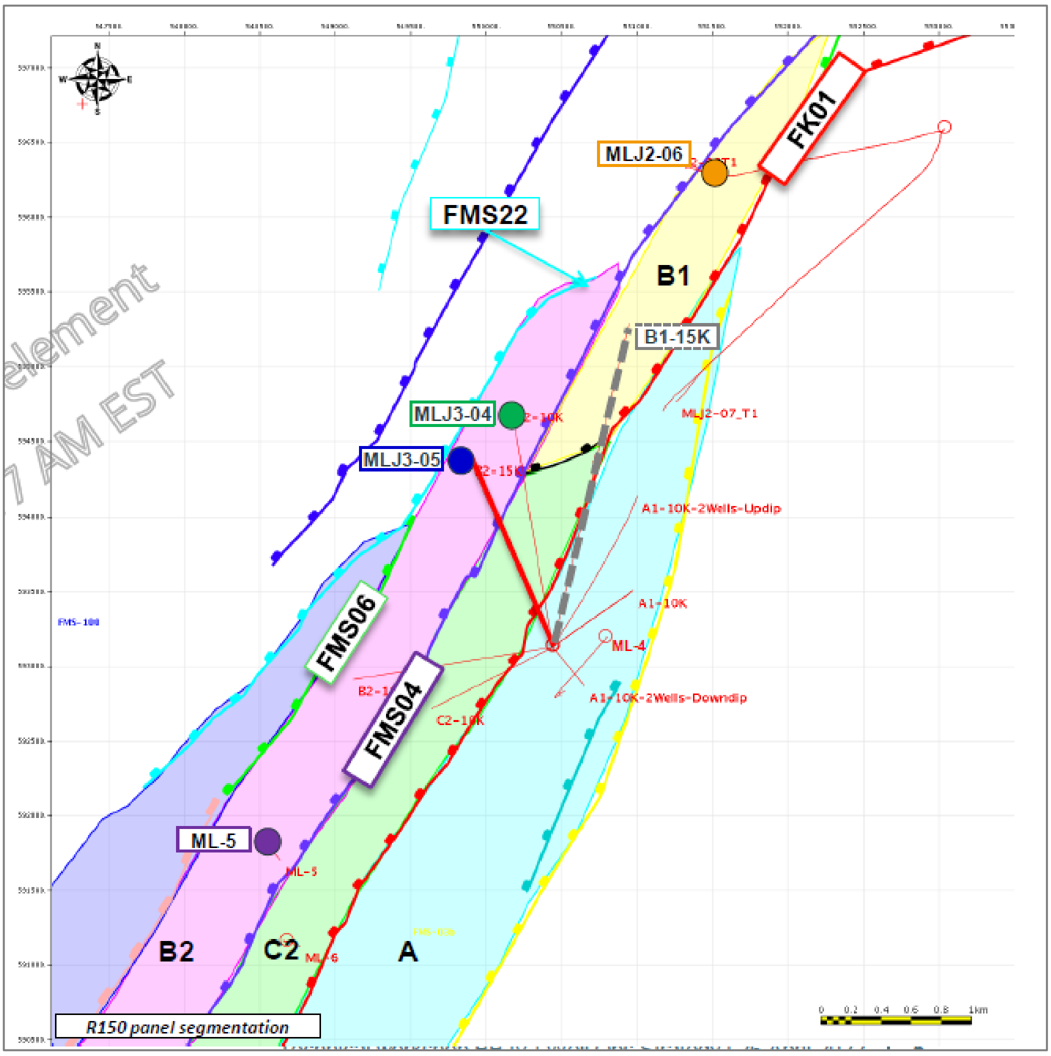

Figure 5-4: Location of proposed B1-15k well in Panel B1.

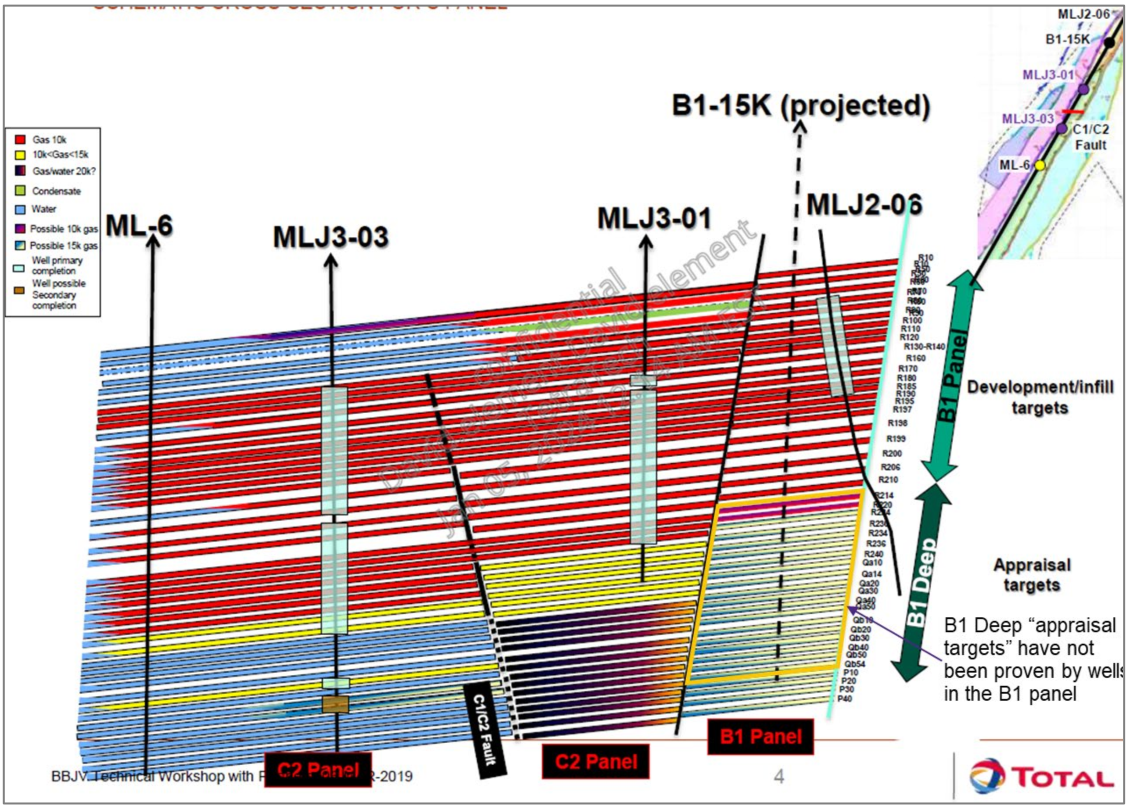

Figure 5-5: **Schematic correlation of C2 Panel wells with fluid type with planned B1-15k well.**

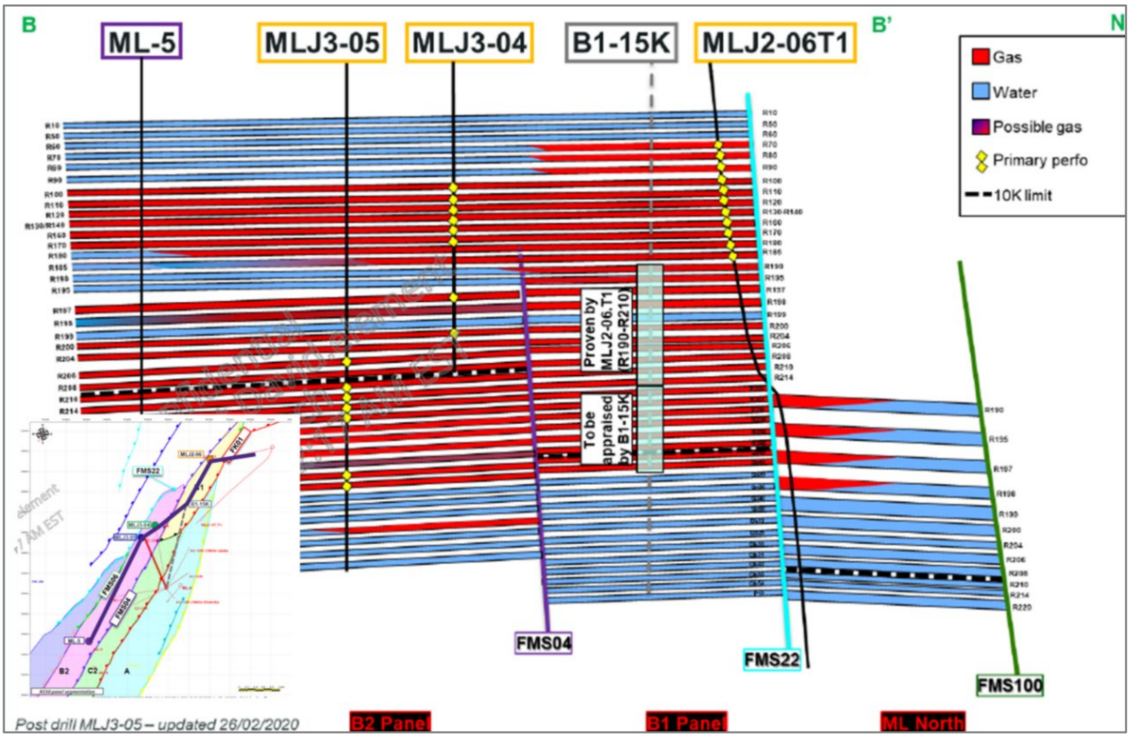

Figure 5-6: **Schematic correlation of B2 and B1 panel wells with fluids type with planned B1-15k well.**

5.1.2.3 Well MLJ1-07 Add Perforation

Consistent with the previous operator, Total, Hibiscus plans to "deepen" the existing MLJ1-07 well drilled on MLJ-North to add perforation and produce the Layer 3 reservoirs. The operation is a perforation through casing of MLJ1-07 as the well has already penetrated Layer 3 and the R190-197 reservoirs are cased above the 7" liner shoe.

There are risks associated with the project that Total had recognised. 15k reservoirs are expected in Layer 3, which may pose challenges for the existing downhole and surface facilities design.

Producing the B1-15k well at the same time as the Layer 3 reservoir could lead to a backpressure effect through the facilities, reducing the incremental gains from the ML1-07 reperforation. This pressure effect is modelled in the current study, but had not been included in the 2024 TTRPSE report.

TTRPSE reviewed the static models for MLJ North and the volumes for the Layer 3 reservoirs. The model volumes are consistent with those quoted by Total (the previous operator) in their Technical Workshop presentation[6], so Total's quoted volumes were adopted for evaluation of Contingent Resources associated with the planned MLJ1-07 add perforation project.

5.1.3 Petrophysics

TTRPSE undertook a brief review of Total's petrophysical interpretation for MLJ2-06T1 and MLJ3-05 wells that were included in the Petrel project. The interpretations looked reasonable. TTRPSE stresses that this was not an in-depth or comprehensive review of the original petrophysical interpretation.

5.1.4 In-Place Volumes

Given the maturity of the asset and the limited time available, TTRPSE has not reviewed the in-place volumes, but has extracted the volume for the best case from Total's static models to present herein for completeness (Table 5-1).

	Gas Initially in Place (GIIP)[1] (Bscf)		
	Low	Best	High
MLJ North Panel	-	1,890	-
MLJ South	-	1,781	-
MLJ West	-	990	-
JMB	-	60	-
JAM	Not included in supplied models		

1. Best estimate Volumes extracted from the Vendor's Best Case model in the 2024 VDR.

Table 5-1: Estimated Gross GIIP for Main Panels.

[6] VDR Document No. 4.2.3.3.2 – 20220426 Layer 3 MLJ1-07 Deepening.pdf

6. RESERVOIR ENGINEERING ASSESSMENT

6.1 Fluid Properties

The fluid is considered gas-condensate, but compositions vary from one reservoir to another, which gives variations in condensate richness. Fluid modelling is complex since the field comprises stacked reservoirs in several structural panels with depth variations of more than 2000 m.

A sample composition is shown in Table 6-1.

Reservoir fluid composition	% mole
N2	0.186
CO2	1.765
C1	85.646
C2	4.852
C3	2.673
IC4	0.505
NC4	0.600
IC5	0.277
NC5	0.178
C6	0.423
C7	0.379
C8	0.259
C9	0.143
C10	0.126
C11+	1.988

Table 6-1: Sample gas composition

The historical CGR evolution versus gas cumulative production is presented in Figure 6-1.

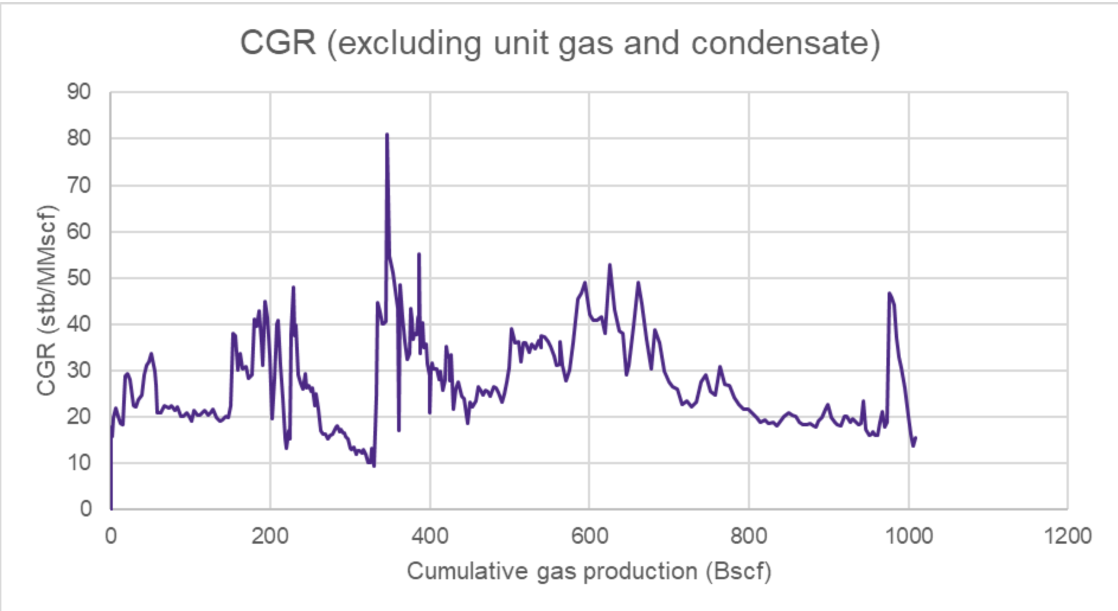

Figure 6-1: CGR versus cumulative gas production.

The average CGR has been approximately 30 stb/MMscf. This decreased to 20 stb/MMscf before anomalously rising to over 40 stb/MMscf in late 2023 following a work over campaign. During 2024 the field average CGR had reduced to type, below 20 stb/MMscf.

6.2 Production History

Historic gas, condensate and water production rates are shown in Figure 6-2. The increase in production after implementation of the MLJ South Redevelopment Project with first production in 2016 is clearly seen. Since 2016, the field was in decline until wells MLJ1-06 and MLJ1-07 (Third Party Gas) were brought back online in October 2022.

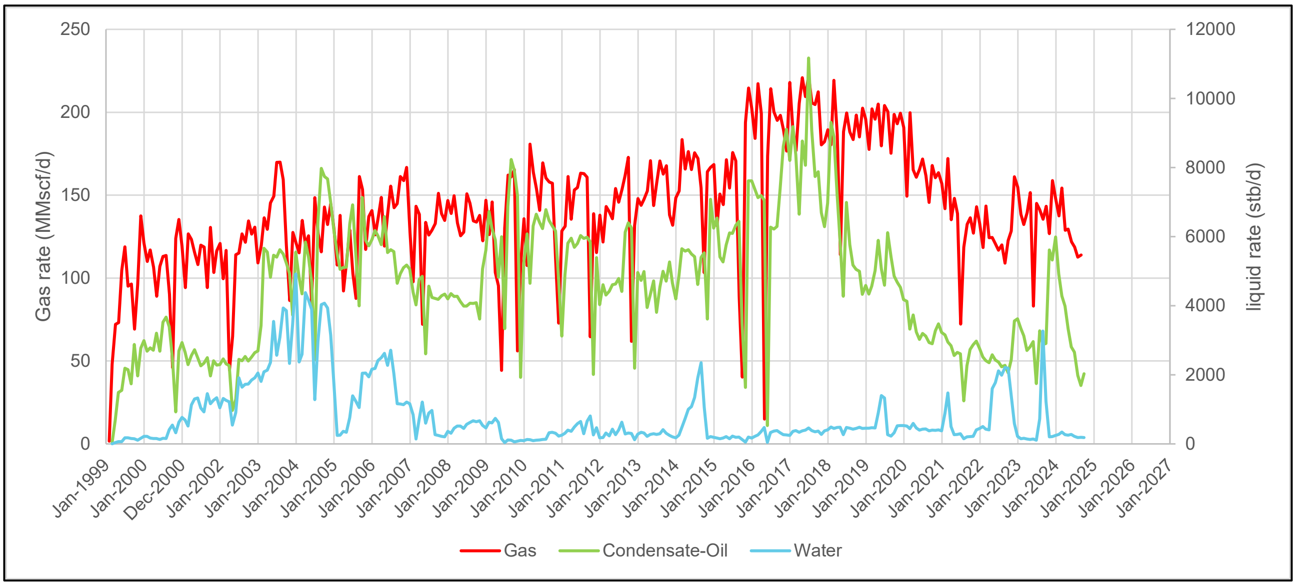

Figure 6-2: Historic Production Rates (including data to September 2024)

Currently, all wells are producing free flow. Production data seen by TTRPSE includes monthly volumes up to and including September 2024. Only 10 wells have been produced continuously during 2024 (two of them being MLJ1-06 and MLJ1-07 Third Party Gas). Out of the 10 wells producing in 2024 well MLJ3-01 produced only from January to July and well MLJ3-04 from January to August. Wells MLJ1-05 and MLJ2-04 are plugged and abandoned, and wells MLJ1-01, MLJ1-02, MLJ1-03, MLJ2-02, MLJ2-03, MLJ2-05 and MLJ3-03 have not produced during 2024.

A total of 1,325 Bscf of gas and 43 MMstb of condensate has been produced up to the end of September 2024.

The wells suffer from calcite deposition over time, which decreases the productivity index (PI). In recent years, some efforts have focused on maintaining the PI of the MLJ3 platform wells by reperforating the producing intervals. This resulted in production increases over several months, which potentially indicates that periodic reperforations could maintain the PI of these wells.

6.3 Simulation models

TTRPSE was provided with four separate reservoir simulation models for the 2025 exercise. These were not available previously through the Total pre-Acquisition dataroom exercise that TTRPSE concluded for Hibiscus in 2024. The new available Simulation Model data which were obtained after Hibiscus started operating, has resulted in more confidence in estimation of volumes. The models are not new builds but are the previous operator Total's interpretation models used for the production forecasting:

- Eclipse models:
  - "MLS" – the MLJ South field
  - "MLW"

  - "Z12"
- Intersect compositional model
  - "MLN" – the North field

For forecasting, Hibiscus had combined the individual MLS, MLW and Z12 models into a single model, using the Eclipse "Reservoir coupling" option. In this coupled reservoir model, a simple, empty reservoir model is set up as the "master", with the MLS, MLW and Z12 models defined as "slaves". Within the simulator the slave processes are activated by the master and run in synchronization with it. This coupled model includes a simple pipeline network and calculates the pressure drop across the main 80 km 18" pipeline to the OPP.

The Third Party Gas was included in the coupled model as "import gas" flowing at a rate which is varied on a month-by-month basis before being terminated at the time compression starts. Once compression starts, the Hibiscus Block B wells will be produced to meet the requirement of the sales contract. If there is additional ullage, Third Party Gas will be produced to maximise revenue for the JV. Including this import gas in the coupled model ensures that the calculated pipeline pressure drop takes account of the additional volume from wells MLJ-06 and MLJ-07 even though those wells are not explicitly modelled.

The MLN model had not been included in the forecast model as it is not possible to couple the Eclipse black oil models and the Intersect compositional models.

TTRPSE has reviewed the Eclipse models, including the history matching and forecast assumptions. History matching has required several local adjustments, not least changes to skin and/or well productivity (WPIMULT). Forecast simulations have to make assumptions about skin and WPIMULT adjustments required for infill wells and for planned workovers.

Consistent with Total's observations from the pre-sale documents examined for the 2024 CPR, we would describe the quality of rate and pressure history matching on a well-by-well as being somewhat variable. Although some wells are matched closely, plots of other wells show only a "Fair" or "Poor" match.

TTRPSE considers that the current Eclipse models may have value for identifying development targets but could be less reliable in predicting the productivity of infill wells and the gains from well interventions (especially new perforations). This is a consequence of the model complexity, and the many history match changes made to static properties and to the well productivities. With such complex models it would not be possible to modify or improve the Eclipse models on the timeframes of a CPR project. For this reason TTRPSE decided not to use the Eclipse models to provide our independent Reserves forecasts. Instead, a new, simple GAP/MBAL model was constructed. However, some observations and conclusions from TTRPSE's Eclipse runs were used to support the development and calibration of the GAP/MBAL model.

Among the Eclipse runs executed by TTRPSE were some cases where the MLS South Field model was run in standalone mode, connected to the same simple pipeline network as the coupled model using the Eclipse Network option. Gas production from the MLS & Z12 wells was varied in this model on a month-by-month basis throughout the forecast period, specifying rates identical to those which had been simulated with the supplied coupled model. This Eclipse run was designed to examine the impact of modifying the simulated MLS field development steps to be closer to the activities specified in the Hibiscus costs workbook – in particular reducing the number of velocity strings to be installed in 2026 from three to two. This TTRPSE simulation showed that this slight alteration to the assumed well activity led to a reduction in overall productivity such that the total gas production fell below the 3.81 MSm^3/d target rate from 2027 to 2029 (when well B1-15k[7] production started). In the client's original coupled Eclipse model, the target gas production rate was met continuously through to 2031. This implies that according to Eclipse simulation, additional well interventions will be required in 2027-2029 otherwise it may not be possible to maintain flow at target rates prior to planned infill drilling in 2029.

[7] This well is called "B1-DEEP" in the Eclipse simulation model.

TTRPSE makes the following suggestions for the Hibiscus dynamic modelling team:

- Confirm that the master/slave arrangement has been correctly set-up in the coupled model.

  The Eclipse manual provides specific advice about defining import gas and operating efficiency factors when running master/slave models:

  – Import gas can be defined for a slave model, but not for the master model.

  – If a single efficiency factor is to be applied for all of the reservoirs, then the same operating efficiency factor should be specified in the slave models as in the master model.

  These instructions have not been followed in the Block B model. This may explain an odd feature noted in the Eclipse output. The sum of the gas production from the three slave models does not match the gas production reported for the master model, unless the efficiency factor is 100%. This may imply one of two things:

  1. The coupled Eclipse model is not achieving a material balance – i.e. not all of the gas produced from the reservoirs is modelled to reach the OPP. If this is the case, the error is equivalent to the downtime, i.e. about 7% of the total production during the forecast period.

  2. Or, the Eclipse model is calculating correct volumes (i.e. honouring the material balance), but the results files for the slave models cannot be used without making manual adjustments to the reported production volumes.

- Several of the well VFP tables need to be extrapolated by Eclipse in the forecast models, since wells flow at rates and pressures beyond the validity range of the input table.

- Confirm the equilibration. Output from the Eclipse MLW model reports that some model cells with different PVT properties are in communication with each other.

- Review the set of model changes required to achieve a history match to reported well pressure and PLT data. Well history match changes have included a combination of adjustments to skin, productivity multipliers and non-Darcy flow parameters. It is worth considering whether there could be a pattern linking the reservoir type, the perforation characteristics or the workover activity to the magnitude of model adjustment that is required. This could help to inform what well productivity adjustments should be input for infill wells and for future well interventions.

Note that TTRPSE has not reviewed many of the reservoir engineering input data in these Eclipse models, such as : fluid PVT property tables, relative permeability and Pc tables, and the definition and calibration of well performance tables.

The GIIP volumes in the Eclipse models are summarised in Table 6-2. Since these Eclipse models have not been used to assess Block B Reserves, no attempt has been made to reconcile these volumes with static models or material balance models.

Model	GIIP, million Sm3	GIIP, Bscf
MLS	46,288	1,635
MLW	22,978	811
Z12	5,046	178
Total (arithmetic)	**74,311**	**2,624**

Table 6-2: Eclipse GIIP Volumes

6.4 Material Balance and Surface Network Modelling

TTRPSE used a material balance model to validate results from the dynamic models and to forecast recoverable volumes. TTRPSE chose this option due to the impracticalities of any attempt to modify such complex Eclipse dynamic models and run the different options required.

TTRPSE used the Petex® software suit to couple a material balance reservoir model using MBAL® and a surface facilities network using GAP®.

The MBAL model was built using the historical production data available and the historical BHP pressures included in the Eclipse models to define the in places after history match.

Well models were defined using the Vertical Lift Performance (VLP) curves included in the supplied Eclipse models, and Inflow Performance Relationship (IPR) curves were defined to match actual data.

The GAP model defined included platforms MLJ-1, MLJ-2 and MLJ-3, the connection pipelines and the 85 km 18" pipeline connecting to the OPP facility on shore. The model does not include any tanks or wells to represent the Third Party Gas production from wells MLJ1-06 and MLJ1-07. Instead, any assumed Third Party Gas flow is defined in the model as a hard-coded table of rates. Third Party Gas flow is combined with the fluids from the South / West / JMB / JAM panels in the GAP model so that the pressure drop calculated for the 85 km 18" pipeline correctly accounts for the Third Party Gas contribution.

The arrangement of the GAP model is shown in Figure 6-3.

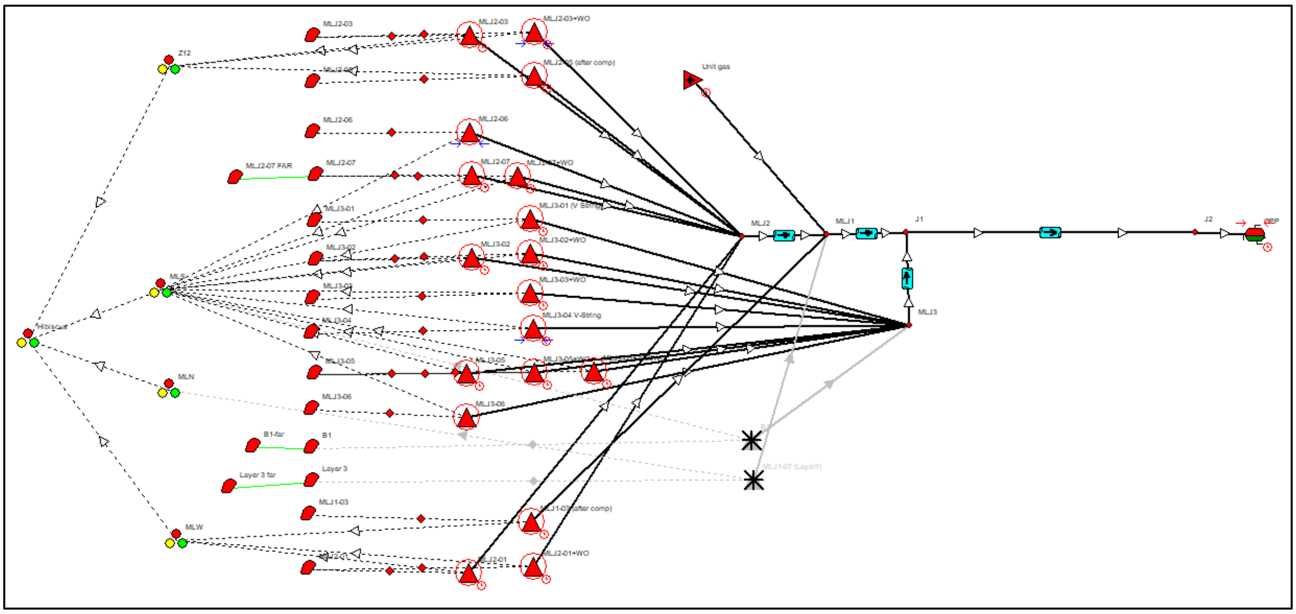

Figure 6-3: GAP model arrangement

The gas in-place volumes for the material balance models are as follows:

Tank	MBAL GIIP, Bscf	Comment
MLJ2-03	60	Drained by well MLJ2-03
MLJ2-05	220	Drained by well MLJ2-05
MLJ2-06	105	Drained by well MLJ2-06
MLJ2-07 FAR	160	Drained by well MLJ2-07
MLJ2-07	150	
MLJ3-01	115	Drained by well MLJ3-01
MLJ3-02	155	Drained by well MLJ3-02
MLJ3-03	80	Drained by well MLJ3-03
MLJ3-04	37	Drained by well MLJ3-04
MLJ3-05	230	Drained by well MLJ3-05
MLJ3-06	200	Drained by well MLJ3-06
MLJ1-03	90	Drained by well MLJ1-03
MLJ2-01	175	Drained by well MLJ2-01
B1	20	Drained by well "B1" (B1-15k (Contingent Resources)
B1-FAR	36	
Layer 3	35	Drained by MLJ1-07 (Layer3) (Contingent Resources)
Layer 3 Far	13	
MLJ1-01	75	Not drained in Reserves/Resources forecast models
MLJ2-02	185	
Total	**2,141**	
Total (drained tanks)	**1,881**	

Table 6-3: Material Balance Modelling - GIIP

Tanks and wells with no forecast production are not included in the GAP/MBAL model (with the exception of tanks MLJ1-01 and MLJ2-02).

6.5 Production Forecasts

6.5.1 Base Forecast

The base forecast from the GAP model includes:

- No further activity (NFA) for all wells in the South / West / JMB / JAM panels
- The 2025 and 2026 workovers
  - 2025 workovers:
    - Wells MLJ2-01, MLJ2-07, MLJ3-02, MLJ3-03, MLJ3-05

 – 2026 workovers:
   ○ Wells MLJ2-03, MLJ3-05
- 2026 velocity string programme.
  – Wells MLJ3-01 and MLJ3-04

Each workover is assumed to improve a well's inflow performance. An increase of 10 MMscf/d is typically assumed (in line with historical production analysis). This is modelled by adjusting the well's Inflow Performance Relationship (IPR) in the GAP/MBAL model.

Installation of velocity strings in wells MLJ3-01 and MLJ3-04 is modelled by changing the well's lift curves (consistent with the Eclipse models).

An operating efficiency of 92.5% has been assumed. A 20-day full field shutdown is assumed for September 2025, and a 7-day TAR in October/November 2025.

LP Project Forecast

The LP compression project is expected to come on stream in November 2025. Based on the documentation provided, compression will decrease the arrival pressure to 17 barg and will limit the production rate to approximately 134 MMscf/d (4 Msm^3/d).

The current WHP of the wells is in the range 70 to 80 barg (all flowing at free flow). After compression, this pressure is expected to decrease to 40 barg (at the 124 MMscf/d limit rate). At the end of the forecast, it is expected a minimum WHP of 25 barg.

A compressor efficiency of 92.5% has been assumed for the Best Case. This results in a plateau rate of approximately 124 MMscf/d.

Once compression starts, the Hibiscus Block B wells will be produced to meet the requirement of the sales contract. If there is additional ullage, Third Party Gas will be produced to maximise revenue for the JV.

The TTRPSE forecast after compression is shown in Figure 6-4. The figure compares the potential with the constrained profile.

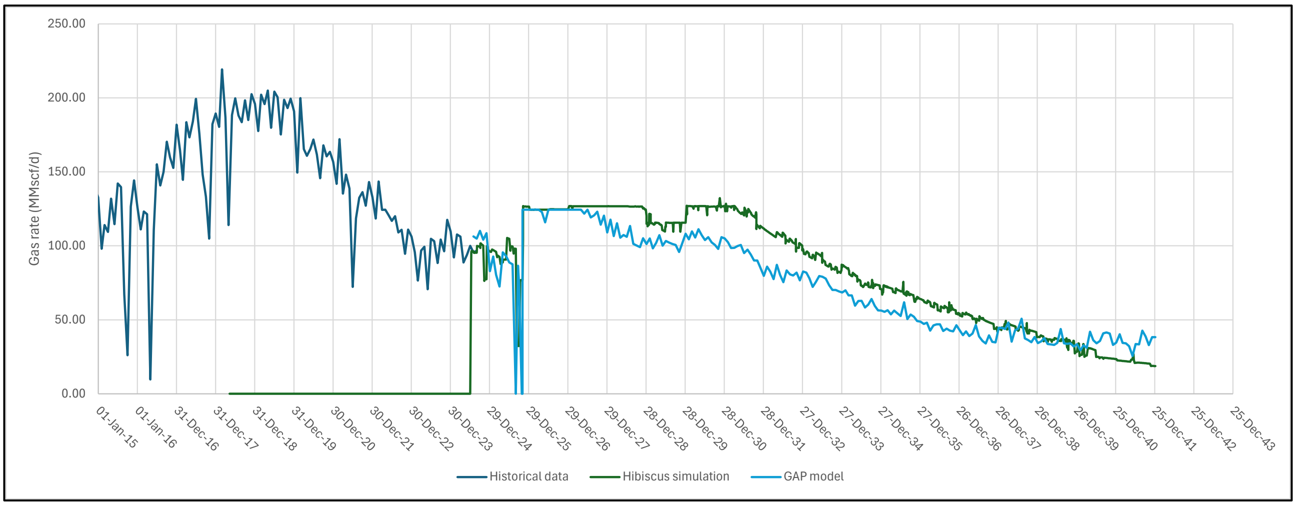

Figure 6-4: **Base case production profile including compression from November 2025**

Shrinkage from the wellhead wet gas volumes to sales gas volumes is assumed to be 2.439%, consistent with historically reported production data. All plots and tables in this section quote gross gas volumes as opposed to sales gas volumes. The gas volumes reported in the Executive Summary (Section 1) and in Section 8 are sales gas volumes.

Table 6-4 summarises the calculated gas volumes and recovery factors from the MBAL/GAP model for this Reserves case (NFA + workovers + LP project). Tank recovery factors range from 31% to 89%, with most tanks reaching a recovery factor in excess of 75%.

Tank	MBAL Tank GIIP, Bscf	Well	Produced Gas[2], Bscf	Recovery Factor
MLJ2-03	60	MLJ2-03	43	72%
MLJ2-05	220	MLJ2-05	67	31%
MLJ2-06	105	MLJ2-06	89	85%
MLJ2-07 FAR + MLJ2-07	310	MLJ2-07	222	72%
MLJ3-01	115	MLJ3-01	85	74%
MLJ3-02	155	MLJ3-02	131	84%
MLJ3-03	80	MLJ3-03	46	58%
MLJ3-04	37	MLJ3-04	28	76%
MLJ3-05	230	MLJ3-05	191	83%
MLJ3-06	200	MLJ3-06	92	46%
MLJ1-03	90	MLJ1-03	78	86%
MLJ2-01	175	MLJ2-01	156	89%
Total[1]	**2,144**		**1,228**	**69%**

(1) Total only includes tanks/wells with modelled production in 2023-2039 forecast (NFA + workovers + LP project)

(2) Field life production to end-2039

Table 6-4: Material Balance Modelling – Recovery Factors

6.5.2 Contingent Projects

The operator is considering two additional projects:

- New well B1-15k in mid 2029
- Additional MLJ North workover to perforate Layer 3 immediately after the B1-15K well in early 2030

The GIIP and the potential recoverable volumes for these two wells are presented in Table 6-5.

Well	Case	GIIP (Bscf)	RF (%)	EUR (Bscf)
MLJ North Layer 3 workover	Low	30	50	15
	Base	48	60	29
	High	60	70	42
B1-15k new well	Low	49	50	25
	Base	56	60	34
	High	78	70	55

Table 6-5: Potential EUR per Well based on RF.

The volumes were incorporated into the GAP/MBAL models.

When these infill wells start producing, there is a back-out effect as overall field flow is subject to compressor constraints and minimum turndown rates. This reduces the increment expected from each infill well[8] increment decreases the potential recovery stated above.

The recovery from the infill wells in isolation aligns with the previous report. However, the new wells have a negative impact on the existing wells (backing them out), resulting in a much smaller final incremental volume. This was only possible to calculate integrating the surface network with all the wells into the calculation.

6.5.3 Full TTRPSE Reserves Forecast

The full TTRPSE pre-ELT production Low, Best and High forecasts for the committed plans are presented in Figure 6-5, and remaining recoverable volumes are summarised in Table 6-6 and Table 6-7. The gas rates plotted here reflect the reserves basis and does not include Third Party Gas. In both the graph and the tables the volumes quoted are sales gas volumes, which are slightly lower than the gross gas volumes[9].

Condensate production has been calculated based on a flat CGR of 15-20-30 stb/MMscf for the low, base, and high cases. These figures are lower than the previous CPR[10] but are now supported by a change in CGR over the last months going back to earlier trend (see Section 6.1).

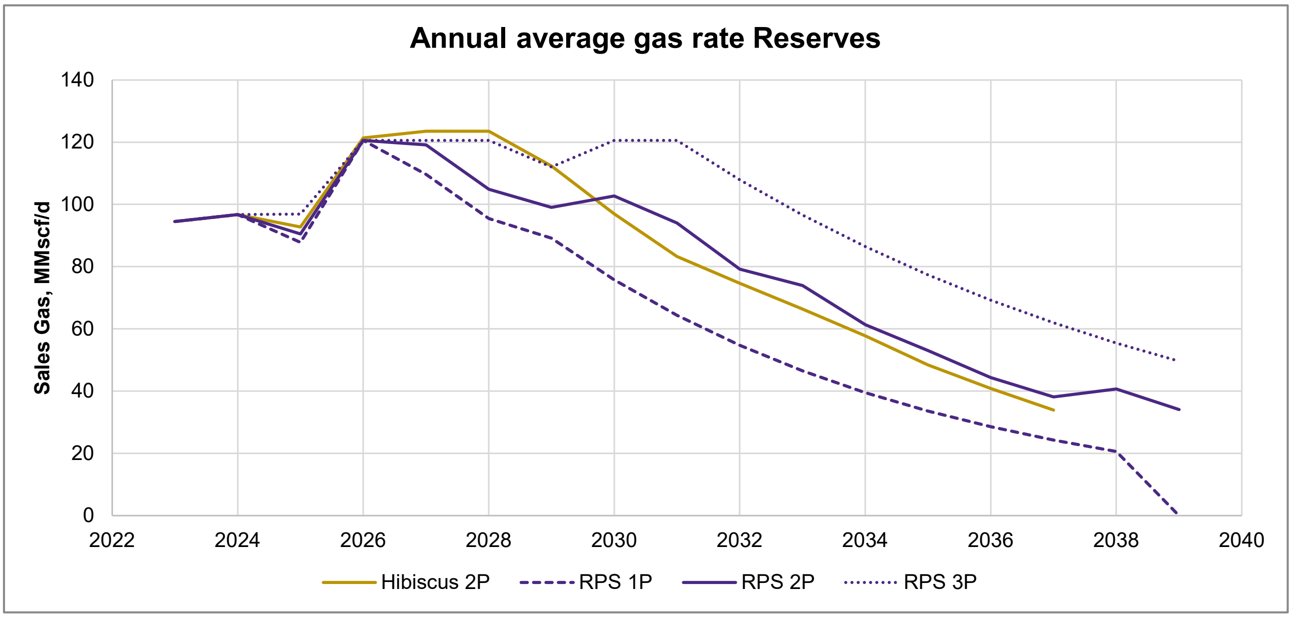

Figure 6-5: Reserves technical production profiles (pre-ELT Sales Gas)

[8] When compiling the 2024 CPR, RPS did not have access to field/well/pipeline models, and did not have time to construct any models. The increment from infill wells was simply added to the base forecast. The increments forecast for the B1-15k and Layer 3 projects in the current study are therefore lower than reported in the 2024 CPR.

[9] Sales gas is assumed to be gross gas x0.97561.

The plateau rate is 124 MMscf/f gross gas, equivalent (after shrinkage) to a sales gas plateau rate of 121 MMscf/d.

[10] Competent Person's Report Maharajalela Jamalulalam Field, Block B, Offshore Brunei. RPS 793-TA000016, 15 June 2024.

Gas Remaining Recoverable volume after 1 January 2025 (Sales Gas, 100% WI, Pre-Economic Limit Test) Bscf			
	Low	**Best**	**High**
Committed plans (includes 2025 compression + 2025 and 2026 Workovers)	325	422	517
Third Party Gas[1]	7	7	7
Total[2]	**332**	**428**	**523**

[1] Third Party Gas in 2025 only, up to compressor start-up.
[2] Arithmetic summation of pre-ELT volumes

Table 6-6: Gas Remaining Recoverable Volumes after 1 January 2025 (committed plans, sales gas volumes)

Condensate Remaining Recoverable volume after 1 January 2025 Gross, 100% WI, Pre-Economic Limit Test MMstb			
	Low	**Best**	**High**
Committed plans (includes 2025 compression + 2025 and 2026 Workovers)	5.00	8.65	15.89
Third Party Gas[1]	0.15	0.15	0.15
Total[2]	**5.15**	**8.80**	**16.05**

[1] Third Party Gas in 2025 only , up to compressor start-up.
[2] Arithmetic summation of pre-ELT volumes

Table 6-7: Condensate Remaining Recoverable Volumes after 1 January 2025 (committed plans)

Table 6-8 shows how the remaining sales gas volume is split between developed and undeveloped projects. The recoverable volumes are higher than those presented in the 2024 CPR. The 2024 CPR used graphical Decline Curve Analysis techniques to forecast production, coupled with a type curve approach for estimating increments from development projects (workovers and LP compression). Such an approach has its limitations, and the present model-based forecasts are considered more reliable. Note the following differences between the 2024 CPR forecast assumptions and the assumptions in the current evaluations:

- In the 2024 CPR, forecasts were based on production data up to 31 December 2023. The present study has used data up to September 2024. Use of these different datasets has led to a difference in the number of wells assumed in the NFA cases[11].
- The 2024 CPR considered two types of workover activity:
  - Two years of workover activities classified as Contingent Resources in the 2024 CPR.
  - An ongoing programme of reperforations which essentially maintained the PI of wells which had decreased (e.g. due to mineral deposition). These were assumed to provide a rate increment which lasted only for 1-2 years.

[11] In the GAP model, a number of the currently shut wells are assumed to restart production under LP compression.

By contrast the current study includes all identified well intervention opportunities in the plan and the increments from the 2025/2026 workover and velocity string programme which are now classified as Reserves.

- The increment from LP compression in the 2P is lower than assumed in the 2024 CPR, against a backdrop of a higher NFA forecast. The production plateau is modelled to extend to 2027 in the Best Cc
- ase (2P) which is earlier than the 2030 date in the 2024 CPR.

Gas Remaining Recoverable volume after 1 January 2025 (Sales Gas, 100% WI, Pre-Economic Limit Test) Bscf				
		Low	**Best**	**High**
Developed	NFA	131	180	230
Undeveloped	Well Interventions	58	76	89
	LP Project	136	166	197
Total		**325**	**422**	**517**

Table 6-8: Gas Remaining Recoverable Volumes after 1 January 2025, Showing Developed and Undeveloped Projects (committed plans, Sales Gas volumes)

6.5.4 Contingent Resources Forecasts

The full TTRPSE production Low, Best and High forecasts including committed plans, and contingent plans are presented in Figure 6-6. The plotted rates reflect the Reserves and Contingent Resource basis and do not include Third Party Gas. Compression starts in late 2025. The gas volumes plotted here are sales gas volumes, which are slightly lower than the gross gas volumes[12].

[12] Sales gas is assumed to be gross gas x0.97561.

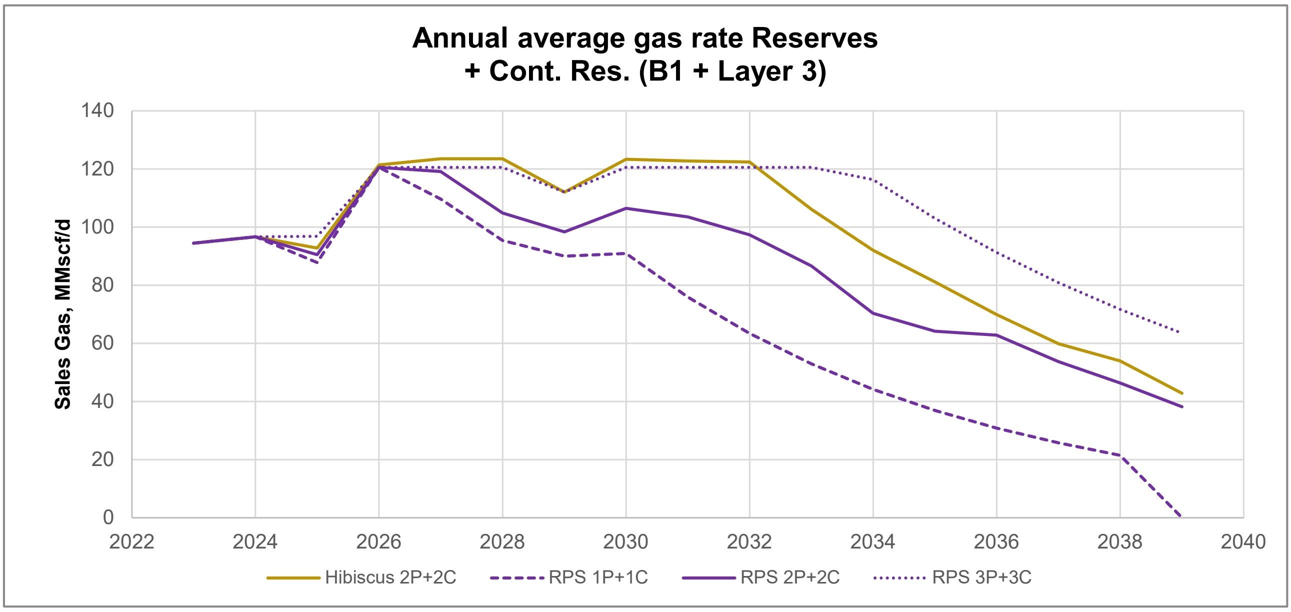

Figure 6-6: Reserves + Contingent Resources Profiles (pre-ELT)

Pre-ELT EUR contingent volumes up to 2039 are presented in Table 6-9 and Table 6-10. Notice that numbers only reflect recoveries until 2039 for comparisons with Hibiscus numbers.

Producing the B1-15k well at the same time as the Layer 3 reservoir could lead to a backpressure effect through the facilities, reducing the incremental gains from the ML1-07 reperforation. This pressure effect is modelled in the current study, but had not been included in the 2024 TTRPSE report.

Gas Remaining Recoverable Contingent Resources after 1 January 2025
Sales Gas, 100% WI, Pre-Economic Limit Test
Bscf

		Low	Best	High
Contingent	B1-15k new well	17	32	45
	Layer 3	4	7	14
Third Party Gas		0	0	0
Total[1]		20	39	60

[1] Arithmetic summation of volumes

Table 6-9: Gas Remaining Recoverable Contingent Resources after 1 January 2025 (sales gas volumes)

Condensate Remaining Recoverable Contingent Resources after 1 January 2025 Gross, 100% WI, Pre-Economic Limit Test MMstb				
		Low	**Best**	**High**
Contingent	**B1-15k new well**	0.25	0.66	1.39
	Layer 3	0.06	0.15	0.45
Third Party Gas		0.00	0.00	0.00
Total[1]		**0.31**	**0.80**	**1.83**

[1] Arithmetic summation of volumes

Table 6-10: Condensate Remaining Recoverable Contingent Resources after 1 January 2025

6.5.5 Additional Sensitivity Cases – Additional Third Party Gas From 2028 Onwards

Additional forecast cases were run to assess the Project NPV impact of adding later Third Party Gas production. Noting the low incremental recovery for the MLJ North Layer 3 project (Contingent Resources), the base model for these sensitivity cases excludes the Layer 3 Contingent Project as uneconomic in the Low Case and Best Case and inconsequential in the High Case.

Any gas volume produced under a Third Party Gas agreement is not considered Reserves or Contingent Resources however could add NPV to the project.

The first Sensitivity Case assumes that Third Party Gas is produced between 2028 and 2030 only – this is applied to the Low Case forecasts. It assumes a single 3 year tranche of gas is negotiated.

The second Sensitivity Case assumes that Third Party Gas is produced at a declining rate between 2028 and 2036 – this is applied to the Best and High forecasts.

This additional Third Party Gas is included in the GAP model as hard coded rates as a “Source” term, in the same way the Third Party Gas volumes produced during 2025 had been modelled.

All the Third Party Gas assumes some decline in production to the source gas compartment as gas production is ongoing and continues regardless of evacuation route.

The assumed Third Party Gas profiles input into the GAP/MBAL model are shown in Table 6-11.

Year	Low Case		Best Case		High Case	
	MMscf/d[1]	Bscf/year[1]	MMscf/d[1]	Bscf/year[1]	MMscf/d[1]	Bscf/year[1]
2028	28.49	10.40	28.49	10.4	28.49	10.4
2029	28.22	10.30	28.22	10.3	28.22	10.3
2030	23.62	8.62	23.62	8.62	23.62	8.62
2031	0		18.00	6.57	18.00	6.57
2032	0		14.33	5.23	14.33	5.23
2033	0		11.53	4.21	11.53	4.21
2034	0		9.51	3.47	9.51	3.47
2035	0		7.97	2.91	7.97	2.91
2036	0		6.27	2.29	6.27	2.29

[1] Quoted values are instantaneous rate. Annual average rates would be lower, due to the assumed 7.5% downtime

Table 6-11: Third Party Gas Input Profiles

Production forecasts from these sensitivity cases are shown in Figure 6-7 (Low Case), Figure 6-8 (Best Case) and Figure 6-9 (High Case). The incremental volumes associated with the additional Third Party Gas derived from the GAP/MBAL model are stated in Table 6-12 (Gas) and Table 6-13 (Condensate).

Although the assumed Third Party Gas production input profiles are the same for the Best and High Cases, the condensate volumes associated with wells MLJ1-06 and MLJ1-07 differ, due to the different assumed CGR values (20 stb/MMscf for the best case and 30 stb/MMscf for the high case).

In each of these sensitivity cases, the extra Third Party Gas produced after 2028 causes a drop in the production from the wells in the South / West / JMB / JAM panels. After the Third Party Gas contribution has reduced (or, in the Low Case example, has stopped), there is a “deferred production” effect such that the rate from those panels is higher than in the case without the extra Third Party Gas. Nonetheless in each of the three cases considered there is less overall production from the South / West / JMB / JAM panels when the extra Third Party Gas is produced. This is particularly so in the High Case, due to all forecasts being terminated at the end of 2039. In the Best and High Cases it is likely that NPV would be improved by delaying the start of any additional Third Party Gas until 2032 or 2033.

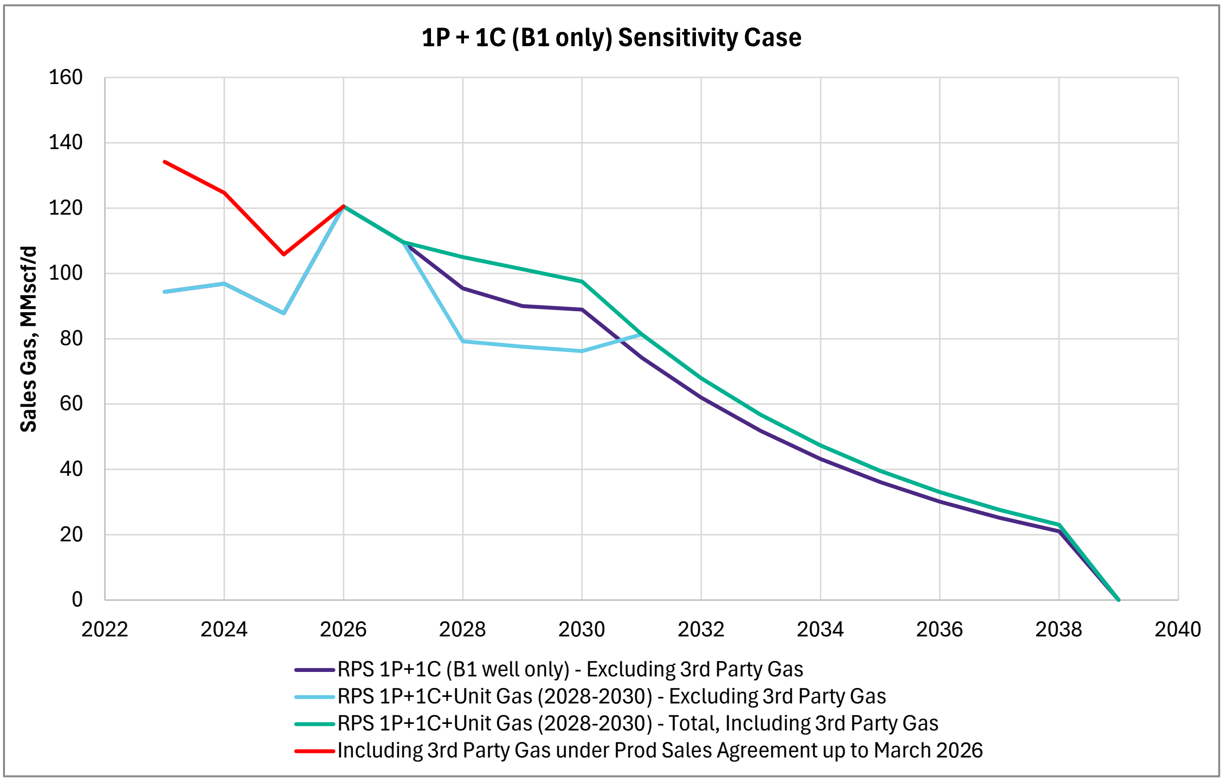

Figure 6-7: Gas Production - Impact of 2028-2030 Third Party Gas – Low Case

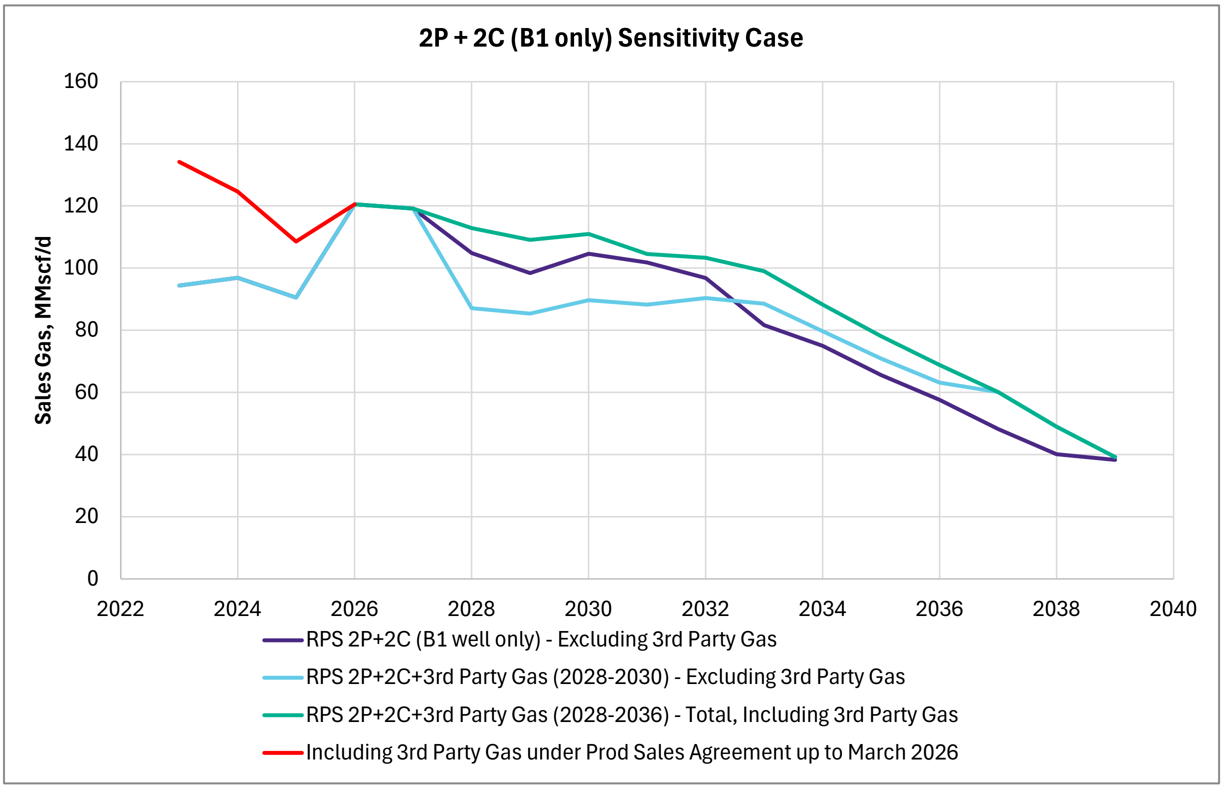

Figure 6-8: Gas Production - Impact of 2028-2036 Third Party Gas – Best Case

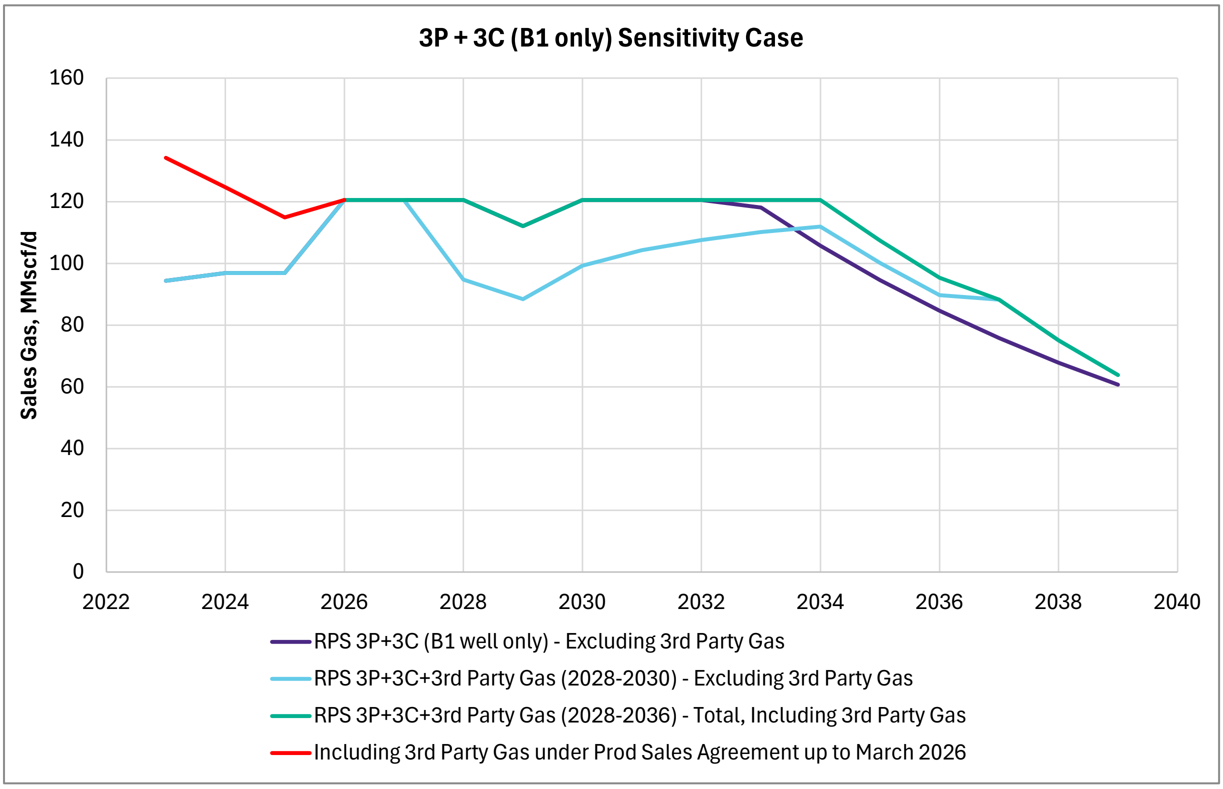

Figure 6-9: Gas Production - Impact of 2028-2036 Third Party Gas – High Case

Impact of Additional Third Party Gas (Post 2028) – Gas Production
Gross, 100% WI, Pre-Economic Limit Test
Bscf

	Low (Third Party Gas from 2028-2030)	Best (Third Party Gas from 2028-2036)	High (Third Party Gas from 2028-2036)
Increment for all wells except MLJ1-06 & MLJ1-07	-3	-8	-26
Third Party Gas	26	49	49
Total[1]	**23**	**41**	**24**

[1] Arithmetic summation of volumes

Table 6-12: Impact of Additional Third Party Gas on Gas Production

Impact of Additional Third Party Gas (Post 2028) – Condensate Production Gross, 100% WI, Pre-Economic Limit Test MMstb			
	Low (Third Party Gas from 2028-2030)	**Best (Third Party Gas from 2028-2036)**	**High (Third Party Gas from 2028-2036)**
Increment for all wells except MLJ1-06 & MLJ1-07	-0.05	-0.16	-0.77
Third Party Gas	0.36	0.99	1.56
Total[1]	**0.31**	**0.82**	**0.79**

[1] Arithmetic summation of volumes

Table 6-13: Impact of Additional Third Party Gas on Condensate Production

7. COST PROFILES

TTRPSE reviewed the costs presented by Hibiscus in the economic model and in other documents located in the VDR. Actual cost data and predicted future costs information in the VDR were valid as of 1st January 2025. TTRPSE has reviewed and opined these costs are reasonable when benchmarked against cost estimates for similar operation in the region.

All costs discussed are 2025 Real Terms and not Money of the Day[13] i.e. do not include any assumptions for inflation.

TTRPSE has produced cost profiles for scenarios

- the Developed Producing case which includes all firm activities
- and a Developed + Contingent case which includes two additional wells that are at the time of this report not approved and only considered contingent.

TTRPSE have produced a Low/Best/High Case for each of these scenarios.

In addition, TTRPSE has produced a Low/Best/High sensitivity case, in which additional Third Party Gas is produced after 2028.

In total, there are twelve TTRPSE produced cost and production profiles used for valuation purposes. Three of these cases are sensitivity cases regarding the Third Party Gas volumes. Third Party Gas production, described in section 6.5.5, is included as it has an impact on the volumes of gas compressed in the new LP compression system and hence impacts the compressor electrical power requirements and compression operating costs. Third Party Gas volumes are used in the TTRPSE calculation of the compression operating costs but are excluded from the reserves volumes quoted.

The twelve cases are:

- Reserves Cases: 1P, 2P and 3P
- Reserves + Contingent Resource Cases (B1-15k infill well only): 1P + 1C, 2P + 2C and 3P + 3C
- Reserves + Contingent Resources (B1-15k infill well, plus Layer 3 Well Intervention): 1P+1C, 2P+2C, 3P+3C; to analyse post compression Layer 3 system pressure backout impact and its incremental economic evaluation
- Reserves + Contingent Resource Sensitivity Cases (Additional Third Party Gas Sensitivities) : 1P + 1C , 2P + 2C and 3P + 3C ; to analyse post compression third party system pressure backout impact and incremental economic evaluation.

7.1 Operating Costs (Opex)

TTRPSE has received an economic model from Hibiscus containing some high level Opex profiles. These have been split by the Hibiscus into the following categories:

- Routine Production Costs
- Non-Routine Production Costs
- Compression Fee
- Transportation Costs
- Allocated Cost + Others

[13] RPS uses the term "Money of the Day" to prices which incorporate the effects of annual inflation and reflect the time value of money.

- Sole Costs (Insurance + Others)

The “Opex” category appears to consist of fixed operating costs and have been accepted by TTRPSE.

The routine production budget consists mainly of costs related to General Maintenance and Operation Contract (personnel working at OPP, routine maintenance and inspection and other routine operational support costs) to ensure and maintain the high level of plant availability as well as the support vessel (FCB). The Operating Service Agreement (OSA) tariff paid to BSP is also part of the routine costs.

Non routine Opex covers activities related to well intervention work classed as Opex and non-routine maintenance and full field shutdown activities.

“Allocated Cost + Others” and “Sole Costs” consists of overheads, G&A and insurance costs

TTRPSE has removed the compression Opex and condensate tariff costs from the baseline Opex as these costs are dependent upon production. TTRPSE has generated electricity cost profiles based on the TTRPSE production profiles combined with data on the LP Compressor taken from the LP Compressor technical datasheet from the VDR. TTRPSE has taken the LP Compressor data and have generated a relationship between gas flow and absorbed power and has utilised this to calculate the absorbed compressor power on an annualised basis against the TTRPSE production profiles. The electricity import cost was supplied by the Hibiscus at a rate of $100/MWh. The compressor flow vs absorbed power taken from the compressor datasheet is shown in Figure 7-1:

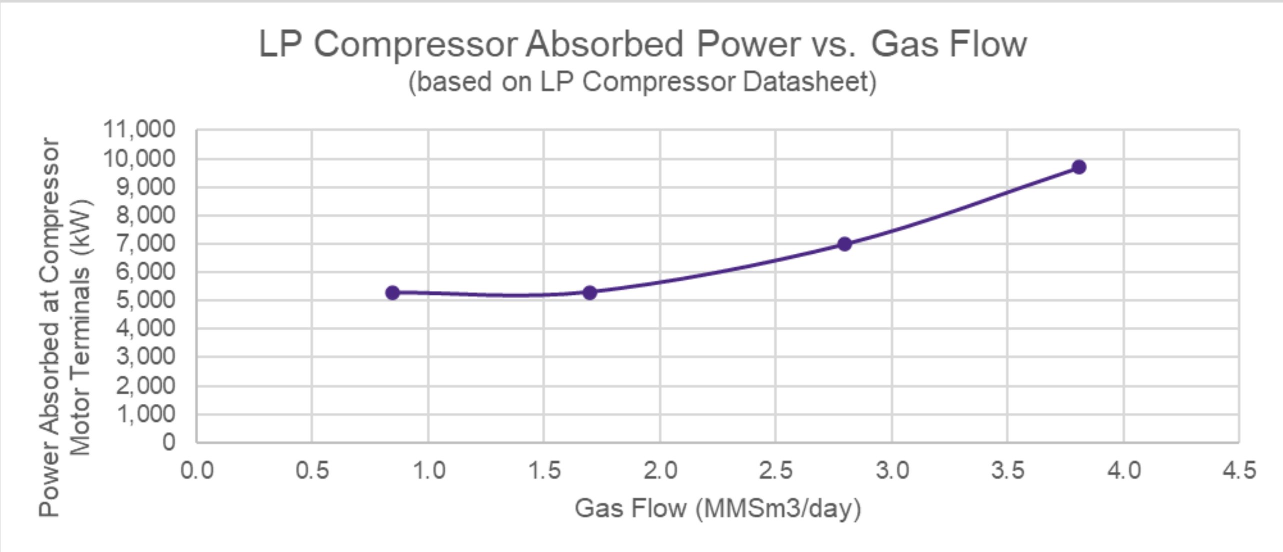

Figure 7-1. Compressor absorbed power vs gas flow.

TTRPSE understands that when flow to the compressor reaches 2.18 MMscm/d (77 MMscf/d) the compressor will enter recycle operation via the anti-surge control loop. Effectively this means that for power requirements the compressor will run at 2.18 MMscm/d as a minimum.

The transportation costs in the Hibiscus model are based on the condensate rates at a unit rate of $1.9/bbl. TTRPSE has maintained this unit cost and calculated the transportation costs against the TTRPSE generated condensate profiles.

Total Capex estimate of $119 million (2025 onwards) covers the following development activities that are either in development or have been moved to firm commitment:

- Studies and Overhead
- Life Extension – Boiler
- Life Extension – Jacket Repair
- LP Compression

- Well Intervention/Velocity String (Rigless; Light Workover)
- General investments

Hibiscus's model also includes updated operator's cost estimates $64 million for the New Well B1-15k (ML03-07) and Well Intervention Perforation deepening in MLJ1-07 Layer3, respectively.

The LP Compression project is underway and expected to be ready for start-up in November 2025.

Hibiscus's Capex estimates have been accepted by TTRPSE.

7.2 Abandonment Costs (Abex)

Total Abex of $ 169 million and $174 million for 2P and 2P plus 2C, respectively, estimated by Hibiscus covers the following activities have been reviewed and accepted by TTRPSE:

- Production Facilities Dismantlement and Disposal
- Project LP mode compressor
- WELLS P&A - 2P
- WELLS P&A - 2C

8. Economic Evaluation

8.1 Contractual Rights Overview

A Petroleum Mining Agreement (PMA) was signed in November 1989, followed by an Amendment Agreement signed in February 2014; and extended until November 2029.

PMA is assumed to be automatically extended from 2029 until November 2039, with renewal being subject to BBJV partners discretion.

8.2 Fiscal Overview

Block B PMA fiscal terms as provided in the dataroom management presentation and applied in the economic model are summarised in Figure 8-1.

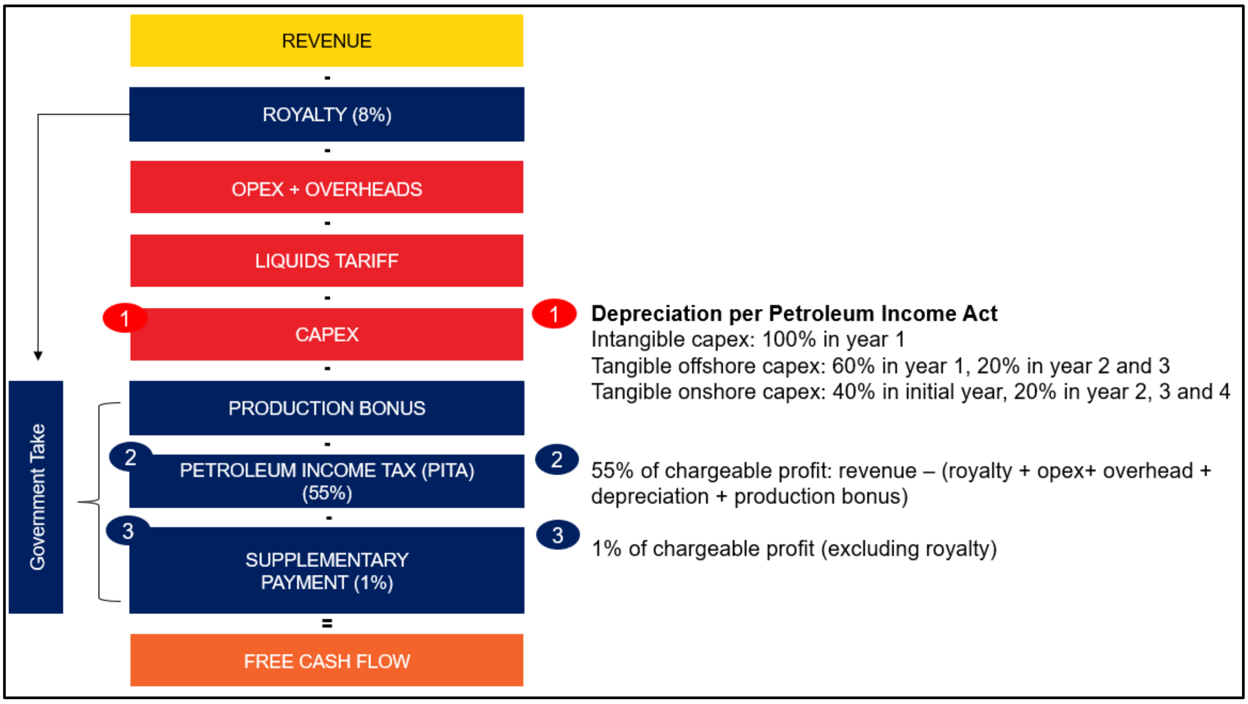

Figure 8-1: Block B PMA Fiscal Terms Summary

8.3 Petroleum Pricing Basis

Based on the data provided by Hibiscus:

- MLJ condensate is sold at a premium to Brent.
- Into Plant Price (IPP) to BLNG gas price formula as per the GSA.
- Inflation: 2% per annum from 2025 for prices and costs.
- USD11/MMBtu JKM LNG prices from 2025 onward (escalated 2% y-o-y thereafter) and JCC premium over Brent of 3.9% are assumed to forecast gas prices.
- Domestic Market Obligation ("DMO") gas price of USD 0.33/MMBtu assumed (DMO price is applicable on 10% of the gas sold)

These price assumptions are applied in TTRPSE commercial evaluation, and the annual forecasts are summarised in Table 8-1.

Year	TTRPSE Q3 2025 Brent Oil Price (US$/bbl) MOD	Realised Condensate Price (US$/bbl) MOD	Realised Gas Price (US$/Mscf) MOD
2025	68.0	67.4	3.7
2026	68.0	68.4	3.9
2027	70.0	70.4	4.0
2028	70.0	70.4	4.4
2029	73.0	73.4	4.5
2030	73.0	73.4	4.5
2031	75.0	75.4	4.7
2032	78.0	78.4	4.8
2033	78.0	78.4	4.9
2034	84.5	84.9	5.1
2035	86.2	86.6	5.2
2036	87.9	88.3	5.4
2037	89.6	90.0	5.5
2038	91.4	91.8	5.6
2039	93.3	93.7	5.7

Table 8-1: Oil and Gas Price Assumptions

8.4 Cashflow Analysis

The Economic Limit Test ("ELT") performed for the determination of Reserves is based on TTRPSE's estimates of recoverable volumes, a review of the Total's estimates of Capex, Opex, and Abex; and inclusion of other financial information and assumptions, as outlined in Section 7.

The licences are assumed to reach its economic limit when the cumulative value of its net cash flow (excluding Abex) before tax ceases to increase. All projects to be classified as Reserves must be economic under defined conditions[14]. TTRPSE has therefore assessed the future economic viability of each case on the basis of its pre-tax undiscounted Net Cash Flow MOD.

An annual inflation rate of 2 per cent has been built into the ELT.

A summary of the Cashflow Analysis is presented in Appendix D.

The effective date of this report is 1st January 2025.

[14] *PRMS 2018: 3.1.2.1 Economic determination of a project is tested assuming a zero percent discount rate (i.e., undiscounted). A project with a positive undiscounted cumulative net cash flow is considered economic.*

8.5 Reserves and Contingent Resources Summary

A summary of Reserves as of 1 January 2025 is provided in Table 8-2 to Table 8-4 for gas, condensate, and barrels of oil equivalent, respectively. The Net Present Value ("NPV") of the asset as of the effective date based on Hibiscus's working interest is presented in Table 8-5.

(Appendix C includes tables of Reserves with effective dates of 1 January 2023 and 14 October 2024).

SUMMARY OF GAS RESERVES
As of 1 January 2025
BASE CASE PRICES AND COSTS

	Full Field Gross Reserves[1] (Bscf)			Net Entitlement Reserves[2] (Bscf)		
	1P	2P	3P	1P	2P	3P
MLJ	325	422	517	122	158	194

Notes:

[1] Gross field Reserves (100% basis) after economic limit test. Economic limit in year 2038 for 1P; year 2039 for 2P and 3P.

[2] Hibiscus' net entitlement based on its 37.5% working interest; after economic limit test. Royalties are paid in cash and treated as production tax. Therefore is not deducted from Hibiscus' Net Entitlement.

Table 8-2: Gas Reserves in MLJ Field as of 1 January 2025

SUMMARY OF CONDENSATE RESERVES
As of 1 January 2025
BASE CASE PRICES AND COSTS

	Full Field Gross Reserves[1] (MMstb)			Net Entitlement Reserves[2] (MMstb)		
	1P	2P	3P	1P	2P	3P
MLJ	5.0	8.6	15.9	1.9	3.2	6.0

Notes:

[1] Gross field Reserves (100% basis) after economic limit test. Economic limit in year 2038 for 1P; year 2039 for 2P and 3P.

[2] Hibiscus' net entitlement based on its 37.5% working interest; after economic limit test. Royalties are paid in cash and treated as production tax. Therefore is not deducted from Hibiscus' Net Entitlement.

Table 8-3: Condensate Reserves in MLJ Field as of 1 January 2025

SUMMARY OF GAS AND CONDENSATE RESERVES (BOE)
As of 1 January 2025
BASE CASE PRICES AND COSTS

	Full Field Gross Reserves[1] (MMboe)[3]			Net Entitlement Reserves[2] (MMboe)[3]		
	1P	2P	3P	1P	2P	3P
MLJ	59.2	79.0	102.0	22.2	29.6	38.3

Notes:

[1] Gross field Reserves (100% basis) after economic limit test. Economic limit in year 2038 for 1P; year 2039 for 2P and 3P.

[2] Hibiscus' net entitlement based on its 37.5% working interest; after economic limit test. Royalties are paid in cash and treated as production tax. Therefore is not deducted from Hibiscus' Net Entitlement.

[3] Conversion rate of 6,000 standard cubic feet per boe.

Table 8-4: Oil Equivalent Reserves in MLJ Field as of 1 January 2025

	ELT Date	Post-Tax Net Present Value (US$ Million, MOD)			
		0%	8%	10%	12%
1P	2038	141	112	105	99
2P	2039	258	182	168	155
3P	2039	421	280	256	234

Table 8-5: Block B Reserves Post-Tax Valuation at TTRPSE Base Case Price Scenario

TTRPSE has classified recoverable volumes from well B1-15K as Contingent Resources – Development Pending, with an estimated Chance of Development (Pd) of over 80%. The MLJ North Layer 3 workover project is estimated to contribute just 7 Bscf incremental gas (Best Case). This project is uneconomic in the Low Case and Best Case and inconsequential in the High Case. This project is not classified as a Contingent Resource project in our final summary.

A summary of Contingent Resources is presented in Table 8-6 to Table 8-8. The Contingent Resources NPV of the asset as of the effective date based on Hibiscus's working interest is presented in Table 8-9 and Table 8-10.

(Appendix C includes tables of Contingent Resources with effective dates of 1 January 2023 and 14 October 2024).

SUMMARY OF GAS CONTINGENT RESOURCES
As of 1 January 2025
BASE CASE PRICES AND COSTS

		Full Field Gross Contingent Resources[1] (Bscf)			Net Entitlement Contingent Resources[2] (Bscf)		
Field	**Project**	**1C**	**2C**	**3C**	**1C**	**2C**	**3C**
MLJ	**MLJ North Layer 3 Workover**	0	0	0	0	0	0
MLJ	**B1-15K**	17	32	45	6	12	17
Total[3, 4]		**17**	**32**	**45**	**6**	**12**	**17**

Notes:

[1] Gross field Contingent Resources (100% basis). Economic limit in year 2038 for 1C; year 2039 for 2C and 3C.

[2] Hibiscus' net entitlement based on its 37.5% working interest; after economic limit test. Royalties are paid in cash and treated as production tax. Therefore is not deducted from Hibiscus' Net Entitlement.

[3] PRMS recommends that for reporting purposes, assessment results should not incorporate statistical aggregation beyond the field, property, or project level. As such, TTRPSE's totals were summed arithmetically and as a result, the total 1C Contingent Resources may be a very conservative assessment and the total 3C Contingent Resources a very optimistic assessment.

[4] It should be noted that all TTRPSE forecasts are cut off at 2039.

[5] Pre economic limit production forecast for 2C and 3C ends in year 2038 and 2039, respectively.

Table 8-6: Gas Contingent Resources in MLJ Field as of 1 January 2025

SUMMARY OF CONDENSATE CONTINGENT RESOURCES
As of 1 January 2025
BASE CASE PRICES AND COSTS

		Full Field Gross Contingent Resources[1] (MMstb)			Net Entitlement Contingent Resources[2] (MMstb)		
Field	**Project**	**1C**	**2C**	**3C**	**1C**	**2C**	**3C**
MLJ	**MLJ North Layer 3 Workover**	0.0	0.0	0.0	0.0	0.0	0.0
MLJ	**B1-15K**	0.3	0.7	1.4	0.1	0.2	0.5
Total[3]		**0.3**	**0.7**	**1.4**	**0.1**	**0.2**	**0.5**

Notes:

[1] Gross field Contingent Resources (100% basis). Economic limit in year 2038 for 1C; year 2039 for 2C and 3C.

[2] Hibiscus' net entitlement based on its 37.5% working interest; after economic limit test. Royalties are paid in cash and treated as production tax. Therefore, is not deducted from Hibiscus' Net Entitlement.

[3] PRMS recommends that for reporting purposes, assessment results should not incorporate statistical aggregation beyond the field, property, or project level. As such, TTRPSE's totals were summed arithmetically and as a result, the total 1C Contingent Resources may be a very conservative assessment and the total 3C Contingent Resources a very optimistic assessment.

[4] Pre economic limit production forecast for 2C and 3C ends in year 2038 and 2039, respectively.

Table 8-7: Condensate Contingent Resources in MLJ Field as of 1 January 2025

SUMMARY OF GAS AND CONDENSATE CONTINGENT RESOURCES (BOE)
As of 1 January 2025
BASE CASE PRICES AND COSTS

		Full Field Gross Contingent Resources[1] (MMboe)[3]			Net Entitlement Contingent Resources[2] (MMboe)[3]		
Field	**Project**	**1C**	**2C**	**3C**	**1C**	**2C**	**3C**
MLJ	**MLJ North Layer 3 Workover**	0.0	0.0	0.0	0.0	0.0	0.0
MLJ	**B1-15K**	3.0	6.0	8.9	1.1	2.2	3.3
Total[4]		**3.0**	**6.0**	**8.9**	**1.1**	**2.2**	**3.3**

Notes:

[1] Gross field Contingent Resources (100% basis). Economic limit in year 2038 for 1C; year 2039 for 2C and 3C.

[2] Hibiscus' net entitlement based on its 37.5% working interest; after economic limit test. Royalties are paid in cash and treated as production tax. Therefore, is not deducted from Hibiscus' Net Entitlement.

[3] Conversion rate of 6,000 standard cubic feet per boe.

[4] PRMS recommends that for reporting purposes, assessment results should not incorporate statistical aggregation beyond the field, property, or project level. As such, TTRPSE's totals were summed arithmetically and as a result, the total 1C Contingent Resources may be a very conservative assessment and the total 3C Contingent Resources a very optimistic assessment.

[5] Pre economic limit production forecast for 2C and 3C ends in year 2038 and 2039, respectively.

Table 8-8: Summary of Oil Equivalent Contingent Resources in MLJ Field as of 1 January 2025

	ELT Date	Post-Tax Net Present Value (US$ Million, MOD)			
		0%	8%	10%	12%
1P+1C	2038	166	125	117	109
2P+2C	2039	316	210	191	175
3P+3C	2039	489	309	279	253

Table 8-9: Block B Reserves and Contingent Resources Post-Tax Valuation at TTRPSE Base Case Price Scenario

	ELT Date	Post-Tax Net Present Value (US$ Million, MOD)			
		0%	8%	10%	12%
1C	2038	24	14	12	10
2C	2039	58	28	23	20
3C	2039	67	29	23	19

Table 8-10: Block B Contingent Resources Post-Tax Valuation at TTRPSE Base Case Price Scenario

RPS's economic valuation of HEB's entitlement in the Asset as at 1 January 2025, based on 2P Reserves and 2C Resources, is USD188 million. This is derived from the total net present value of the Asset's 2P Reserves of USD168 million and 2C Resources of USD20 million, using a discount rate of 10% and 12% respectively.

8.6 Sensitivity Analysis

A Low Price Case and High Price Case are also shown in Figure 8-2 in Money of the Day (MOD) and have been used for price sensitivity purposes on the TTRPSE 2P case.

TTRPSE has also analysed sensitivity of 2P NPV to discount rate (Figure 8-3). Sensitivity of 2P NPV or other key parameters is presented in Figure 8-4. In this analysis, the sensitivity to the key parameters is based on plus and minus of 20 per cent (except for oil price).

Figure 8-2: TTRPSE Brent Price Forecasts (Q3 2025)

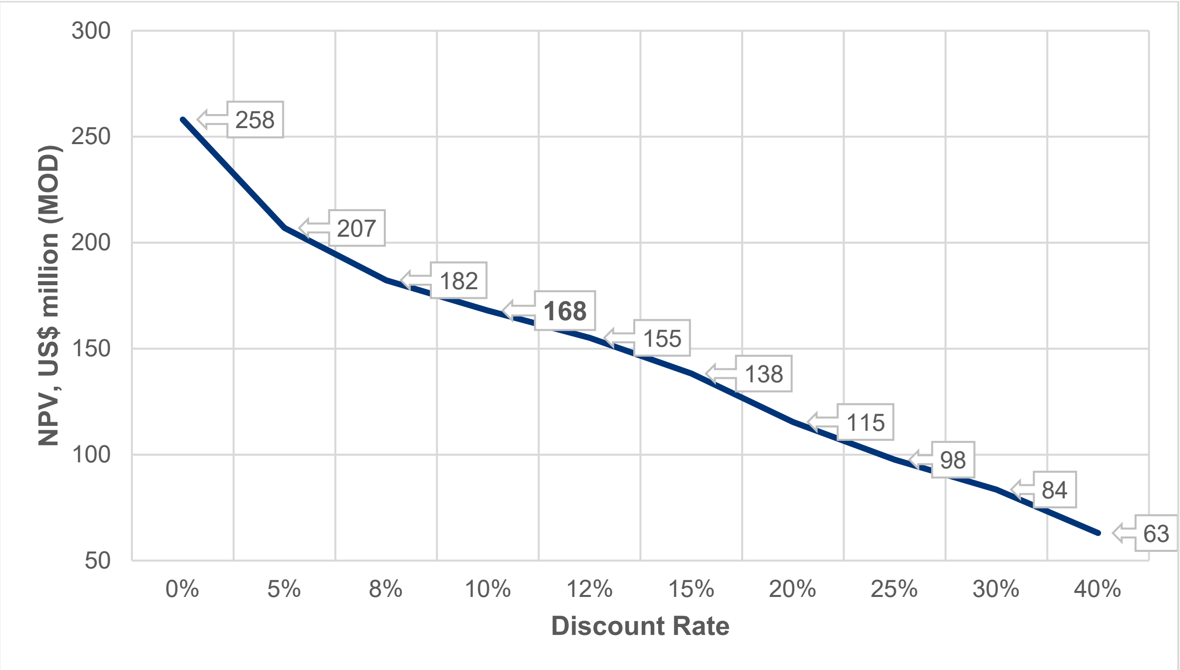

Figure 8-3: Summary of NPV of 2P Reserves as of 1 January 2025 (Sensitivity Analysis of Discount Rate)

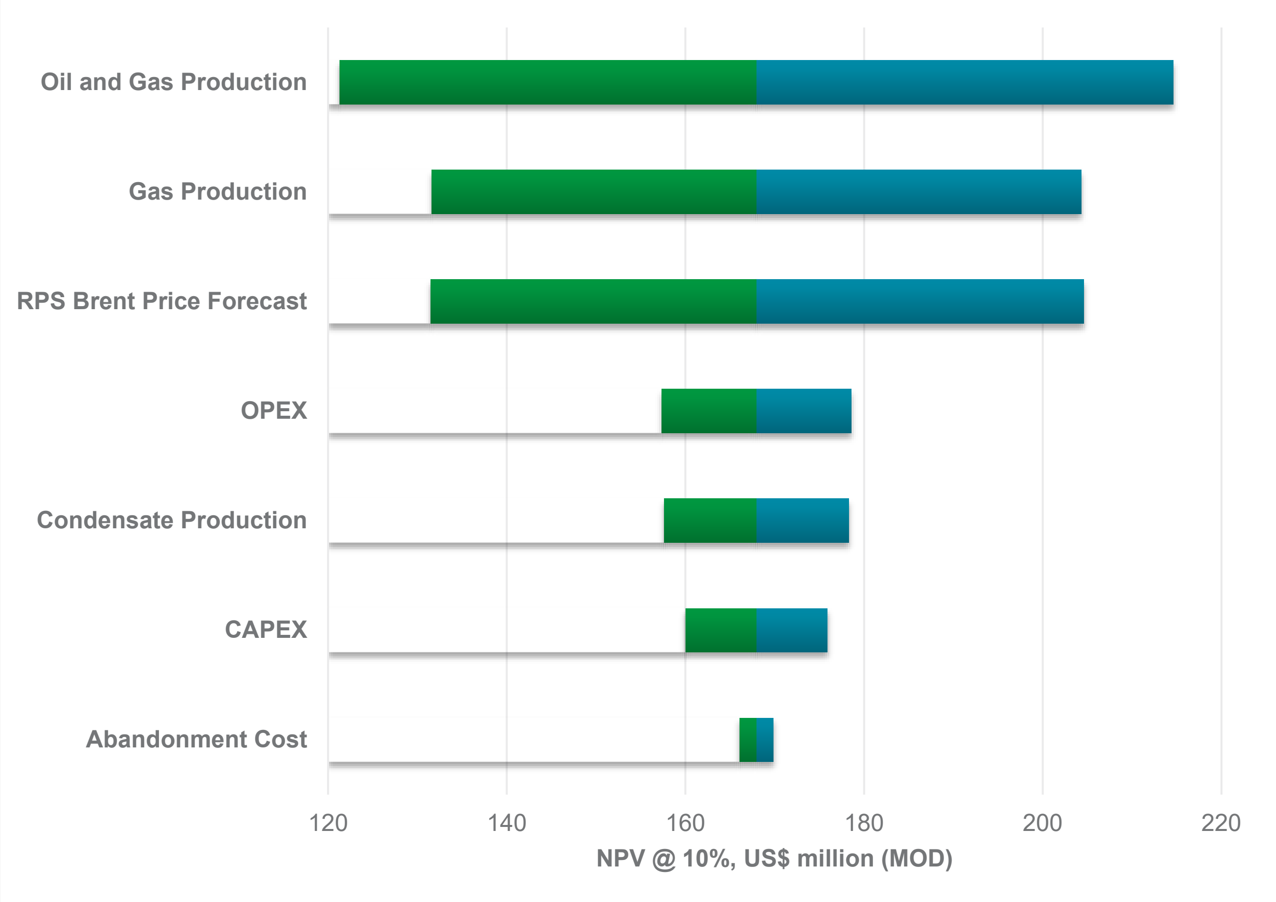

Figure 8-4: Summary of NPV of 2P Reserves as of 1 January 2025 (Sensitivity Analysis of Key Parameters , +/-20%; TTRPSE Low and High Brent price forecast as per Figure 8-2)

8.7 Reserves Reconciliation

Table 8-11 shows the Reserves reconciliation to the 2024 CPR. There were workover activities classified as Contingent Resources in the 2024 CPR which are now classified as Reserves (undeveloped). The reconciliation table accounts for this.

Overall, there is a Reserves increase. The changes are due to:

1. The current study uses simulation models (GAP/MBAL), whereas the 2024 CPR was based on graphical DCA and type curve approaches. The model-based forecasts are considered more reliable.
2. In the 2024 CPR, forecasts were based on production data up to 31 December 2023. The present study has used data up to September 2024. Use of these different datasets has led to a difference in the number of wells assumed in the NFA cases.
3. The compressor capacity has increased to 134.5 MMscf/d after a Factory Acceptance Test proving limit was sighted.
4. The assumed CGR has been adjusted, based on latest condensate data. The current range is 15-20-25 stb/MMscf for low-base-high (compared to 20-30-40 stb/MMscf in the 2024 CPR.

Separately the 2024 CPR assumed a Third Party Gas production profile contribution up to 2030, reducing the capacity for Brunei Block B production while on plateau. Once compression starts in late 2025, the Block B wells will be able to supply all gas required for the sales contract for a number of years, and Block – B gas would be prioritised over Third Party Gas. Further Third Party Gas extensions could be agreed, and could contribute to revenue but have not been assumed as current Reserves cases.

	1P	2P	3P
	Bscf	Bscf	Bscf
TTRPSE 2024 CPR (effective date 1-Jan-2023)			
Reserves	213	328	432
Workovers (2C to 2P migration)	7.6	27.5	22.1
Production 2023-2024	(69.8)	(69.8)	(69.8)
Technical revision	174.3	136.1	132.6
Tetra Tech RPS Energy 2025 Reserves (Effective date 1-Jan-2025)	**325.1**	**421.8**	**516.9**

Table 8-11: Gas Reserves – Reconciliation

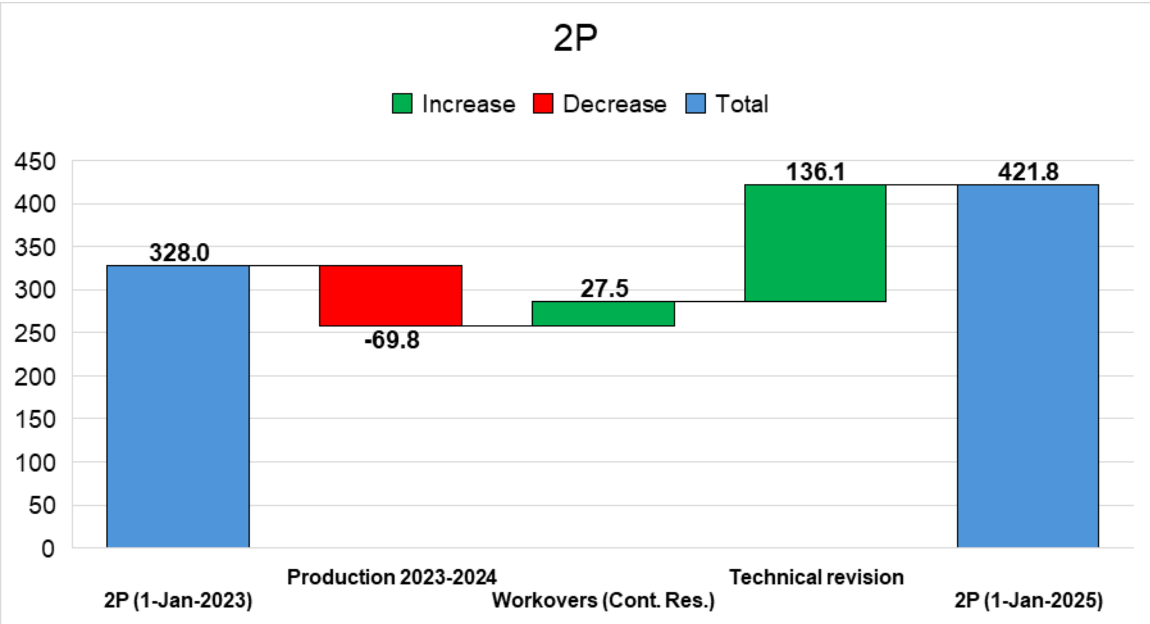

Figure 8-5: Gas Reserves Reconciliation

9. Consultant's Information

Tetra Tech RPS Energy Limited ("TTRPSE") confirms the following:

- The evaluation presented in this report reflects our informed judgment, based on accepted standards of professional investigation, but is subject to generally recognized uncertainties associated with the interpretation of geological, geophysical, and engineering data. The evaluation has been conducted within our understanding of petroleum legislation, taxation and other regulations that currently apply to these interests. However, TTRPSE is not in a position to attest to the property title, financial interest relationships or encumbrances related to the property. Our estimates of Reserves are based on data provided by Total to Hibiscus. We have accepted, without independent verification, the accuracy and completeness of this data.

- The report represents TTRPSE's best professional judgment and should not be considered a guarantee or prediction of results. It should be understood that any evaluation, particularly one involving future performance and development activities may be subject to significant variations over short periods of time as new information becomes available.

- TTRPSE has been remunerated on a fee basis, not connected to asset or client financial performance, past or future, in any way.

- TTRPSE confirms that there is no conflict of interest related to this work. Furthermore, the management and employees of TTRPSE have no interest in any of these assets evaluated nor related with the analysis carried out as part of this report.

- TTRPSE confirms also that neither it nor its management and employees have any interest in Hibiscus EP (Brunei) B.V..

- All staff and associates working on this evaluation meet the professional qualifications requirements of a Qualified Reserves Auditor as specified in the SPE Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (June 2019):

  - A minimum of 10 years practical experience in petroleum engineering or petroleum geology or similar.

  - Have at least a bachelor's or advanced degree in Petroleum Engineering, Geology, or other discipline of engineering or physical science.

  - Has received and is maintaining in good standing, a registered or certified professional licence or equivalent thereof from an appropriate governmental authority or professional organisation.

A summary of experience and relevant qualifications is provided in Table 9-1.

Name	Role	Years of Experience	Qualifications	Professional Memberships
Eleanor Rollett	Competent Person	>30	BSc. Honours 1st Class Geology, Glasgow University (1986-1990) Postgraduate Diploma Information Technology with Distinction, Open University (2002)	Chartered Geologist since 2017 (CGeol) and Fellow of the Geological Society London EAGE - member
James Hodson	Geoscience Lead	15	PhD Sedimentology, University of East Anglia MSc Petroleum Geoscience and Management, University of Manchester BSc (Hons) Geology, University of Manchester	Fellow, Geological Society of London
Adolfo Perez	Reservoir Engineering Lead	>20	MSc Reservoir Evaluation and Management, Heriot Watt University MSc Geotechnical Engineering, University of Barcelona BSc (Hons) Geology, University of Barcelona	SPE AMEI
David Element	Project Manager and Reservoir Engineering Lead	>30	BA Physics/Theoretical Physics, Cambridge University	SPE
David Walker	Costs/Facilities Lead	>20	MEng Chemical Process Engineering University of Sheffield	
Joseph Tan	Economics Lead	>20	BEng (Hons.) Petroleum Engineering, Universiti Teknologi Malaysia, 2001	Member – SPE Member – South East Asia Petroleum Exploration Society (SEAPEX) Member and Malaysia Section Lead – Association of International Energy Negotiators (AIEN)

Table 9-1: Summary of Consultant Personnel

Appendix A
Glossary

1C	The low estimate of Contingent Resources. There is estimated to be a 90% probability that the quantities actually recovered could equal or exceed this estimate
2C	The best estimate of Contingent Resources. There is estimated to be a 50% probability that the quantities actually recovered could equal or exceed this estimate
3C	The high estimate of Contingent Resources. There is estimated to be a 10% probability that the quantities actually recovered could equal or exceed this estimate
1P	The low estimate of Reserves (proved). There is estimated to be a 90% probability that the quantities remaining to be recovered will equal or exceed this estimate
2P	The best estimate of Reserves (proved+probable). There is estimated to be a 50% probability that the quantities remaining to be recovered will equal or exceed this estimate
3P	The high estimate of Reserves (proved+probable+possible). There is estimated to be a 10% probability that the quantities remaining to be recovered will equal or exceed this estimate
1U	The unrisked low estimate of Prospective Resources
2U	The unrisked best estimate of Prospective Resources
3U	The unrisked high estimate of Prospective Resources
AVO	Amplitude versus Offset
B	Billion
bbl(s)	Barrels
bbls/d	Barrels per day
Bcm	Billion cubic metres
B_g	Gas formation volume factor
B_{gi}	Gas formation volume factor (initial)
B_o	Oil formation volume factor
B_{oi}	Oil formation volume factor (initial)
B_w	Water volume factor
boe	Barrels of oil equivalent
stb/d	Barrels of oil per day
BHP	Bottom hole pressure
Bscf	Billions of standard cubic feet
bwpd	Barrels of water per day
condensate	A mixture of hydrocarbons which exist in gaseous phase at reservoir conditions but are produced as a liquid at surface conditions
cP	Centipoise
Eclipse	A reservoir modelling software package
E_{gi}	Gas Expansion Factor
EMV	Expected Monetary Value
EUR	Estimated Ultimate Recovery
FBHP	Flowing bottom hole pressure
FTHP	Flowing tubing head pressure

ft	Feet
FWHP	Flowing well head pressure
FWL	Free Water Level
GDT	Gas Down To
GIIP	Gas Initially in Place
GOC	Gas oil Contact
GOR	Gas/oil ratio
GRV	Gross rock volume
GWC	Gas water contact
IPR	Inflow performance relationship
IRR	Internal rate of return
KB	Kelly Bushing
k_a	Absolute permeability
k_h	Horizontal permeability
km	Kilometres
LPG	Liquefied Petroleum Gases
m	Metres
m^3	Cubic metres
m^3/d	Cubic metres per day
ma	Million years
M	Thousand
M$	Thousand US dollars
MBAL	Material balance software
Mbbls	Thousand barrels
mD	Permeability in millidarcies
MD	Measured depth
MDT	Modular formation dynamics tester tool
MM	Million
MMbbls	Million barrels
MMscf/d	Millions of standard cubic feet per day
MMstb	Million stock tank barrels (at 14.7 psi and 60° F)
MMt	Millions of tonnes
MM$	Million US dollars
MPa	Mega pascals
m/s	Metres per second
msec	Milliseconds
Mt	Thousands of tonnes
mV	Millivolts
NTG or N:G	Net to gross ratio
NGL	Natural Gas Liquids
NPV	Net Present Value
OWC	Oil water contact
P90	There is estimated to be at least a 90% probability (P_{90}) that this quantity will equal or exceed this low estimate

P50	There is estimated to be at least a 50% probability (P_{50}) that this quantity will equal or exceed this best estimate
P10	There is estimated to be at least a 10% probability (P_{10}) that this quantity will equal or exceed this high estimate
PDR	Physical data room
Petrel	A geoscience and reservoir engineering software package
petroleum	Naturally occurring mixtures of hydrocarbons which are found beneath the Earth's surface in liquid, solid or gaseous form
phi	Porosity
p_i	Initial reservoir pressure
PI	Productivity index
ppm	Parts per million
psi	Pounds per square inch
psia	Pounds per square inch (absolute)
psig	Pounds per square inch (gauge)
p_{wf}	Flowing bottom hole pressure
PSDM	Pre-stack depth migrated seismic data
PSTM	Pre-stack time migrated seismic data
PVT	Pressure volume temperature
rb	Barrel(s) at reservoir conditions
rcf	Reservoir cubic feet
REP™	A Monte Carlo simulation software package
RF	Recovery factor
RFT	Repeat formation tester
RKB	Relative to kelly bushing
rm^3	Reservoir cubic metres
SCADA	Supervisory control and data acquisition
SCAL	Special Core Analysis
scf	Standard cubic feet measured at 14.7 pounds per square inch and 60° F
scf/d	Standard cubic feet per day
scf/stb	Standard cubic feet per stock tank barrel
SGS	Sequential Gaussian Simulation
SIBHP	Shut in bottom hole pressure
SIS	Sequential Indicator Simulation
sm^3	Standard cubic metres
S_o	Oil saturation
S_{oi}	Initial oil saturation
S_{or}	Residual oil saturation
S_{orw}	Residual oil saturation relative to water
sq. km	Square kilometers
stb	Stock tank barrels measured at 14.7 pounds per square inch and 60° F
stb/d	Stock tank barrels per day
STOIIP	Stock tank oil initially in place
S_w	Water saturation
S_{wc}	Connate water saturation

$	United States Dollars
t	Tonnes
THP	Tubing head pressure
Tscf	Trillion standard cubic feet
TVDSS	True vertical depth (sub-sea)
TVT	True vertical thickness
TWT	Two-way time
US$	United States Dollar
VDR	Virtual data room
VLP	Vertical lift performance
V_{sh}	Shale volume
VSP	Vertical Seismic Profile
W/m/K	Watts/metre/° K
WC	Water cut
WUT	Water Up To
Z	A measure of the “non-idealness” of gas
ϕ	Porosity
μ	Viscosity
μ_g	Viscosity of gas
μ_o	Viscosity of oil
μ_w	Viscosity of water

Appendix B
Summary of Reporting Guidelines

PRMS is a fully integrated system that provides the basis for classification and categorization of all petroleum reserves and resources.

B.1 Basic Principles and Definitions

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.

The technical estimation of petroleum resources quantities involves the assessment of quantities and values that have an inherent degree of uncertainty. Quantities of petroleum and associated products can be reported in terms of volumes (e.g., barrels or cubic meters), mass (e.g., metric tonnes) or energy (e.g., Btu or Joule). 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.

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.

B.1.1 Petroleum Resources Classification Framework

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 sulphide, and sulphur. In rare cases, non-hydrocarbon content can be greater than 50%.

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.

Figure A.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.

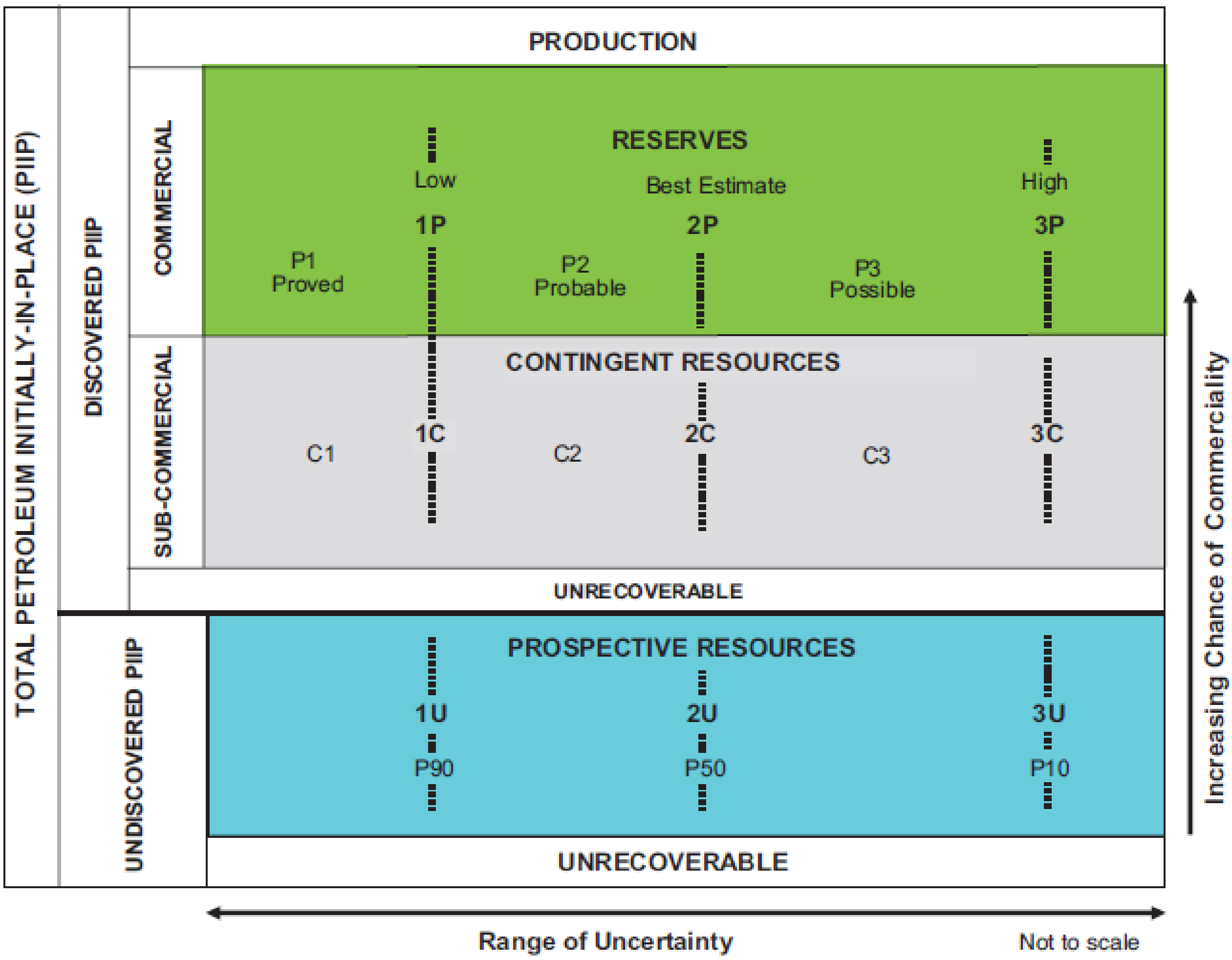

Figure A.1: Resources classification framework

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.

The following definitions apply to the major subdivisions within the resources classification:

- **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.

- **Discovered PIIP** is the quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations before production.

- **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 PRMS 2018 Section 3.2, Production Measurement).

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.

- **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.

Reserves are recommended as sales quantities as metered at the reference point. Where the entity also recognizes quantities consumed in operations (CiO) (see PRMS 2018 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.

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.

- **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.

- **Undiscovered PIIP** is that quantity of petroleum estimated, as of a given date, to be contained within accumulations yet to be discovered.

- **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.

- **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.

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.

Other terms used in resource assessments include the following:

- **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.

- **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.

Whenever these terms are used, the conditions associated with their usage must be clearly noted and documented.

B.1.2 Project Based Resource Evaluations

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.

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 A.2).

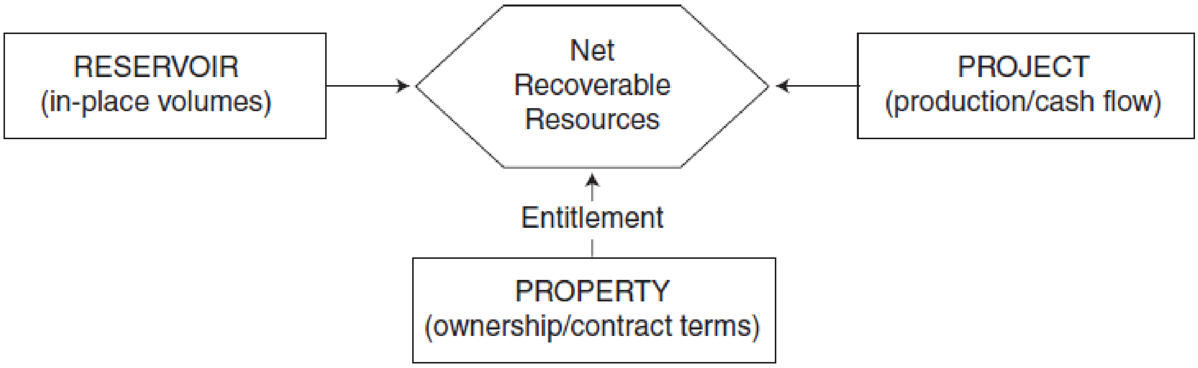

Figure A.2: Resources Evaluation

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.

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).

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.

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.

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 PRMS 2018 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 PRMS 2018 Section 2.2.1, Range of Uncertainty). For completeness, a developed field is also considered to be a project.

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. When multiple options for development exist early in project maturity, these options should be reflected as competing project alternatives to avoid double counting until decisions further refine the project scope and timing. Once the scope is described and the timing of decisions on future activities established, the decision steps will generally align with the project's classification. To assign recoverable resources of any class, a project's development plan, with detail that supports the resource commercial classification claimed, is needed.

The estimates of recoverable quantities must be stated in terms of the production derived from the potential development program even for Prospective Resources. Given the major uncertainties involved at this early stage, the development program will not be of the detail expected in later stages of maturity. In most cases, recovery efficiency may be based largely on analogous projects. In-place quantities for which a feasible project cannot be defined using current or reasonably forecast improvements in technology are classified as Unrecoverable.

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 PRMS 2018 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.

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 PRMS 2018 Section 3.2.1, Reference Point) and may permit forecasts of CiO quantities (see PRMS 2018 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 PRMS 2018 Section 3.1.1, Net Cash-Flow Evaluation).

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.

B.2 Classification and Categorization Guidelines

To consistently characterize petroleum projects, evaluations of all resources should be conducted in the context of the full classification system shown in Figure A.1. These guidelines reference this classification system and support an evaluation in which projects are "classified" based on their chance of commerciality, P_c (the vertical axis labelled Chance of Commerciality) and estimates of recoverable and marketable quantities associated with each project are "categorized" to reflect uncertainty (the horizontal axis). The actual workflow of classification versus categorization varies with individual projects and is often an iterative analysis leading to a final report. Report here refers to the presentation of evaluation results within the entity conducting the assessment and should not be construed as replacing requirements for public disclosures under guidelines established by regulatory and/or other government agencies.

B.2.1 Resources Classification

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.

B.2.1.1 Determination of Discovery Status

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 PRMS 2018 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.

Where a discovery has identified recoverable hydrocarbons but 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.

B.2.1.2 Determination of Commerciality

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:

- Evidence of a technically mature, feasible development plan.
- Evidence of financial appropriations either being in place or having a high likelihood of being secured to implement the project.
- Evidence to support a reasonable time-frame for development.
- 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 PRMS 2018 Section 3.1.1, Net Cash-Flow Evaluation).
- A reasonable expectation that there will be a market for forecast sales quantities of the production required to justify development. There should also be similar confidence that all produced streams (e.g., oil, gas, water, CO_2) can be sold, stored, re-injected, or otherwise appropriately disposed.
- Evidence that the necessary production and transportation facilities are available or can be made available.
- Evidence that legal, contractual, environmental, regulatory, and government approvals are in place or will be forthcoming, together with resolving any social and economic concerns.

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 PRMS 2018 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.

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 A.2.1.2. 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.

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.

B.2.1.3 Project Status and Chance of Commerciality

Evaluators have the option to establish a more detailed resources classification reporting system that can also provide the basis for portfolio management by subdividing the chance of commerciality axis according to project maturity. Such sub-classes may be characterized qualitatively by the project maturity level descriptions and associated quantitative chance of reaching commercial status and being placed on production.

As a project moves to a higher level of commercial maturity in the classification (see Figure A.1 vertical axis), there will be an increasing chance that the accumulation will be commercially developed, and the project quantities move to Reserves. For Contingent and Prospective Resources, this is further expressed as a chance of commerciality, P_c, which incorporates the following underlying chance component(s):

- The chance that the potential accumulation will result in the discovery of a significant quantity of petroleum, which is called the "chance of geologic discovery," P_g.

- Once discovered, the chance that the known accumulation will be commercially developed is called the "chance of development," P_d.

There must be a high degree of certainty in the chance of commerciality, P_c, for Reserves to be assigned; for Contingent Resources, $P_c = P_d$; and for Prospective Resources, P_c is the product of P_g and P_d.

Contingent and Prospective Resources can have different project scopes (e.g., well count, development spacing, and facility size) as development uncertainties and project definition mature.

B.2.1.3.1 Project Maturity Sub-classes

As Figure A.3 illustrates, development projects and associated recoverable quantities may be sub- classified according to project maturity levels and the associated actions (i.e., business decisions) required to move a project toward commercial production.

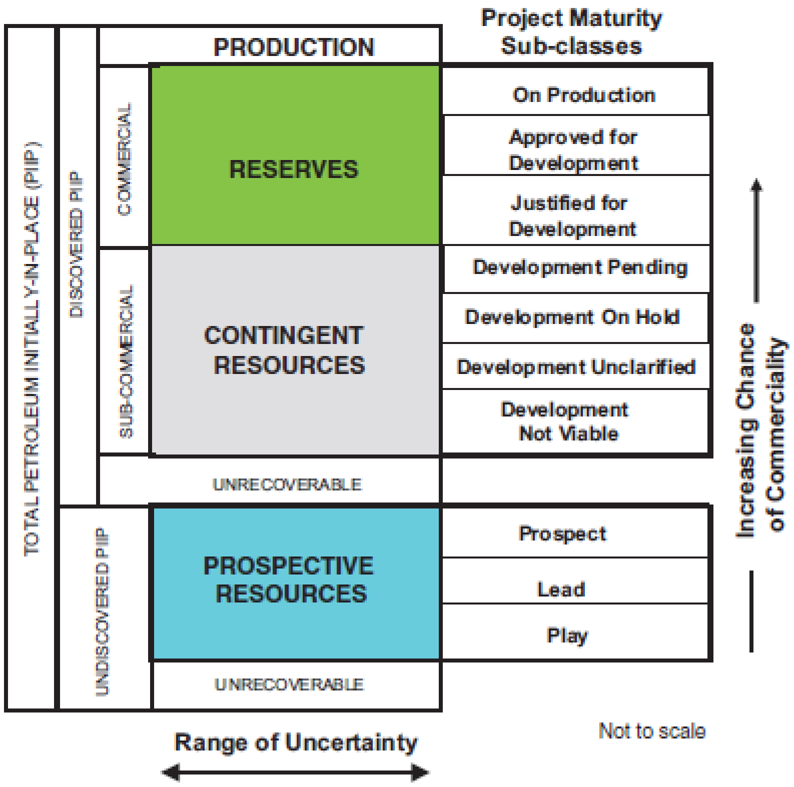

Figure A.3: Sub-classes based on project maturity.

Maturity terminology and definitions for each project maturity class and sub-class are provided in PRMS 2018 Table I. This approach supports the management of portfolios of opportunities at various stages of exploration, appraisal, and development. Reserve sub-classes must achieve commerciality while Contingent and Prospective Resources sub-classes may be supplemented by associated quantitative estimates of chance of commerciality to mature.

Resources sub-class maturation is based on those actions that progress a project through final approvals to implementation and initiation of production and product sales. The boundaries between different levels of project maturity are frequently referred to as project "decision gates."

Projects that are classified as Reserves must meet the criteria as listed in Section A.2.1.2, Determination of Commerciality. Projects sub-classified as Justified for Development are agreed upon by the managing entity and partners as commercially viable and have support to advance the project, which includes a firm intent to proceed with development. All participating entities have agreed to the project and there are no known contingencies to the project from any official entity that will have to formally approve the project.

Justified for Development Reserves are reclassified to Approved for Development after a FID has been made. Projects should not remain in the Justified for Development sub-class for extended time periods without positive indications that all required approvals are expected to be obtained without undue delay. If there is no longer the reasonable expectation of project execution (i.e., historical track record of execution, project progress), the project shall be reclassified as Contingent Resources.

Projects classified as Contingent Resources have their sub-classes aligned with the entity's plan to manage its portfolio of projects. Thus, projects on known accumulations that are actively being studied, undergoing feasibility review, and have planned near-term operations (e.g., drilling) are placed in Contingent Resources Development Pending, while those that do not meet this test are placed into either Contingent Resources On Hold, Unclarified, or Not Viable.

Where commercial factors change and there is a significant risk that a project with Reserves will no longer proceed, the project shall be reclassified as Contingent Resources.

For Contingent Resources, evaluators should focus on gathering data and performing analyses to clarify and then mitigate those key conditions or contingencies that prevent commercial development. Note that the Contingent Resources sub-classes described above and shown in Figure A.3 are recommended; however, entities are at liberty to introduce additional sub-classes that align with project management goals.

For Prospective Resources, potential accumulations may mature from Play, to Lead and then to Prospect based on the ability to identify potentially commercially viable exploration projects. The Prospective Resources are evaluated according to chance of geologic discovery, P_g, and chance of development, P_d, which together determine the chance of commerciality, P_c. Commercially recoverable quantities under appropriate development projects are then estimated. The decision at each exploration phase is whether to undertake further data acquisition and/or studies designed to move the Play through to a drillable Prospect with a project description range commensurate with the Prospective Resources sub-class.

B.2.1.3.2 Reserves Status

Once projects satisfy commercial maturity (criteria given in PRMS 2018 Table 1), the associated quantities are classified as Reserves. These quantities may be allocated to the following subdivisions based on the funding and operational status of wells and associated facilities within the reservoir development plan (PRMS 2018 Table 2 provides detailed definitions and guidelines):

- **Developed Reserves** are quantities expected to be recovered from existing wells and facilities.
  - **Developed Producing Reserves** are expected to be recovered from completion intervals that are open and producing at the time of the estimate.
  - **Developed Non-Producing Reserves** include shut-in and behind-pipe reserves with minor costs to access.
- **Undeveloped Reserves** are quantities expected to be recovered through future significant investments.

The distinction between the “minor costs to access” Developed Non-Producing Reserves and the “significant investment” needed to develop Undeveloped Reserves requires the judgment of the evaluator taking into account the cost environment. A significant investment would be a relatively large expenditure when compared to the cost of drilling and completing a new well. A minor cost would be a lower expenditure when compared to the cost of drilling and completing a new well.

Once a project passes the commercial assessment and achieves Reserves status, it is then included with all other Reserves projects of the same category in the same field for estimating combined future production and applying the economic limit test (see PRMS 2018 Section 3.1, Assessment of Commerciality).

Where Reserves remain Undeveloped beyond a reasonable time-frame or have remained Undeveloped owing to postponements, evaluations should be critically reviewed to document reasons for the delay in initiating development and to justify retaining these quantities within the Reserves class. While there are specific circumstances where a longer delay (see Section A.2.1.2, Determination of Commerciality) is justified, a reasonable time-frame to commence the project is generally considered to be less than five years from the initial classification date.

Development and Production status are of significant importance for project portfolio management and financials. The Reserves status concept of Developed and Undeveloped status is based on the funding and operational status of wells and producing facilities within the development project. These status designations are applicable throughout the full range of Reserves uncertainty categories (1P, 2P, and 3P or Proved, Probable, and Possible). Even those projects that are Developed and On Production should have remaining uncertainty in recoverable quantities.

B.2.1.3.3 Economic Status

Projects may be further characterized by economic status. All projects classified as Reserves must be commercial under defined conditions (see PRMS 2018 Section 3.1, Assessment of Commerciality Assessment). Based on assumptions regarding future conditions and the impact on ultimate economic viability, projects currently classified as Contingent Resources may be broadly divided into two groups:

- **Economically Viable Contingent Resources** are those quantities associated with technically feasible projects where cash flows are positive under reasonably forecasted conditions but are not Reserves because it does not meet the commercial criteria defined in Section A.2.1.2.

- **Economically Not Viable Contingent Resources** are those quantities for which development projects are not expected to yield positive cash flows under reasonable forecast conditions.

The best estimate (or P50) production forecast is typically used for the economic evaluation for the commercial assessment of the project. The low case, when used as the primary case for a project decision, may be used to determine project economics. The economic evaluation of the project high case alone is not permitted to be used in the determination of the project's commerciality.

For Reserves, the best estimate production forecast reflects a specific development scenario recovery process, a certain number and type of wells, facilities, and infrastructure.

The project's low-case scenario is tested to ensure it is economic, which is required for Proved Reserves to exist (see Section A.2.2.2, Category Definitions and Guidelines). It is recommended to evaluate the low case and the high case (which will quantify the 3P Reserves) to convey the project dōwnside risk and upside potential. The project development scenarios may vary in the number and type of wells, facilities, and infrastructure in Contingent Resources, but to recognize Reserves, there must exist the reasonable expectation to develop the project for the best estimate case.

The economic status may be identified independently of, or applied in combination with, project maturity sub-classification to describe the project more completely. Economic status is not the only qualifier that allows defining Contingent or Prospective Resources sub-classes. Within Contingent Resources, applying the project status to decision gates (and/or incorporating them in a plan to execute) more appropriately defines whether the project is placed into the sub-class of either Development Pending versus On Hold, Not Viable, or Unclarified.

Where evaluations are incomplete and it is premature to clearly define the associated cash flows, it is acceptable to note that the project economic status is "undetermined."

B.2.2 Resources Categorization

The horizontal axis in the resources classification in Figure A.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:

- The total petroleum remaining within the accumulation (in-place resources).

- 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).

- 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).

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.

There must be a single set of defined conditions applied for resource categorization. Use of different commercial assumptions for categorizing quantities is referred to as “split conditions” and are not allowed. Frequently, an entity will conduct project evaluation sensitivities to understand potential implications when making project selection decisions. Such sensitivities may be fully aligned to resource categories or may use single parameters, groups of parameters, or variances in the defined conditions.

Moreover, a single project is uniquely assigned to a sub-class along with its uncertainty range. For example, a project cannot have quantities classified in both Contingent Resources and Reserves, for instance as 1C, 2P, and 3P. This is referred to as “split classification.”

B.2.2.1 Range of Uncertainty

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 PRMS 2018 Section 4.2, Resources Assessment Methods).

When the range of uncertainty is represented by a probability distribution, a low, best, and high estimate shall be provided such that:

- There should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate.
- There should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate.
- There should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

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.

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 A.2.2.2, Category Definitions and Guidelines).

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.

While there may be significant chance that sub-commercial and undiscovered accumulations will not achieve commercial production, it is useful to consider the range of potentially recoverable quantities independent of such likelihood when considering what resources class to assign the project quantities.

B.2.2.2 Category Definitions and Guidelines

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 PRMS 2018 Section 4.2, Resources Assessment Methods). Also, combinations of these methods may be used.

Use of consistent terminology (Figure A.1 and Figure A.3) 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. PRMS 2018 Table 3 provides criteria for the Reserves categories determination.

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.

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.

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 PRMS 2018 Section 4.2.1, Aggregating Resources Classes).

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.

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 PRMS 2018 Section 3.1, Assessment of Commerciality).

PRMS 2018 Tables 1, 2, and 3 present category definitions and provide guidelines designed to promote consistency in resources assessments. The following summarize the definitions for each Reserves category in terms of both the deterministic incremental method and the deterministic scenario method, and also provides the criteria if probabilistic methods are applied. For all methods (incremental, scenario, or probabilistic), low, best, and high estimate technical forecasts are prepared at an effective date (unless justified otherwise), then tested to validate the commercial criteria, and truncated as applicable for determination of Reserves quantities.

- Proved Reserves are those quantities of Petroleum that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable from known reservoirs and under defined technical and commercial conditions. If deterministic methods are used, the term “reasonable certainty” is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate.

- Probable Reserves are those additional Reserves which analysis of geoscience and engineering data indicate 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.

- Possible Reserves are those additional Reserves that analysis of geoscience and engineering data suggest are less likely to be recoverable than Probable Reserves. The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P) Reserves, which is equivalent to the high-estimate scenario. When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate. Possible Reserves that are located outside of the 2P area (not upside quantities to the 2P scenario) may exist only when the commercial and technical maturity criteria have been met (that incorporate the Possible development scope).

> Stand- alone Possible Reserves must reference a commercial 2P project (e.g., a lease adjacent to the commercial project that may be owned by a separate entity), otherwise stand-alone Possible is not permitted.

One, but not the sole, criterion for qualifying discovered resources and to categorize the project's range of its low/best/high or P90/P50/P10 estimates to either 1C/2C/3C or 1P/2P/3P is the distance away from known productive area(s) defined by the geoscience confidence in the subsurface.

A conservative (low-case) estimate may be required to support financing. However, for project justification, it is generally the best-estimate Reserves or Resources quantity that passes qualification because it is considered the most realistic assessment of a project's recoverable quantities. The best estimate is generally considered to represent the sum of Proved and Probable estimates (2P) for Reserves, or 2C when Contingent Resources are cited, when aggregating a field, multiple fields, or an entity's resources.

It should be noted that under the deterministic incremental method, discrete estimates are made for each category and should not be aggregated without due consideration of associated confidence. Results from the deterministic scenario, deterministic incremental, geostatistical and probabilistic methods applied to the same project should give comparable results (see PRMS 2018 Section 4.2, Resources Assessment Methods).

If material differences exist between the results of different methods, the evaluator should be prepared to explain these differences.

B.2.3 Incremental Projects

The initial resources assessment is based on application of a defined initial development project, even extending into Prospective Resources. Incremental projects are designed to either increase recovery efficiency, reduce costs, or accelerate production through either maintenance of or changes to wells, completions, or facilities or through infill drilling or by means of improved recovery. Such projects are classified according to the resources classification framework (Figure A.1), with preference for applying project maturity sub-classes (Figure A.3). Related incremental quantities are similarly categorized on the range of uncertainty of recovery. The projected recovery change can be included in Reserves if the degree of commitment is such that the project has achieved commercial maturity (See Section A.2.1.2, Determination of Commerciality). The quantity of such incremental recovery must be supported by technical evidence to justify the relative confidence in the resources category assigned.

An incremental project must have a defined development plan. A development plan may include projects targeting the entire field (or even multiple, linked fields), reservoirs, or single wells. Each incremental project will have its own planned timing for execution and resource quantities attributed to the project. Development plans may also include appraisal projects that will lead to subsequent project decisions based on appraisal outcomes.

Circumstances when development will be significantly delayed and where it is considered that Reserves are still justified should be clearly documented. If there is no longer the reasonable expectation of project execution (i.e., historical track record of execution, project progress), forecast project incremental recoveries are to be reclassified as Contingent Resources (see PRMS 2018 Section 2.1.2, Determination of Commerciality).

B.2.3.1 Workovers, Treatments and Changes of Equipment

Incremental recovery associated with a future workover, treatment (including hydraulic fracturing stimulation), re-treatment, changes to existing equipment, or other mechanical procedures where such projects have routinely been successful in analogous reservoirs may be classified as Developed Reserves, Undeveloped Reserves, or Contingent Resources, depending on the associated costs required (see Section A.2.1.3.2, Reserves Status) and the status of the project's commercial maturity elements.

Facilities that are either beyond their operational life, placed out of service, or removed from service cannot be associated with Reserves recognition. When required facilities become unavailable or out of service for longer than a year, it may be necessary to reclassify the Developed Reserves to either Undeveloped Reserves or Contingent Resources. A project that includes facility replacement or restoration of operational usefulness must be identified, commensurate with the resources classification.

B.2.3.2 Compression

Reduction in the backpressure through compression can increase the portion of in-place gas that can be commercially produced and thus included in resources estimates. If the eventual installation of compression meets commercial maturity requirements, the incremental recovery is included in either Undeveloped Reserves or Developed Reserves, depending on the investment on meeting the Developed or Undeveloped classification criteria. However, if the cost to implement compression is not significant, relative to the cost of one new well in the field, or there is reasonable expectation that compression will be implemented by a third party in a common sales line beyond the reference point, the incremental quantities may be classified as Developed Reserves. If compression facilities were not part of the original approved development plan and such costs are significant, it should be treated as a separate project subject to normal project maturity criteria.

B.2.3.3 Infill Drilling

Technical and commercial analyses may support drilling additional producing wells to reduce the wells spacing of the initial development plan, subject to government regulations. Infill drilling may have the combined effect of increasing recovery and acceleration production. Only the incremental recovery (i.e. recovery from infill wells less the recovery difference in earlier wells) can be considered as additional Reserves for the project; this incremental recovery may need to be reallocated.

B.2.3.4 Improved Recovery

Improved recovery is the additional petroleum obtained, beyond primary recovery, from naturally occurring reservoirs by supplementing the natural reservoir energy. It includes secondary recovery (e.g., waterflooding and pressure maintenance), tertiary recovery processes (thermal, miscible gas injection, chemical injection, and other types), and any other means of supplementing natural reservoir recovery processes.

Improved recovery projects must meet the same Reserves technical and commercial maturity criteria as primary recovery projects.

The judgment on commerciality is based on pilot project results within the subject reservoir or by comparison to a reservoir with analogous rock and fluid properties and where a similar established improved recovery project has been successfully applied.

Incremental recoveries through improved recovery methods that have yet to be established through routine, commercially successful applications are included as Reserves only after a favourable production response from the subject reservoir from either (a) a representative pilot or (b) an installed portion of the project, where the response provides support for the analysis on which the project is based. The improved recovery project's resources will remain classified as Contingent Resources Development Pending until the pilot has demonstrated both technical and commercial feasibility and the full project passes the Justified for Development "decision gate."

B.2.4 Unconventional Resources

The types of in-place petroleum resources defined as conventional and unconventional may require different evaluation approaches and/or extraction methods. However, the PRMS resources definitions, together with the classification system, apply to all types of petroleum accumulations regardless of the in- place characteristics, extraction method applied, or degree of processing required.

- Conventional resources exist in porous and permeable rock with pressure equilibrium. The PIIP is trapped in discrete accumulations related to a local geological structure feature and/or stratigraphic condition. Each conventional accumulation is typically bounded by a down dip contact with an aquifer, as its position is controlled by hydrodynamic interactions between buoyancy of petroleum in water versus capillary force. The petroleum is recovered through wellbores and typically requires minimal processing before sale.

- Unconventional resources exist in petroleum accumulations that are pervasive throughout a large area and are not significantly affected by hydrodynamic influences (also called "continuous-type deposit"). Usually there is not an obvious structural or stratigraphic trap. Examples include coalbed methane (CBM), basin-centred gas (low permeability), tight gas and tight oil (low permeability), gas hydrates, natural bitumen (very high viscosity oil), and oil shale (kerogen) deposits. Note that shale gas and shale oil are sub-types of tight gas and tight oil where the lithologies are predominantly shales or siltstones. These accumulations lack the porosity and permeability of conventional reservoirs required to flow without stimulation at economic rates. Typically, such accumulations require specialized extraction technology (e.g., dewatering of CBM, hydraulic fracturing stimulation for tight gas and tight oil, steam, and/or solvents to mobilize natural bitumen for in-situ recovery, and in some cases, surface mining of oil sands). Moreover, the extracted petroleum may require significant processing before sale (e.g., bitumen upgraders).

For unconventional petroleum accumulations, reliance on continuous water contacts and pressure gradient analysis to interpret the extent of recoverable petroleum is not possible. Thus, there is typically a need for increased spatial sampling density to define uncertainty of in-place quantities, variations in reservoir and hydrocarbon quality, and to support design of specialized mining or in-situ extraction programs. In addition, unconventional resources typically require different evaluation techniques than conventional resources.

Extrapolation of reservoir presence or productivity beyond a control point within a resources accumulation must not be assumed unless there is technical evidence to support it. Therefore, extrapolation beyond the immediate vicinity of a control point should be limited unless there is clear engineering and/or geoscience evidence to show otherwise.

The extent of the discovery within a pervasive accumulation is based on the evaluator's reasonable confidence based on distances from existing experience, otherwise quantities remain as undiscovered. Where log and core data and nearby producing analogs provide evidence of potential economic viability, a successful well test may not be required to assign Contingent Resources. Pilot projects may be needed to define Reserves, which requires further evaluation of technical and commercial viability.

A fundamental characteristic of engagement in a repetitive task is that it may improve performance over time. Attempts to quantify this improvement gave rise to the concept of the manufacturing progress function commonly called the "learning curve." The learning curve is characterized by a decrease in time and/or costs, usually in the early stages of a project when processes are being optimized. At that time, each new improvement may be significant. As the project matures, further improvements in time or cost savings are typically less substantial. In oil and gas developments with high well counts and a continuous program of activity (multi-year), the use of a learning curve within a resources evaluation may be justified to predict improvements in either the time taken to carry out the activity, the cost to do so, or both. While each development project is unique, review of analogs can provide guidance on such predictions and the range of associated uncertainty in the resulting recoverable resources estimates (see also PRMS 2018 Section 3.1.2 Economic Criteria).

Source: Petroleum Resources Management System (revised June 2018), Version 1.01, Society of Petroleum Engineers.

Appendix C
Reserves and Contingent Resources Summary

The effective date of this report is 1 January 2025.

In 2024, TTRPSE prepared a Competent Person's Report for Hibiscus with an effective date of 1 January 2023[15].

To facilitate direct comparison between this report and the 2024 report, this Appendix tabulates the Reserves and Contingent Resources from the current analysis, assuming an effective date of 1 January 2023. Note that 1 January 2023 is the effective date of the transaction and acquisition of the MLJ Field from Total.

Reserves and Contingent Resources as of 1 January 2023

SUMMARY OF GAS RESERVES
As of 1 January 2023
BASE CASE PRICES AND COSTS

	Full Field Gross Reserves[1] (Bscf)			Net Entitlement Reserves[2] (Bscf)		
	1P	2P	3P	1P	2P	3P
MLJ	395	492	587	148	184	220

Notes:

[1] Gross field Reserves (100% basis) after economic limit test. Economic limit in year 2038 for 1P; year 2039 for 2P and 3P.

[2] Hibiscus' net entitlement based on its 37.5% working interest; after economic limit test. Royalties are paid in cash and treated as production tax. Therefore is not deducted from Hibiscus' Net Entitlement.

Table C.1: Gas Reserves in MLJ Field as of 1 January 2023

SUMMARY OF CONDENSATE RESERVES
As of 1 January 2023
BASE CASE PRICES AND COSTS

	Full Field Gross Reserves[1] (MMstb)			Net Entitlement Reserves[2] (MMstb)		
	1P	2P	3P	1P	2P	3P
MLJ	6.8	10.4	17.7	2.5	3.9	6.6

Notes:

[1] Gross field Reserves (100% basis) after economic limit test. Economic limit in year 2038 for 1P; year 2039 for 2P and 3P.

[2] Hibiscus' net entitlement based on its 37.5% working interest; after economic limit test. Royalties are paid in cash and treated as production tax. Therefore is not deducted from Hibiscus' Net Entitlement.

Table C.2: Condensate Reserves in MLJ Field as of 1 January 2023

[15] Competent Person's Report Maharajalela Jamalulalam Field, Block B, Offshore Brunei. RPS 793-TA000016, 15 June 2024.

SUMMARY OF RESERVES (BOE)
As of 1 January 2023
BASE CASE PRICES AND COSTS

	Full Field Gross Reserves[1] (MMboe)[3]			Net Entitlement Reserves[2] (MMboe)[3]		
	1P	2P	3P	1P	2P	3P
MLJ	72.6	92.4	115.5	27.2	34.6	43.3

Notes:

[1] Gross field Reserves (100% basis) after economic limit test. Economic limit in year 2038 for 1P; year 2039 for 2P and 3P.

[2] Hibiscus' net entitlement based on its 37.5% working interest; after economic limit test. Royalties are paid in cash and treated as production tax. Therefore is not deducted from Hibiscus' Net Entitlement.

[3] Conversion rate of 6,000 standard cubic feet per boe.

Table C.3: Oil Equivalent Reserves in MLJ Field as of 1 January 2023

	ELT Date	Post-Tax Net Present Value (US$ Million, MOD)			
		0%	8%	10%	12%
1P	2038	224	182	173	165
2P	2039	341	244	227	212
3P	2039	505	332	303	279

Table C.4: Block B Reserves Post-Tax Valuation at TTRPSE Base Case Price Scenario

TTRPSE has classified recoverable volumes from well B1-15K as Contingent Resources – Development Pending, with an estimated Chance of Development (Pd) of over 80%. Layer 3 project is uneconomic in the Low Case and Best Case and inconsequential in the High Case. Therefore, the project is not classified as Contingent Resources.

SUMMARY OF GAS CONTINGENT RESOURCES
As of 1 January 2023
BASE CASE PRICES AND COSTS

		Full Field Gross Contingent Resources[1] (Bscf)			Net Entitlement Contingent Resources[2] (Bscf)		
Field	Project	1C	2C	3C	1C	2C	3C
MLJ	MLJ North Layer 3 Workover	0	0	0	0	0	0
MLJ	B1-15K	17	32	45	6	12	17
Total[3, 4]		**17**	**32**	**45**	**6**	**12**	**17**

Notes:

[1] Gross field Contingent Resources (100% basis). Economic limit in year 2038 for 1C; year 2039 for 2C and 3C.

[2] Hibiscus' net entitlement based on its 37.5% working interest; after economic limit test. Royalties are paid in cash and treated as production tax. Therefore is not deducted from Hibiscus' Net Entitlement.

[3] PRMS recommends that for reporting purposes, assessment results should not incorporate statistical aggregation beyond the field, property, or project level. As such, TTRPSE's totals were summed arithmetically and as a result, the total 1C Contingent Resources may be a very conservative assessment and the total 3C Contingent Resources a very optimistic assessment.

[4] It should be noted that all TTRPSE forecasts are cut off at 2039.

[5] Pre economic limit production forecast for 2C and 3C ends in year 2038 and 2039, respectively.

Table C.5: Gas Contingent Resources in MLJ Field as of 1 January 2023

SUMMARY OF CONDENSATE CONTINGENT RESOURCES
As of 1 January 2023
BASE CASE PRICES AND COSTS

		Full Field Gross Contingent Resources[1] (MMstb)			Net Entitlement Contingent Resources[2] (MMstb)		
Field	**Project**	**1C**	**2C**	**3C**	**1C**	**2C**	**3C**
MLJ	**MLJ North Layer 3 Workover**	0.0	0.0	0.0	0.0	0.0	0.0
MLJ	**B1-15K**	0.3	0.7	1.4	0.1	0.2	0.5
Total[3]		**0.3**	**0.7**	**1.4**	**0.1**	**0.2**	**0.5**

Notes:

[1] Gross field Contingent Resources (100% basis). Economic limit in year 2038 for 1C; year 2039 for 2C and 3C.

[2] Hibiscus' net entitlement based on its 37.5% working interest; after economic limit test. Royalties are paid in cash and treated as production tax. Therefore, is not deducted from Hibiscus' Net Entitlement.

[3] PRMS recommends that for reporting purposes, assessment results should not incorporate statistical aggregation beyond the field, property, or project level. As such, TTRPSE's totals were summed arithmetically and as a result, the total 1C Contingent Resources may be a very conservative assessment and the total 3C Contingent Resources a very optimistic assessment.

[4] Pre economic limit production forecast for 2C and 3C ends in year 2038 and 2039, respectively.

Table C.6: Condensate Contingent Resources in MLJ Field as of 1 January 2023

SUMMARY OF GAS AND CONDENSATE CONTINGENT RESOURCES (BOE)
As of 1 January 2023
BASE CASE PRICES AND COSTS

		Full Field Gross Contingent Resources[1] (MMboe)[3]			Net Entitlement Contingent Resources[2] (MMboe)[3]		
Field	**Project**	**1C**	**2C**	**3C**	**1C**	**2C**	**3C**
MLJ	**MLJ North Layer 3 Workover**	0.0	0.0	0.0	0.0	0.0	0.0
MLJ	**B1-15K**	3.0	6.0	8.9	1.1	2.2	3.3
Total[4]		**3.0**	**6.0**	**8.9**	**1.1**	**2.2**	**3.3**

Notes:

[1] Gross field Contingent Resources (100% basis). Economic limit in year 2038 for 1C; year 2039 for 2C and 3C.

[2] Hibiscus' net entitlement based on its 37.5% working interest; after economic limit test. Royalties are paid in cash and treated as production tax. Therefore, is not deducted from Hibiscus' Net Entitlement.

[3] Conversion rate of 6,000 standard cubic feet per boe.

[4] PRMS recommends that for reporting purposes, assessment results should not incorporate statistical aggregation beyond the field, property, or project level. As such, TTRPSE's totals were summed arithmetically and as a result, the total 1C Contingent Resources may be a very conservative assessment and the total 3C Contingent Resources a very optimistic assessment.

[5] Pre economic limit production forecast for 2C and 3C ends in year 2038 and 2039, respectively.

Table C.7: Oil Equivalent Contingent Resources in MLJ Field as of 1 January 2023

	ELT Date	Post-Tax Net Present Value (US$ Million, MOD)			
		0%	8%	10%	12%
1P+1C	2038	249	194	183	173
2P+2C	2039	400	269	247	229
3P+3C	2039	572	357	323	295

Table C.8: Block B Reserves and Contingent Resources Post-Tax Valuation at TTRPSE Base Case Price Scenario

	ELT Date	Post-Tax Net Present Value (US$ Million, MOD)			
		0%	8%	10%	12%
1C	2038	24	12	10	9
2C	2039	58	25	20	17
3C	2039	67	26	20	16

Table C.9: Block B Contingent Resources Post-Tax Valuation at TTRPSE Base Case Price Scenario

Hibiscus' acquisition of the MLJ Field from Total was completed on 14 October 2024 (on which date Hibiscus became the Operator). Although the effective date of this report is 1 January 2025, the following tables summarise and Contingent Resources from the current analysis, assuming an effective date of 14 October 2024.

Reserves and Contingent Resources as of 14 October 2024

SUMMARY OF GAS RESERVES
As of 14 October 2024
BASE CASE PRICES AND COSTS

	Full Field Gross Reserves[1] (Bscf)			Net Entitlement Reserves[2] (Bscf)		
	1P	2P	3P	1P	2P	3P
MLJ	333	429	524	125	161	197

Notes:

[1] Gross field Reserves (100% basis) after economic limit test. Economic limit in year 2038 for 1P; year 2039 for 2P and 3P.

[2] Hibiscus' net entitlement based on its 37.5% working interest; after economic limit test. Royalties are paid in cash and treated as production tax. Therefore is not deducted from Hibiscus' Net Entitlement.

Table C.10: Gas Reserves in MLJ Field as of 14 October 2024

SUMMARY OF CONDENSATE RESERVES
As of 14 October 2024
BASE CASE PRICES AND COSTS

	Full Field Gross Reserves[1] (MMstb)			Net Entitlement Reserves[2] (MMstb)		
	1P	2P	3P	1P	2P	3P
MLJ	5.2	8.8	16.1	1.9	3.3	6.0

Notes:

[1] Gross field Reserves (100% basis) after economic limit test. Economic limit in year 2038 for 1P; year 2039 for 2P and 3P.

[2] Hibiscus' net entitlement based on its 37.5% working interest; after economic limit test. Royalties are paid in cash and treated as production tax. Therefore is not deducted from Hibiscus' Net Entitlement.

Table C.11: Condensate Reserves in MLJ Field as of 14 October 2024

SUMMARY OF RESERVES (BOE)
As of 14 October 2024
BASE CASE PRICES AND COSTS

	Full Field Gross Reserves[1] (MMboe)[3]			Net Entitlement Reserves[2] (MMboe)[3]		
	1P	2P	3P	1P	2P	3P
MLJ	60.6	80.4	103.5	22.7	30.2	38.8

Notes:

[1] Gross field Reserves (100% basis) after economic limit test. Economic limit in year 2038 for 1P; year 2039 for 2P and 3P.

[2] Hibiscus' net entitlement based on its 37.5% working interest; after economic limit test. Royalties are paid in cash and treated as production tax. Therefore is not deducted from Hibiscus' Net Entitlement.

[3] Conversion rate of 6,000 standard cubic feet per boe.

Table C.12: Oil Equivalent Reserves in MLJ Field as of 14 October 2024

	ELT Date	Post-Tax Net Present Value (US$ Million, MOD)			
		0%	8%	10%	12%
1P	2038	165	130	123	115
2P	2039	287	203	188	174
3P	2039	458	305	279	255

Table C.13: Block B Reserves Post-Tax Valuation at TTRPSE Base Case Price Scenario

TTRPSE has classified recoverable volumes from well B1-15K as Contingent Resources – Development Pending, with an estimated Chance of Development (Pd) of over 80%. Layer 3 project is uneconomic in the Low Case and Best Case and inconsequential in the High Case. Therefore, the project is not classified as Contingent Resources.

SUMMARY OF GAS CONTINGENT RESOURCES
As of 14 October 2024
BASE CASE PRICES AND COSTS

		Full Field Gross Contingent Resources[1] (Bscf)			Net Entitlement Contingent Resources[2] (Bscf)		
Field	**Project**	**1C**	**2C**	**3C**	**1C**	**2C**	**3C**
MLJ	**MLJ North Layer 3 Workover**	0	0	0	0	0	0
MLJ	**B1-15K**	17	32	45	6	12	17
Total[3, 4]		**17**	**32**	**45**	**6**	**12**	**17**

Notes:

[1] Gross field Contingent Resources (100% basis). Economic limit in year 2038 for 1C; year 2039 for 2C and 3C.

[2] Hibiscus' net entitlement based on its 37.5% working interest; after economic limit test. Royalties are paid in cash and treated as production tax. Therefore is not deducted from Hibiscus' Net Entitlement.

[3] PRMS recommends that for reporting purposes, assessment results should not incorporate statistical aggregation beyond the field, property, or project level. As such, TTRPSE's totals were summed arithmetically and as a result, the total 1C Contingent Resources may be a very conservative assessment and the total 3C Contingent Resources a very optimistic assessment.

[4] It should be noted that all TTRPSE forecasts are cut off at 2039.

[5] Pre economic limit production forecast for 2C and 3C ends in year 2038 and 2039, respectively.

Table C.14: Gas Contingent Resources in MLJ Field as of 14 October 2024

SUMMARY OF CONDENSATE CONTINGENT RESOURCES
As of 14 October 2024
BASE CASE PRICES AND COSTS

		Full Field Gross Contingent Resources[1] (MMstb)			Net Entitlement Contingent Resources[2] (MMstb)		
Field	**Project**	**1C**	**2C**	**3C**	**1C**	**2C**	**3C**
MLJ	**MLJ North Layer 3 Workover**	0.0	0.0	0.0	0.0	0.0	0.0
MLJ	**B1-15K**	0.3	0.7	1.4	0.1	0.2	0.5
Total[3]		**0.3**	**0.7**	**1.4**	**0.1**	**0.2**	**0.5**

Notes:

[1] Gross field Contingent Resources (100% basis). Economic limit in year 2038 for 1C; year 2039 for 2C and 3C.

[2] Hibiscus' net entitlement based on its 37.5% working interest; after economic limit test. Royalties are paid in cash and treated as production tax. Therefore, is not deducted from Hibiscus' Net Entitlement.

[3] PRMS recommends that for reporting purposes, assessment results should not incorporate statistical aggregation beyond the field, property, or project level. As such, TTRPSE's totals were summed arithmetically and as a result, the total 1C Contingent Resources may be a very conservative assessment and the total 3C Contingent Resources a very optimistic assessment.

[4] Pre economic limit production forecast for 2C and 3C ends in year 2038 and 2039, respectively.

Table C.15: Condensate Contingent Resources in MLJ Field as of 14 October 2024

SUMMARY OF GAS AND CONDENSATE CONTINGENT RESOURCES (BOE)
As of 14 October 2024
BASE CASE PRICES AND COSTS

		Full Field Gross Contingent Resources[1] (MMboe)[3]			Net Entitlement Contingent Resources[2] (MMboe)[3]		
Field	**Project**	**1C**	**2C**	**3C**	**1C**	**2C**	**3C**
MLJ	**MLJ North Layer 3 Workover**	0.0	0.0	0.0	0.0	0.0	0.0
MLJ	**B1-15K**	3.0	6.0	8.9	1.1	2.2	3.3
Total[4]		**3.0**	**6.0**	**8.9**	**1.1**	**2.2**	**3.3**

Notes:

[1] Gross field Contingent Resources (100% basis). Economic limit in year 2038 for 1C; year 2039 for 2C and 3C.

[2] Hibiscus' net entitlement based on its 37.5% working interest; after economic limit test. Royalties are paid in cash and treated as production tax. Therefore, is not deducted from Hibiscus' Net Entitlement.

[3] Conversion rate of 6,000 standard cubic feet per boe.

[4] PRMS recommends that for reporting purposes, assessment results should not incorporate statistical aggregation beyond the field, property, or project level. As such, TTRPSE's totals were summed arithmetically and as a result, the total 1C Contingent Resources may be a very conservative assessment and the total 3C Contingent Resources a very optimistic assessment.

[5] Pre economic limit production forecast for 2C and 3C ends in year 2038 and 2039, respectively.

Table C.16: Summary of Oil Equivalent Contingent Resources in MLJ Field as of 14 October 2024

	ELT Date	Post-Tax Net Present Value (US$ Million, MOD)			
		0%	8%	10%	12%
1P+1C	2038	190	144	134	126
2P+2C	2039	346	231	211	193
3P+3C	2039	527	334	302	274

Table C.17: Block B Reserves and Contingent Resources Post-Tax Valuation at TTRPSE Base Case Price Scenario

	ELT Date	Post-Tax Net Present Value (US$ Million, MOD)			
		0%	8%	10%	12%
1C	2038	25	14	12	10
2C	2039	59	28	23	19
3C	2039	69	29	23	19

Table C.18: Block B Contingent Resources Post-Tax Valuation at TTRPSE Base Case Price Scenario

Appendix D

Cash Flows Summary

2P

2P	Unit	Total	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Gross Daily Gas Production Rate	MMscfd	492 Bscf	95	97	91	121	119	105	99	103	94	79	74	61	53	44	38	41	34	-	-	
Gross Daily Third Party Gas Rate	MMscfd	32 Bscf	40	28	21	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Total Gross Daily Gas rate processed	MMscfd	524 Bscf	134	125	111	121	119	105	99	103	94	79	74	61	53	44	38	41	34	-	-	
Gross Daily Condensate Production	Bcpd	10.4 MMstb	2,436	2,467	1,856	2,471	2,443	2,150	2,030	2,105	1,927	1,623	1,516	1,257	1,087	910	782	835	699	-	-	
Gross Daily Third Party Condensate	Bcpd	.8 MMstb	1,128	630	418	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Gross Annual Gas Sales	**Bscf**	**492 Bscf**	**34**	**35**	**33**	**44**	**43**	**38**	**36**	**37**	**34**	**29**	**27**	**22**	**19**	**16**	**14**	**15**	**12**			
Gross Annual Condensate Production	**MMstb**	**10.4 MMstb**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**0**	**0**	**0**	**0**	**0**	**0**			
Gross Gas + Condensate	**MMboe**	**92 MMboe**	**7**	**7**	**6**	**8**	**8**	**7**	**7**	**7**	**6**	**5**	**5**	**4**	**4**	**3**	**3**	**3**	**2**	**-**	**-**	
Net Daily Gas Sales	MMscfd	184 Bscf	35	36	34	45	45	39	37	39	35	30	28	23	20	17	14	15	13			
Net Daily Condensate Production	Bcpd	3.9 MMstb	914	925	696	927	916	806	761	789	723	609	569	471	408	341	293	313	262			
Net Condensate and Gas Production	Boepd	35 MMboe	6,821	6,969	6,355	8,460	8,363	7,360	6,952	7,207	6,599	5,556	5,191	4,304	3,722	3,117	2,676	2,858	2,395			
Net Annual Gas Sales	**Bscf**	**184 Bscf**	**13**	**13**	**12**	**16**	**16**	**14**	**14**	**14**	**13**	**11**	**10**	**8**	**7**	**6**	**5**	**6**	**5**			
Net Annual Condensate Production	**MMstb**	**3.9 MMstb**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**			
Net Annual Gas + Condensate Production	**MMboe**	**35 MMboe**	**2**	**3**	**2**	**3**	**3**	**3**	**3**	**3**	**2**	**2**	**2**	**2**	**1**	**1**	**1**	**1**	**1**			
Brent Price	$/bbl		82	81	68	68	70	70	73	73	75	78	78	84	86	88	90	91	93			
JKM LNG Price	$/MMBtu		15	11	11	11	11	12	12	12	12	13	13	13	13	14	14	14	15			
Realized Gas Price	$/Mscf		5	4	4	4	4	4	5	5	5	5	5	5	5	5	5	6	6			
Realized Condensate Price	$/bbl		84	82	67	68	70	70	73	73	75	78	78	85	87	88	90	92	94			
Net Gas Revenue	USD mm	945	69	63	51	72	73	70	69	72	67	59	55	49	43	37	32	35	30			
Net Condensate Revenue	USD mm	303	28	28	17	23	24	21	20	21	20	17	16	15	13	11	10	10	9			
Total Revenue	USD mm	1,248	97	90	68	95	97	91	89	93	87	76	72	63	56	48	42	45	39			
Royalty	USD mm	(100)	(8)	(7)	(5)	(8)	(8)	(7)	(7)	(7)	(7)	(6)	(6)	(5)	(4)	(4)	(3)	(4)	(3)	-		
Opex	USD mm	(295)	(16)	(21)	(20)	(20)	(18)	(20)	(21)	(19)	(19)	(16)	(17)	(15)	(15)	(14)	(14)	(15)	(15)			
Capex	USD mm	(84)	(20)	(17)	(31)	(11)	(1)	(1)	(1)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	-	-	-			
Hibiscus' Carry of BEE's Capex	USD mm	(32)	(8)	(7)	(12)	(4)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	-	-	-			
Carry Reimbursement to Hibiscus	USD mm	32	8	7	12	4	0	0	0	0	0	0	0	0	0	0	-	-	-			
Overhead Charges	USD mm	18	2	2	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1			
Abex	USD mm	(86)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	(51)	(34)	-
Supplementary Payment	USD mm	(9)	(1)	(1)	(0)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(0)	(0)	(0)	(0)	(0)	(0)	-	-	-
Petroleum Income Tax	USD mm	(372)	-	(36)	(33)	(10)	(24)	(32)	(28)	(33)	(36)	(33)	(29)	(26)	(23)	(20)	(16)	(13)	(15)	(11)	28	19
Free Cash Flows from Third Party Gas	USD mm	22	12	8	2	(1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
Free Cash Flows to Hibiscus	**USD mm**	**341**	**66**	**18**	**(17)**	**47**	**46**	**32**	**33**	**34**	**24**	**20**	**19**	**17**	**13**	**10**	**9**	**15**	**5**	**(61)**	**(6)**	**19**
2024 Free Cash Flows to Hibiscus (Closing to 31 Dec)				6																		

2P + 2C

2P + 2C	Unit	Total	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Gross Daily Gas Production Rate	MMscfd	524 Bscf	95	97	91	121	119	105	98	105	102	97	82	75	66	58	48	40	38	-	-	
Gross Daily Third Party Gas Rate	MMscfd	73 Bscf	40	28	21	-	-	8	11	6	3	6	17	13	12	11	12	9	1	-	-	
Total Gross Daily Gas rate processed	MMscfd	596 Bscf	134	125	111	121	119	113	109	111	105	103	99	88	78	69	60	49	39	-	-	
Gross Daily Condensate Production	Bcpd	11.1 MMstb	2,435	2,467	1,856	2,471	2,443	2,150	2,017	2,144	2,087	1,985	1,674	1,536	1,345	1,182	989	822	786	-	-	
Gross Daily Third Party Condensate	Bcpd	1.6 MMstb	1,128	630	418	-	-	164	219	131	55	133	355	273	255	230	244	182	18	-	-	
Gross Annual Gas Sales	**Bscf**	**524 Bscf**	**34**	**35**	**33**	**44**	**43**	**38**	**36**	**38**	**37**	**35**	**30**	**27**	**24**	**21**	**18**	**15**	**14**			
Gross Annual Condensate Production	**MMstb**	**11.1 MMstb**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**0**	**0**	**0**	**0**	**0**			
Gross Gas + Condensate	**MMboe**	**98 MMboe**	**7**	**7**	**6**	**8**	**8**	**7**	**7**	**7**	**7**	**7**	**6**	**5**	**4**	**4**	**3**	**3**	**3**	**-**	**-**	
Net Daily Gas Sales	MMscfd	196 Bscf	35	36	34	45	45	39	37	39	38	36	31	28	25	22	18	15	14			
Net Daily Condensate Production	Bcpd	4.2 MMstb	913	925	696	927	916	806	756	804	783	744	628	576	504	443	371	308	295			
Net Condensate and Gas Production	Boepd	37 MMboe	6,820	6,969	6,355	8,460	8,363	7,360	6,905	7,342	7,145	6,795	5,733	5,261	4,606	4,046	3,387	2,815	2,690			
Net Annual Gas Sales	**Bscf**	**196 Bscf**	**13**	**13**	**12**	**16**	**16**	**14**	**13**	**14**	**14**	**13**	**11**	**10**	**9**	**8**	**7**	**5**	**5**			
Net Annual Condensate Production	**MMstb**	**4.2 MMstb**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**			
Net Annual Gas + Condensate Production	**MMboe**	**37 MMboe**	**2**	**3**	**2**	**3**	**3**	**3**	**3**	**3**	**3**	**2**	**2**	**2**	**2**	**1**	**1**	**1**	**1**			
Brent Price	$/bbl		82	81	68	68	70	70	73	73	75	78	78	84	86	88	90	91	93			
JKM LNG Price	$/MMBtu		15	11	11	11	11	12	12	12	12	13	13	13	13	14	14	14	15			
Realized Gas Price	$/Mscf		5	4	4	4	4	4	5	5	5	5	5	5	5	5	5	6	6			
Realized Condensate Price	$/bbl		84	82	67	68	70	70	73	73	75	78	78	85	87	88	90	92	94			
Net Gas Revenue	USD mm	1,014	69	63	51	72	73	70	68	73	73	72	61	59	53	47	41	34	34			
Net Condensate Revenue	USD mm	324	28	28	17	23	24	21	20	22	22	21	18	18	16	14	12	10	10			
Total Revenue	USD mm	1,337	97	90	68	95	97	91	89	95	95	93	79	77	69	62	53	45	44			
Royalty	USD mm	(107)	(8)	(7)	(5)	(8)	(8)	(7)	(7)	(8)	(8)	(7)	(6)	(6)	(6)	(5)	(4)	(4)	(3)	-		
Opex	USD mm	(297)	(16)	(21)	(20)	(20)	(18)	(20)	(21)	(19)	(20)	(17)	(18)	(15)	(15)	(15)	(15)	(15)	(15)			
Capex	USD mm	(110)	(20)	(17)	(31)	(11)	(1)	(2)	(25)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	-	-	-			
Hibiscus' Carry of BEE's Capex	USD mm	(42)	(8)	(7)	(12)	(4)	(0)	(1)	(10)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	-	-	-			
Carry Reimbursement to Hibiscus	USD mm	42	8	7	12	4	0	1	10	0	0	0	0	0	0	0	-	-	-			
Overhead Charges	USD mm	19	2	2	2	2	1	1	2	1	1	1	1	1	1	1	1	1	1			
Abex	USD mm	(89)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	(52)	(35)	-
Supplementary Payment	USD mm	(9)	(1)	(1)	(0)	(1)	(1)	(1)	(0)	(1)	(1)	(1)	(1)	(1)	(1)	(0)	(0)	(0)	(0)	-	-	-
Petroleum Income Tax	USD mm	(399)	-	(36)	(33)	(10)	(24)	(32)	(27)	(19)	(36)	(36)	(37)	(30)	(30)	(26)	(23)	(18)	(14)	(13)	29	19
Free Cash Flows from Third Party Gas	USD mm	54	12	8	2	(1)	-	3	3	2	1	2	6	4	4	3	4	3	(0)	(0)		
Free Cash Flows to Hibiscus	**USD mm**	**400**	**66**	**18**	**(17)**	**47**	**46**	**34**	**13**	**51**	**31**	**35**	**23**	**30**	**22**	**19**	**15**	**11**	**9**	**(66)**	**(6)**	**19**
2024 Free Cash Flows to Hibiscus (Closing to 31 Dec)				6																		